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September 23, 2016

Ms. Laurel Ross
Acting Commission Secretary
British Columbia Utilities Commission
Sixth Floor – 900 Howe Street
Vancouver, BC V6Z 2N3

Dear Ms. Ross:

RE: Project No. 3698869
British Columbia Utilities Commission (BCUC or Commission)
British Columbia Hydro and Power Authority (BC Hydro)
F2017-F2019 Revenue Requirements Application (Application)
Supplementary Information regarding Fiscal 2015 and Fiscal 2016 Capital Additions and Forecast Capital Expenditures over the Test Period

At the procedural conference of September 1, 2016, Commission Staff requested further information on our fiscal 2015 and fiscal 2016 capital additions and forecast capital projects over the test period.[1] As agreed to at the Procedural Conference, BC Hydro has since worked with Commission staff to clarify the extent of further information required and is now filing the requested information.

Specifically, Commission staff requested that BC Hydro provide the following additional information:

1. The forecast capital expenditures in each of fiscal 2017, fiscal 2018 and fiscal 2019 for all non-technology capital projects in excess of $20 million and all technology capital projects in excess of $5 million, and
2. For all non-technology capital projects in excess of $20 million and all technology capital projects in excess of $5 million that entered service in fiscal 2015 and fiscal 2016, the following information:
   (a) Capital addition amounts;
   (b) Identification of whether the project was a growth or sustaining capital project;
   (c) Whether the project is exempt from Commission review pursuant to section 11 of Direction 7, and as discussed in section 2.3.1, page 2-7 of the Application; and

[1] See page 302, line 15 to page 303, line 1, Transcript Volume 6.

(d) The in-service date, start of construction date, definition approval date, implementation approval dollar amount, implementation approval in-service date, and authorized amount as of March 31, 2016.

With respect to 2(c) above, BC Hydro determined whether a project is exempt from Commission review pursuant to section 11 of Direction 7 based on the meaning of "extension" used in BC Hydro's existing Capital Filing Guidelines. BC Hydro notes that its Capital Filing Guidelines and the meaning of "extension" will be the subject of the upcoming Capital Expenditures and Projects Review proceeding.

The information requested in number 1 above is provided in the attached Supplemental Appendix I-A, which provides the information originally included in Appendix I that was filed in the Application, with the requested additional information presented in three columns on the right-hand side of the spreadsheet.

In addition, certain information provided in the original Appendix I, related to Transmission project information and Technology project information was incorrect and has been corrected in Supplemental Appendix I-A. Specifically:

- Certain Transmission capital projects referenced Note A in column F of Appendix I, and these have been corrected by Note D in Supplemental Appendix I-A; and
- The Current Pre-Implementation Cost Estimate for the Technology Supply Chain Applications project provided in column K of Appendix I has been corrected by Note 11 in Supplemental Appendix I-A.

These corrections are identified in red type in Supplemental Appendix I-A.

The information requested in number 2 above is provided in the attached Supplemental Appendix I-B.

There were no Distribution capital projects that met the required threshold of greater than $20 million, therefore there are no Supplemental Appendices I-A or I-B for Distribution capital projects.

For further information, please contact Fred James at 604-623-4317 or by email at bchydroregulatorygroup@bchydro.com.

Yours sincerely,

Tom Loski
Chief Regulatory Officer

bh/rh

Enclosure

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August 17, 2016

Ms. Laurel Ross
Acting Commission Secretary
British Columbia Utilities Commission
Sixth Floor – 900 Howe Street
Vancouver, BC V6Z 2N3

Dear Ms. Ross:

RE: Project No. 3698869
British Columbia Utilities Commission (BCUC or Commission)
British Columbia Hydro and Power Authority (BC Hydro)
Fiscal 2017 to Fiscal 2019 Revenue Requirements Application (the Application)

BC Hydro is writing to provide Errata No. 1 to the Application. We note that none of these errata have an impact on the forecasted revenue requirements over the test period or approvals sought in the Application. With this filing we are:

- Correcting some minor typographical and reference errors;
- Replacing Appendix X, as the Application inadvertently included a stale version of Table X-1; and
- Correcting a reference error that has an impact to the OATT rate sheets and has a $0.1 million impact to the Transmission Revenue Requirement in each of fiscal 2018 and fiscal 2019 (this correction has no impact to the Total Rate Revenue Requirement or the Rate Smoothing Account transfers).

We are including in this filing a list of the errata to the Application, with explanatory notes, and revised Chapter and Appendix pages that reflect the impacts of these corrections, with the exception of minor revisions to Appendix A (Financial Schedules). Due to the immaterial impact of the errata to the Financial Schedules and the extensive time and effort required to make changes to the schedules, BC Hydro will issue a revised Schedule A reflecting the adjustments to the Financial Schedules in its compliance filing subsequent to the Decision issued by the Commission on this application.

We apologize for these errata to our Application.

For further information, please contact Fred James at 604-623-4317 or by email at bchydroregulatorygroup@bchydro.com.

Yours sincerely,

(for) Tom Loski
Chief Regulatory Officer

fj/rh

Enclosure

Copy to: BC Hydro F12/F14 Revenue Requirements Application Registered Intervener Distribution List.

Fiscal 2017 to Fiscal 2019
Revenue Requirements Application

ERRATA – August 17, 2016

From the Fiscal 2017 to Fiscal 2019 Revenue Requirements Binder:

REMOVE	INSERT	NOTE
Volume 1		
Page 1-15	Page 1-15 – Revision 1 – August 17, 2016	1
Page 1-23	Page 1-23 – Revision 1 – August 17, 2016	2
Page 1-24	Page 1-24 – Revision 1 – August 17, 2016	3
Page 1-37	Page 1-37 – Revision 1 – August 17, 2016	4
Page 1-38	Page 1-38 – Revision 1 – August 17, 2016	5
Page 1-39	Page 1-39 – Revision 1 – August 17, 2016	6
Page 1-42	Page 1-42 – Revision 1 – August 17, 2016	7
Page 1-44	Page 1-44 – Revision 1 – August 17, 2016	8
Page 4-26	Page 4-26 – Revision 1 – August 17, 2016	9
Page 6-3	Page 6-3 – Revision 1 – August 17, 2016	10
Page 6-4	Page 6-4 – Revision 1 – August 17, 2016	11
Page 6-6	Page 6-6 – Revision 1 – August 17, 2016	11
Page 6-7	Page 6-7 – Revision 1 – August 17, 2016	11
Page 6-72	Page 6-72 – Revision 1 – August 17, 2016	11
Page 6-73	Page 6-73 – Revision 1 – August 17, 2016	11
Page 6-80	Page 6-80 – Revision 1 – August 17, 2016	11

REMOVE	INSERT	NOTE
Page 6-81	Page 6-81 – Revision 1 – August 17, 2016	11
Page 6-83	Page 6-83 – Revision 1 – August 17, 2016	11
Page 6-96	Page 6-96 – Revision 1 – August 17, 2016	11
Page 6-97	Page 6-97 – Revision 1 – August 17, 2016	11
Page 9-1	Page 9-1 – Revision 1 – August 17, 2016	12
Page 9-4	Page 9-4 – Revision 1 – August 17, 2016	13
Page 9-5	Page 9-5 – Revision 1 – August 17, 2016	13
Page 9-16	Page 9-16 – Revision 1 – August 17, 2016	13
Page 9-17	Page 9-17 – Revision 1 – August 17, 2016	13
Page 9-19	Page 9-19 – Revision 1 – August 17, 2016	13
Page 9-20	Page 9-20 – Revision 1 – August 17, 2016	13
Page 10-37	Page 10-37 – Revision 1 – August 11, 2016	14
Volume 2		
Appendix K, Page 18	Appendix K Revision 1 – Page 18 – August 17, 2016	11
Appendix K, Page 19	Appendix K Revision 1 – Page 19 – August 17, 2016	11
Appendix K, Page 20	Appendix K Revision 1 – Page 20 – August 17, 2016	11
Appendix K, Page 28	Appendix K Revision 1 – Page 28 – August 17, 2016	11
Appendix K, Page 35	Appendix K Revision 1 – Page 35 – August 17, 2016	11
Appendix K, Page 36	Appendix K Revision 1 – Page 36 – August 17, 2016	11
Appendix K, Page 37	Appendix K Revision 1 – Page 37 – August 17, 2016	11
Appendix K, Page 40	Appendix K Revision 1 – Page 40 – August 17, 2016	11
Appendix T, Page 16	Appendix T Revision 1 – Page 16 – August 17, 2016	13
Appendix T, Page 17	Appendix T Revision 1 – Page 17 – August 17, 2016	13
Appendix T – Attachment 1, Page 61	Appendix T Revision 1 – Page 61 – August 17, 2016	13
Appendix T – Attachment 1, Page 62	Appendix T Revision 1 – Page 62 – August 17, 2016	13

REMOVE	INSERT	NOTE
Appendix T – Attachment 1, Page 63	Appendix T Revision 1 – Page 63 – August 17, 2016	13
Appendix T – Attachment 1, Page 64	Appendix T Revision 1 – Page 64 – August 17, 2016	13
Appendix T – Attachment 2, Page 30	Appendix T Revision 1 – Page 30 – August 17, 2016	13
Appendix T – Attachment 2, Page 31	Appendix T Revision 1 – Page 31 – August 17, 2016	13
Appendix T – Attachment 2, Page 32	Appendix T Revision 1 – Page 32 – August 17, 2016	13
Appendix T – Attachment 2, Page 33	Appendix T Revision 1 – Page 33 – August 17, 2016	13
Appendix W	Appendix W Revision 1 – August 17, 2016	15
Appendix X	Appendix X, Revision 1 – August 17, 2016	16

Notes:

1. Revised section 1.4.1, page 1-15, line 1 and line 2 to reflect correct amounts in fiscal 2014 and fiscal 2016.
2. On Table 1-1, revised formula reference for Total Percentage Increase and added a line number to the last row (13) of the table. There are no further changes to the values in the table.
3. On Table 1-2, revised all formula references.
4. On Table 1-6, line 7, revised schedule reference. On line 2, line 5 and Total Revenue Requirement line, included formatting edits.
5. On Table 1-7, revised line 7 to reflect correct schedule reference and correct fiscal 2016 RRA amount. There are no further changes to the values in the table. Revised section 1.6.3, line 8 to reflect correct table references.
6. Revised section 1.6.3.2, line 18 to reflect correct table references.
7. Revised section 1.6.3.7, line 12 to reflect the correct amount for fiscal 2016. Revised line 13 to reflect correct table reference. Revised line 16 to reflect the correct amount in fiscal 2019. The previous $26 million reference reflected the combined fiscal 2017 to fiscal 2019 amount.

8. Revised section 1.7.2, line 14 to reflect the Total Revenue Requirements in fiscal 2017. The previous $4,469 million reference reflected the Revenue Recovered under Rate Caps as shown on Table 1-8 rather than the Total Revenue Requirements amount reflected on the same table. The draft Order in Appendix B reflects the Total Revenue Requirements for fiscal 2017 and does not require any revision.
9. Revised section 4.4.2.6, line 10 to correct amounts for fiscal 2017 and fiscal 2018. The fiscal 2017 and fiscal 2018 amounts had been transposed.
10. Revised section 6.2.1, line 20 to state the correct asset category.
11. Revised tables to reflect correct Contribution in Aid amounts including impacted table totals. The replaced amounts are consistent with the Application. Also revised section 6.2.2, line 8 to state the correct asset category.
12. Revised section 9.1, line 4 to reflect correct table reference.
13. Revised Maximum Capacity Supply (MW) amount for fiscal 2017, fiscal 2018 and fiscal 2019 as described in section 9.3.3 on page 9-16, line 15 and 16 to align with the corresponding amounts included in section 3.4.2.1, page 3-32, Table 3-9, line (d). This single change impacts the Network Integration Transmission Service Revenue Requirement and monthly charge and is offset by changes to the Point-To-Point Transmission Service revenue and rates. This correction has no impact to the Total Rate Revenue Requirement or the Rate Smoothing Account transfers. There is a minor impact to the Transmission Revenue Requirement of $(0.1) million in each of fiscal 2018 and fiscal 2019 year and the fiscal 2017 OATT rate sheets are also impacted. The Chapters and Appendices impacted by this correction are submitted in this Errata application and include Chapter 9, Appendix T and Appendix T – Attachment 1. In addition, there are minor impacts (less than $2 million for an individual item) to six schedules in the RRA Model in Appendix A (Schedule 1.0, 3.0, 3.4, 3.5, 8.0 and 15.0. Due to the immaterial impact on the Financial Schedules and extensive time and effort required to change those schedules, BC Hydro will revise and

issue a revised Schedule A reflecting this adjustment in its Compliance filing subsequent to the Decision issued by the Commission on the Application.

14. Revised footnote 77 to reflect correct Appendix reference.
15. Revised Table 1 to 10 in Appendix W to reflect correct table headings.
16. Replaced Appendix X, as the Application included a stale version of the table. This replaced table is consistent with the Application.

BC Hydro
Power smart

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August 17, 2016

Ms. Laurel Ross
Acting Commission Secretary
British Columbia Utilities Commission
Sixth Floor – 900 Howe Street
Vancouver, BC V6Z 2N3

Dear Ms. Ross:

RE: Project No. 3698869
British Columbia Utilities Commission (BCUC or Commission)
British Columbia Hydro and Power Authority (BC Hydro)
Fiscal 2017 to Fiscal 2019 Revenue Requirements Application (the Application)
Evidentiary Update

BC Hydro writes to file this Evidentiary Update to update the Application with the following three items, which result in no change to BC Hydro's Forecast revenue requirements on approvals sought over the test period:

- **Order in Council (OIC) No. 589 issued on July 28, 2016 (Attachment No. 1):** OIC No. 589 amends Heritage Special Direction No. HC1 concerning BC Hydro's dividend payable to the Province for fiscal 2017 (payable on or before June 30, 2017). OIC No. 589 results in no change to BC Hydro's forecast revenue requirements over the test period or its approvals sought in the Application;
- **OIC No. 590 issued on July 28, 2016 (Attachment No. 2):** OIC No. 590 amends Direction No. 7 to specify the amount of BC Hydro's distributable surplus over each fiscal year of the test period and subsequent fiscal years. The amounts specified by OIC No. 590 align with those included in BC Hydro's Application. However, OIC No. 590 does result in minor reductions from BC Hydro's forecast distributable surpluses in each year of the test period due to OIC No. 590 not including decimal places, whereas BC Hydro's forecast is made to the first decimal place. BC Hydro proposes to update its financial schedules for these minor reductions in its compliance filing following the Commission's Decision in this proceeding. Otherwise, OIC No. 590 results in no change to BC Hydro's forecast revenue requirements over the test period or its approvals sought in the Application; and
- **BC Hydro's Report on Demand Side Management Activities for Fiscal 2016 (Attachment No. 3):** This report was filed with the Commission on August 5, 2016 in accordance with past Commission directions. The report results in no change to

BC Hydro's forecast revenue requirements over the test period or approvals sought in the Application, including its proposed demand-side management plan.

These three items are described further below.

1 OIC No. 589 (Attachment No. 1): Dividends Payable Pursuant to Heritage Special Directive No. HC1, as Amended

OIC No. 589 was issued by the Province to BC Hydro on July 28, 2016 and concerns BC Hydro's dividends payable to the Province.

BC Hydro's dividend payable is calculated in accordance with section 3 of Heritage Special Directive No. HC1, as amended.[1] For fiscal 2017, section 3 of Heritage Special Directive No. HC1 requires a dividend payable equal to 85 per cent of BC Hydro's net income provided that such a payment will not cause BC Hydro's debt/equity ratio to exceed 80:20. If such a payment would cause BC Hydro's debt/equity ratio to exceed this level, then the payment is the maximum that can be made without exceeding this level.

OIC No. 589 amends section 3 of Heritage Special Directive No. HC1 by adding the requirement that the dividend payable for fiscal 2017 (payable by June 30, 2017) must be "an amount not less than $259 million". This results in no change to BC Hydro's revenue requirements over the test period for the reasons explained below.

BC Hydro's current forecast for the dividend payable for fiscal 2017 is $271 million, as set out in the financial schedules included in Appendix A of the Application. This amount is subject to change throughout the fiscal year primarily due to changes in debt balances. The actual dividend payable for fiscal 2017 will not be determined until after the completion of the financial statements for the year. If the actual dividend payable for fiscal 2017 is different than $271 million, the resulting lower or higher finance charges required to pay the dividend will form part of the variance to be deferred to the Total Finance Charges Regulatory Account. OIC No. 589 specifies that the final dividend payable for fiscal 2017 will not be lower than $259 million, which is the same amount that is in the Province's *Budget 2016*.

For fiscal 2018 and subsequent years, Heritage Special Directive No. HC1, as amended, specifies that the dividends payable by BC Hydro will be reduced by $100 million per year from the dividend payable in the immediately preceding fiscal year until it reaches zero and will thereafter remain at zero until BC Hydro achieves a debt/equity ratio of 60:40.[2] As this was already a component of Heritage Special Directive No. HC1, BC Hydro's current forecast reflects this mechanism.

---

1 See OIC No. 095, included in Appendix C of the Application.

2 On page 1-15, line 21 of the Application, BC Hydro incorrectly attributed this requirement of Heritage Special Direction No. HC1 to Direction No. 7.

2 OIC No. 590 (Attachment No. 2): Distributable Surplus Pursuant to Direction No. 7

OIC No. 590 was issued by the Province to the Commission on July 28, 2016 and concerns the distributable surplus (i.e., allowed net income) to be earned by BC Hydro.

BC Hydro's distributable surplus is calculated in accordance with section 4 of Direction No. 7 to the Commission. Section 4(d) of Direction No. 7 required a distributable surplus calculated based on a specified percentage rate of return on deemed equity.

OIC No. 590 repeals section 4(d) of Direction No. 7 and sets specific amounts for the distributable surplus to be earned in fiscal 2017, fiscal 2018 and fiscal 2019 and subsequent fiscal years. Specifically, OIC No. 590 requires that the Commission must allow BC Hydro to collect sufficient revenue in a fiscal year to achieve an annual rate of return on deemed equity that would be necessary to yield a distributable surplus of: (i) $684 million in fiscal 2017; (ii) $698 million in fiscal 2018; and (iii) $712 million in fiscal 2019 and subsequent fiscal years.

The amounts specified by OIC No. 590 for the distributable surpluses align with those included in the financial schedules in Appendix A of the Application. This is because the amounts set by OIC No. 590 in each of fiscal 2017, fiscal 2018 and fiscal 2019 result from the calculation previously included in section 4(d) of Direction No. 7. However, there are minor differences due to OIC No. 590 not including decimal places, whereas BC Hydro's forecast of the distributable surplus is made to the first decimal place. OIC No. 590 therefore results in minor reductions from BC Hydro's current forecast of the distributable surpluses over the test period. BC Hydro proposes to update its financial schedules for these minor reductions in its compliance filing following the Commission's Decision in this proceeding.

For fiscal 2020 and subsequent years, the distributable surplus is fixed by OIC No. 590 at the fiscal 2019 amount of $712 million. Previously under section 4(d) of Direction No. 7, the distributable surplus for fiscal 2020 and subsequent years would have grown at the rate of forecast growth in the British Columbia Consumer Price Index. Hence, the distributable surplus for fiscal 2020 and beyond will be less than would have been the case before OIC No. 590. As fiscal 2020 is outside the test period of the Application, this change has no impact on BC Hydro's forecast revenue requirements in the test period.

The narratives in the Application describing the calculation of distributable surpluses under Direction No. 7 reflect Direction No. 7 as it read prior to OIC No. 590. These narratives are located on the following pages of the Application:

- Page 1-15, lines 15 to 19;
- Page 2-6, line 21 to page 2-7, line 3;
- Page 2-20, Table 2-6, ROE, Synopsis, and
- Page 8-6, lines 7 to 14.

Generally, these portions of the Application have been superseded by the description provided above of the distributable surpluses pursuant to the amendments to Direction No. 7 made by OIC No. 590.

3 BC Hydro's Report on Demand Side Management Activities for Fiscal 2016 (Attachment No. 3)

Appendix Y to the Application contains the reports on demand side management activity for each of fiscal 2014 and fiscal 2015. In Appendix Y – Attachment 3, BC Hydro indicated that it would provide its fiscal 2016 report upon its completion later in 2016.

BC Hydro's Report on Demand-Side Management Activities for Fiscal 2016 was filed with the Commission on August 5, 2016. BC Hydro is attaching the fiscal 2016 report with this Evidentiary Update. For ease of reference, the fiscal 2016 report may be inserted into a hard copy of the Application as Appendix Y – Attachment 3 of the Application.

For further information, please contact Fred James at 604-623-4317 or by email at bchydroregulatorygroup@bchydro.com.

Yours sincerely,

(for) Tom Loski
Chief Regulatory Officer

fj/rh

Enclosure

Copy to: BCUC BC Hydro F12/F14 Revenue Requirements Application Registered Intervener Distribution List.

BC Hydro
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July 28, 2016

Ms. Laurel Ross
Acting Commission Secretary
British Columbia Utilities Commission
Sixth Floor – 900 Howe Street
Vancouver, BC V6Z 2N3

Dear Ms. Ross:

RE: Project No. 3698869
British Columbia Utilities Commission (BCUC or Commission)
British Columbia Hydro and Power Authority (BC Hydro)
Fiscal 2017 to Fiscal 2019 Revenue Requirements Application

BC Hydro writes further to Commission Order No. G-40-16 enclosing its Fiscal 2017 to Fiscal 2019 Revenue Requirements Application.

Communications regarding this application are to be addressed to:

Tom Loski Chief Regulatory Officer BC Hydro 1600-333 Dunsmuir Street Vancouver, BC V6B 5R3 Telephone: 604-623-4046 Fax: 604-623-4407 Email: bchydroregulatorygroup@bchydro.com	Matthew Ghikas Legal Counsel Fasken Martineau 2900-550 Burrard Street Vancouver, BC V6C 0A3 Telephone: 604-631-3191 Fax: 604-631-3232 Email mghikas@fasken.com	Christopher Bystrom Legal Counsel Fasken Martineau 2900-550 Burrard Street Vancouver, BC V6C 0A3 Telephone: 604-631-4715 Fax: 604-631-3232 Email cbystrom@fasken.com

For further information, please contact the undersigned.

Yours sincerely,

Tom Loski
Chief Regulatory Officer

tl/af
Enclosure

Copy to: BCUC F12/F14 Revenue Requirements Application Registered Intervener Distribution List.

BC Hydro
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Chapter 6. Capital Expenditures and Additions

Chapter 7. Deferral and Other Regulatory Accounts

Chapter 10. Demand Side Management Expenditures

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Fiscal 2017 to Fiscal 2019
Revenue Requirements Application

Chapter 1

Application Overview

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1.1 Introduction

1.1.1 Application – Prudent Actions to Deliver Affordable, Reliable and Clean Electricity for Our Customers

British Columbia Hydro and Power Authority (**BC Hydro**) files this Revenue Requirements Application requesting final British Columbia Utilities Commission approval of rates for a three-year test period of fiscal 2017, fiscal 2018 and fiscal 2019.[1]

British Columbia has among the lowest rates in North America, highest reliability in Canada and last year, over 98 per cent of the electricity generated in the province was clean. BC Hydro's generating facilities and transmission and distribution system were built mostly in the 1960s, 1970s and 1980s and BC Hydro continues to forecast long-term load growth across all customer classes. In 2013, BC Hydro set out a 10 Year Rates Plan to keep rates low and predictable even in the face of an unprecedented program to refurbish and expand our system.

On March 22, 2016, the British Columbia Utilities Commission approved an interim increase of 4.0 per cent effective April 1, 2016.[2] BC Hydro is now requesting permanent general rate increases of 4.0 per cent on April 1, 2016, 3.5 per cent on April 1, 2017 and 3.0 per cent on April 1, 2018. These general rate increases reflect the cap on rates as set out in BC Hydro's 2013 10 Year Rates Plan and as directed by section 9 of Direction No. 7 to the British Columbia Utilities Commission (refer to Appendix C).

The proposed rates and revenue requirements in this Application reflect BC Hydro's significant effort to manage and control its costs in order to deliver on the 2013 10 Year Rates Plan covering fiscal years 2015 to 2024, despite forecasting approximately $3.5 billion less revenue over that period compared to the

1 BC Hydro's fiscal year runs from April 1 to March 31.
2 British Columbia Utilities Commission Order No. G-40-16.

assumptions at the time the 10 Year Rates Plan was announced, due to several factors, including a recent decline in the rate of industrial customer load growth (attributable in part to declining commodity prices for their products and the delay in the final investment decision for Liquefied Natural Gas (**LNG**) projects).

The 2013 10 Year Rates Plan is built on the basis of average rate increases of 2.6 per cent in the last five years of the plan from fiscal 2020 to fiscal 2024, including the full recovery of the balance in the Rate Smoothing Regulatory Account (which captures the unrecovered portion of the revenue requirements from the earlier years of the 2013 10 Year Rates Plan).

This application describes a number of steps that BC Hydro has taken, and will continue to take, to achieve the targets of the 2013 10 Year Rates Plan. Since the introduction of the 2013 10 Year Rates Plan BC Hydro has, among other things:

- Restructured its operations to support strong delivery of key outcomes;
- Initiated a Workforce Optimization program to replace external contractors with internal staff to reduce costs and/or improve outcomes;
- Initiated a Work Smart program which has resulted in a gain of 22,500 annual hours of capacity;
- Prioritized capital spending to maintain system reliability and meet emerging need;
- Modernized and improved the cost-effectiveness of its demand-side management plans;
- Targeted renewal of expiring Independent Power Producer **(IPP)** contracts at prices less than what they are currently paid, recognizing that those producers have typically recovered most of their capital costs over their original contract terms; and

- Undertaken several initiatives, including a base budget review, to manage operating costs to offset the impacts of inflation and other cost pressures.

Despite these steps, the recent decline in the rate of industrial customer load growth posed a new and significant impediment to achieving the 2013 10 Year Rates Plan. BC Hydro delayed the filing of this three-year Application (originally scheduled for late February 2016) in order to determine the impact of these developments on our demand and revenue forecast. BC Hydro then identified additional cost saving opportunities in order to ensure that we remained on track to meet the 2013 10 Year Rates Plan. In the intervening period, BC Hydro has amended its plans from what it was expecting to file in February 2016, in order to:

- Reduce forecast capital expenditures by $381.2 million, capital additions by $392.5 million and dismantling costs by $70 million from fiscal 2017 to fiscal 2019;
- Reduce forecast finance charges, including by employing a debt management strategy for future debt that could yield savings of approximately $45 million over the three-year test period; and
- Find additional operating cost savings so that base operating costs increases could be limited to an average of only 1.2 per cent per year.

As part of this recent examination, BC Hydro also identified a number of steps that will not affect the test period, but would be implemented in the latter years of the 2013 10 Year Rates Plan to further offset pressure presented by the recent decline in the rate of industrial load growth. For example, BC Hydro is currently reviewing the Standing Offer Program to reflect the declining costs of new power technology and changing system needs.

Consistent with section 9 of Direction No. 7, BC Hydro is requesting that the balance of its revenue requirement that is not forecast to be recovered by the proposed rates be recorded in the Rate Smoothing Regulatory Account. BC Hydro is also seeking approval of the use of certain regulatory accounts and the acceptance of the expenditures on demand-side management that BC Hydro anticipates making from fiscal 2017 to fiscal 2019. The orders sought are listed in section 1.7, and the Draft Order is included in Appendix B.

With the approvals sought in this Application, and with the additional steps contemplated for the years beyond this test period, BC Hydro is forecasting to be able to meet the targets in its 2013 10 Year Rates Plan and deliver on its key goals and priorities discussed in this Application.

1.1.2 Chapter Structure

This Chapter is intended to provide a high level overview of the context for this Application, and the key components and drivers of the revenue requirements. The Chapter is organized as follows:

- Section 1.2 describes BC Hydro and its mandate, highlighting factors that inform how BC Hydro is balancing considerations of reliability, affordability, customer service, load growth, safety and security in the current context;
- Section 1.3 summarizes key elements of BC Hydro's operating environment related to reliability, service, load growth that continue to place upward pressure on rates and costs;
- Section 1.4 explains how the 2011 Government Review and the 2013 10 Year Rates Plan has informed this Application;
- Section 1.5 explains how BC Hydro is taking steps necessary to position it to keep rates low as set out in the 2013 10 Year Rates Plan while continuing to deliver upon the other elements of our corporate mission;
- Section 1.6 provides an overview of the fiscal 2017 to fiscal 2019 revenue requirements, including the cost drivers over the test period and cost control measures and budget reductions partially offsetting those drivers;

- Section 1.7 describes the specific approvals that BC Hydro is requesting from the British Columbia Utilities Commission;
- Section 1.8 lays out a proposed regulatory timetable that will take the process to the stage of responding to two rounds of Information Requests;
- Section 1.9 sets out the Application structure; and
- Section 1.10 provides contact information for communications regarding the Application.

1.2 BC Hydro and Its Corporate Mission

In this section we provide a high level overview of BC Hydro's operations and corporate mission.

1.2.1 BC Hydro is a Large and Complex System

BC Hydro is a Crown corporation established under the *Hydro and Power Authority Act*. BC Hydro is the third largest electric utility in Canada with a customer base serving 95 per cent of British Columbia's population in a service area that encompasses most of British Columbia with the exception of the City of New Westminster (which provides its own service) and the south-central part of the province served by FortisBC Inc. BC Hydro has approximately 1.9 million customer accounts representing service to approximately 4.0 million people and businesses.

BC Hydro's system includes 30 hydroelectric generating facilities, two natural gas-fired generating facilities and 127 IPP projects with whom BC Hydro contracts to purchase energy.

BC Hydro delivers electricity over 78,000 kilometers of transmission and distribution lines. The transmission system includes facilities used to transmit electricity, usually at voltages greater than 69 kilovolts (**kV**); and the distribution system includes electrical lines, cables, transformers and switches used to distribute electricity from substations to customers, generally at voltages lower than 69 kV.

The peak demand on BC Hydro's integrated system in fiscal 2016 was 9,602 megawatts (**MW**), which includes sales by BC Hydro to other utilities such as the City of New Westminster and FortisBC Inc. The total integrated system gross energy requirement, including sales by BC Hydro to other utilities, was 55,345 Gigawatt Hours (**GWh**) in fiscal 2016. The off-grid, Non-Integrated Areas demand adds another 328 GWh resulting in 55,674 GWh of total gross requirement.

BC Hydro's powers and mandate to generate, conserve, acquire and supply electricity are set out in the *Hydro and Power Authority Act*. As a provincial Crown corporation, the owner and sole shareholder of BC Hydro is the Province of British Columbia. BC Hydro reports to Government through the Minister of Energy and Mines. The legal and regulatory regime under which BC Hydro operates is described more fully in Chapter 2.

1.2.2 Our Mission – Provide Our Customers with Reliable, Affordable, Clean Electricity, Safely

BC Hydro's mission is to provide our customers with reliable, affordable, clean electricity throughout B.C., safely. BC Hydro's Fiscal 2017 – Fiscal 2019 Service Plan (found in Appendix E and also discussed in Chapter 2) identifies four key goals that reflect what success will look like when we deliver on our mission:

1. Customers will experience reliable electricity and responsive service;
2. Rates will continue to be affordable;
3. We will fulfill the province's commitment to lead with clean and renewable power; and
4. Our workforce and the public will be safe.

BC Hydro has set performance measures for each of its key goals and will be working towards meeting these goals over the next three years. These performance measures are set out in Chapter 2 in Table 2-1 to Table 2-5 in the section that discusses our Service Plan.

1.3 Key Elements of BC Hydro's Operating Environment

We summarize below a number of the factors related to reliability, service, changing demand and load growth, First Nations, safety, security and technology that continue to influence our business planning and costs over the test period.

1.3.1 We Are Maintaining System Reliability and Integrity with Aging Infrastructure

BC Hydro's generation facilities and transmission and distribution system were built mostly in the 1960s, 1970s and 1980s. The average age of our hydroelectric facilities is over 45 years and 400,000 transmission and distribution assets require remediation or replacement within ten years. Reinvestment in these facilities is required to ensure customers continue to receive safe and reliable power, consistent with BC Hydro's track record of reliability as described in section 2.3.7.1 of Chapter 2.

The need to maintain and refurbish many of BC Hydro's aging assets has been identified and explored in previous BC Hydro revenue requirement applications to the British Columbia Utilities Commission. BC Hydro's fiscal 2017 to fiscal 2019 capital plans reflect the continuing importance of reinvesting in the electric system assets for the long-term benefit of customers.

Chapter 6 provides details of BC Hydro's capital planning processes, capital delivery structure and capital plans for the next three years. In addition, in Appendix G we provide our 10 Year Capital Forecast.

1.3.2 Our Customers' Expectations are Changing

BC Hydro has always been focused on customers and the need to provide them with a reliable supply of electricity. The generation and transmission and distribution systems are designed, built and maintained with that purpose in mind. However, changing technology is affecting customer expectations and how they view their experience with BC Hydro. Customers now prefer "low-touch" digital (web/mobile) channels and their expectations of service from BC Hydro have grown beyond simply keeping the lights on. Electric vehicles and home energy management systems are increasing in popularity. Personalized services are becoming the norm, not the exception in all industries. Consequently, we are focusing on how BC Hydro interacts with customers and are adopting a new customer strategy discussed further in Chapter 5 (section 5.5.1). This strategy includes building a more accessible and responsive culture and tone as well as improving service in key customer-facing functions such as interconnections.

1.3.3 We Have Responded to Changing Demand and Load Resource Balance

BC Hydro's revenue requirement is a function of the forecast load on the system. BC Hydro continues to forecast long-term growth in its load forecast for each of the residential, light industrial/commercial and large industrial sectors. However, while still reflecting growth, this load forecast is lower than the forecasts in the 2013 Integrated Resource Plan which were used as an input into the 2013 10 Year Rates Plan. Developments in recent months have amplified this issue and illustrate the fact that load forecasting is inherently an uncertain undertaking. The lower load forecast upon which this Application is based has prompted BC Hydro to take additional cost control measures discussed later in this chapter in section 1.5 in order to remain on track to meet the targets set out in the 2013 10 Year Rates Plan.

The residential and light industrial/commercial sectors represent about two thirds of BC Hydro's domestic demand. The load forecast shows that the demand growth in these two sectors tends to be steady as it is driven by growth in population and general economic trends. The large industrial sector makes up the remaining one third of BC Hydro's domestic demand. This sector has historically exhibited variability in its load due to factors such as fluctuations in global commodity demand. Demand uncertainty in this sector is expected to persist.

The main sources of the reduced growth forecast for the residential and light industrial/commercial sector is lower growth projections in economic drivers such as housing starts. For the industrial sector, the lower forecast is due to lower commodity prices. The lower commodity prices have resulted in a reduced outlook for the pulp and paper and mining sectors as well as delayed forecast in-service dates for several mining, and oil and gas projects and reduced expectations for potential new mining and oil and gas loads.

The LNG sector faces uncertainty with regard to possible future load. FortisBC Energy Inc. is currently constructing an expansion of its all-electric Tilbury Island LNG facility. Further expansion at Tilbury is possible, but will depend on market conditions. Two other potential LNG projects, LNG Canada and Woodfibre LNG, are currently expected to take service from BC Hydro. If all of these three LNG developments move forward, the resulting demand will be close to the 3,000 GWh/year of expected total LNG demand included in the 2013 Integrated Resource Plan and the 2013 10 Year Rates Plan. However, as timelines for LNG final investment decisions have been delayed, BC Hydro expects less revenue from LNG customers during the 2013 10 Year Rates Plan period. BC Hydro's load forecast includes the announced loads and in-service dates for these three developments.[3]

On February 5, 2016, the Province announced a five-year Mining Customer Payment Plan program, under which major mines would be allowed to defer payment of up to 75 per cent of two years' worth of their electricity bills, with repayment plus interest as commodity prices recover. This arrangement is expected to mitigate some of the impact of low commodity prices on load; however, the exact extent to which this arrangement will prevent load loss that otherwise would have occurred, is unknown.

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3 On July 11, 2016 LNG Canada announced that it has delayed its final investment decision beyond December 2017, however, this has not been reflected in this Application as the impact is not yet known.

BC Hydro has responded to the updated load forecast with new initiatives to reduce costs in order to remain on track to achieve the targets in the 2013 10 Year Rates Plan. Some of these initiatives have impacts in the test period and are discussed in this Application and others would be implemented in future years.

With the updated load forecast, BC Hydro has also updated its Load Resource Balance. The Load Resource Balance is the difference between BC Hydro's forecast load (demand) and forecast supply. There have been some key changes since the 2013 Integrated Resource Plan was approved with respect to:

- The load forecast (as discussed above);
- Our demand-side management (conservation) savings;
- Forecasted IPP supply;
- The impact of major maintenance work on BC Hydro's capacity resources; and
- Assumption that no North Coast capacity additions will take place prior to the end of fiscal 2024. BC Hydro continues to assess regional considerations which will inform future decisions on resource acquisitions outside the 2013 10 Year Rates Plan period.

Section 3.4, Chapter 3 discusses both the 2013 Integrated Resource Plan and the updated Load Resource Balance and concludes that despite the changes in the Load Resource Balance the Recommended Actions from the 2013 Integrated Resource Plan are generally still appropriate for BC Hydro.

1.3.4 Customer Driven Growth is Necessitating Capacity Investments

While BC Hydro is now forecasting a lower rate of growth in industrial load, overall forecast demand for electricity continues to increase as a result of a growing population and economy. Demand is forecast to increase by 39 per cent over the next 20 years before demand-side management and with LNG and 29 per cent after demand-side management, with LNG. There are regions of the province where

BC Hydro's system is reaching its capacity to reliably serve customers. Growth in some sectors of the economy is also driving a need to reinforce our system in certain regions of the province that do not have adequate infrastructure in place to provide reliable service. Increased customer load in Northeast B.C., Metro Vancouver and in the Okanagan is driving investments in system reinforcement and customer connections. Capital investment in these areas has caused increases to BC Hydro's revenue requirements during the test period and the remaining years of the 2013 10 Year Rates Plan. (Refer to Chapter 6 and Appendices I and J for details of BC Hydro's forecast capital expenditures).

1.3.5 Our Commitment to First Nations

BC Hydro's Statement of Aboriginal Principles set out in Chapter 5 (section 5.6.5) guides our dealings with First Nations. The legal landscape with regard to First Nations is changing and First Nations expectations are rising with respect to how BC Hydro addresses their priorities. BC Hydro's operating footprint will continue to expand on traditional First Nations territory as it continues to build and fulfill the capital plan. BC Hydro must work to ensure that the Crown meets its legal obligation to consult, mitigate impacts, and if necessary accommodate, First Nations in circumstances where BC Hydro's proposed actions have the potential to impact a First Nation's asserted rights or title. BC Hydro's dealings with, and commitments to, First Nations are discussed further in Chapter 5, section 5.6.5 and Chapter 6, section 6.4.3.

1.3.6 Our Commitment to Safety

Operating an electrical generation, transmission and distribution system is inherently hazardous. BC Hydro is continually looking for ways to improve its safety record, and must do better. Table 2-5 in Chapter 2, section 2.3.6.4 shows that BC Hydro continues to have difficulty in meeting the most critical safety targets for Zero Fatality and Serious Injury and Lost Time Injury Frequency measures. Further investment in safety is required in the near term, and BC Hydro has placed a priority on safety-related initiatives during the test period. Safety is discussed further in Chapter 5, section 5.7.6.

1.3.7 The Ongoing Task of Meeting Mandatory Reliability Standards

Mandatory and enforceable reliability standards (**Mandatory Reliability Standards**), as approved by the British Columbia Utilities Commission, include requirements for security of generation assets and the transmission system. BC Hydro has developed and implemented plans for emergency response (including civil disobedience and terrorism), critical infrastructure protection and real-time operations. We will continue to refine these plans to meet any changes to the standards as required by the British Columbia Utilities Commission.

BC Hydro has built a strong reliability standards program with a culture of compliance. Implementing the standards, while adding costs, has also made BC Hydro's maintenance program more effective, has streamlined planning and operational processes and has ensured a consistent level of cyber and physical security in relation to critical assets. However, the task is ongoing. It is necessary to enhance cybersecurity platforms and develop new solutions to provide data loss prevention, advanced malware protection and next generation firewall capabilities, as discussed further in Chapter 5 (section 5.2.1) and Chapter 6 (section 6.5.5).

1.3.8 Our Technology Focus

Information Technology supports many of BC Hydro's key business functions, such as resource and plant management, engineering and design, project management, supply chain, work planning and scheduling, power restoration, billing and customer service and operational support. Capital investment is needed over fiscal 2017 to fiscal 2019 to support, maintain, extend and improve BC Hydro's hardware, software and telecommunications assets.

During the test period, technology expenditures will be particularly focused on improving services to customers, improving how our work is executed and increasing the resilience of our systems. Capital expenditures will be made to maintain and upgrade data centre computing, storage and network capacity to support continued growth and enhancements. BC Hydro also plans to develop a new supply chain system, an application for which will be filed with the British Columbia Utilities Commission for their review. BC Hydro's technology expenditures are discussed further in Chapter 5 (section 5.5.7.) and Chapter 6 (section 6.5.5). BC Hydro annually prepares a Five-Year Technology Strategic Plan, the current version of which is included in Appendix O.

1.4 Government Review, 2013 10 Year Rates Plan and Cost Control

The 2011 Government review of BC Hydro and the 2013 10 Year Rates Plan, discussed below, provide additional context for this Application. BC Hydro has already undertaken and initiated important steps to reduce costs and position ourselves to meet the challenge posed by the 2013 10 Year Rates Plan. Those initiatives are reflected in the forecast revenue requirements over the test period.

1.4.1 2011 Government Review and Steps Taken In Response

In March 2011, BC Hydro filed its Fiscal 2012 - Fiscal 2014 Revenue Requirements Application. In the Fiscal 2012 - Fiscal 2014 Revenue Requirements Application BC Hydro was focused on the significant investment program required to renew and upgrade BC Hydro's infrastructure to ensure the continued delivery of safe and reliable electricity to customers and the impact that those investments would have on rates. BC Hydro was also facing cost pressures due to inflation, customer growth and improving public, employee and contractor safety. BC Hydro's initial Fiscal 2012 - Fiscal 2014 Revenue Requirements Application requested rate increases of 13.89 per cent, 5.33 per cent and 6.81 per cent that were to be smoothed to annual increases of 9.73 per cent by way of a rate smoothing regulatory account.

The British Columbia Utilities Commission suspended the Fiscal 2012 - Fiscal 2014 Revenue Requirements Application proceeding while Government undertook a review of BC Hydro to reduce the proposed rate increases. The Government appointed a panel of senior Government officials to conduct the review of BC Hydro to evaluate and make recommendations with respect to:

1. BC Hydro's governance framework, including organizational structure and business planning;
2. BC Hydro's financial performance, including forecasting, operating costs and cost containment strategies, capital planning and expenditure strategies, and rate structures; and
3. Other matters that the panel deemed important.

In June 2011 the review panel provided its report to the Premier and Minister of Energy, Mines and Natural Gas. The report included 50 recommendations directed to BC Hydro on a range of matters from operational efficiencies to capital planning, procurement and rate structures. It also included six recommendations to be implemented by Government.

BC Hydro took a number of steps during the course of the review, and following the issuance of the panel's report, that enabled its proposed rate increase for the fiscal 2012 to fiscal 2014 period to be reduced from 32 per cent to 16 per cent over the three years. BC Hydro completed implementation of all of the panel's recommendations by March 2014, including reducing operating costs by $391 million over a three-year period, reprioritizing capital expenditures, and eliminating approximately 800 positions mainly from non-operational functions and adding approximately 150 positions to operational front-line functions for a net reduction of approximately 650 positions.

In addition to fulfilling the Government review recommendations, during the last two years BC Hydro has restructured and changed how we are doing business. The number of executives and senior managers has been reduced from ~~80~~ 73 at the end of fiscal 2014 to ~~72~~ 63 as at the end of fiscal 2016. BC Hydro has implemented a Work Smart program that uses Lean methodology[4] to identify opportunities to make internal processes more efficient. BC Hydro has also undertaken a Workforce Optimization program to assess the potential to replace contracted resources with internal staff to reduce costs and assure internal control of key functions.

Government has carried out the six recommendations contained in the report that were directed to it. These were:

- ***Adjusting the self-sufficiency policy***: Order in Council 035 was issued on February 2, 2012 amending Special Direction No. 10 to the British Columbia Utilities Commission in order to change the definition of "critical water conditions" to "average water conditions", reducing the extent of BC Hydro's need for additional energy resources;
- ***Changing the calculation of BC Hydro's return on equity and dividend:*** Pursuant to Direction No. 7, BC Hydro's return on equity for fiscal 2017 will remain at 11.84 per cent. However, starting in fiscal 2018 BC Hydro will no longer earn a return on its deemed equity, but instead will earn what is required to yield a distributable surplus in fiscal 2018 and future years equal to the previous year's distributable surplus plus B.C. inflation. The result of this change is a reduction in the percentage rate of return on equity. In addition, beginning in fiscal 2018, Direction No. 7 requires that BC Hydro's dividend will begin to be reduced by $100 million per year until it reaches zero, and will not resume until BC Hydro reaches a debt/equity ratio of 60:40;
- ***Water Rental Rates***: In fiscal 2018 the Tier 3 water rental rate will be eliminated and this is reflected in the revenue requirements sought in the Application; and

[4] Refer to section 5.3.1.2.

- ***Rate Design***: Three of the recommendations completed by Government were related to the design of BC Hydro's rates and are not relevant to this Application.

Overall, the positive steps taken by BC Hydro and Government in response to the 2011 Government Review positioned BC Hydro to move forward with a longer term rates plan.

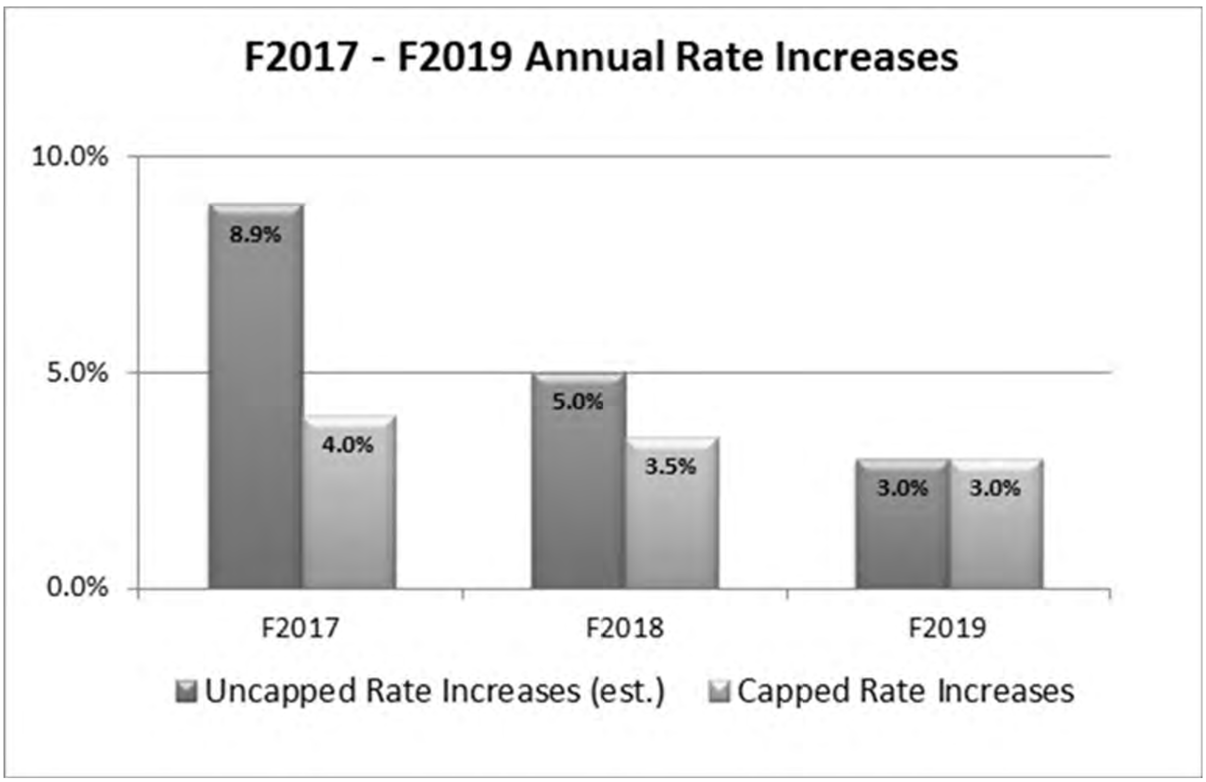
1.4.2 The 2013 10 Year Rates Plan

Building on the implementation of the 2011 review recommendations, BC Hydro worked with Government on further opportunities to reduce pressure on BC Hydro's rates. In November 2013 BC Hydro and the Minister of Energy and Mines announced a 2013 10 Year Rates Plan to balance the objectives of keeping rates as low as possible and funding needed investments. Among the actions decided upon in developing the 2013 10 Year Rates Plan were reductions in planned capital expenditures from an average of $2.1 billion to $1.7 billion per year (not including Site C); eliminating a further 341 non-operational positions, and terminating or deferring 27 electricity purchase agreements with IPPs by mutual agreement.

In the first two years of the 2013 10 Year Rates Plan (i.e., fiscal 2015 and fiscal 2016) rate increases of 9 per cent and 6 per cent were prescribed by Direction No. 6. BC Hydro's revenue requirements in these years were in excess of the revenue collected from its customers under the prescribed rate increases. The difference between the amount collected in rates and the overall forecast revenue requirements was recorded in the Rate Smoothing Regulatory Account as prescribed by Direction No. 6, section 3(u).

The test period of this Application represents the third, fourth and fifth years of the 2013 10 Year Rates Plan. The rate increases over the test period are limited by Direction No. 7 to no more than 4.0 per cent, 3.5 per cent and 3.0 per cent for fiscal 2017, fiscal 2018 and fiscal 2019, respectively. Over the three-year test period, BC Hydro's forecast revenue requirements as originally planned are higher than the revenue to be recovered under the maximum rate increases. If the caps on rate increases set out in Direction No. 7 were not in place, it is estimated that BC Hydro's proposed rate increases for these years would have been 8.9 per cent, 5.0 per cent and 3.0 per cent respectively. Figure 1-1 illustrates the annual rate increases with and without the Rate Smoothing Regulatory Account. Pursuant to Direction No. 7, the difference between the amount collected in rates and BC Hydro's overall allowed forecast revenue requirements is recorded in the Rate Smoothing Regulatory Account.

Figure 1-1 Annual Rate Increases With and Without Rate Smoothing Regulatory Account



The final five years of the 2013 10 Year Rates Plan target rate increases of 2.6 per cent in each of fiscal 2020 to fiscal 2024, subject to British Columbia Utilities Commission review and approval. The 2013 10 Year Rates Plan also includes fully recovering the balance in the Rate Smoothing Regulatory Account at the end of fiscal 2024.

The targets in the latter years of the 2013 10 Year Rates Plan and the requirement to recover the Rate Smoothing Regulatory Account balance by fiscal 2024 have direct implications for the current Revenue Requirements Application. Any transfers to the Rate Smoothing Regulatory Account over this test period will be recovered over the remaining years of the 2013 10 Year Rates Plan. In order to meet this challenge, BC Hydro has taken a number of steps summarized in section 1.5 below including restructuring, prioritizing capital spending, undertaking Workforce Optimization, reducing costs and making changes to our energy portfolio.

Government's steps to legislatively limit the return on equity component of BC Hydro's rates and reduce the dividend payable to Government are a key component of the 2013 10 Year Rates Plan. Government has also fixed the Deferral Account Rate Rider at 5 per cent for the duration of the 2013 10 Year Rates Plan, and stipulated that the amount of the forecast revenue from the Deferral Account Rate Rider above the amount applied to reduce the balance of the Cost of Energy Deferral Accounts be reflected as revenue.[5] BC Hydro provides more detail with regard to the allocation of revenue from the Deferral Account Rate Rider in section 7.5.1 of Chapter 7.

The proposed rates and revenue requirement in this test period place BC Hydro on track to meet the targets set by the 2013 10 Year Rates Plan.

1.5 Restructuring, Additional Cost Control and Prioritization

This Application describes a number of steps that BC Hydro has taken, and will continue to take, to achieve the targets of the 2013 10 Year Rates Plan while

5 Direction No. 7, section 10.

continuing to deliver safe, reliable and responsive service. Since the introduction of the 2013 10 Year Rates Plan, BC Hydro has, among other things:

- Restructured its operations;
- Undertaken several initiatives to manage operating costs to offset the impacts of inflation and other cost pressures;
- Reduced forecast finance charges by employing a debt management strategy for future debt that could yield savings of approximately $45 million over the three-year test period;
- Prioritized and reduced forecast capital expenditures by $381.2 million and capital additions by $392.5 million from fiscal 2017 to fiscal 2019;
- Reduced forecast dismantling costs;
- Optimized our energy portfolio; and
- Updated its Demand-side Management Plan.

Each of these initiatives is addressed briefly below.

1.5.1 Restructuring

In fiscal 2016 BC Hydro has restructured to better position us to deliver on the capital plan, maintain safety and customer service, and find efficiencies.

As detailed in the Organization Chart in Appendix DD, BC Hydro has four business groups (not including Powerex) comprised of the:

- Training, Development and Generation Business Group;
- Transmission, Distribution and Customer Service Business Group;
- Capital Infrastructure Project Delivery Business Group; and

- Operations Support Business Group (includes the key business units of Safety and Security and Emergency Management; Chief Human Resources Officer and Corporate Affairs; Finance and Supply Chain and General Counsel).

Prior to the restructuring, BC Hydro had a capital infrastructure project delivery group in both Generation and Transmission and Distribution. The Capital Infrastructure Project Delivery Business Group was created to assume responsibility and oversight of the Project Delivery, Dam Safety, Environmental Risk Management, Aboriginal Relations and Properties Key Business Units and to assist with co-ordination and collaboration across all business groups.

BC Hydro created the Project Delivery Key Business Unit (as part of the Capital Infrastructure Project Delivery Business Group) to lead the execution of complex generation, transmission and substation projects. This new group is tasked with ensuring that these capital projects are delivered on time and on budget. A separate key business unit within this business group has responsibility for delivering the Site C Clean Energy Project.

BC Hydro has brought the planning and support for safety initiatives together under a Senior Vice-President of Safety, Security and Emergency Management, reporting directly to the President and Chief Executive Officer. The change will provide a more unified approach to safety and meet the challenge of improving our safety record. The responsibility of this executive is to ensure that all parts of BC Hydro are prepared for emergencies and that we have taken appropriate steps to ensure the safety and security of our employees and the public.

BC Hydro is moving to a more customer-oriented culture and a renewed focus on our everyday interactions with our customers. The former Customer Care Key Business Unit has been integrated with the former Transmission and Distribution Business Group, and now renamed the Transmission, Distribution and Customer Service Business Group.

BC Hydro has also created a new Operations and Business Support Group combining demand-side management, energy planning and economic development, business planning and risk, policy and regulatory, communications and human resources functions under the guidance of a Chief Human Resources Officer and Senior Vice-President of Corporate Affairs. This change is intended to ensure a coordinated approach to energy and business planning, with emphasis on our corporate priorities that are discussed in section 1.6.1 below.

Our restructuring efforts, as discussed in section 1.4.1,, have resulted in the number of executives and senior managers decreasing from 80 at the end of fiscal 2014 to 72 as at the end of fiscal 2016. The BC Hydro organisation chart reflecting these changes is provided in Appendix DD. BC Hydro discusses the restructuring in greater detail in Chapter 5, section 5.2.

1.5.2 Our Efforts to Manage Operating Cost Pressures

BC Hydro is focusing on key priorities during the test period while taking operating cost control measures.

BC Hydro planned its operating costs for the test period using top-down and bottom-up elements. The top-down element was primarily driven by two considerations:

1. Aligning investments with our updated vision, key goals and priorities; and
2. Managing our overall costs to stay within the 2013 10 Year Rates Plan objectives.

The bottom-up element involved Business Groups evaluating savings opportunities and cost pressures, since most of BC Hydro’s operating costs are subject to inflationary pressures. These elements culminated with an iterative review by the executive team, resulting in the additional expenditures and savings proposed for the test period.

Table 1-1 below summarizes the components of the base operating cost over the test period. BC Hydro uses base operating costs as the key measure for the assessment of BC Hydro's operating costs. BC Hydro's efforts to control costs and focus on key priorities are reflected in 'base operating costs', which corresponds with a cost presentation in BC Hydro's Service Plan.

Base operating costs before sustainment costs related to the Smart Metering and Infrastructure program are increasing by 1.6 per cent in fiscal 2017, 0.3 per cent in fiscal 2018 and 1.6 per cent fiscal 2019. This represents an average of 1.2 per cent over the three years.

Operating costs, FTEs and savings related to the sustainment of the Smart Metering and Infrastructure technologies are included in BC Hydro's test period totals as all sustainment activities will have been integrated into the Business Groups by the end of fiscal 2016. These costs were previously deferred pursuant to British Columbia Utilities Commission orders. In fiscal 2017, $44.3 million of additional operating costs are planned, partially offset by $22.2 million of operating cost savings resulting in a net ongoing cost increase of $22.1 million. Key operating cost savings from the Smart Metering and Infrastructure project relate to reduced manual meter reading, while key operating expenditures include technology costs to support new and existing systems and devices. The Smart Metering and Infrastructure project also creates additional energy cost reductions that are not captured in operating costs, resulting in an overall net positive benefit to ratepayers.

Table 1-1 Base Operating Costs during the Test Period

			F2017 Plan ($ million)	F2018 Plan ($ million)	F2019 Plan ($ million)
1	Base Operating Cost (Table 5-5 Chapter 5)	A	**712.7**	**746.5**	**747.2**
2	**Test Period Savings/Efficiencies**	B	**(33.2)**	**(0.3)**	**(0.2)**
3	**Test Period Cost Increases**				
4	Unavoidable Costs		10.1	7.6	9.3
5	Capital-Driven		19.0	(3.1)	2.6
6	Initiatives		6.5	(1.5)	
7	Other Cost Pressures		9.3	(0.6)	0.2
8	**Total Test Period Cost Increases**	C	44.9	2.4	12.1
9	Net Increase/(Decrease) Excluding Smart Metering and Infrastructure - Operationalized Cost Net of Savings	D=B+C	11.7	2.1	11.9
10	**Total Percentage Increase** Excluding Smart Metering and Infrastructure - Operationalized Costs Net of Savings (%)	D/A	**1.6**	**0.3**	**1.6**
	Smart Metering and Infrastructure	E	22.1	(1.4)	(0.1)
11	Net Increase/(Decrease) Including Smart Metering and Infrastructure - Operationalized Cost Net of Savings	F=D+E	33.8	0.7	11.8
12	**Base Operating Costs**	**G=A+F**	**746.5**	**747.2**	**759.0**
13	**Total Percentage Increase** Including Smart Metering and Infrastructure - Operationalized Costs Net of Saving (%)	~~G/A~~G-A/A	**4.7**	**0.1**	**1.6**

Table 1-2 below, depicts BC Hydro's net operating costs during the test period. Net operating costs include base operating costs. The other costs, that together with base operating costs comprise "net operating costs" are primarily operating costs related to Electricity Purchase Agreements that are accounted for as capital leases and smoothing the impact into rates of capital overheads that are no longer eligible to be capitalized under International Financial Reporting Standards. Table 1-2 highlights in particular the increases or decreases associated with these accounting requirements.

Table 1-2 Net operating Costs during the Test Period

Base Operating Costs (Table 1-1)	A	**746.5**	**747.2**	**759.0**
Operating Costs Related to Electricity Purchase Agreements Accounted for as Capital Leases (Schedule 5.1 line 15)	~~A~~B	28.2	63.6	54.3
IFRS Ineligible Capital Overhead	~~B~~C	102.9	125.3	147.7
Net Operating Costs (Schedule 5.0 line 12)	~~C=A+B~~D=A+B+C	**877.6**	**936.1**	**961.0**

As discussed in Chapter 5, some cost increases are required during the test period to support key priorities, initiatives and ongoing operations. These costs, which are reflected in base operating costs, can be categorized as follows:

1. **Unavoidable costs** – this category includes rising fees from external regulators such as the Western Electricity Coordinating Council, which BC Hydro is required to be a member of due to its oversight of Mandatory Reliability Standards. This category also includes increases related to BC Hydro's collective agreements, as well as compensation increases for management and professional staff that align with increases in the collective agreements. Additionally, increases for Canada Post are included in this category;

2. **Capital-driven** – this category includes costs related to ensuring the success of BC Hydro's capital program, including higher capital project investigation costs at the front-end of projects to ensure successful delivery, as well as higher maintenance costs as a result of our growing asset base;

3. **Initiatives** – this category includes costs for initiatives that are not expected to be permanent expenditures, some of which reduce during the test period. BC Hydro is investing in safety initiatives to improve our safety record, as well in our customer service strategy to make it easier to do business with us; and

4. **Other cost pressures** – this category includes all other cost pressures, including higher storm restoration costs related to storms in recent years, as well as investments in technology and other areas.

BC Hydro has, at the same time, sought to identify areas where cost savings can be achieved. The budgeting process identified $33.2 million of annual savings in fiscal 2017 that will continue through fiscal 2018 and fiscal 2019. The savings include:

- $15 million in the Transmission, Distribution and Customer Service Business Group related to an initiative to identify operational efficiencies and savings;
- $6.9 million from reducing the number of consultants used, reducing donations and sponsorships, reducing property lease costs, and cancelling BC Hydro's membership in the Canadian Electricity Association;
- $7 million in labour costs due to the decommissioning of the Burrard Thermal Plant and its conversion to operating as a synchronous condense facility; and
- $4.3 million in company-wide savings from ongoing efforts to find cost savings and efficiencies.

In addition to the hard savings noted above, BC Hydro implemented a Work Smart program that uses Lean methodology to examine internal processes for opportunities to make them more efficient. A Workforce Optimization program underway is intended to ensure that BC Hydro has the most efficient balance of internal and external resources. As a result of that program, we have identified around 170 full-time equivalents (**FTEs**) that can be replaced with internal staff to reduce costs and improve outcomes.

1.5.3 We Implemented a Debt Management Strategy to Lock-In Low Interest Rates

In 2015, BC Hydro developed a debt management strategy in order to capitalize on current historically low interest rates. The British Columbia Utilities Commission approval of the Debt Management Regulatory Account in March 2016 allowed BC Hydro to proceed with a debt management strategy that included the hedging of interest rates on future debt issues. The hedging of future debt has allowed

BC Hydro to forecast interest cost savings of around $45 million over the three-year test period.

1.5.4 We Prioritized and Reduced Forecast Capital Expenditures and Additions

BC Hydro's recent response to reduced forecast load growth included re-prioritizing capital expenditures and additions, taking into account projects that were customer driven and likely not now required as a result of the reduced load forecast. Some growth projects were cancelled while others have been deferred to later years when the load will have increased to the point that they will again be required. This exercise resulted in a reduction in planned capital expenditures of $381.2 million and a reduction in planned capital additions of $392.5 over fiscal 2017 to fiscal 2019.

1.5.5 We Reduced Forecast Dismantling Costs

With the deferral and cancellation of some capital projects noted above in section 1.5.4, BC Hydro has been able to reduce its forecasted operating costs related to dismantling by $70 million over the test period. This is a result of projects not proceeding that, if they had, would have required costs of dismantling of existing facilities before the new projects could commence construction.

1.5.6 We Optimized our Energy Portfolio

BC Hydro's recent response to lower forecasted load growth also included an examination of BC Hydro's energy portfolio.

Fourteen of BC Hydro's existing electricity purchase agreements with IPPs are expiring by the end of fiscal 2019. Consistent with the approved 2013 Integrated Resource Plan, BC Hydro continues to assume renewal of 50 percent of the energy and capacity contributions from biomass Electricity Purchase Agreements and 75 per cent from the run-of-river hydroelectric Electricity Purchase Agreements that are due to expire within the remaining years of the 2013 10 Year Rates Plan. Renewal of Electricity Purchase Agreements with existing facilities has the long term benefit of delaying future greenfield resources. BC Hydro is targeting renewal of contracts for those facilities that have the lowest cost, greatest certainty of continued operation and best system support characteristics. Due to the fact that Electricity Purchase Agreement renewals are related to existing projects for which the IPPs initial capital investments have been fully or largely recovered during the term of the initial Electricity Purchase Agreement, BC Hydro expects to negotiate a lower energy price than the initial Electricity Purchase Agreement. In its Electricity Purchase Agreement renewal negotiations, BC Hydro will consider the IPPs opportunity cost, the electricity spot market, the cost of service for the IPPs (including fibre supply costs for biomass facilities) and other factors such as the attributes of the energy produced and other non-energy benefits.

BC Hydro is not requesting any approvals in this Application with respect to the renewal of Electricity Purchase Agreements. They will be subject to separate British Columbia Utilities Commission review pursuant to section 71 of the *Utilities Commission Act*. Any variances from forecast energy costs in this Application as a result of the British Columbia Utilities Commission review of the section 71 filings will be captured in the Non-Heritage Deferral Account.

The Standing Offer Program is a legislated requirement pursuant to subsection 15(2) of the *Clean Energy Act*. Subsection 15(3) provides that BC Hydro may establish the terms and conditions of the offers under the Standing Offer Program. The current Standing Offer Program price was informed by prices from the Clean Power Call in 2010. Since then:

- The cost for developing some new clean energy resources has declined (e.g. wind and solar);
- The Pacific Northwest, including BC Hydro, has become more constrained in operation during the freshet oversupply period; and

- BC Hydro is expecting to have a greater need for new capacity resources over energy resources.

Accordingly, BC Hydro has initiated an optimization process for the Standing Offer Program and Micro-Standing Offer Program to reflect future system needs, consider recent advancements in technology and align with the 2013 10 Year Rates Plan. Changes are expected to apply to projects with in-service dates starting in calendar 2020 so that projects that are significantly advanced are not unduly impacted.

1.5.7 We Updated Demand-Side Management Plan

In June 2015, we initiated a process to modernize and improve the cost-effectiveness of our demand-side management programs to use new technologies, and respond to changing customer expectations and system needs. As a result of this process, BC Hydro reduced the average cost of its demand-side management programs to $22/MWh while remaining on track to meet the *Clean Energy Act* target to offset at least 66 per cent of incremental demand from 2008 to 2020 through conservation and maintaining the capability to acquire further demand-side management electricity savings in the future should those savings be required.

BC Hydro has eliminated or modified programs that are not as cost-effective or are less aligned with customer expectations and system needs, while retaining or expanding programs that align well with new priorities.

Given the reduction in the rate of growth of demand for electricity in the short term and the targets in the 2013 10 Year Rates Plan, BC Hydro has reduced its overall level of planned demand-side management expenditures.

1.6 The Fiscal 2017 – Fiscal 2019 Revenue Requirements

In this section, BC Hydro provides a high-level overview of the fiscal 2017 to fiscal 2019 revenue requirements. We first discuss the five company-wide operational priorities that are guiding our company-wide actions during the test period. We also discuss the major components of the revenue requirements. Although some of these costs are beyond BC Hydro's control, BC Hydro is managing controllable costs in order to deliver on the targets in the 2013 10 Year Rates Plan.

1.6.1 Our Key Priorities During the Test Period

BC Hydro has identified five internal company-wide operational priorities for the fiscal 2017 to fiscal 2019 test period, in addition to our day-to-day work of safely generating and delivering electricity to customers. The five priorities are listed below, along with some general discussion about how these priorities influence our forecasted revenue requirements. Further details are provided in other Chapters of this Application.

1.6.1.1 Making it Easier for Customers to do Business with Us

BC Hydro plans to invest to make it easier for customers to do business with us, recognizing the evolving expectations of customers. Our aim is to provide more accessible and responsive service to our customers, in key function areas such as interconnections, and to adopt a more customer-centric tone and culture. Examples include:

- BC Hydro is looking to improve basic systems, processes and analytics. Examples are changing bills so that they are easier to read and creating more mobile and self-service tools such as online booking of appointments;
- With investments in Smart Meters, customers have access to more information about their energy use. BC Hydro is now able to deliver more timely information

when outages occur and we can more easily facilitate moves and opening of new accounts; and

- BC Hydro is also using social media channels to keep customers informed when there are situations that may impact them such as advance notices of outages.

BC Hydro is proposing additional funding for this priority in fiscal 2017, which is described further in Chapter 5, section 5.5.1.1.

1.6.1.2 Deliver Capital Projects On Time and On Budget

BC Hydro's capital program is designed to ensure clean sources of electricity supply are available to meet demand, and to provide the infrastructure needed to deliver electricity reliably to customers. BC Hydro must continue to invest in reliability and growth projects, but has prioritized projects in order to meet the 2013 10 Year Rates Plan. BC Hydro has also taken steps to facilitate delivery of capital projects on time and on budget.

A large portion of BC Hydro's system was built in the 1960s,1970s and 1980s and is reaching or exceeding expected end-of-life. A significant proportion of the risks facing BC Hydro's major assets can be attributed to their age. The physical condition along with the performance, maintenance and repair cost history, and criticality of equipment and facilities are significant drivers for planning and prioritizing refurbishment or replacement. Equipment health assessments are an industry standard approach to assessing the reliability risk associated with capital equipment.

BC Hydro continually evaluates the condition of its assets, which informs the reliability risk associated with those assets. For example, there are currently a number of major generating components that are assessed to have a high likelihood of failing within the next ten years without proactive measures. Transmission and Distribution Asset Management assessed that 12 per cent of its over 4 million individual assets should be addressed in the next ten years for reliability reasons.

Please refer to Appendices R and S for more information about our asset health indices.

BC Hydro will experience significant load growth over the next 20 years. The need to meet this increased demand while operating the system safely and reliably will influence asset management and capital expenditure decisions. Load growth is driving the addition of Site C Clean Energy Project, the expansion of existing generating capacity, the expansion of bulk and regional transmission facilities, and the integrated information technology improvements needed to support expansion in a changing environment.

In December, 2014, the Province approved the Site C Clean Energy Project to proceed to construction. Construction started in fiscal 2016 with forecast completion in fiscal 2025. The Site C Clean Energy Project will be the third dam and hydroelectric generating station on the Peace River in northeast B.C. It will provide 1,100 MW of capacity, and produce 5,100 GWh of electricity each year – enough to power the equivalent of about 450,000 homes each year for more than 100 years. The expenditures on the Site C Clean Energy Project are approximately 30 per cent of our total capital expenditure forecast over the next ten years. Given the size and duration of the Site C Clean Energy Project, it has been set up as its own key business unit within the newly formed Capital Infrastructure Project Delivery Business Group to support successful project completion. The Site C Clean Energy Project construction will be ongoing over the three-year test period and will not have an impact on rates until it is completed and placed into service as a capital addition (after the current test period).

BC Hydro has well developed processes for assessing, prioritizing and executing on capital projects. Examples include:

- BC Hydro has developed and implemented robust processes for capital investment planning and delivery across the organization to ensure that the appropriate capital investments are planned to start and be delivered at the right time, and within established budgets. BC Hydro has worked to integrate its planning and capital delivery processes where possible, based on a collaborative approach across our generation, transmission, distribution, technology, vehicle fleet and properties functions;

- BC Hydro has also developed a Capital Investment Framework, which includes a standardized approach to applying our corporate risk matrix for capital investment planning across the organization. Potential capital projects within the business group's capital investment portfolios are reviewed within the risk framework to identify and consider the risks and impacts of potentially delaying or proceeding with a project. This process allows for a categorization and prioritization of projects;
- As noted above BC Hydro has created a new Project Delivery Key Business Unit within the Capital Infrastructure Project Delivery Business Group whose purpose is to execute the multi-billion dollar portfolio of large generation, transmission and substation projects; and
- BC Hydro has implemented business tools such as Project and Portfolio Management to manage the delivery of our large and complex capital plan on time and on budget.

BC Hydro's annual capital expenditures average $2.4 billion over the next three years, including expenditures on the Site C Clean Energy Project. Table 1-2 provides a snapshot of forecast expenditures during the test period. Only forecast capital additions (as reflected in Table 1-4), and not forecast capital expenditures (as depicted in Table 1-3), affect rates during the test period.

Table 1-3 Forecast Capital Expenditures (Fiscal 2017 to Fiscal 2019)

Fiscal Year	F2017 ($ million)	F2018 ($ million)	F2019 ($ million)
Capital Expenditures (with Site C Clean Energy Project and net of Contributions in Aid)	2,518	2,312	2,318

Over the same period, BC Hydro is planning on capital additions as set out in Table 1-4. BC Hydro records a capital addition when assets are placed into service.

Table 1-4 Forecast Capital Additions (Fiscal 2017 to Fiscal 2019)

Fiscal Year	F2017 ($ million)	F2018 ($ million)	F2019 ($ million)
Capital Additions (net of Contributions in Aid)	1,648	1,402	2,303

1.6.1.3 Explore the Full Potential of Energy Conservation

For over 25 years, BC Hydro's demand-side management programs have supported energy conservation and encouraged the adoption of more energy efficient products and equipment. Over the same period, a lot has changed. Customer acceptance of certain energy efficient products has increased, new technologies have improved access to energy data, and changing customer expectations and system needs have presented new opportunities in areas such as capacity-focused demand-side management and low-carbon electrification.

In June 2015, we initiated a process to modernize and improve the cost-effectiveness of our demand-side management programs to use new technologies and respond to changing customer expectations and system needs.

BC Hydro's Demand-Side Management Plan continues investments in areas such as capacity-focused conservation, including a load curtailment pilot program for large industrial customers. BC Hydro is also increasing its focus on measures that provide new tools, information and technologies to customers to help them make use of available energy data, including from smart meters, to make smart choices about their energy consumption. By having access to information more specific to them, customers can make informed choices and save money.

Further information on BC Hydro's demand-side management expenditures and tools for the fiscal 2017 to fiscal 2019 period is provided in Chapter 10.

1.6.1.4 Strengthening Our Proud and Valued Workforce

BC Hydro's priorities include strengthening its workforce with the expectation that an engaged workforce is also a safe and productive workforce.

BC Hydro's Workforce Plan (Appendix F) sets out the principles that BC Hydro will follow in resourcing its large capital projects to determine the best mix of employees versus external resources, including contractors and outsourcing. Actions that are identified to address capacity gaps include maintaining talent pipelines into BC Hydro, so that we are best positioned to have the optimum level of trainees. In addition, BC Hydro will draw upon First Nations and other local sources of talent in areas where we have had difficulty in finding and keeping people with the right skills, and thereby reduce the costs of hiring new workers.

BC Hydro has over 5,500 employees operating out of 95 different locations through British Columbia. Keeping our employees engaged, trained and informed is crucial to making sure they understand what is expected of them. BC Hydro is developing engagement programs to improve employee alignment with our priorities, to increase productivity and to reduce voluntary attrition, thereby resulting in further savings from not having to hire new workers.

1.6.1.5 Continue to Improve the Way We Operate

BC Hydro's priorities also include continuing to improve the way we operate to help meet the 2013 10 Year Rates Plan and keep rates affordable and predictable. A number of initiatives to improve the way we operate have been discussed in section 1.5 above. Two initiatives related specifically to our workforce are discussed further below.

BC Hydro's Workforce Optimization program has the goal of converting external contractors to internal staff in cases where it reduces costs and/or improves outcomes (e.g., reduces risk). The program is expected to achieve net benefits through capital savings offset by slightly higher operating expenditures due to training and other expenses associated with internal staff. Notwithstanding adding FTEs as part of this program, BC Hydro has kept its FTE levels relatively constant during the test period. As shown in Table 1-5, planned FTEs are lower in operating, and deferred, and higher in capital, reflecting requirements to implement its capital plan.

Please note, in the tables in this Chapter, references to F2015 RRA or F2016 RRA signifies the Plan amount from the Fiscal 2015 – Fiscal 2016 Revenue Requirements Rate Application.

Table 1-5 FTEs during the Test Period

	(FTEs, Including Overtime)	F2016 RRA	F2017 Plan	F2018 Plan	F2019 Plan
1	Operating	3,935	3,872	3,881	3,884
2	Capital	2,150	2,269	2,311	2,329
3	Deferred	280	155	152	152
4	**BC Hydro Total**	**6,365**	**6,296**	**6,344**	**6,365**
5	Percentage Change (%)		-1.1	0.8	0.3

BC Hydro has also implemented its Work Smart program, which focuses on employee-led process improvement initiatives to further improve the way we operate. Based on the Lean business philosophy which is being implemented in numerous public and private jurisdictions in North America, the program focuses on a structured approach focused on customer needs, streamlining work and eliminating non-value added activities. Work Smart initiatives have been implemented across the company, from customer build to safety to aboriginal engagement, and as of the end of fiscal 2016 have generated an estimated additional capacity of 22,550 hours annually.

1.6.2 Overview of Revenue Requirement

The details of BC Hydro's forecasts and plans for fiscal 2017, fiscal 2018 and fiscal 2019 are presented in the various chapters of this Application. The following two tables provide two summary views of the revenue requirements.

Table 1-6 below provides a summary of the components of BC Hydro's revenue requirements over the test period and shows the revenue shortfall that will result from the existing rates. Each component is shown on a gross basis (assuming that no regulatory accounts existed – referred to as the Gross View) with the net transfers to the Deferral Accounts and other regulatory accounts shown separately on lines 9 and 10 and with references to the Revenue Requirements Model found in Appendix A.

Table 1-7 summarizes BC Hydro's revenue requirements for fiscal 2017, fiscal 2018 and fiscal 2019 with the net Deferral Account and other regulatory account transfers reallocated to the appropriate components of the revenue requirement. This view presents the costs for each component of the revenue requirement that are recovered in existing rates (referred to as the Current View). A reconciliation of the Gross View and the Current View for each component of the revenue requirement is provided on Schedule 3.0 of Appendix A.

The Gross View is informative as it provides information on the total costs incurred on each of the components that make up the revenue requirements. The Current View is more relevant to this Application, as it provides the costs on the same basis as they are recovered in rates from our customers.

Table 1-6 Summary of Fiscal 2017 – Fiscal 2019 Revenue Requirements – Gross View

		Schedule Reference (Appendix A)	F2016 RRA ($ million)	F2017 Plan ($ million)	F2018 Plan ($ million)	F2019 Plan ($ million)
			1	2	3	4
1	**Cost of Energy**	1.0 L1	1,391.7	1,549.3	1,657.8	1,762.9
2	**Operating Costs**	1.0 L2	1,146.6	1,185.0	1,250.9	1,183.4
3	**Taxes**	1.0 L3	224.1	223.3	231.8	238.7
4	**Amortization**	1.0 L4	758.0	785.4	825.7	855.6
5	**Finance Charges**	1.0 L5	838.3	711.4	745.9	785.0
6	**Return on Equity**	1.0 L6	651.9	684.7	698.4	712.4
7	**Non-Tariff Revenue**	1.0 L7+L21	(126.6)	(138.9)	(147.4)	(149.9)
8	**Inter-Segment Revenue**	1.0 L8	(53.5)	(62.5)	(64.3)	(65.3)
9	**Deferral Account Transfers**	1.0 L12	199.2	181.8	197.0	215.3
10	**Other Regulatory Account Transfers**	1.0 L16	(215.4)	(293.9)	(406.5)	(327.0)
11	**Subsidiary Net Income**	1.0 L19	(115.1)	(119.7)	(119.9)	(120.2)
12	**Other Utilities Revenue**	1.0 L20	(16.5)	(12.6)	(12.0)	(12.1)
14	**Deferral Rider Revenue**	1.0 L22	(223.0)	(223.5)	(231.3)	(241.8)
	Total Revenue Requirements		**4,459.7**	**~~4,469.9.0~~ 4,469.9**	**4,626.1**	**4,836.8**
15	**Less Revenue at F2016 Rates**		**(4,459.7)**	**(4,298.0)**	**(4,297.8)**	**(4,362.5)**
16	**Revenue Shortfall**	1.0 L29	0.0	171.9	328.3	474.2
	Rate Smoothing Account Transfer	2.2 L172	121.2	210.0	285.9	299.4
17	**Annualized Rate Increase (%)**	1.0 L30	6.00	4.00	3.50	3.00
18	**Deferral Account Rate Rider (%)**	1.0 L31	5.00	5.00	5.00	5.00
19	**Net Bill Increase (%)**	1.0 L32	6.00	4.00	3.50	3.00

Table 1-7 Summary of Fiscal 2017 – Fiscal 2019 Revenue Requirements – Current View

		Schedule Reference	F2016 RRA ($ million)	F2017 Plan ($ million)	F2018 Plan ($ million)	F2019 Plan ($ million)
			1	2	3	4
1	**Cost of Energy**	3.0 L64	1,514.3	1,723.9	1,838.6	1,951.8
2	**Operating Costs**	3.0 L65	977.7	976.3	936.4	941.0
3	**Taxes**	3.0 L66	224.1	223.3	231.8	238.7
4	**Amortization**	3.0 L67	796.0	863.0	922.2	962.8
5	**Finance Charges**	3.0 L68	726.6	506.9	523.2	566.6
6	**Return on Equity**	3.0 L69	651.9	684.7	698.4	712.4
7	**Non-Tariff Revenue**	3.0 L70+L74	~~(126.6)~~ (123.3)	(138.9)	(147.4)	(149.9)
8	**Inter-Segment Revenue**	3.0 L71	(53.5)	(62.5)	(64.3)	(65.3)
9	**Subsidiary Net Income**	3.0 L72	(14.7)	(70.8)	(69.3)	(67.3)
10	**Other Utilities Revenue**	3.0 L73	(16.5)	(12.6)	(12.0)	(12.1)
12	**Deferral Rider Revenue**	3.0 L75	(223.0)	(223.5)	(231.3)	(241.8)
	Total Revenue Requirements		**4,459.7**	**4,469.9**	**4,626.1**	**4,836.8**
13	**Less Revenue at F2016 Rates**		**(4,459.7)**	**(4,298.0)**	**(4,297.8)**	**(4,362.5)**
14	**Revenue Shortfall**	1.0 L29	0.0	171.9	328.3	474.3
	Rate Smoothing Account Transfers	2.2 L172	121.2	210.0	285.9	299.4
15	**Annualized Rate Increase (%)**	1.0 L30	6.00	4.00	3.50	3.00
16	**Deferral Account Rate Rider (%)**	1.0 L31	5.00	5.00	5.00	5.00
17	**Net Bill Increase (%)**	1.0 L32	6.00	4.00	3.50	3.00

1.6.3 Components of the Fiscal 2017 to Fiscal 2019 Rate Increases

The following sections provide a more detailed description of the each of the components identified in ~~Table 1-5~~ Table 1-6 and ~~Table 1-6~~ Table 1-7 above.

1.6.3.1 Cost of Energy

The principal drivers of the increase in the Cost of Energy are:

1. Higher forecast IPP purchases of $464 million in fiscal 2019 compared to fiscal 2016, primarily the result of IPP projects becoming operational over the

test period. BC Hydro has been acquiring energy from IPPs to help meet increased demand from a growing population and economy in accordance with the 2013 Integrated Resource Plan, which guides the composition of our energy portfolio; and

2. Higher forecast Non-Heritage Deferral Account recoveries of approximately $96 million as a result of a higher than forecast balance in the account.

These increases are partially offset by:

1. A decrease in forecast Heritage Energy costs of approximately $18 million. This decrease is mainly as a result of lower forecast water rentals due to the Government's elimination of Tier 3 water rental rates during the test period; and
2. Lower forecast Heritage Deferral Account recoveries of approximately $23 million as there was lower hydro generation than forecast in fiscal 2015 and fiscal 2016 and therefore, lower water rental costs.

Each of these drivers is discussed in Chapter 4 of the Application.

1.6.3.2 Operating Costs

Base operating costs are forecast to increase from $712.7 million in fiscal 2016 to $759.0 million in fiscal 2019 (base operating costs differ from operating costs shown in ~~Table 1-5~~ Table 1-6 and ~~Table 1-6~~ Table 1-7 as base operating costs are net of regulatory account transfers and provisions and do not include costs related to IPP capital leases of $21 million or ineligible capital overhead under IFRS rules of $67 million – for further information refer to Chapter 5, section 5.3.2). The principal drivers of the increase in operating costs are the following:

1. An increase of approximately $27 million over three years in unavoidable costs comprised of mandatory fees imposed by third parties such as the Western Electricity Coordinating Council and Canada Post changes, and labour expenditures required under collective agreements with unions and crane

remediation work in compliance with WorkSafeBC (further details are provided in section 5.3.2 in Chapter 5);

2. An increase of approximately $33 million over three years in forecast base operating costs to fund key priorities, initiatives and ongoing operations, which is offset by test period savings and efficiencies of approximately $33.7 million;
3. Approximately $21 million of Smart Metering and Infrastructure operationalized costs, net of savings. These costs were previously deferred to the Smart Metering and Infrastructure Regulatory Account prior to fiscal 2017 (refer to Chapter 5, section 5.2.1).

1.6.3.3 Taxes

The *Hydro and Power Authority Act* exempts BC Hydro from all property taxes other than those levied in respect of schools. In addition, BC Hydro pays grants-in-lieu of general municipal, regional district and local government taxes. Over the test period, taxes are forecast to increase primarily as a result of increased property values (for land, buildings and electric system assets) and increased forecast revenue from electricity sales (which leads to higher grants-in-lieu). Further information on the calculation of taxes is found in section 8.6 of Chapter 8.

1.6.3.4 Amortization

The increase in forecast amortization from $796 million in fiscal 2016 to $963 million in fiscal 2019 is principally driven by the following factors (refer to Table 8-2 in Chapter 8 for more detail):

1. A forecast increase in BC Hydro’s net assets to maintain and expand our electricity system, which increases amortization by approximately $132 million; and

2. An increase in forecast amortization of the Demand-Side Management Regulatory Account of approximately $23 million. This increase in amortization is consistent with the increase in additions over the test period.

1.6.3.5 Finance Charges

Current finance charges are forecast to decrease from $727 million in fiscal 2016 to $566 million in fiscal 2019. The principal drivers of the net $160 million decrease in finance charges are:

1. A forecast increase in Interest During Construction of approximately $90 million, which reduces finance charges;
2. A change in accounting treatment of certain electricity purchase agreements with IPPs which results in an overall decrease in forecast finance charges of approximately $51 million; and
3. An increase in the recovery of the credit balances in various regulatory accounts, including a forecast increase of $76 million in recovery of the Total Finance Charges Regulatory Account and a forecast increase of $38 million in recovery of the Foreign Exchange Gains/Losses Regulatory Account.

Forecast finance charges have also been reduced as a result of BC Hydro’s debt management strategy, which includes the use of interest rate hedges for future debt issues.

These decreases are partially offset by an increase in forecast borrowing costs of approximately $107 million resulting from the forecast increase in BC Hydro debt over the test period.

1.6.3.6 Return on Equity

Return on equity increases from $652 million in fiscal 2016 to $712 million in fiscal 2019. Consistent with the requirements of section 4 of Direction No. 7, the principal drivers of the increase in return on equity are:

1. An increase in forecast mid-year deemed equity from fiscal 2016 to fiscal 2017, which, after applying the allowed return on equity of 11.84 per cent, results in an increase in return on equity of $33 million in fiscal 2017; and
2. The application of the forecast increase in the British Columbia Consumer Price Index to the annual return on equity for fiscal 2018 and fiscal 2019 (pursuant to Direction No. 7), which results in an increase in return on equity of $28 million in fiscal 2019 compared to fiscal 2017. This increase in return on equity is less than the increase that would have resulted if the annual allowed return on equity remained at 11.84 per cent in each year. Although the return on equity amount is increasing, the percentage rate of return is declining.

1.6.3.7 Non-Tariff Revenue

The increase in non-rate revenue from $~~350~~ 346 million in fiscal 2016 to $392 million in fiscal 2019 (this includes lines 7, and 12 from ~~Table 1-6~~Table 1-7) partially offsets the cost increases noted above. The principal drivers of the increase in non-rate revenue are:

1. An increase in forecast LNG revenue of approximately $~~26~~ 11 million in fiscal 2019 versus fiscal 2016; and
2. An increase of $19 million in forecast Deferral Account Rate Rider revenue from $223 million in fiscal 2016 to $242 million in fiscal 2019. Pursuant to section 10 of Direction No. 7, the Deferral Account Rate Rider revenue is forecast based on applying the rate rider of 5 per cent (in each of the test years) to total rate revenue; therefore, the increase is attributable to the forecast increase in total rate revenue from fiscal 2016 to fiscal 2019.

1.6.3.8 Inter-Segment Revenue

Forecast inter-segment revenues increase from $53.5 million in fiscal 2016 to $65.3 million in fiscal 2019. These revenues remain relatively flat over the test period, increasing $1 million per year. Inter-segment revenue is largely related to

BC Hydro's operations with Powerex. Further information is found in Chapter 8, section 8.8.

1.6.3.9 Subsidiary Net Income

Forecast subsidiary net income from Powerex and Powertech remains flat over the test period at around $120 million per year. Refer to Chapter 8, section 8.9 for a more information.

1.6.3.10 Other Utilities Revenue

Other utilities revenue consists of sales to Seattle City Light and is forecast to remain relatively constant over the test period at $12 million per year. The forecast is calculated as the product of forecast sales and the price per MWh committed in the Skagit Valley Treaty.

1.6.3.11 Rate Smoothing

Transfers to the Rate Smoothing Regulatory Account are forecasted to increase from $121 million in fiscal 2016 to $210 million in fiscal 2017, $286 million in fiscal 2018 and $299 million in fiscal 2019. The forecasted rate smoothing transfer is a calculated amount necessary to keep rate increases within the rate caps laid out in section 9 of Direction No. 7, and will vary from year to year. In accordance with the 2013 10 Year Rates Plan, this account will be reduced to zero in fiscal 2024.

1.7 Approvals Sought

The approvals sought by BC Hydro in this Application are set out in the subsections below. A draft order is included as Appendix B. BC Hydro notes that the *Clean Energy Act*, Direction No. 7, and other Orders in Council prescribe a number of aspects of BC Hydro's revenue requirements as described in detail in Chapter 2.

1.7.1 Rates

Pursuant to sections 58 to 60 of the *Utilities Commission Act* and section 9(1) of Direction No. 7, BC Hydro seeks approval of the final rates set out in Table T-1 in

Appendix T for fiscal 2017, fiscal 2018 and fiscal 2019, effective April 1, 2016, 2017 and 2018, respectively.[6] Appendix T includes general rate increases and increases to the Open Access Transmission Tariff (**OATT**) rates. BC Hydro is also requesting approval to collect the difference between the final OATT rates approved by the British Columbia Utilities Commission and the interim refundable OATT rates approved in Order No. G-40-16 through a one-time charge to OATT customers, as described in Chapter 9.

1.7.2 Revenue Requirements

Pursuant to sections 58 to 60 of the *Utilities Commission Act* and section 9(2) of Direction No. 7, and for the purpose of determining the amounts to be deferred to the Rate Smoothing Regulatory Account for each of fiscal 2017, fiscal 2018 and fiscal 2019, BC Hydro requests that the British Columbia Utilities Commission determine that for fiscal 2017, fiscal 2018 and fiscal 2019 BC Hydro's approved revenue requirement is equal to $~~4,469~~4,679 million, $4,912 million, and $5,136 million, respectively.

1.7.3 Regulatory Accounts

Pursuant to sections 58 to 60 of the *Utilities Commission Act* and section 9(2) of Direction No. 7, BC Hydro requests approval of the deferral to the Rate Smoothing Regulatory Account of $210 million for fiscal 2017, $285.9 million for fiscal 2018 and $299.4 million for fiscal 2019, representing the differences between the approved revenue requirements and the revenues expected to be collected under the approved rates, as set in the table below.

[6] The 4 per cent, 3.5 per cent and 3 per cent increases are applied to BC Hydro's tariff as shown in Appendix T.

Table 1-8 Fiscal 2017 to Fiscal 2019 Amounts Transferred to the Rate Smoothing Regulatory Account

	F2017 ($ million)	F2018 ($ million)	F2019 ($ million)
Total Revenue Requirements	4,679.0	4,912.0	5,136.2
Revenue Recovered under Rate Caps	4,469.9	4,626.1	4,836.8
Amount Transferred to Rate Smoothing Regulatory Account	210.0	285.9	299.4

Pursuant to sections 58 to 60 of the *Utilities Commission Act* and section 7 of Direction No. 7, BC Hydro seeks the following approvals as described in Chapter 7, section 7.4 and summarized in Table 7-9:

- Continuing certain existing accounts;
- Renaming certain accounts;
- Adjusting the scope of certain accounts;
- Approval of amortization periods for recovery of balances in regulatory accounts that do not have an approved recovery mechanism; and
- Approval of the application of interest to certain regulatory accounts.

1.7.4 Depreciation Rates

The approval of the depreciation rates for fiscal 2015 and fiscal 2016 for certain property, plant and equipment at the Burrard Synchronous Condense facility as set out in Chapter 8, Table 8-1.

1.7.5 Demand-Side Management Expenditure Schedule

Pursuant to section 44.2(3) of the *Utilities Commission Act*, BC Hydro seeks British Columbia Utilities Commission acceptance of the following demand-side management expenditure schedule:

Table 1-9 Fiscal 2017 to Fiscal 2019 Demand-Side Measures Expenditure Schedule

	Demand-Side Measures Expenditures ($ million)
F2017	113.7
F2018	104.8
F2019	100.7
Thermo-Mechanical Pulp (F2017-F2019)[7]	55.8
Three-Year Total	375.0

1.8 Proposed Regulatory Process

BC Hydro proposes the following regulatory review process as shown in Table 1-10.

BC Hydro is also proposing to hold an information session in late summer/early fall 2017, which will be after the British Columbia Utilities Commission's decision on this application, at the mid-point of the three-year test period. The purpose of this session would be to provide an update on BC Hydro's financial performance and its progress in meeting its 2013 10 Year Rates Plan targets. BC Hydro would not be proposing any changes to its revenue requirements; the session would be informational only.

Table 1-10 Proposed Regulatory Review Process

Process	Date (2016)
Registration of Interveners and Interested Parties	August 31
Procedural/Scoping Conference	September 8
British Columbia Utilities Commission Information Request No. 1 to BC Hydro	September 15
Intervener Information Request No. 1 to BC Hydro	September 22
BC Hydro responds to British Columbia Utilities Commission and Intervener Information Request No. 1	October 21
British Columbia Utilities Commission and Intervener Information Request No. 2	November 9
BC Hydro responds to British Columbia Utilities Commission and Intervener Information Request No. 2	December 16

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

1.9 Description of the Application Structure

The remainder of the Application is organized as follows:

Chapter 2	Sets out the legal and regulatory context in which BC Hydro is filing this application.
Chapter 3	Provides BC Hydro's load and revenue forecasts for the test period.
Chapter 4	Provides information on the forecast Cost of Energy for the test period.
Chapter 5	Presents the operating costs of the company, including details of operating costs and full time equivalents by each Key Business Unit.
Chapter 6	Summarizes BC Hydro's forecast of capital expenditures and additions for the test period. Details of individual capital projects are included in Appendices I and J.
Chapter 7	Contains details on BC Hydro's energy Deferral Accounts and other regulatory accounts.
Chapter 8	Provides information on other revenue requirements items not discussed in previous chapters, including amortization, finance charges, and return on equity.
Chapter 9	Provides the derivation of the transmission revenue requirement and the proposed OATT rates.
Chapter 10	Contains all information with regard to BC Hydro's request pursuant to section 44.2 of the *Utilities Commission Act* for acceptance of Demand-Side Management Expenditures for fiscal 2017 to fiscal 2019.

Appendix A contains the detailed financial schedules of the revenue requirements model, and is intended to provide in a single location the details of the elements which make up the revenue requirements for the test period. The working revenue requirements model that produces the schedules is provided in electronic form as part of this filing.

1 ## 1.10 Communications

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Fiscal 2017 to Fiscal 2019
Revenue Requirements Application

Chapter 2

Legal Framework for Application

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List of Tables

2.1 Chapter Overview

This Chapter provides a review of key enactments and policies that have impacted BC Hydro and that continue to guide its plans and actions during the three test years of this application. This Chapter also reviews the regulatory framework applicable to the British Columbia Utilities Commission's consideration of the approvals sought and, in section 2.2.1, provides a discussion of those aspects of the BC Hydro's forecast revenue requirements that are exempt from British Columbia Utilities Commission oversight during the test period.

2.2 Key Statutes and Policies Applicable to BC Hydro

2.2.1 The *Hydro and Power Authority Act*

BC Hydro was created over 50 years ago to generate and safely deliver clean, reliable and low cost electricity to homes and businesses in British Columbia. The *Hydro and Power Authority Act* provides BC Hydro its powers and mandate to generate, conserve, acquire and supply electricity and related products. BC Hydro is a provincial Crown corporation and is for all purposes an agent of the B.C. Government.

The Lieutenant Governor in Council appoints BC Hydro's Board of Directors and Chair. The directors are required to manage the affairs of BC Hydro or supervise the management of those affairs. BC Hydro reports to the Government through the Minister of Energy and Mines. The Minister of Finance is the fiscal agent of BC Hydro.

The *Hydro and Power Authority Act* also specifies the statutory provisions of British Columbia that apply to BC Hydro, including:

- Most environmental protection, and public and worker safety regulations;

- Government financial administration and information regulations (e.g., *Budget Transparency and Accountability Act*, *Financial Information Act* and several sections of the *Financial Administration Act*);
- The *Clean Energy Act*; and
- Most but not all provisions of the *Utilities Commission Act*.

The Lieutenant Governor in Council may issue directives under section 35 of the *Hydro and Power Authority Act* directing BC Hydro to pay a specified dividend to the government, and may also direct BC Hydro to pay a specified amount to past or present customers. Heritage Special Directive No. HC1 to BC Hydro specifies the calculation of the dividend that BC Hydro is required to pay to the government each fiscal year.

2.2.2 The *Budget Transparency and Accountability Act*

As a government organization under the *Budget Transparency and Accountability Act*, BC Hydro prepares a service plan each year that addresses the fiscal year of the plan and the following two fiscal years. The service plan includes a statement of BC Hydro's goals, specific objectives and performance measures, and summaries of our major capital project plans. A copy of BC Hydro's fiscal 2017 to fiscal 2019 service plan is provided in Appendix E and a discussion of the goals and performance measure over that period is found in section 2.3.6 of this chapter.

2.2.3 The 2010 *Clean Energy Act*

The *Clean Energy Act* consolidated the British Columbia Transmission Corporation and BC Hydro effective July 2010. The *Clean Energy Act also* confirmed the requirement for BC Hydro to achieve electricity self-sufficiency by 2016 and each year thereafter, and established a new regulatory regime for approval of BC Hydro's integrated resource plans. Pursuant to section 3 of the *Clean Energy Act*, BC Hydro submits its integrated resource plans to the Minister of Energy and Mines every five years, and the Lieutenant Governor in Council may by order approve the Integrated

Resource Plan. BC Hydro's 2013 Integrated Resource Plan, the most recent plan, was submitted to the Minister in November 2013 and was approved by Order-in-Council No. 514 dated November 25, 2013.

The *Clean Energy Act* also provides for BC Hydro to increase investments in clean, renewable energy across the province by completing the projects and programs listed in section 7 of the *Clean Energy Act*, including the Northwest Transmission Line, Mica Units 5 and 6, Revelstoke Unit 6, the Site C Clean Energy Project, procurement of clean energy from IPPs and customers, and the smart metering and smart grid program. Most of the projects and programs listed in section 7 of the *Clean Energy Act* are complete or nearing completion. Construction on the Site C Clean Energy Project began in 2015 and BC Hydro is currently undertaking work to advance the Revelstoke Unit 6 project to the environmental assessment stage.

The Standing Offer Program required by section 15 of the *Clean Energy Act* is ongoing, and is currently BC Hydro's only active program to acquire electricity from others.

2.2.4 The *Utilities Commission Act*

Pursuant to section 32(x) of the *Hydro and Power Authority Act*, the *Utilities Commission Act* applies to BC Hydro, except sections 44.1(long-term resource and conservation planning), 50 (restraint on issuance of securities), 51(c) (restraint on issuance of securities), 52 (restraint on disposition of property), 57(2) (reserve funds), 95 (liens on land) and 98 (dissolution of utility on default).

Two sections of the *Utilities Commission Act* that do not apply to BC Hydro are with regard to the issuance of securities (Sections 50 and 51(c)), which are defined to include shares, bonds, debentures, notes or other obligations. The result of this exemption is that BC Hydro does not need to seek British Columbia Utilities Commission approval for the issuance of securities. Further, section 52 exempts BC Hydro from any requirements to seek British Columbia Utilities Commission approval for the disposition of property, franchises, licences, permits, concessions, privileges or rights.

BC Hydro is a public utility under the *Utilities Commission Act*, and its rates are subject to approval by the British Columbia Utilities Commission in accordance with the applicable provisions of the *Utilities Commission Act*, *Clean Energy Act* and regulations.

2.2.5 Government's Mandate Letter to BC Hydro

The Government issues a letter to BC Hydro each year that confirms BC Hydro's mandate, provides government's strategic direction and sets out key performance expectations for the fiscal year. Government's mandate letter to BC Hydro for the fiscal 2017 period sets out the following strategic actions:

- Continue to implement the 2013 10 Year Rates Plan to keep electricity rates low and predictable by optimizing resources and advancing its revenue requirements and rate design applications;
- Deliver our overall capital plan portfolio on time and on budget to maintain the reliability of the system, support B.C.'s economic growth and meet the needs of customers;
- Deliver the Site C Clean Energy Project on time and on budget and ensure First Nations and local communities have the ability to participate in economic development opportunities arising from the construction of the project;
- Work with Clean Energy B.C. to identify further opportunities for clean energy producers in British Columbia;
- Improve customer satisfaction by providing timely and responsive service and exploring innovative energy conservation solutions such as load curtailment rates; and

- Implement the five-year safety plan to ensure the safety of our workforce and the public.

A copy of the mandate letter is provided in Appendix D.

2.3 Regulatory Framework Applicable to the Application

This section reviews notable aspects of the unique regulatory framework applicable to the British Columbia Utilities Commission's consideration of this application.

2.3.1 Directions No. 6 and No. 7 to the British Columbia Utilities Commission and Constraint on British Columbia Utilities Commission Oversight

On March 5, 2014, following the announcement of the 2013 10 Year Rates Plan, government provided direction to the British Columbia Utilities Commission pursuant to Direction No. 6 to the British Columbia Utilities Commission (Order in Council No. 96) with respect to BC Hydro's rates, demand-side management expenditures, regulatory accounts and regulatory account transfers for the fiscal 2014 to fiscal 2016 period. Government also issued Direction No. 7 to the British Columbia Utilities Commission (Order in Council No. 97) on March 5, 2014.

Directions No. 6 and 7 were issued pursuant to section 3(1) of the *Utilities Commission Act*. Pursuant to section 3(2) of the *Utilities Commission Act* the British Columbia Utilities Commission must comply with a direction issued under subsection 3(1) despite any other provision of the *Utilities Commission Act*, the *Clean Energy Act*, the regulations under either of those Acts, and any previous British Columbia Utilities Commission decision.

Pursuant to Direction Nos. 6 and 7, the British Columbia Utilities Commission issued Order No. G-48-14 dated March 24, 2014 setting BC Hydro's rates for fiscal 2014 to fiscal 2016. With the issuance of Order No. G-48-14, Direction No. 6 has no ongoing effect. Direction No. 7 applies to the British Columbia Utilities

Commission's regulation of BC Hydro going forward and specifically for the test period covered by this application.

Direction No. 7 includes the following directives that are relevant to this application and which constrain regulatory oversight by the British Columbia Utilities Commission of certain aspects BC Hydro's revenue requirements:

- BC Hydro's rate increases for fiscal 2017, fiscal 2018 and fiscal 2019 are capped at 4 per cent, 3.5 per cent and 3 per cent, respectively;[8]
- The British Columbia Utilities Commission must order BC Hydro to defer to the Rate Smoothing Regulatory Account the portion of BC Hydro's allowed revenue requirement for each of fiscal 2017 to fiscal 2019 that is forecast not to be recovered by the rates above;[9]
- The deferral account rate rider remains at 5 per cent;[10]
- The British Columbia Utilities Commission must ensure that the rates allow BC Hydro to collect sufficient revenue to enable it to (a) provide reliable electricity service, (b) meet all of its debt service, tax and other financial obligations, and (c) comply with government policy directives requiring BC Hydro to construct, operate or extend a plant or system;[11]
- The calculation of BC Hydro's deemed equity for rate-making purposes is prescribed, and BC Hydro's allowed rate of return on deemed equity is equal to:[12]
  - for fiscal 2017, 11.84 per cent; and
  - for fiscal 2018 and fiscal 2019, the percentage necessary to yield a distributable surplus[13] in the fiscal year equal to the product of (i) the

8 Direction No. 7, section 9(1).
9 Direction No. 7, section 9(2).
10 Direction No. 7, section 10.
11 Direction No. 7, section 4(a) to (c).
12 Direction No. 7, section 4(d)(i) and (ii).

distributable surplus in the immediately preceding fiscal year, and (ii) 100 per cent plus the percentage change in the British Columbia consumer price index in the applicable fiscal year.

- The British Columbia Utilities Commission must ensure that the rates allow BC Hydro to allocate annual distributable surpluses in the manner specified by Heritage Special Directive No. HC1 to BC Hydro;[14]
- Requirements for regulatory accounts;[15]
- The net income of BC Hydro's subsidiaries is to be included for rate-making purposes;[16]
- The British Columbia Utilities Commission must not disallow the recovery in rates of the costs that have been incurred by BC Hydro or its subsidiary Powerex Corp. related to:[17]
  - the construction of extensions to BC Hydro's plant or system that come into service before fiscal 2017[18];
  - energy supply contracts entered into before fiscal 2017 (note that BC Hydro will be filing for review by the British Columbia Utilities Commission under section 71 of the *Utilities Commission Act* all renewals of energy purchase agreements and any new energy purchase agreements made during the test period);
  - the Rock Bay settlement;
  - the First Nations settlements;

[13] Distributable surplus, as defined in section 1 of Direction No. 7, has the same meaning as in Heritage Special Directive No. HC1 to the British Columbia Hydro and Power Authority, which is equal to "for a fiscal year, the consolidated net income earned by the authority and its subsidiaries from all sources, as included in the authority's audited consolidated financial statements for that year".

[14] Direction No. 7, section 8.

[15] Direction No. 7, section 7.

[16] Direction No. 7, section 6.

[17] Direction No. 7, section 11.

[18] Appendix K provides information on capital additions in fiscal 2015 and fiscal 2016.

- the California settlements;
- the Burrard costs; and
- the costs deferred in the SMI regulatory account.

- The British Columbia Utilities Commission must refrain from performing its duty under section 4(5) of the *Clean Energy Act* (regarding expenditures for export) when setting rates for BC Hydro for fiscal 2017 and fiscal 2018.[19] (Refer to section 2.3.7.1 for further discussion);
- The British Columbia Utilities Commission may not exercise any power under Part 3 of the *Utilities Commission Act* in regard to the gas and electricity trading activities of Powerex.[20]

The Application sections include references to specific provisions of Direction No. 7 where they are pertinent to the subject matter discussed. A complete copy of Direction No. 7 is provided in Appendix C of this application.

2.3.2 Section 44.2 of the *Utilities Commission Act*

In this application, we are seeking acceptance of a demand-side management expenditure schedule pursuant to section 44.2 of the *Utilities Commission Act*. Section 44.2(5.1) applies to the British Columbia Utilities Commission's consideration of expenditure schedules filed by BC Hydro. Pursuant to section 44.2(5.1), in considering whether to accept the demand-side management expenditure schedule filed by BC Hydro, the British Columbia Utilities Commission must consider:[21]

- The interests of persons in British Columbia who receive or may receive service from BC Hydro;

[19] Direction No. 7, section 12.
[20] Direction No. 7, section 13.
[21] Section 44.2(5.1) used to require that the British Columbia Utilities Commission "consider and be guided by" the specified criteria. The *Miscellaneous Statutes Amendment Act (No. 3), 2015* amended sections 44.2(5.1), 46(3.3) and 71(2.21) and (2.51) by striking out "and be guided by", effective as of November 17, 2015.

- British Columbia's energy objectives;
- The applicable Integrated Resource Plan approved by the Lieutenant Governor in Council; and
- The extent to which the demand-side measures are cost-effective within the meaning prescribed by the Demand-Side Measures Regulation.

Pursuant to section 44.2(3), the British Columbia Utilities Commission must accept the schedule if the British Columbia Utilities Commission considers that making the expenditures would be in the public interest or reject the schedule. Alternatively, the British Columbia Utilities Commission may accept or reject a part of the schedule.

The information and analysis supporting BC Hydro's demand-side management expenditure schedule request is provided in Chapter 10 of the Application.

2.3.3 Direction to the British Columbia Utilities Commission respecting the Authority's Thermal-mechanical Pulping Program

Pursuant to the Direction to the British Columbia Utilities Commission Respecting the Authority's TMP Program (Order in Council No. 404 approved and ordered on July 14, 2015), the British Columbia Utilities Commission must not disallow the recovery in rates of the costs incurred by BC Hydro, up to $100 million, in carrying out the thermal-mechanical pulping program to provide funding to increase the electrical energy efficiency of mills that use thermo-mechanical pulping processes. In addition, the Direction specifies that thermal-mechanical pulping program costs are to be deferred to BC Hydro's Demand-Side Management Regulatory Account. A copy of the Direction to the British Columbia Utilities Commission respecting the Authority's Thermal-Mechanical Pulping Program is included in Appendix CC.

2.3.4 Direction to the British Columbia Utilities Commission respecting a Mining Customer Payment Plan

Pursuant to the Direction to the British Columbia Utilities Commission Respecting Mining Customers (Order in Council No. 123 approved and ordered on

February 29, 2016), BC Hydro has set up a mechanism to allow certain mining customers in the province to temporarily defer payment of a portion of their BC Hydro electricity bills, to help those mines remain in operation while the prices for the commodities they produce are low. On the portion of bills for which payment has been temporarily deferred, interest is charged at rates prescribed in the Direction. Customers will pay back the unpaid portion of bills, plus the prescribed interest, when commodity prices are higher or at the end of the program in accordance with the Direction. The Direction requires the setting up of a regulatory account to defer to future fiscal years specified amounts related to mining customers and the amount due under the payment plan that are impaired. British Columbia Utilities Commission Order No. G-34-16 approved the Mining Customer Payment Plan Regulatory Account. Further details are found in Chapter 7. A copy of the Direction to the British Columbia Utilities Commission Respecting Mining Customers is included in Appendix C.

2.3.5 Integrated Resource Plan

The 2013 Integrated Resource Plan and Load Resource Balances provide context for BC Hydro's expectations respecting renewal of electricity purchase agreements with IPPs and acquisitions under the Standing Offer Program, as discussed in section 3.4.3.4 and 3.4.3.5 of this application. The 2013 Integrated Resource Plan and Load Resource Balances are also considerations relevant to the fiscal 2017 to fiscal 2019 Demand-Side Management Expenditures discussed in Chapter 10 of this application.

2.3.6 2016/17 – 2018/19 Service Plan

Annually, BC Hydro is required to file a service plan to Government in accordance with the *Budget Transparency and Accountability Act*. The Fiscal 2017 – Fiscal 2019 Service Plan is found in Appendix E. The Service Plan establishes BC Hydro's mission as being to provide our customers with reliable, affordable, clean electricity throughout B.C., safely. It stipulates four strategic goals to guide our actions, each supported by corresponding strategies, performance measures and targets.

BC Hydro will be working towards meeting these goals over the next three years. The performance measures are set out in Table 2-1 to Table 2-4 below, for each of the four respective key goals. The tables also indicate how we have done over the last five years for those measures that were in place (Appendix E also provides the information in Table 2-1 to Table 2-4 including detailed footnotes).

2.3.6.1 Goal 1 - Set the Standard for Reliable and Responsive Service. We will Evaluate Ourselves Using Four Performance Measures: SAIDI, SAIFI, Key Generating Facility Forced Outage Factor, a CSAT[22] Index and the Attainment of a Gold Progressive Aboriginal Relations Designation

The following measures are important to assess performance in generation and system reliability compared to other peer utilities; to consistently be responsive to our customers; and to recognize the importance of proactive First Nations engagement and partnerships. A new measure was also introduced in the Fiscal 2017 to Fiscal 2019 Service Plan to reflect the investments in key generating facilities to ensure the reliability of supply throughout the year.

[22] Performance Measure descriptions, rationale, date source information and benchmarking is available at www.bchydro.com/performance.

Table 2-1 Performance Measures – Reliable and Responsive Service

Performance Measures	Four-Year Average	Actual F2014	Actual F2015	Target F2016	Actual F2016	Target F2017	Target F2018	Target F2019
SAIDI (duration) [total outage duration (in hours) experienced by an average customer in a year]	3.25	3.59[3]	3.07	3.22	**3.01**	3.22	3.20	3.20
SAIFI (frequency) [Number of sustained disruptions per year] (excluding major events)	1.43	1.56	1.30	1.40	**1.48**	1.40	1.35	1.35
Key Generating Facility Forced Outage Factor	2.0	1.6	1.5[5]	NR[6]	**NR**	2.0	2.0	1.8
CSAT Index [Customer Satisfaction Index: % of customers satisfied or very satisfied]	86.8	85.0	86.0	85.0	**87.0**	85.0	85.0	85.0
Progressive Aboriginal Relations Designation	Gold	Gold	Gold	Gold	**Gold**	Gold	Gold	Gold

Refer to Appendix E for detailed footnotes to this table

Service Quality and Reliability

Since fiscal 2012 BC Hydro's service quality and system reliability have performed better than the overall average of Canadian Utilities as measured by the Canadian Electrical Association and reported to the British Columbia Utilities Commission in BC Hydro's annual report on reliability indices. Appendix U is the May 2016 Annual Reporting of Reliability Indices, which provides a detailed description of each measure.

Operating a 78,000 km transmission and distribution system across British Columbia and its varied terrain is challenging. BC Hydro considers that SAIFI and SAIDI are important as these measure our ability to reliably deliver power to customers. SAIFI is a measure of the number of sustained interruptions an average customer will experience over a year, and SAIDI is a measure of the amount of time, in hours, that an average distribution customer is without power in a year. The results show that BC Hydro has consistently been performing better than our Canadian Electrical Association peers over the three years since fiscal 2013 (for both measures, the lower the number the better):[23]

- For fiscal 2013, fiscal 2014 and fiscal 2015, the Canadian Electrical Association average SAIDI measures were 4.66, 9.49 and 6.38, respectively;
- With regard to the SAIFI measure, the Canadian Electrical Association average measures were 2.54, 2.72 and 2.39 for each of fiscal 2013, fiscal 2014 and fiscal 2015, respectively.

A new measure is the Key Generating Station Forced Outage Factor which measures the total forced outage time in a period relative to the total number of hours in the period (usually a year). Given the ageing of our generating assets, BC Hydro is now refocusing on the performance of its Key Generating Facility units' health. Our target is to keep the Key Generating Station Forced Outage Factor below 2 per cent.

In addition, BC Hydro must implement Mandatory Reliability Standards as adopted by the British Columbia Utilities Commission. The standards program requires on-site audits conducted by the Western Electricity Co-ordinating Council every three years. BC Hydro has been through two on-site audits and achieved a "no findings" result for both.

The measures in Table 2-1 above are averages across BC Hydro's system. Within our system, there are areas that already have reduced reliability and service quality or are at risk as they are reaching the limits of their design. We have identified those areas and are focusing our capital plans to address these risks and increase reliability and quality of service, under a prioritization framework as described in Chapter 6.

[23] Fiscal 2016 measures from the Canadian Electrical Association are not yet available.

Customer Service

A further measure of BC Hydro's service to our customers is the Customer Satisfaction Index, noted above in Table 2-1, which tells us what percentage of our customers were satisfied or very satisfied. Over the last five years, BC Hydro has had a Customer Satisfaction Index in the range of 89 per cent to 85 per cent, indicating the large majority of customers approve of our service as shown in Table 2-1. While these Customer Satisfaction Index results are good, customers' expectations of service are changing and are getting higher with respect to what they view as basic customer service. We can no longer just compare ourselves to other utilities, as our customers are basing their service expectations on their experience with other service providers such as banks, airlines, and retail outlets. As a result, in order to maintain our Customer Satisfaction Index at the current level, we believe we need to do more to make it easier for our customers to do business with us (refer to section 5.5.1.1. of Chapter 5 for more discussion of our customer strategy).

2.3.6.2 Goal 2 – Ensure Rates Are Among the Most Affordable in North America

Given the scope of system infrastructure renewal and expansion investments underway, it is important to benchmark our rates against other utilites to ensure that British Columbia's competitive advantage of low cost electricity is protected. This includes closely monitoring capital project spending to ensure projects are being delivered on time and on budget.

Table 2-2 Performance Measure – Affordable Rates

Performance Measures	Four-Year Average	Actual F2014	Actual F2015	Target F2016	Actual F2016	Target F2017	Target F2018	Target F2019
Competitive Rates	1st quartile	1st quartile	1st quartile	1st quartile	1st quartile	1st quartile	1st quartile	1st quartile
Project Budget to Actual Cost	-1.8% on $3.94 billion	-4.75% on $3.33 billion	-1.8% on $3.94 billion	Within +5% to -5% of budget excluding project reserve amounts	Within +5% t-0.18% on $6.49 billion	Within +5% to -5% of budget excluding project reserve amounts	Within +5% to -5% of budget excluding project reserve amounts	Within +5% to -5% of budget excluding project reserve amounts

Refer to Appendix E for detailed footnotes to this table.

Customer Rates

BC Hydro has amongst the lowest rates of a major utility in North America.

BC Hydro participates in Hydro Quebec's annual comparison of electricity rates and our residential rates, small power rates, medium power rates and large power average prices are the third, fifth, fourth and fifth lowest in North America among the major utilities surveyed, placing all of our rates in the first quartile. Table 2-3 below illustrates the ranking for our residential customers. (Refer to Appendix EE for the Hydro-Quebec 2015 Electricity Rate Comparison Annual Report and BC Hydro's report to Government, which both provide information on the rankings of all of customer classes).

Table 2-3 First Quartile Average Power Prices – Residential Customer Class

Rank	Hydro-Quebec Electricity Prices Comparison Report Prices as of April 1, 2015 (cents/kWh)							
	Utility	**City**	**625 kWh**	**750 kWh**	**1,000 KWh**	**2,000 kWh**	**3,000 kWh**	**Average[1]**
1	Hydro-Quebec	Montreal	7.63	7.31	7.19	7.90	8.13	7.63
2	Manitoba Hydro	Winnipeg	8.55	8.35	8.11	7.75	7.62	8.08
3	BC Hydro	Vancouver	9.27	9.54	10.29	11.42	11.8	10.46
4	EPCOR Energy	Edmonton	12.91	12.3	11.55	10.41	10.04	11.44
5	Nfld Power	St. John's	12.41	12.03	11.55	10.84	10.6	11.49
6	ENMAX	Calgary	12.94	12.37	11.66	10.58	10.23	11.56

1 Simple average of rates.

Capital Projects

BC Hydro also has a record of delivering its capital projects on budget. BC Hydro plans and manages its overall capital plan on a portfolio basis, and updates its plans several times throughout the year. BC Hydro uses a five-year rolling average of its total project portfolio to measure how well we have performed in delivering projects on budget. This measure has consistently shown since fiscal 2012 that BC Hydro has been coming in under budget on its overall capital project portfolio. Most recently, over the last five years from fiscal 2012 to fiscal 2016, BC Hydro has completed 563 capital projects, with capital expenditures totalling $6.5 billion. These projects in aggregate were delivered 0.18 per cent under budget.

2.3.6.3 Goal 3 – Continue British Columbia's Leading Commitment to Clean and Renewable Power

The following measures reflect core provincial government requirements for clean generation and energy conservation program delivery savings as set out in the *Clean Energy Act*. The calculation for the conservation portfolio savings was revised this year to reflect an incremental annual approach versus the cumulative savings over the 2007 to 2020 year horizon.

Also shown in Table 2-4 below, BC Hydro has been able to meet its requirement under the *Clean Energy Act* to generate at least 93 per cent of energy from clean or renewable resources. Since fiscal 2012 we have exceeded that target in every year.

Table 2-4 Performance Measures – Renewable, Clean Power

Performance Measures	Four-Year Average	Actual F2014	Actual F2015	Target F2016	Actual F2016	Target F2017	Target F2018	Target F2019
Energy Conservation Portfolio (New Incremental GWh/year)	800	500	7003	NR4	NR	700	700	600
Clean Energy (%)	97.8	97.1	97.9	93.0	98.3	93.0	93.0	93.0

Refer to Appendix E for detailed footnotes to this table

2.3.6.4 Goal 4 – Safety Above All

The following measures reflect that BC Hydro, as an electric utility, operates in a high hazard environment and must ensure that our workforce safely executes their work without injury. BC Hydro must also ensure that the public is safe around our assets. As the safety record of BC Hydro continues to lag compared to other utilities, a new measure is being introduced in the fiscal 2017 to fiscal 2019 Service Plan to improve the timeliness of corrective actions from identified deficiencies following safety incidents (injuries and near misses) that have a direct impact on the safety of our workforce.

Table 2-5 Performance Measures – Safety

Performance Measures	Four-Year Average	Actual F2014	Actual F2015	Target F2016	Actual F2016	Target F2017	Target F2018	Target F2019
Zero Fatality & Serious Injury [Loss of life or the injury has resulted in a permanent disability]	0.75	0	1[3]	0	0	0	0	0
Lost Time Injury Frequency, [Number of employee injury incidents resulting in lost time (beyond the day of the injury) per 200,000 hours worked]	1.1	1.1[5]	1.0	1.0	1.1	1.0	0.9	0.8
Timely Completion of Corrective Actions (%)	84	84	78[7]	NR[8]	NR	85	90	95

Refer to Appendix E for detailed footnotes to this table

We are proposing additional funding in fiscal 2017 to fiscal 2019 for these significant priorities, which are described further in section 5.7.6 of Chapter 5.

2.3.7 The *Clean Energy Act*

Sections 7 and 8 of the *Clean Energy Act* are relevant to the British Columbia Utilities Commission's consideration of this application. Section 7 specifies a list of projects, programs, contracts and expenditures of BC Hydro and exempts them from British Columbia Utilities Commission approval requirements under sections 45 to 47 and 71 of the *Utilities Commission Act* to the extent applicable. Section 8 of the *Clean Energy Act* provides that in setting rates under the *Utilities Commission Act* for BC Hydro, the British Columbia Utilities Commission must ensure that the rates allow BC Hydro to collect sufficient revenue in each fiscal year to enable it to recover its costs incurred with respect to (i) the achievement of electricity self-sufficiency, and (ii) the projects, programs, contracts and expenditures referred to in section 7 of the *Clean Energy Act*.

In addition, the *Clean Energy Act*, section 2, defines British Columbia's energy objectives, which the British Columbia Utilities Commission is required to consider in reviewing the demand-side management expenditure schedule included with the Application as noted above.

2.3.7.1 Expenditures for Export

Section 4(5) of the *Clean Energy Act* does not apply to this application. Section 4(5) requires that the British Columbia Utilities Commission ensure that BC Hydro's rates do not recover "expenditures for export", which are defined in the *Clean Energy Act* as follows:

> ""expenditures for export" means the amount of an expenditure for the construction or extension of a plant or system or for an acquisition of electricity that is in addition to the amount the authority would have had to spend
>
> (a) to achieve electricity self-sufficiency; and
>
> (b) to undertake anything referred to in section 7(1), except to the extent the expenditure is accounted for in paragraph (a)"

According to this definition, "expenditures for export" are the costs of constructing physical works or purchasing energy in addition to those costs that BC Hydro would have to spend to "achieve electricity self-sufficiency" and to undertake the exempt projects and programs that are list in section 7(1) of the *Clean Energy Act*.

Since the enactment of the *Clean Energy Act*, the prospects of export sales of renewable energy in excess of that required to meet self-sufficiency requirements have diminished considerably. Subsequently, Direction No. 7 was issued, which, as amended by Order in Council No. 539 dated July 19, 2016, states “the commission must refrain from performing its duty under section 4(5) of the *Clean Energy Act* when setting rates for the authority for F2014, F2015, F2016, F2017, F2018 and F2019.” BC Hydro therefore does not address the topic of expenditures for export in this application.

2.3.8 Meter Choices Program Charges

BC Hydro is not seeking approval in this application of any changes to the Meter Choices Program. In the context of BC Hydro’s 2015 Rate Design Application, the British Columbia Utilities Commission determined in Order No. G-175-15 that there was no compelling reason for the Meter Choices Program rates to be revisited in the rate design proceeding as the rates had just recently been set and there was no evidence in support of reviewing them at that time.

BC Hydro is currently in the process of a detailed review of the costs of the Meter Choices Program. This review is expected to be completed in the fall of 2016 and will be submitted to the British Columbia Utilities Commission. If the analysis indicates a change to the Meter Choices Program rates is necessary, BC Hydro will be filing a separate application with the British Columbia Utilities Commission for approval of the new rates.

2.4 Summary of Regulatory Framework

Table 2-6 below provides a summary of the key statutes that have an impact on the regulatory oversight of BC Hydro by the British Columbia Utilities Commission. The table provides a synopsis of the regulatory framework the British Columbia Utilities Commission is guided by on key policy areas addressed in this application. The specific sources identified should be consulted for the actual wording of the statutes.

Table 2-6 Key Regulatory Statutes

Policy Area	Synopsis	Source
British Columbia Utilities Commission Review Exemptions	BC Hydro is exempt from sections 45 to 47 and 71 (Certificate of Public Convenience and Necessity & Energy Supply Contracts) of the *Utilities Commission Act* to the extent applicable, with respect to the following projects, programs, contracts and expenditures of BC Hydro: • The Northwest Transmission Line, • Mica Units 5 and 6, • Revelstoke Unit 6, • Site C Clean Energy Project, • A bio-energy Phase 2 call to acquire up to 1 000 gigawatt hours per year of electricity, • One or more agreements with pulp and paper customers eligible for funding under Canada's Green Transformation Program, • The clean power call request for proposals, • The standing offer program.	*Clean Energy Act*
British Columbia Utilities Commission Review Exemptions	Section 32 of the *BC Hydro Power and Authority Act* exempts BC Hydro from sections 50, 51 (c), and 52 of the *Utilities Commission Act* with respect to the need for British Columbia Utilities Commission approval to issue securities, including the setting of interest rates for those securities, or for the disposition of property.	*BC Hydro Power and Authority Act*
ROE	BC Hydro's rate of return on equity will remain at 11.84 per cent for fiscal 2017. For fiscal 2018 and fiscal 2019 BC Hydro will earn the return on equity that is required to yield a distributable surplus (essentially net income) in fiscal 2018 and in future years equal to the previous years net income plus BC inflation.	Direction No. 7
Dividend	Special Direction HC1 sets out the dividend calculation for BC Hydro.	HC1
Deferral Account Rate Rider	The British Columbia Utilities Commission must set the deferral account rate rider for fiscal 2015 and future fiscal years at 5% and may not change the rider except on application by BC Hydro.	Direction No. 7
Powerex	The British Columbia Utilities Commission may not exercise any power under Part 3 of the *Utilities Commission Act* in regard to the gas and electricity trading activities of Powerex Corp.	Direction No. 7

Policy Area	Synopsis	Source
Expenditures for Export	The British Columbia Utilities Commission must refrain from performing its duty under section 4 (5) of the *Clean Energy Act* when setting rates for BC Hydro for F2014, F2015, F2016, F2017, F2018 and F2019. Section 4(5) of the *Clean Energy Act* states: "(5) In setting rates for BC Hydro, the British Columbia Utilities Commission must ensure that the rates do not allow the authority to recover: (a) its expenditures for export as set out in a report approved by the Lieutenant Governor in Council under subsection (4), and (b) any other expenditures for export."	Direction No. 7 Order in Council No. 539
Rates Smoothing Account	The British Columbia Utilities Commission must not allow BC Hydro's rates to increase by more than: • 4% in F2017, • 3.5% in F2018 or • 3% in F2019. If the base line rate change exceeds the above values, the British Columbia Utilities Commission must order BC Hydro to defer to the rate smoothing regulatory account the forecast revenue that BC Hydro earns minus the forecast revenue that BC Hydro would have earned from the above rate increases.	Direction No. 7
Cost Recovery	When setting rates for BC Hydro under the *Utilities Commission Act*, the British Columbia Utilities Commission must not disallow the recovery in rates of the costs that were incurred by BC Hydro with respect to: • *Construction of extensions to BC Hydro's plant or system that come into service before F2017* • *Energy supply contracts entered into before F2017* • *The Rock Bay settlement* • *The First Nations settlement* • *The California settlements* • *The Burrard Costs* • *The costs deferred to the SMI Regulatory Account*	Direction No. 7
Thermal-Mechanical Pulping Program	The British Columbia Utilities Commission must not disallow for any reason the recovery of rates of the costs incurred by the authority in carrying out the Thermal-Mechanical Pulping program. The costs recovered by rates cannot exceed $100 million. BC Hydro is to defer to the Demand-Side Management Regulatory Account costs incurred as a result of carrying out the Thermal-Mechanical Pulping program.	Order in Council No. 404 (TMP Pricing)

Policy Area	Synopsis	Source
Regulatory Accounts	When setting rates for the BC Hydro, the British Columbia Utilities Commission: • Must allow BC Hydro to continue to defer heritage deferral account variances between the actual and forecast heritage payment obligation. • Must allow BC Hydro to continue to defer to the trade income deferral account the variances between actual and forecast trade income. • Must, in regard to the non-heritage deferral account, allow BC Hydro to defer variances between actual and forecast cost of energy arising from differences between actual and forecast domestic customer load, and Burrard costs. • Must, in regard to the Demand-Side Management Regulatory Account, allow BC Hydro to defer to that account BC Hydro's cost arising from demand-side management programming, with the account having a 15 year amortization. • Must allow BC Hydro to continue to defer to the Rock Bay remediation account the Rock Bay costs. • Must allow BC Hydro to continue to defer to the asbestos remediation account the asbestos costs. • Must allow BC Hydro to continue to defer to the non-current pension remediation account the non-current costs. • Must allow BC Hydro to establish the following regulatory accounts: – An account to defer for recovery in rates in future fiscal years of BC Hydro those portions of the BC Hydro's allowed revenue requirement in a particular fiscal year that we not recovered in rates in that particular fiscal year; – An account to defer the variances between BC Hydro's actual and forecast real property gain/loss. • Must allow the First Nations costs and real property sales regulatory accounts to accrue interest in a fiscal year at BC Hydro's weighted average cost of debt in that year. • Must set BC Hydro's rates in such a way as to allow the regulatory accounts to be cleared from time to time and within a reasonable period.	Direction No. 7
Mining Customers	The British Columbia Utilities Commission must allow BC Hydro to establish a regulatory account to defer to future fiscal years amounts equal to the sum of the impaired account balances of mining customers (refer to Order in Council for definition of eligible). This account will include interest charges determined in a fiscal year at a rate equal to BC Hydro's weighted average cost of debt in that fiscal year.	Order in Council No. 123 (Mining)

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Fiscal 2017 to Fiscal 2019

Revenue Requirements Application

Chapter 3

Load and Revenue Forecast

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3.1 Introduction

This chapter provides our Load Forecast and the associated Revenue Forecast. It provides context from the approved 2013 Integrated Resource Plan, updated Load Resource Balances[24] and Long Run Marginal Costs.

On February 26, 2016 BC Hydro announced that it would delay filing its Fiscal 2017 - Fiscal 2019 Revenue Requirements Application. The delay allowed BC Hydro to update the Load Forecast and the Load Resource Balances to reflect the current outlook of certain sectors, including more recent developments in mining and LNG plant[25] loads. BC Hydro finalized the Load Forecast presented in this application in May 2016, The Load Forecast and Load Resource Balances take into account these recent developments in the mining and LNG sectors and also reflect current information on loads from other industry sectors. The May 2016 Load Forecast continues to predict long-term load growth across all three customer sectors; however, load is forecast at a lower growth rate compared to the 2013 Integrated Resource Plan. Over the next 20 years (fiscal 2017 to fiscal 2036), BC Hydro expects demand growth with LNG before demand-side management to be 39 per cent, and demand growth with LNG after demand-side management to be 29 per cent.

The Load Forecast, Revenue Forecast and Integrated Resource Plan inform BC Hydro's revenue requirements as follows:

- ***Load Forecast:*** The Load Forecast is a key input into BC Hydro's short-term operational and financial planning and revenue projections, and long-term resource planning processes. The first three years of the Load Forecast shown in section 3.2 are key inputs for the Revenue Forecast described in section 3.3 and the Cost of Energy described in Chapter 4 for the test period (fiscal 2017 to

[24] Load Resource Balance is the difference between BC Hydro's forecast load and forecast supply.

[25] BC Hydro is aware of the July 11, 2016 announcement by LNG Canada that they have delayed their Final Investment Decision beyond December 2017; however, this has not been reflected in this Application as the impact is not yet known.

fiscal 2019). The Load Forecast is also a key input for BC Hydro's Load Resource Balances and our Ten Year Rates Plan;

- ***Revenue Forecast:*** The Revenue Forecast is based on the energy sales as shown in section 3.2.2 and the electric rate schedules for fiscal 2016 that were approved by British Columbia Utilities Commission Order No. G-48-14. In general, the Revenue Forecast is compared to the Total Rate Revenue Requirement, shown in Appendix A, Schedule 1.0, to determine the Revenue Shortfall, from which BC Hydro's proposed rate increases and transfers to the Rate Smoothing Regulatory account are derived; and
- ***Integrated Resource Plan:*** The 2013 Integrated Resource Plan with updated Load Resource Balances and the Long Run Marginal Cost provide context for BC Hydro's expectations respecting renewal of Electricity Purchase Agreements with IPP and acquisitions under the Standing Offer Program, as discussed in section 3.4.3.5 and 3.4.3.6 of this chapter. The 2013 Integrated Resource Plan with updated Load Resource Balances and the Long Run Marginal Cost are also relevant to the fiscal 2017 to fiscal 2019 demand-side management expenditures discussed in Chapter 10 of the Application. Further details regarding the Integrated Resource Plan under the *Clean Energy Act* can be found in Chapter 2, section 3.4.1.

This Chapter is organized as follows:

- Section 3.2 describes BC Hydro's Load Forecast methodology and results for the test period for each of BC Hydro's main customer sectors. The Load Forecast methodology is generally consistent with the methodology used to prepare the December 2012 Load Forecast contained in the 2013 Integrated Resource Plan and with prior Load Forecasts reviewed by the British Columbia

Utilities Commission.[26] The approach to forecasting electrified downstream LNG loads is discussed in section 3.2.1.1;

- Section 3.3 describes how BC Hydro has used an appropriate Revenue Forecast methodology and shows the forecasted revenue for the test period from each of BC Hydro's main customer sectors; and
- Section 3.4 describes the updated Load Resource Balances and the Long-Run Marginal Costs. It explains that the recommended actions from BC Hydro's approved 2013 Integrated Resource Plan, with a modification related to the outlook for demand-side management, remain appropriate.

Please note, in the tables in this Chapter, references to F2015 RRA or F2016 RRA signifies the Plan amount from the Fiscal 2015 – Fiscal 2016 Revenue Requirements Rate Application.

3.2 Load Forecast

This section describes the methodologies used to develop the Load Forecast (high and low band and mid-level projection) and the forecast results. BC Hydro believes that the methodology is sound and the results are reasonable. BC Hydro's core methodology, which is consistent with the British Columbia Utilities Commission's resource planning guidelines, includes a detailed gross (pre-demand-side management) load projection of large industrial accounts and their uses of electricity as well as end use projections of electricity for the residential and commercial sectors. Previous British Columbia Utilities Commission reviews of the Load Forecast, such as the review undertaken for BC Hydro's 2008 Long Term Acquisition Plan proceeding, concluded that BC Hydro's Load Forecast was acceptable. The Government's review of BC Hydro in 2011 indicated its forecasting process is well planned, and produces reliable results.

[26] The Load Forecast has been before the British Columbia Utilities Commission in the following processes: 2003 Vancouver Island Generation Project – Certificate of Public Convenience and Necessity Application, 2006 Vancouver Island Call for Tenders Electricity Purchase Agreements, 2006 Integrated Electricity Plan, 2008 Long-term Acquisition Plan and 2008 LTAP Evidentiary and the Update Fiscal 2009 and Fiscal 2010 Revenue Requirements Application.

3.2.1 Load Forecast Methodology[27]

BC Hydro's main customer sectors are residential, light industrial/commercial (i.e., general service sector distribution voltage connected), large industrial[28] (i.e., transmission voltage connected) and other. The other sector includes street lights, irrigation, and sales to other utilities including Fortis BC Electric, the City of New Westminster, Seattle City Light and Hyder, Alaska. When combined, these sectors form the total domestic sales forecast.

The total domestic sales forecast is prepared prior to taking Demand-Side Management Plan savings into account. The Demand-Side Management Plan savings are subsequently subtracted from the residential, light industrial/commercial, and large industrial categories to provide the net after Demand-Side Management Load Forecast needed to estimate revenues as described in section 3.3. Elements that make up the demand-side management savings are found in Chapter 10 of this application.

The Load Forecast is prepared using models that align the relationship between sales and drivers of future sales. Drivers include projections of economic variables such as Gross Domestic Product (**GDP**), efficiency of residential and commercial appliances, temperature, commodity prices and electricity rate increases.[29]

Load forecasting is inherently an uncertain undertaking with volatile drivers of future requirements. As such, the Load Forecast consists of a high and low band and includes a mid-level projection. In general, load projections in the industrial sector

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27 The current peak demand methodology is consistent to the methodology used to develop the peak demand forecast contained in the 2013 Integrated Resource Plan. The methodology in this section focuses on the energy sales forecast as these projections determine anticipated revenues. The peak demand forecast for this Load Forecast is provided in Schedule 14.0 of Appendix A of this Application.

28 The large industrial sector also includes larger universities which are served at transmission voltage. These large universities are considered to be commercial transmission customers and are included in sub-category industrial other.

29 Consistent with prior load forecasts, the residential, light industrial/commercial, large industrial and other sector sales forecasts before Demand-Side Management reflect the result of future rate increases, which is known as rate impacts. The forecast with rate impact applies an elasticity of -0.05 to each of the main customer sectors. This calculation uses rate increase projections in real dollar terms, including the Deferred Account Rate Rider.

are represented as a probabilistic assessment of their likelihood to materialize and, while the probabilities for individual customers are held confidential, the summation of the loads provides a reasonable system wide estimate.

The following sub-sections provide an overview of the specific characteristics, methodologies and models used to develop the forecasts for each of the main customer sectors. While following the same general approach, each sector has different drivers of growth and they also differ by whether trending forecast programs are used or whether they are produced on an account by account basis.

3.2.1.1 Liquefied Natural Gas

The forecasting of electrified Liquefied Natural Gas (**LNG**) plant loads has been approached differently in this Load Forecast. The sector is unique in that it is not yet developed, there are only three proponents that are proposing to electrify from the grid (therefore not allowing for a confidential aggregation of a probabilistic Load Forecast), and is of keen public interest. For these reasons, BC Hydro has decided to transparently include the volume of load which these proponents have announced will be supplied by BC Hydro (and for which BC Hydro has service requests) and the load estimates and in-service dates are based upon publicly available information. The LNG Load Forecast during the test period is relatively small compared to the longer-term outlook, ranging from 57 GWh in fiscal 2017 to 139 GWh in both fiscal 2018 and fiscal 2019.

The LNG proponents that have requested electricity service from BC Hydro and are included in the Load Forecast are:

- FortisBC Energy Inc. is currently constructing an expansion of its all-electric Tilbury Island LNG facility; further expansion at Tilbury is possible, but will depend on market conditions;
- LNG Canada to be located in Kitimat, has agreed with BC Hydro and the government to electricity supply terms for its ancillary loads. On July 11, 2016

LNG Canada announced that it would be delaying its final investment decision beyond December 2017. However, this has not been reflected in this application as the impact is not yet known; and

- Woodfibre LNG to be located near Squamish, is planning to electrify both its ancillary and compression loads. It is expected to make a final investment decision within the current fiscal year. BC Hydro is currently working on an Electricity Supply Agreement with Woodfibre LNG.

By fiscal 2024, the LNG Load Forecast increases to 2,662 GWh per year which represents the total of the announced loads.

3.2.1.2 Residential

BC Hydro's residential sector currently represents about 34 per cent of BC Hydro's total domestic sales. Electricity sales to this sector tend to be relatively steady as they are driven by population growth and general economic trends. Any large fluctuations in sales from year to year are mainly due to weather. The residential sales forecast is prepared on a temperature normalized basis;[30] normal temperature is defined as a ten-year rolling average of monthly heating and cooling degree days.[31] BC Hydro has been using a ten-year rolling average for at least 15 years and more utilities are moving from a longer (30-year) rolling average to a ten-year period.[32] BC Hydro notes that FortisBC Electric also uses a ten-year rolling average in their electricity Load Forecast.

The central equation in estimating the residential sales forecast is the product of the number of accounts times the average use per account. The inputs are derived as follows:

- The number of account additions is based on a housing starts projection; and

30 The commercial distribution portion of the light industrial/commercial sector is prepared with normal temperature. The large industrial sales, being relatively weather insensitive, are not weather normalized.

31 Refer to Table 3-3 below for a definition of heating degree days.

32 2013 Weather Normalization Survey, Itron, published March 2014.

- The forecasts of the residential average use per account are determined with Statistically Adjusted End Use Models.[33] The models' drivers are historical average actual use per account, economic drivers including population and disposable income, normalized temperature projections, billing days, forecasts of average appliance stock efficiencies and data from BC Hydro's residential end-use survey. Forecasts of average appliance stock efficiency come from the 2015 US Energy Information Administration average efficiency projections for the Pacific region.

BC Hydro notes that the Statistically Adjusted End Use Models model is used by approximately 60 different utilities and organizations throughout North America and continues to be supported by the model's developer. BC Hydro believes that the Statistically Adjusted End Use Models methodology is appropriate for residential sector forecasting and commercial sector forecasting, which is discussed in the next section.

3.2.1.3 Light Industrial/Commercial Sector

BC Hydro's light industrial/commercial sector currently represents about 36 per cent of BC Hydro's total domestic electricity sales. Similar to the residential sector, load growth in this sector tends to be steady as it is driven by growth in population and general economic trends.

- ***Commercial*** - About 80 per cent of electricity sales to the light industrial/commercial sector come from commercial distribution demand from large and small offices in a variety of sectors such as finance, insurance, health service facilities and warehouses. The commercial distribution sales forecasts are estimated with Statistically Adjusted End Use Models.[34] The model's drivers are historical actual billed sales, US Energy Information Administration

[33] A basic structure of the Statistically Adjusted End Use Models model can be found at: https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId=%7B53D490D2-B0B3-4E0E-AB2D-CBB02AEC5841%7D&documentTitle=20119-66219-03.

.[34] The commercial and residential Statistically Adjusted End Use Models models have the same structure and are estimated over a ten-year rolling period.

forecasts of average efficiencies of commercial end-use equipment, billing days, normalized temperature projections, and economic projections for retail sales, employment, and commercial GDP output; and

- ***Light industrial*** - Light Industrial loads connected at the distribution level represent about 20 per cent of sales to the light industrial/commercial sector. Light industrial loads consist of forestry, oil and gas, coal mines and other industrial customers connected at distribution voltage. The forecast of sales to forestry, coal, and the oil and gas portion of the light industrial distribution sector is developed using production forecasts and information gathered from BC Hydro’s key account managers for specific loads such as distribution coal mines or gas producers. The other industrial distribution loads are developed from a regression model, where the driver of the sales is real GDP for B.C. as this variable has a strong relationship to other industrial distribution loads.

Table 3-3 shows some of the key drivers used to develop the May 2016 residential and light industrial sectors sales projections. The economic projections below are from the Province and an economic consultant (Robert Fairholm) who develops regional and province-wide economic projections for BC Hydro. Most of these economic projections were compiled near the end of March 2015.

Table 3-1 Key Drivers Used in the Fiscal 2017 to Fiscal 2019 Domestic Sales Forecast

	Residential and Commercial Distribution Drivers[35]	Residential Driver[36]	Commercial Distribution Sales Economic Drivers (Annual Growth %)[37]			Light Industrial Distribution Sales Economic Driver[14]
Calendar Year	Normal Heating Degree Days	Residential Accounts	Employment	Retail Sales	Commercial GDP	Real Total Provincial GDP
2016	2,796	1,779,597	0.6	1.9	1.9	2.4
2017	2,796	1,805,393	1.2	2.4	2.3	2.3
2018	2,796	1,831,066	1.8	2.6	3.4	2.3

3.2.1.4 Large Industrial Sector

BC Hydro's large industrial sector currently represents about 27 per cent of BC Hydro's total domestic sales. The large industrial sector has historically exhibited volatility in sales due to several factors such as fluctuations in global commodity prices and unpredictable events such as temporary or permanent closure of large industrial facilities.

BC Hydro prepares the electricity sales forecast for the large industrial sector on an account-by-account basis. The forecast drivers include production forecasts, electric intensity (i.e., kWh/unit of production), and probability weightings. The probability weightings represent the risk assessment of future expansion or contraction or the likelihood of previous trends in sales continuing.

Given the uncertain and binary nature of large industrial loads, a range of forecasts were developed for each industrial sub-sector considering:

[35] The column shows an example for the Lower Mainland of the ten-year rolling average of Heating Degree Days based on temperatures at the Vancouver International Airport. A heating degree day is the difference between the daily average temperature and 18 Degrees Celsius.

[36] The number of residential accounts is based on housing starts projections from Robert Fairholm Economic Consultant projection of March 2015. The accounts projection in the table above is on a fiscal year basis.

[37] Employment, retail sales and commercial output forecast growth rates are based on Robert Fairholm Economic Consultant projection of March 2015. The forecast of GDP growth rate is based on the B.C. Ministry of Finance February 2016 Provincial Budget. All growth rate projections are on a total provincial basis.

- An assessment of current state of the global economy;
- A range of projected outcomes for BC's major global trading partners who purchase BC's exports; and
- Supply and demand balance outlooks of major commodities for each sub-sector, including a projected range of future commodity prices.

A mid projection of commodity prices, which is assessed to be the most likely, informs the mid forecast and its probability weightings. These probability weightings also consider factors that pertain to the individual circumstances of customers. For example, a customer's project that does not have environmental approval and is in initial discussions with BC Hydro would have a different probability than a customer's project that is in the final stages of taking electrical service.

BC Hydro's high and low band and mid-level large industrial forecast is also informed by industrial consultants' reports to BC Hydro, various government reports and publications from various sources such as the B.C. Oil and Gas Commission, information on websites for various companies and information on customer operations obtained from BC Hydro key account managers.

The large industrial sector is comprised of three main sub-sectors: mining, forestry, and oil and gas. At the sub-sector level, the main drivers of industrial load are as follows:

- ***Mining*** – Growth in the B.C.'s mining sector depends on global commodity prices which are driven by economic growth within parts of Asia, such as China, and the relative supply demand balance for copper, molybdenum, and coal markets. Other factors, which impact mining sales and sales to other industrial sub-sectors, include the availability of financing, regulatory and environmental approvals and First Nations considerations;
- ***Forestry*** – The forestry sector is comprised of pulp and paper, wood and chemical loads and is approximately 50 per cent of the total large industrial

sales. Approximately 65 per cent of the forestry sector is the pulp and paper sector. Sales to the pulp and paper sector depend upon global pulp prices, exchange rates, BC fibre supply, the demand for pulp products such as newsprint, packaging and speciality coated papers, and the capacity and cost competitiveness of BC pulp and paper mills. Forestry also includes sales to large sawmills where growth trends depend on the U.S. housing market, exchange rates, and the availability of wood. Sales to the chemical sector are linked to large kraft pulp mills in BC and the opportunity for exports; and

- ***Oil and Gas*** – oil and gas includes sales to oil pipelines, oil refineries, gas pipelines, and upstream gas producer and processor loads situated in North East BC. Electricity sales to gas producers depend upon: (i) natural gas market prices and prices for natural gas liquids; (ii) LNG prices which are determined by the world demand and supply; and (iii) the relative cost of gas and electricity. Upstream gas loads have been estimated using a probabilistic assessment of gas demand for electrified and non-electrified downstream LNG, a projected outlook of North American demand and supply for gas, and probabilities that these loads, if they proceed, would take electric supply from BC Hydro.

3.2.1.5 Other Sector

The Other sector currently represents about 3 per cent of BC Hydro's total domestic sales. Electricity demand in this sector comes from irrigation, street light customers and sales to other utilities including FortisBC Electric, City of New Westminster, Seattle City Light, and Hyder, Alaska.

Sales to FortisBC Electric are about 500 GWh per year or one per cent of total domestic sales. The forecast of sales from BC Hydro to FortisBC Electric considers Load Forecast information provided by FortisBC and projections of electricity market prices relative to the cost of purchases from BC Hydro under Rate Schedule 3808. The forecast of sales to the City of New Westminster is based on information on new residential and commercial loads provided to BC Hydro's distribution planners by city planners and historical load factors. Forecasts for irrigation and street lighting are informed by historical growth trends. The forecast of sales to Seattle City Light is determined by the conditions of the Skagit Valley Treaty.

3.2.1.6 Electric Vehicles

Electric Vehicle projections are dealt with separately from the Statistically Adjusted End Use Models modelling. Future electric vehicle loads are based on BC Hydro's projections using a vehicle stock turn over model. These estimates have been added to residential and light industrial/commercial sector forecasts projections from the Statistically Adjusted End Use Models.

Electric vehicle load growth depends upon drivers such as electricity rates, fuel price, capital costs, consumer adoption (including promotions and incentives from programs such as the BC Government's Clean Energy Vehicle program), efficiency of electric vehicles, and driving population. As discussed in section 3.2.2.1 below, electric vehicle load is less than 50 GWh per year in the test period.

3.2.1.7 Monte Carlo Analysis

A Monte Carlo analysis combines the individual sector high low band forecasts to produce BC Hydro's high and low total system Load Forecast band.[38] The Monte Carlo analysis involves the sampling of distributions for key load uncertainty variables such as economic activity (i.e., GDP), electric vehicles, heating degree days, and distributions of sales for each of the industrial sub-sectors (mining, oil and gas, forestry and other industrial). The distribution of sales for these sub-sectors includes the mid forecast, a high sales forecast and a low sales forecast.

For the residential and light industrial/commercial sectors, the key uncertainty variables are temperature and economic growth. A temperature distribution captures the mean and standard deviation of heating degree days over the past ten years.

[38] The total system load includes the loads that make up the domestic system as well as sales BC Hydro own use, distribution and transmission losses however it excludes sales to the Non-Integrated areas. The high load forecast is the mean of the upper twenty percent tail of the total system load which results from the Monte Carlo simulation.

The real B.C. GDP influences population trends, employment and income and electricity sales. As such, variations to the mid forecast of real B.C. GDP growth determine the high and low load outcomes from the Monte Carlo analysis.

The next section describes the results of the forecasts and the uncertainty considerations in developing the sales projections.

3.2.2 Domestic Energy Sales Forecast – Fiscal 2017 to Fiscal 2019

Table 3-2 summarizes the actual sales for fiscal 2015 and fiscal 2016 and the May 2016 electricity sales forecast (before demand-side management) for the major sectors over the test years. The variances for fiscal 2015 Plan to fiscal 2015 actual costs and fiscal 2016 Plan to fiscal 2016 actual costs are explained Appendix K, section 2. The projected uncertainty range around the mid total domestic sales forecasts is shown below. Actual and forecast sales are on an accrued sales basis[39] and do not include distribution or transmission losses. The final sales data for fiscal 2016 was not available at the time the Load Forecast was finalized. As such, the Load Forecasting models include sales data up to fiscal 2015. Table 3-2 includes the actual fiscal 2016 information that was available after the forecast was completed.

Table 3-2 Fiscal 2017 to Fiscal 2019 Domestic Energy Sales Forecast (Mid, Low, High)

	(GWh)	F2015 RRA	F2015 Actual	F2016 RRA	F2016 Actual	F2017 Plan	F2018 Plan	F2019 Plan
		1	2	3	4	5	6	7
1	Residential	18,805	17,047	18,743	17,331	18,654	18,979	19,327
2	Light Industrial and Commercial	18,277	18,564	18,346	18,421	19,212	19,360	19,655
3	Large Industrial	14,444	14,020	15,032	13,669	13,752	13,936	14,555
4	Other	1,604	1,567	1,638	1,602	1,611	1,618	1,634
5	Total Mid Domestic Sales	53,130	51,199	53,759	51,023	53,229	53,894	55,171
6	Total Low Domestic Sales	53,130	51,199	53,759	51,023	51,100	51,468	52,259
7	Total High Domestic Sales	53,130	51,199	53,759	51,023	55,371	56,415	58,255

39 Revenue is recognized at the time energy is delivered to the company's customers, the amount of revenue can be measured reliability and collection is reasonably assured. Revenue is determined on the basis of billing cycles and also includes accruals for electricity deliveries not yet billed.

Note the residential and light industrial/commercial sales for fiscal 2015 and fiscal 2016 in Table 3-2 are actual sales that have not yet been weather normalized to reflect normal temperatures. With temperature normalization, these two years of actuals will have a higher level of sales. The revenue requirements application forecast for these sectors is prepared on a weather normalized basis.[40]

In Table 3-2, the LNG load projection described in section 3.2.1.1 is included in the mid, high, and low large industrial sector sales forecast. The energy forecast of these loads during the test years is 57 GWh per year in fiscal 2017 and 139 GWh per year in both fiscal 2018 and fiscal 2019. Beyond the test years, the forecast LNG load reaches approximately 2,700 GWh/year by fiscal 2024. Timelines for LNG final investment decisions continue to be uncertain.

3.2.2.1 Residential and Light Industrial/Commercial

Sales to the residential sector are expected to grow by about 325 GWh per year or 1.7 per cent between fiscal 2017 and fiscal 2018 and 350 GWh per year or 1.8 per cent between fiscal 2018 and fiscal 2019. This growth is mainly driven by the projection of housing starts that increases the total number of residential accounts, which are forecast to grow by 1.4 per cent per annum between fiscal 2017 and fiscal 2018 and 1.4 per cent per annum between fiscal 2018 and fiscal 2019.

Sales to the light industrial/commercial sector, over the same time period, are projected to grow by about 150 GWh per year or 0.8 per cent and about 295 GWh per year or 1.5 per cent. This growth mainly reflects the projection of the growth in regional economic drivers. Global economic uncertainty is a major factor that influences the rate of growth of electricity sales in the large industrial sector; it is expected that diverse areas of the BC economy, such as the Lower Mainland, will continue to grow and this will drive commercial distribution sales.

[40] Unless otherwise stated, the growth rates over a multi-year period are calculated on a compound basis.

A forecast of electricity demand from electric vehicles is included in the residential and light industrial/commercial sales projections. Electric vehicle demand is projected to be under 50 GWh per year and estimated total number of electric vehicles (i.e., total stock) is about 6,000 in fiscal 2017 and about 11,000 in fiscal 2019. Beyond the test years, electric vehicle load is forecast to be about 70 GWh per year in fiscal 2022, about 430 GWh per year in fiscal 2027 and 1,760 GWh per year by fiscal 2036. The forecast of the total number of electric vehicles is about 30,000 in fiscal 2022, about 164,000 in fiscal 2027 and about 580,000 in fiscal 2036.

Electric vehicle load impacts, along with forecasts of population and housing starts are main drivers of the long-term residential sales projections. Residential sales per year, over the long-term, are expected to grow on a compound basis by 1.9 per cent[41] between fiscal 2017 and fiscal 2022, 2.1 per cent between fiscal 2017 and fiscal 2027 and 1.9 per cent between fiscal 2017 and fiscal 2036. Over the same time frame, the light industrial/commercial sector is expected to grow by 1.6 per cent, 1.7 per cent and 1.7 per cent, per year respectively. The commercial distribution portion of the light industrial/commercial sector contributes most of the growth. The long-term sales forecast for the commercial sector follow the long-term economic growth projections.

The estimated incremental effects of Smart Metering and Infrastructure and Revenue Assurance Operations, relative to fiscal 2015 have also been included in the Load Forecast over the entire forecast period. These effects include: (i) incremental sales from entities (such as grow ops) previously diverting electricity which are switching to become paid revenues, and (ii) a reduction in losses from grow-ops leaving the system. The forecast of incremental sales from grow-ops previously diverting electricity to paid revenues is about 60 GWh per year based on

41 Unless otherwise stated, the growth rates over a multi-year period such as from fiscal 2017 to fiscal 2022, fiscal 2017 to fiscal 2027 and fiscal 2017 to fiscal 2036 are calculated on a compound basis. Compound growth rates is the rate of growth rate that gets you from the initial value (i.e. fiscal 2017 sales) to the ending ending value (e.g. fiscal 2022).

Revenue Assurance Operations analysis of grow op load. The incremental switch to paid revenue is included in the residential sales forecast. With evolving legal and regulatory environment, there are too many unknowns to accurately project additional growth in load and revenue from the future legalization of marijuana in Canada.

3.2.2.2 Large Industrial Sector

Electricity sales to the large industrial sector and the sub-sectors are shown in the Table 3-3 below.

Total larger industrial sales are expected to grow by about 185 GWh per year or 1.3 per cent between fiscal 2017 and fiscal 2018 and about 620 GWh per year or 4.4 per cent between fiscal 2018 and fiscal 2019. Over the long-term, large industrial sales are expected to grow by 4.3 per cent between fiscal 2017 and fiscal 2022. This growth rate reflects a ramp up in oil and gas sector loads including gas producer loads and an increase in LNG load from the above mentioned LNG projects expected to take electrical service from BC Hydro. Over the mid period of the forecast from fiscal 2017 to fiscal 2027 the growth rates is expected to be 2.7 per cent and over the long term it is expected to be 1.5 per cent between fiscal 2017 and fiscal 2036.

Table 3-3 Fiscal 2017 to Fiscal 2036 - Large Industrial Sales Forecasts

			Large Industrial Sub Sectors						LOW (Note 2)	MID (Note 2)	HIGH (Note 2)
	GWh (Note 3)		Oil and Gas	Coal and Metal Mining	Forestry	Other	Total Sales	LNG (Note 1)	Total Large Industrial Sales with LNG	Total Large Industrial Sales with LNG	Total Large Industrial Sales with LNG
			1	2	3	4	5	6	7	8	9
1	Actual	F2015	1,113	3,798	7,938	1,171	14,020		14,020	14,020	14,020
2	Actual	F2016	1,274	3,875	7,374	1,147	13,669		13,669	13,669	13,669
3	Forecast	F2017	1,639	3,804	7,047	1,204	13,695	57	13,220	13,752	14,346
4	Forecast	F2018	1,993	3,728	6,801	1,276	13,797	139	13,333	13,936	14,631
5	Forecast	F2019	2,652	3,834	6,593	1,337	14,416	139	13,812	14,555	15,417
6	Forecast	F2022	3,223	4,054	6,137	1,408	14,822	2,148	15,876	16,970	18,288
7	Forecast	F2027	3,827	4,063	5,892	1,514	15,296	2,662	16,554	17,958	19,672
8	Forecast	F2036	4,100	4,100	5,740	1,634	15,574	2,662	16,493	18,236	20,359

Note:
1. LNG sales in column 6 is based on announced LNG as described in section 3.2.1.1
2. LNG sales in column 6 is also included in the low, mid and high sales projections in columns 7,8,9
3. All sales figures in table above excluded losses.

The short-term and long-term mid sales projections and uncertainties for each major industrial sub-sector is described below.

Oil and Gas

Most of the growth in the sales to the large industrial sector over the test years stems from the oil and gas sector. Sales to the oil and gas sector are expected to grow by about 350 GWh per year between fiscal 2017 and fiscal 2018 and about 660 GWh between fiscal 2018 and fiscal 2019. This growth is primarily led by an expected increase in demand from gas producers in Northeast B.C.

From fiscal 2017 to fiscal 2022 sales to the oil and gas sector is expected to grow annually by 14.5 per cent. This trend is expected to remain strong over the medium and long-term; from fiscal 2017 to fiscal 2027 and from fiscal 2017 to fiscal 2036, electricity sales to this sector is forecast to grow by 8.8 per cent and 4.9 per cent, respectively. Sales growth over the medium and long-term is driven by new oil and condensate pipeline projects and gas producer and processor loads.

The projections in the oil and gas sector are highly uncertain because the magnitude of these loads vary dependent on factors including: increases in natural gas and natural gas liquids market prices (currently at low levels); final investment decision and approvals on LNG projects; and commitments to specific projects from gas producers that have requested electric service from BC Hydro.

Mining

Between fiscal 2012 and fiscal 2015, sales to BC Hydro's mining sector have grown by a total of 1,087 GWh or 40 per cent. Reopened mining operations such as Copper Mountain and New Afton, additional new mines such as Mount Milligan, and Red Chris and major upgrades to existing mines have contributed to these sales. However, since 2011, commodity prices for copper, molybdenum, gold and metallurgical coal have declined due to a slowdown in world demand (from China, in particular) and increased supply from new projects worldwide. Several mining operations have temporarily curtailed production or announced indefinite shutdowns due to low prices.

During the test years, sales to mining (metal and coal) are expected to be 3,804 GWh per year in fiscal 2017 and then decline by 76 GWh or 2.0 per cent to 3,728 GWh per year in fiscal 2018 and then increase by 106 GWh or 2.8 per cent to 3,834 GWh per year in fiscal 2019. The forecast contemplates the announcement from the Province on February 5, 2016, that major mines will be able to defer payment of the equivalent of up to 75 per cent of two years' worth of electricity bills, with repayment plus interest as commodity prices recover.

Beyond the test years, mining sales (metal and coal) are expected grow by 1.3 per cent on a compound basis between fiscal 2017 and fiscal 2022, 0.7 per cent between fiscal 2017 and fiscal 2027 and 0.4 per cent between fiscal 2017 and fiscal 2036. Over this time period, the expected increase in sales from new mining loads will be offset by several mining projects reaching end of life.

Forestry

Over the test years, sales to forestry sector are expected to decline by about 450 GWh per year or 6.4 per cent. This decline is led by an expected drop in pulp and paper sales. Factors such as slower economic growth in China and a decline in demand for newsprint, due to digital substitution, are drivers behind expected drop in sales.

Beyond the test years, forestry sales are expected to decline on a compound growth rate basis of 2.7 per cent between fiscal 2017 and fiscal 2022, 1.8 per cent between fiscal 2017 and fiscal 2027, and 1.1 per cent between fiscal 2017 and fiscal 2036. These downward projections are due to an expected drop in pulp and paper sales. Declining sales to this sector factors reflects a continued downward trend in the demand for newsprint and growing competitive pressures from new pulp mills in the other parts of the world. These factors, such as declining demand for pulp related products (newsprint) and new lower cost South American pulp mills, which can produce pulp from trees that have shorter growing spans, are the major risk considerations around the mid sales pulp and paper forecast. As for the other major load of the Forestry sector, the other risk factors include the harvest rates of viable wood from non-pine beetle killed trees, resolution to softwood lumber trade issues and growth in the U.S. economy and housing starts.

Other Large Industrial Customers

Sales to other transmission customers (beyond Oil and Gas, Mining and Forestry) are expected to be relatively stable over the entire forecast period. Sales growth in this sector is anticipated to be led by expansion at various ports, terminals and potential new operations. Sales to other large industrial customers are expected to grow by 3.2 per cent between fiscal 2017 and fiscal 2022. During this period there is anticipated additional sales from new plants and expansions from existing universities, transportation and cement operations. Between fiscal 2017 and fiscal 2022, the growth is projected to be lower at 2.3 per cent as there is less expansion over this time period. From fiscal 2017 to fiscal 2036 the growth is forecast to be 1.6 per cent.

3.2.2.3 Other Sector (Street Lights, Irrigation, and Other Utilities)

From fiscal 2017 to fiscal 2019, electricity sales to this sector are expected to grow in total by about 22 GWh or 1.4 per cent. Most of this growth is led by sales to FortisBC Electric and the City of New Westminster. The forecast of electricity sales to the City of New Westminster is expected to be strong over the test years as the City is expected to expand housing and commercial developments.

3.2.3 Domestic Energy Sales Forecast less Demand-Side Management – Fiscal 2017 to Fiscal 2019 Plan

Table 3-4 below summarizes the domestic energy sales forecast for the test years as shown on Schedule 14.0 contained in Appendix A of the Application. All of the forecasts in the table below include estimates of electricity demand-side management savings and Var and Voltage Optimization energy reductions, which are based on improvements to BC Hydro substations to optimize voltage levels.

Table 3-4 Fiscal 2017 to Fiscal 2019 Domestic Energy Sales Forecast Less Demand-Side Management - Plan

	(GWh)	F2015 RRA	F2015 Actual	F2016 RRA	F2016 Actual	F2017 Plan	F2018 Plan	F2019 Plan
		1	2	3	4	5	6	7
1	Residential	18,805	17,047	18,743	17,331	18,036	18,112	18,250
2	Light Industrial and Co	18,277	18,564	18,346	18,421	18,832	18,785	18,899
3	Large Industrial	14,444	14,020	15,032	13,669	13,380	13,323	13,882
4	Other	1,604	1,567	1,638	1,602	1,611	1,618	1,634
5	Total	53,130	51,199	53,759	51,023	51,860	51,838	52,664

3.3 Revenue Forecast

The preparation of the Revenue Forecast at currently approved fiscal 2016 rates is used to determine the revenue shortfall from which BC Hydro’s proposed rate increases and transfers to the Rate Smoothing Regulatory Account are derived. Domestic revenues are comprised of revenues from the sale of electricity to BC Hydro’s customers within the province and to certain customers outside of the province under treaty or long-term contract with BC Hydro (specifically, the Skagit Valley Treaty commitment and sales to Hyder, Alaska). Domestic revenues do not include any Open Access Transmission Tariff revenues, which are addressed in Chapter 9. The domestic Revenue Forecast is provided on Schedule 14.0 of Appendix A.

The sections below describe the method used by BC Hydro to forecast domestic revenues at currently approved fiscal 2016 rates and set out the Revenue Forecast for fiscal 2017 to fiscal 2019. BC Hydro believes that its revenue forecasting approach, and the results it yields, are reasonable.

3.3.1 Revenue Forecast Methodology

BC Hydro's domestic Revenue Forecast is based on the energy sales forecast less demand-side management discussed in section 3.2 and the fiscal 2016 rates approved by British Columbia Utilities Commission Order No. G-48-14. Similar to the energy sales forecast, the Revenue Forecast is divided into four customer sectors: residential; light industrial/commercial; large industrial; and other. The method used to forecast revenue from each sector is discussed below.

3.3.1.1 Residential Sector

The residential Revenue Forecast is the sum of the Revenue Forecasts for basic charge and energy charge. Basic charge revenue is the product of forecast number of accounts and residential basic charge. Energy charge revenue is the product of forecast consumption for the residential class and residential energy charges.

3.3.1.2 Light Industrial/Commercial Sector

The light industrial/commercial sector includes the Small General Service, Medium General Service, and Large General Service customer classes, and the Revenue Forecast is the sum of the Revenue Forecasts for the three General Service customer classes.

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

The Medium General Service and Large General Service Revenue Forecasts are the sum of the Revenue Forecasts for the basic charge, demand charge and energy charge. Basic charge revenue is the product of forecast number of accounts and Medium General Service and Large General Service basic charge. Demand charge revenue is the product of projected demand and Medium General Service and Large General Service demand charge. Energy charge revenue is the sum of Part 1 energy charge revenue and Part 2 energy charge revenue (or Part 2 revenue reduction). Part 1 energy charge revenue is the product of forecast Historical Baseline Loads and Part 1 energy charge Historical Baseline Load is defined as the rolling three year historical energy usage. Part 2 energy charge revenue (or revenue reduction) is the product of forecast consumption above (or below) forecast Historical Baseline Loads for the class and Part 2 energy charge (credit).

3.3.1.3 Large Industrial Sector

The large industrial Revenue Forecast is the sum of the Revenue Forecast for each transmission service stepped rate customer and each transmission service exempt rate customer. The Revenue Forecast for each customer is the sum of energy charge revenue and demand charge revenue. The energy charge revenue for transmission service stepped rate customers is calculated by comparing the forecast consumption for each customer to the customer’s fiscal 2016 interim Customer Baseline Load. Forecast consumption for each customer up to and including 90 per cent of the customer’s Customer Baseline Load is priced at the Tier 1 energy charge, and the balance of forecast consumption above the customer’s Customer Baseline Load is priced at the Tier 2 energy charge. The energy charge revenue for transmission service exempt rate customers is the product of forecast consumption and transmission service exempt rate energy charge. The demand charge revenue is the product of projected demand and large industrial demand charge.

3.3.1.4 Other Sector

The Revenue Forecast for the other sector is the sum of the Revenue Forecasts for irrigation, street lighting customers, and sales to other utilities including City of New Westminster, FortisBC, Seattle City Light, and Hyder, Alaska. The Revenue Forecasts for irrigation and street lighting customers are the products of forecast sales to irrigation and street lighting customers and the average revenue rates applicable for the respective customer classes.

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

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

The Revenue Forecast for Seattle City Light is the product of forecast sales to Seattle City Light and the price per MWh committed in the Skagit Valley Treaty.

The Revenue Forecast for Hyder, Alaska is the product of forecast sales to Hyder, Alaska and the average revenue rate for the customer class.

3.3.2 Revenue Forecast – Fiscal 2017 to Fiscal 2019 Plan

Table 3-5 below summarizes the domestic Revenue Forecast as shown on Schedule 14.0

Table 3-5 Fiscal 2017 to Fiscal 2019 Domestic Revenues – Plan

	($ million)	F2015 RRA	F2015 Actual	F2016 RRA	F2016 Actual	F2017 Plan	F2018 Plan	F2019 Plan
		1	2	2	3	4	5	6
1	Residential	1,812.0	1,630.8	1,917.6	1,754.2	1,841.1	1,850.1	1,865.2
2	Light Industrial and Commercial	1,512.4	1,521.1	1,608.5	1,604.7	1,637.7	1,633.6	1,643.2
3	Large Industrial	744.0	712.9	826.1	730.0	719.9	720.4	759.5
4	Other	116.2	114.7	124.2	120.2	116.2	116.4	117.6
5	Subtotal	4,184.5	3,979.5	4,476.3	4,209.1	4,314.9	4,320.5	4,385.6
6	Revenue from Deferral Rider	208.4	198.1	223.0	209.6	223.5	231.3	241.8
7	Total	4,392.9	4,177.6	4,699.3	4,418.7	4,538.4	4,551.8	4,627.4

The Revenue Forecast for fiscal 2017 to fiscal 2019 is based on fiscal 2016 rates approved by British Columbia Utilities Commission Order No. G-48-14, and excludes the proposed rate increases sought in this application and the impact of any future rate structure changes.

Note that miscellaneous non-tariff revenue is not included in the Domestic Revenues shown in Table 3-5. Refer to Schedule 15 of Appendix A for details of miscellaneous non-tariff revenue.

In fiscal 2017, total revenue is forecast to increase by $105.8 million or 2.5 per cent over the actual fiscal 2016 revenue. The percentage increase in total domestic revenue of 2.5 per cent was higher than the percentage increase in total domestic energy sales of 1.6 per cent because the increase in energy sales was primarily from residential customers, whose average forecast revenue rate of $102.1 per MWh was higher than the average forecast fiscal 2017 revenue rate of $87.5 per MWh paid by all customers. In fiscal 2018, total revenue is forecast to remain relatively unchanged from the fiscal 2017 Plan revenue, with an increase of $5.6 million or 0.13 per cent, consistent with energy sales which are forecast to also remain similar to the fiscal 2017 Plan, with a decrease of 0.04 per cent as discussed in section 3.2.3.

In fiscal 2019, total revenue is forecast to increase by $70.6 million or 1.5 per cent over the fiscal 2018 Plan revenue, consistent with energy sales which are forecast to increase by 1.6 per cent as discussed in section 3.2.3.

3.4 Integrated Resource Plan

This section provides an overview of BC Hydro's 2013 Integrated Resource Plan including the recommended actions most relevant to the fiscal 2017 to fiscal 2019 test period of this application, updated Load Resource Balances and the Long Run Marginal Costs. It explains that the recommended actions from BC Hydro's approved 2013 Integrated Resource Plan, with a modification related to demand-side management, remain appropriate.

3.4.1 Background on Integrated Resource Plan

The Integrated Resource Plan is BC Hydro's long term plan that sets out recommended actions to ensure our customers will continue to receive cost-effective, reliable electricity with manageable risks, consistent with the requirements and objectives of the *Clean Energy Act*. The 2013 Integrated Resource Plan was approved by the Lieutenant Governor in Council in November 2013.

The Integrated Resource Plan provides the context for:

- Demand-side management expenditures requested in this application (details discussed in Chapter 10); and
- Renewal of Electricity Purchase Agreements with IPPs as well as acquisitions under the Standing Offer Program.

While the estimate of costs from IPP acquisitions inform the Cost of Energy calculation and are described in detail in Chapter 4 of this application, BC Hydro is not requesting as part of this application British Columbia Utilities Commission acceptance of any contract renewals. BC Hydro will be filing Electricity Purchase Agreements related to renewals separately from this application for review by the British Columbia Utilities Commission as required under section 71 of the *Utilities Commission Act*. To the extent that the Cost of Energy purchases forecast in this application related to contracts declared unenforceable under section 71, forecast costs would not be recovered from ratepayers. BC Hydro's actual energy costs (other things being equal) will be lower than forecasted and this favourable difference will be credited to the Non-Heritage Deferral Account as described in Chapter 7.

A review of the 2013 Integrated Resource Plan is planned for the fall of 2016. The review is a commitment in Chapter 8 of the 2013 Integrated Resource Plan (Clean Energy Strategy). It will not affect the test years of this application, since the Integrated Resource Plan review will not be discussing any actions in the test period. The review is intended to determine whether there is any need for acquisition (in addition to those already in Recommended Actions) beyond the test period of this application prior to the next Integrated Resource Plan in 2018. At this time, additional acquisition is not expected to be required.

BC Hydro has reviewed the Recommended Actions of the 2013 Integrated Resource Plan in light of the updated Load Resource Balances. The Recommended Actions of the 2013 Integrated Resource Plan are generally still appropriate despite the changes in the Load Resource Balances. BC Hydro has either implemented, or continues to implement, the 18 Recommended Actions, but has modified the approach to demand-side management. Given the present circumstances, BC Hydro is planning to continue for the test period a demand-side management expenditure moderation strategy similar to the strategy that was implemented in Recommended Action 1 of the 2013 Integrated Resource Plan for fiscal 2014 to fiscal 2016 to the Revenue Requirement Application Test Years of fiscal 2017 to fiscal 2019.
BC Hydro will continue to exceed the *Clean Energy Act* target of achieving at least 66 per cent of incremental demand through conservation to 2020 (refer to section 3.4.3.1 for details).

3.4.2 Load Resource Balances

The Load Resource Balances presented in this section are current to May 2016 and form the basis for this application. The Load Resource Balance is the difference between BC Hydro's forecast load and forecast supply. BC Hydro presents the Load Resource Balances for both energy and capacity.

The energy Load Resource Balance is presented in two views:

- ***Planning View:*** The Planning View[42] reflects the capability of resources based on BC Hydro's planning criteria, including the requirement contained in subsection 6(2) of the *Clean Energy Act* to achieve electricity self-sufficiency under prescribed water conditions from its hydroelectric Heritage assets (refer to section 1.2.2 of the Integrated Resource Plan). This view is relevant for setting the context for resource acquisitions. The planning view is summarized in the Energy Load Resource Balances (Table 3-6 and Table 3-8) as "Surplus/Deficit as % of Net Load (planning view)" where lower than 100 per cent means that there is a system shortfall and a need for additional resources; and
- ***Operational View:*** The Operational View[43] shows the forecasted operation of these same resources given market conditions, expected system conditions in the near term and average conditions in the long term. This view is shown in Table 3-6 and Table 3-8, and this view is relevant for forecasting revenue requirements because it mimics actual operation.

The capacity Load Resource Balance (Table 3-7 and Table 3-9) shows system capability based on BC Hydro's planning criteria (refer to section 1.2.2 of the Integrated Resource Plan).

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[42] The most obvious difference between the Planning View and the Operational View is the energy from dispatchable thermal resources. The Planning View reflects the firm energy that dispatchable thermal resources are capable of generating and can be relied upon for planning purpose (Island Generation at 2,170 GWh and Prince Rupert Generating Station at 180 GWh). In contrast, the Operational View shows how much dispatchable thermal resources is expected to run (Island Generation at 140 GWh and Prince Rupert at 0 GWh).

[43] The Operational View reflects near term conditions that are better known for fiscal 2017 to fiscal 2019 (e.g., near term reservoir elevations and expected water conditions) and assumes average conditions in the longer term (fiscal 2020 and beyond).

3.4.2.1 Key changes in Load Resource Balances Since 2013 Integrated Resource Plan

The Planning View of the Load Resource Balance in the context of the approved 2013 Integrated Resource Plan drives the need for resource acquisitions such as demand-side management savings, and IPP contract renewals. The Planning View of the updated Load Resource Balances with existing and committed resources[44] in Table 3-6 and Table 3-7 show that new energy and capacity resources are needed in fiscal 2022 and fiscal 2020 respectively (compared to fiscal 2017 for both energy and capacity in the 2013 Integrated Resource Plan). The Recommended Actions in the approved 2013 Integrated Resource Plan are still appropriate as discussed and the Load Resource Balances with planned resources per the Recommended Actions, in addition to existing and committed resources, are shown in Table 3-8 and Table 3-9 (refer to section 3.4.3 for more details on the Recommended Actions).

[44] Existing supply-side resources include BC Hydro's Heritage hydroelectric and thermal generating resources, as well as IPP facilities delivering electricity to BC Hydro. Committed supply-side resources are resources for which material regulatory and BC Hydro executive approvals have been secured (including Site C).

Table 3-6 Energy Load Resource Balance with Existing and Committed Resources

(GWh)		F2017	F2018	F2019	F2020	F2021	F2022	F2023	F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031	F2032	F2033	F2034	F2035	F2036
Existing and Committed Heritage Resources																					
Heritage Resources (including Site C)	(a)	48,445	46,895	46,014	48,491	48,491	48,491	48,491	48,857	52,383	53,777	53,777	53,777	53,777	53,777	53,777	53,777	53,777	53,777	53,777	53,777
Existing and Committed IPP Resources	(b)	13,252	14,681	14,457	14,456	14,188	13,874	13,639	13,302	12,906	12,506	12,399	12,075	11,559	10,811	10,351	10,295	10,255	10,106	9,568	8,201
Total Supply (Operating View)**	(c) = a + b	61,697	61,576	60,471	62,947	62,680	62,366	62,130	62,159	65,289	66,283	66,176	65,853	65,336	64,589	64,129	64,073	64,033	63,884	63,345	61,979
Demand - Integrated System Total Gross Requirements																					
2016 May Mid Load Forecast Before DSM*		-58,334	-59,013	-60,413	-61,371	-62,309	-63,675	-64,836	-66,008	-67,109	-68,310	-69,267	-70,256	-71,222	-72,296	-73,374	-74,535	-75,462	-76,393	-77,215	-78,089
Expected LNG Load		-61	-148	-148	-252	-1,265	-2,299	-2,721	-2,848	-2,848	-2,848	-2,848	-2,848	-2,848	-2,848	-2,848	-2,848	-2,848	-2,848	-2,848	-2,848
Sub-total	(d)	-58,395	-59,162	-60,561	-61,624	-63,574	-65,974	-67,557	-68,856	-69,957	-71,158	-72,115	-73,104	-74,070	-75,144	-76,222	-77,383	-78,310	-79,241	-80,063	-80,937
Existing and Committed Demand Side Management & Others Measures																					
SMI Theft Reduction		83	83	83	83	83	83	83	83	83	83	83	83	83	83	83	83	83	83	83	83
Voltage and VAR Optimization		67	152	171	188	219	240	254	259	263	268	285	290	295	300	305	310	315	320	325	331
2016 DSM Plan F16 savings		982	970	939	940	935	926	923	917	912	885	863	855	848	844	807	770	760	758	757	736
Sub-total	(e)	1,131	1,204	1,193	1,211	1,237	1,249	1,260	1,258	1,258	1,235	1,231	1,228	1,226	1,227	1,195	1,163	1,157	1,161	1,165	1,150
		F2017	**F2018**	**F2019**	**F2020**	**F2021**	**F2022**	**F2023**	**F2024**	**F2025**	**F2026**	**F2027**	**F2028**	**F2029**	**F2030**	**F2031**	**F2032**	**F2033**	**F2034**	**F2035**	**F2036**
Surplus/(Deficit) (Operational View) **	(f) = c + d + e	**4,433**	**3,619**	**1,102**	**2,535**	**343**	**(2,359)**	**(4,167)**	**(5,439)**	**(3,410)**	**(3,640)**	**(4,708)**	**(6,023)**	**(7,508)**	**(9,328)**	**(10,898)**	**(12,148)**	**(13,120)**	**(14,197)**	**(15,553)**	**(17,808)**
Surplus / Deficit as % of Net Load (Planning View) **		**107%**	**106%**	**103%**	**108%**	**104%**	**99%**	**94%**	**92%**	**95%**	**95%**	**93%**	**91%**	**89%**	**87%**	**85%**	**84%**	**83%**	**82%**	**80%**	**78%**
Low Load Forecast Surplus/(Deficit) (Operational View) **		6,754	6,179	4,115	5,925	4,210	2,026	598	(400)	1,931	1,995	1,137	68	(1,156)	(2,710)	(4,054)	(4,965)	(5,680)	(6,578)	(7,881)	(10,007)
High Load Forecast Surplus/(Deficit) (Operational View) **		2,046	727	(2,492)	(1,870)	(4,669)	(8,111)	(10,807)	(12,442)	(10,787)	(11,403)	(12,634)	(14,277)	(16,143)	(18,433)	(20,276)	(21,819)	(23,058)	(24,417)	(26,190)	(28,795)

* 2016 Integrated System Load Forecast with losses

** See section 3.4.2 for description of Operational versus Planning View

Table 3-7 Peak Capacity Load Resource Balance with Existing and Committed Resources

(MW)		F2017	F2018	F2019	F2020	F2021	F2022	F2023	F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031	F2032	F2033	F2034	F2035	F2036
Existing and Committed Heritage Resources																					
Heritage Resources (including Site C)	(a)	11,372	11,410	11,416	11,416	11,416	11,480	11,480	11,480	12,020	12,211	12,211	12,211	12,211	12,211	12,625	12,625	12,625	12,625	12,625	12,625
Existing and Committed IPP Resources	(b)	1,593	1,685	1,633	1,583	1,502	1,473	1,179	1,144	1,081	1,037	1,037	987	950	818	818	814	808	754	730	675
14% of Supply Requiring Reserves***	(c)	-1,787	-1,805	-1,798	-1,792	-1,780	-1,785	-1,744	-1,739	-1,813	-1,833	-1,833	-1,826	-1,821	-1,803	-1,861	-1,860	-1,859	-1,852	-1,848	-1,841
Effective Load Carrying Capability	(d) = a + b + c	11,178	11,290	11,250	11,208	11,138	11,168	10,915	10,885	11,289	11,414	11,414	11,372	11,340	11,226	11,582	11,579	11,574	11,528	11,506	11,459
Demand - Integrated System Peak																					
2016 May Mid Load Forecast Before DSM*		-10,776	-11,021	-11,209	-11,374	-11,541	-11,737	-11,930	-12,119	-12,313	-12,515	-12,708	-12,943	-13,155	-13,386	-13,614	-13,840	-14,074	-14,303	-14,542	-14,774
Expected LNG Load		-19	-19	-19	-72	-222	-329	-361	-361	-361	-361	-361	-361	-361	-361	-361	-361	-361	-361	-361	-361
Sub-total	(e)	-10,795	-11,039	-11,228	-11,447	-11,763	-12,066	-12,291	-12,480	-12,674	-12,876	-13,069	-13,304	-13,516	-13,747	-13,975	-14,201	-14,435	-14,664	-14,903	-15,135
Existing and Committed Demand Side Management & Others Measures																					
SMI Theft Reduction		11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11
Voltage and VAR Optimization		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2016 DSM Plan F16 savings		216	214	210	211	210	207	204	201	198	193	189	185	183	180	174	168	165	165	165	162
Sub-total	(f)	227	226	222	222	221	218	215	212	209	204	200	197	194	192	186	179	176	176	176	173
		F2017	**F2018**	**F2019**	**F2020**	**F2021**	**F2022**	**F2023**	**F2024**	**F2025**	**F2026**	**F2027**	**F2028**	**F2029**	**F2030**	**F2031**	**F2032**	**F2033**	**F2034**	**F2035**	**F2036**
Surplus / (Deficit) **	(g) = d + e + f	**610**	**476**	**244**	**(17)**	**(404)**	**(680)**	**(1,160)**	**(1,383)**	**(1,176)**	**(1,258)**	**(1,455)**	**(1,735)**	**(1,982)**	**(2,329)**	**(2,208)**	**(2,443)**	**(2,685)**	**(2,960)**	**(3,221)**	**(3,502)**
Low Load Forecast Surplus / (Deficit) **		1,030	944	792	600	297	110	(300)	(472)	(208)	(235)	(390)	(617)	(810)	(1,102)	(933)	(1,102)	(1,286)	(1,523)	(1,764)	(2,004)
High Load Forecast Surplus / (Deficit) **		160	(74)	(434)	(845)	(1,348)	(1,758)	(2,398)	(2,683)	(2,542)	(2,690)	(2,916)	(3,260)	(3,578)	(4,013)	(3,943)	(4,232)	(4,527)	(4,863)	(5,213)	(5,559)

* 2016 Integrated System Load Forecast with losses
** Planning View is shown in this table. Capacity load resource balances are only shown in Planning View. See section 3.4.2.
*** This is also referred to as the Planning Reserve - the system generating capacity beyond that required to meet peak demand that is necessary to meet reliability criteria. See section 1.2.2 of the IRP for more details on the criteria.

Table 3-8 Energy Load Resource Balance after Planned Resources

(GWh)		F2017	F2018	F2019	F2020	F2021	F2022	F2023	F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031	F2032	F2033	F2034	F2035	F2036
Existing and Committed Heritage Resources																					
Heritage Resources (including Site C)	(a)	48,445	46,895	46,014	48,491	48,491	48,491	48,491	48,857	52,383	53,777	53,777	53,777	53,777	53,777	53,777	53,777	53,777	53,777	53,777	53,777
Existing and Committed IPP Resources	(b)	13,252	14,681	14,457	14,456	14,188	13,874	13,639	13,302	12,906	12,506	12,399	12,075	11,559	10,811	10,351	10,295	10,255	10,106	9,568	8,201
Future Supply-Side Resources																					
IPP Renewals		61	234	569	647	779	936	1,114	1,349	1,628	1,951	2,032	2,223	2,617	3,328	3,788	3,828	3,863	4,011	4,549	5,515
Standing Offer Program		62	87	173	284	394	505	616	726	837	948	1,058	1,169	1,280	1,390	1,501	1,612	1,722	1,833	1,934	2,045
Revolstoke 6												26	26	26	26	26	26	26	26	26	26
Sub-total	(c)	123	321	742	931	1,173	1,441	1,730	2,075	2,465	2,899	3,117	3,418	3,923	4,745	5,315	5,466	5,612	5,870	6,509	7,585
Total Supply (Operational View) **	(d) = a + b + c	61,820	61,897	61,213	63,879	63,853	63,806	63,860	64,235	67,754	69,182	69,293	69,271	69,259	69,334	69,444	69,538	69,644	69,754	69,855	69,564
Demand - Integrated System Total Gross Requirements																					
2016 May Mid Load Forecast Before DSM*		-58,334	-59,013	-60,413	-61,371	-62,309	-63,675	-64,836	-66,008	-67,109	-68,310	-69,267	-70,256	-71,222	-72,296	-73,374	-74,535	-75,462	-76,393	-77,215	-78,089
Expected LNG Load		-61	-148	-148	-252	-1,265	-2,299	-2,721	-2,848	-2,848	-2,848	-2,848	-2,848	-2,848	-2,848	-2,848	-2,848	-2,848	-2,848	-2,848	-2,848
Sub-total	(e)	-58,395	-59,162	-60,561	-61,624	-63,574	-65,974	-67,557	-68,856	-69,957	-71,158	-72,115	-73,104	-74,070	-75,144	-76,222	-77,383	-78,310	-79,241	-80,063	-80,937
Existing and Committed Demand Side Management & Others Measures																					
SMI Theft Reduction		83	83	83	83	83	83	83	83	83	83	83	83	83	83	83	83	83	83	83	83
Voltage and VAR Optimization		67	152	171	188	219	240	254	259	263	268	285	290	295	300	305	310	315	320	325	331
2016 DSM Plan F16 savings		982	970	939	940	935	926	923	917	912	885	863	855	848	844	807	770	760	758	757	736
Planned Demand Side Management Measures																					
2016 DSM Plan F17 to F19 savings		389	988	1,679	1,896	1,931	1,969	1,956	1,935	1,917	1,908	1,896	1,853	1,787	1,694	1,613	1,547	1,462	1,300	1,224	1,190
2016 DSM Plan F20+ savings		0	0	0	292	904	1,454	1,897	2,310	2,637	2,946	3,229	3,500	3,758	4,006	4,248	4,473	4,690	4,908	5,116	4,976
Sub-total	(f)	1,521	2,192	2,873	3,399	4,072	4,672	5,112	5,502	5,811	6,089	6,356	6,581	6,770	6,927	7,055	7,183	7,310	7,368	7,505	7,317
		F2017	**F2018**	**F2019**	**F2020**	**F2021**	**F2022**	**F2023**	**F2024**	**F2025**	**F2026**	**F2027**	**F2028**	**F2029**	**F2030**	**F2031**	**F2032**	**F2033**	**F2034**	**F2035**	**F2036**
Surplus / (Deficit) (Operational View) **	(g) = d + e + f	**4,945**	**4,928**	**3,524**	**5,654**	**4,351**	**2,505**	**1,416**	**881**	**3,608**	**4,113**	**3,534**	**2,748**	**1,959**	**1,117**	**278**	**(662)**	**(1,355)**	**(2,118)**	**(2,704)**	**(4,056)**
Surplus / Deficit as % of Net Load (Planning View) **		**113%**	**115%**	**115%**	**114%**	**111%**	**108%**	**106%**	**105%**	**109%**	**110%**	**109%**	**107%**	**106%**	**105%**	**103%**	**102%**	**101%**	**99.97%**	**99%**	**97%**
Small Gap Surplus/(Deficit) (Operational View) **		7,266	7,487	6,536	9,044	8,219	6,890	6,181	5,920	8,949	9,749	9,380	8,839	8,311	7,735	7,122	6,521	6,085	5,500	4,968	3,745
Large Gap Surplus/(Deficit) (Operational View) **		2,559	2,036	*(70)*	1,250	*(661)*	*(3,248)*	*(5,224)*	*(6,122)*	*(3,768)*	*(3,650)*	*(4,392)*	*(5,505)*	*(6,676)*	*(7,987)*	*(9,100)*	*(10,334)*	*(11,294)*	*(12,339)*	*(13,341)*	*(15,043)*

* 2016 Integrated System Load Forecast with losses

** See section 3.4.2 for description of Operational versus Planning view

Table 3-9 Peak Capacity Load Resource Balance after Planned Resources

(MW)		F2017	F2018	F2019	F2020	F2021	F2022	F2023	F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031	F2032	F2033	F2034	F2035	F2036
Existing and Committed Heritage Resources																					
Heritage Resources (including Site C)	(a)	11,372	11,410	11,416	11,416	11,416	11,480	11,480	11,480	12,020	12,211	12,211	12,211	12,211	12,211	12,625	12,625	12,625	12,625	12,625	12,625
Existing and Committed IPP Resources	(b)	1,593	1,685	1,633	1,583	1,502	1,473	1,179	1,144	1,081	1,037	1,037	987	950	818	818	814	808	754	730	675
Future Supply-Side Resources																					
IPP Renewals		9	23	55	79	120	135	419	441	450	486	486	514	538	671	671	674	680	705	862	901
Standing Offer Program		4	6	12	19	27	34	41	49	56	64	71	79	86	94	101	108	116	123	138	145
Revolstoke 6												488	488	488	488	488	488	488	488	488	488
Sub-total	(c)	13	29	66	98	147	169	460	490	507	550	1,045	1,080	1,112	1,252	1,260	1,271	1,284	1,316	1,488	1,534
Total Supply	(d) = a + b + c	12,978	13,124	13,115	13,098	13,065	13,122	13,120	13,113	13,608	13,797	14,293	14,279	14,273	14,281	14,702	14,709	14,717	14,695	14,843	14,834
14% of Supply Requiring Reserves***	(e)	-1,788	-1,809	-1,808	-1,805	-1,801	-1,809	-1,808	-1,807	-1,884	-1,910	-1,980	-1,978	-1,977	-1,978	-2,037	-2,038	-2,039	-2,036	-2,057	-2,055
Effective Load Carrying Capability	(f) = d + e	11,189	11,315	11,307	11,293	11,264	11,313	11,311	11,306	11,725	11,887	12,313	12,301	12,296	12,303	12,665	12,671	12,678	12,659	12,786	12,779
Demand - Integrated System Peak																					
2016 May Mid Load Forecast Before DSM*		-10,776	-11,021	-11,209	-11,374	-11,541	-11,737	-11,930	-12,119	-12,313	-12,515	-12,708	-12,943	-13,155	-13,386	-13,614	-13,840	-14,074	-14,303	-14,542	-14,774
Expected LNG Load		-19	-19	-19	-72	-222	-329	-361	-361	-361	-361	-361	-361	-361	-361	-361	-361	-361	-361	-361	-361
Sub-total	(g)	-10,795	-11,039	-11,228	-11,447	-11,763	-12,066	-12,291	-12,480	-12,674	-12,876	-13,069	-13,304	-13,516	-13,747	-13,975	-14,201	-14,435	-14,664	-14,903	-15,135
Existing and Committed Demand Side Management & Others Measures																					
SMI Theft Reduction		11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11
Voltage and VAR Optimization		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2016 DSM Plan F16 savings		216	214	210	211	210	207	204	201	198	193	189	185	183	180	174	168	165	165	165	162
Planned Demand Side Management Measures																					
2016 DSM Plan F17 to F19 savings		66	167	272	310	314	316	311	305	299	295	290	282	272	259	247	237	225	207	198	195
2016 DSM Plan F20+ savings		0	0	0	47	170	285	358	421	468	514	554	593	629	663	696	725	753	788	822	808
Sub-total	(h)	293	392	494	578	706	818	884	938	977	1,013	1,045	1,072	1,095	1,114	1,128	1,142	1,154	1,171	1,196	1,176
		F2017	**F2018**	**F2019**	**F2020**	**F2021**	**F2022**	**F2023**	**F2024**	**F2025**	**F2026**	**F2027**	**F2028**	**F2029**	**F2030**	**F2031**	**F2032**	**F2033**	**F2034**	**F2035**	**F2036**
Surplus / (Deficit) **	(i) = f + g + h	**687**	**668**	**573**	**424**	**206**	**65**	**(96)**	**(236)**	**27**	**23**	**289**	**70**	**(124)**	**(330)**	**(182)**	**(389)**	**(603)**	**(833)**	**(921)**	**(1,180)**
Small Gap Surplus / (Deficit) **		1,107	1,136	1,121	1,041	908	856	765	675	995	1,046	1,354	1,188	1,048	897	1,093	953	796	604	536	317
Large Gap Surplus / (Deficit) **		237	118	(105)	(403)	(737)	(1,013)	(1,334)	(1,536)	(1,339)	(1,409)	(1,172)	(1,455)	(1,721)	(2,014)	(1,917)	(2,177)	(2,445)	(2,736)	(2,913)	(3,237)

* 2016 Integrated System Load Forecast with losses

** Planning View is shown in this table. Capacity load resource balances are only shown in Planning View. See section 3.4.2.

*** This is also referred to as the Planning Reserve - the system generating capacity beyond that required to meet peak demand that is necessary to meet reliability criteria. See section 1.2.2 of the IRP for more details on the criteria.

The key changes on the Load Resource Balances since the 2013 Integrated Resource Plan are as follows:

- **Load Forecast:** The Load Forecast continues to predict long-term load growth across all three customer sectors (refer to section 3.2 for details); however, load is forecast to be lower compared to the 2013 Integrated Resource Plan. For the residential and commercial sectors, the lower forecast is due to lower projections in economic drivers such as housing starts. For the industrial sector, the lower forecast is due to factors including delays of in service dates for several mining, LNG, and oil and gas projects, reduced expectations for potential new mining and oil and gas loads given current low commodity prices, the closure of Paper Excellence's Howe Sound Thermo-Mechanical Pulp Facility, and a reduced outlook for the pulp and paper sector;
- **Demand-Side Management Savings:**[22] Demand-side management continues to be a key resource in the Load Resource Balance and there have been changes since the 2013 Integrated Resource Plan:
  - ▶ First, energy savings from conservation rate structures have been less than forecasted, but energy savings from codes and standards have increased. In particular, customers' response to the Large General Service and Medium General Service two part baseline rates was considerably lower than forecasted in the 2013 Integrated Resource Plan. Most of the energy savings forecast from the Large General

[22] While the demand-side management savings shown throughout this Application are based on the same Demand-Side Management Pan, there are two estimates of the savings. The latest and more detailed estimate, prepared based on a bottom up approach, it is the basis for both the Load Resource Balances in Table 3 8 and Table 3 9, as well as the demand side management numbers quoted in section 3.4.3 and Chapter 10 of the Application. The rest of the Application reflects an earlier high level estimate, prepared using a "top down" approach for the purpose of informing the Revenue Forecasting process for the Application. The difference in savings between the two estimates is minor (71GWh, 154 GWh and 29 GWh (with losses) in fiscal 2017, fiscal 2018, and fiscal 2019, respectively.

Service and Medium General Service rates occurred prior to fiscal 2015 and are reflected in actual sales; and

- Second, BC Hydro has determined that it is appropriate to continue a strategy of moderation of demand-side management spending through fiscal 2017 to fiscal 2019 (refer to section 3.4.3.1 for more details). This moderation strategy has been extended as an assumption for years fiscal 2020 and beyond (i.e., relatively constant expenditure levels, adjusted for inflation). Actual expenditure levels (and the resulting energy savings) for fiscal 2020 and beyond will be determined in the 2018 Integrated Resource Plan and subsequent applications for expenditure schedules under section 44.2 of the *Utilities Commission Act*.

- **IPP Forecasts:** The forecast of IPP supply from existing Electricity Purchase Agreements has increased. Refer to sections 3.4.3.5 and 3.4.3.6 for more information on the IPP-related recommended actions and section 4.4.2.3 for details on the IPP forecast up to fiscal 2019;
- **Major Maintenance:** BC Hydro's heritage assets are aging with many requiring major maintenance work to ensure reliable operation. Given the capacity need and the cost-effective strategy to rely on the market as a bridging resource to the Site C Clean Energy Project, BC Hydro has delayed major maintenance work at the Mica generating station to avoid taking major units out of service during the period prior to the in-service date of the Site C Clean Energy Project. The updated capacity Load Resource Balance reflects the current view of scheduling maintenance outages for generating units 1 to 4 (410 MW each for dependable capacity) when the Site C Clean Energy Project comes online. It is currently estimated that the units will be out of service for 12 to 18 months each. The resulting impact is a 410 MW reduction in capacity contribution from BC Hydro's heritage resources for a period of approximately five years, which will advance BC Hydro's need for

new capacity resources, such as Revelstoke Unit 6, after the Site C Clean Energy Project. The impact of the outage on energy is minimal; and

- **North Coast capacity addition:** The 2013 Integrated Resource Plan includes a recommended action to "Explore natural gas-fired generation for the North Coast (Recommended Action 11): Working with industry, explore natural gas supply options on the North Coast to enhance transmission reliability and to meet expected load." In the 2013 Integrated Resource Plan Base Resource Plan with LNG, BC Hydro estimated that 400 MW of Simple Cycle Gas Turbines may be required to meet capacity requirement starting in fiscal 2020. In fiscal 2015, BC Hydro completed an assessment of adding up to 400 MW of both natural gas and clean generating capacity in the North Coast region. However, given the current reduced need for capacity in the system prior to the Site C Clean Energy Project, BC Hydro has assumed no North Coast capacity additions will take place before the end of fiscal 2024. BC Hydro continues to assess regional considerations which will inform future decisions on resource acquisitions outside the 2013 10 Year Rates Plan.

3.4.2.2 Accounting For Uncertainties on the Load Resource Balances

BC Hydro continues to monitor its Load Resource Balance as it faces significant uncertainties. The magnitude of the uncertainty is shown by the range of surplus/deficit presented in each of the load resource balances in Table 3-8 and Table 3-9. Considering these uncertainties, the Load Resource Balance with planned resources (Table 3-9) shows that additional capacity resources may be needed as early as fiscal 2019.[23]

[23] The risk of capacity shortfall is BC Hydro's primary concern because, unlike energy, capacity is required at specific times to meet load requirements and maintain system security and reliability.

Net Load Uncertainty

Forecasting net load is subject to the uncertainties of both the Load Forecast and demand-side management savings estimates. The key uncertainties on the Load Forecast and their assessment are discussed in section 3.2.2.

The key uncertainties relating to demand-side management delivery going forward are described in detail in Chapter 10, section 10.6. BC Hydro assessed demand-side management uncertainties using professional judgement, combined with Monte Carlo analysis to derive a quantified range of uncertainty of energy and associated capacity estimates. The uncertainty analysis is a two-step process whereby a bottom-up uncertainty assessment at the demand-side management initiative level is further informed by a top-down assessment at the demand-side management portfolio level that considers other higher level economic, policy and market conditions that could influence energy and capacity savings in the future.

“High demand-side management” and “low demand-side management” savings estimates are calculated as the mean of the upper and lower twentieth percentile tails of the distributions. The mid-level estimate is referred to as “mid demand-side management” and is the mean of the central 60 per cent of the distribution.

BC Hydro developed an uncertainty band around the load resource balance surplus/deficit[24] as shown in Table 3-8 and Table 3-9. Consistent with the approach taken in the 2013 Integrated Resource Plan (refer to section 4.3.4.3 of the 2013 Integrated Resource Plan), this uncertainty band is estimated by considering net Load Forecast scenarios. These scenarios are comprised of combinations of Load Forecast and demand-side management savings estimates, and include:

[24] The load resource balance surplus/deficit reflects net load combination of mid load forecast and mid Demand-Side Management.

- A low Load Forecast combined with low demand-side management savings estimate[25] (a scenario with the least need for new resources, referred to as Small Gap); and
- A high Load Forecast combined with low demand-side management savings (a scenario with the most need for new resources, referred to as Large Gap).

In all cases, the same LNG load was included in the Load Forecast. The resulting Load Resource Balance surplus/deficit for these net load scenarios are shown in Table 3-8 and Table 3-9.

Resource Uncertainty

In addition to the uncertainties on the net Load Forecast, there are uncertainties on the IPP forecast, including contract attrition and delivery uncertainties.

- Contract attrition uncertainty (the uncertainty of contracts reaching commercial operation) is limited because most projects with Electricity Purchase Agreements are already in, or nearing, commercial operation and future Standing Offer Program Electricity Purchase Agreements require all material permits in advance of signing Electricity Purchase Agreements;
- Prior to and during the initial years of operations, there is uncertainty on energy delivery to the BC Hydro system relative to the IPPs' initial estimates. This uncertainty diminishes as BC Hydro gains operational information, and as new projects comprise a relatively small portion of the overall IPP portfolio; and

Customers only pay the actual energy costs. From the perspective of BC Hydro and its customers, variances between forecast and actual energy costs are captured in the Non-Heritage Deferral Account.

[25] Low Demand-Side Management is used in this scenario to reflect that prolonged period of low load growth would likely have BC Hydro scaling back Demand-Side Management efforts.

3.4.3 2013 Integrated Resource Plan Recommended Actions Relevant to the Test Period

The recommended actions from the approved 2013 Integrated Resource Plan, with some modifications to reflect the changed circumstances described above, continue to drive our resource acquisitions during the test period. Table 3-8 and Table 3-9 show the Load Resource Balances with planned future resources per recommended actions in the 2013 Integrated Resource Plan, in addition to existing and committed resources. The recommended actions relevant for the fiscal 2017 to fiscal 2019 test period, each of which is discussed below, are as follows:

- Demand Side Management:
  - Moderate current demand-side management spending and maintain long-term target (Recommended Action 1);
  - Pursue Demand-Side Management Capacity Conservation (Recommended Action 2);
  - Explore more Codes and Standards (Recommended Action 3); and
  - Supporting Clean Energy Sector - work with government to advance electrification (Recommended Action 10).
- Optimize existing portfolio of IPP resources (Recommended Action 4); and
- Supporting Clean energy sector – Standing Offer Program (Recommended Action 10).

3.4.3.1 Recommended Action 1: Moderate current Demand-Side Management spending and maintain long-term target

Demand-side management is a major element in BC Hydro's Integrated Resource Plan because it is cost-effective and has minimal environmental footprint. It also contributes to and aligns with several of BC's energy objectives as stated in section 2 of the *Clean Energy Act* (refer to details in Chapter 10, section 10.3.6).

Recommended Action 1 in the 2013 Integrated Resource Plan was:

> Moderate current demand-side management spending and maintain long-term target. Target expenditures of $445 million ($175 million, $145 million and $125 million per year) on conservation and efficiency measures during fiscal 2014 to fiscal 2016. Prepare to increase spending to achieve 7,800 GWh/year in energy savings and 1,400 MW in capacity savings by fiscal 2021.

The 2013 Integrated Resource Plan included an outlook for demand-side management savings and spending beyond fiscal 2016. This outlook was premised on ramping up to achieve the 7,800 GWh/year and 1,400 MW target by fiscal 2021 (based on a fiscal 2013 start year).

Subsequent to the 2013 Integrated Resource Plan, BC Hydro determined that it is appropriate to continue a moderation strategy for demand-side management and still achieve the 66 per cent target in 2020 in the *Clean Energy Act.*[26] Spending through the fiscal 2017 to fiscal 2019 period will be reduced to approximately $375 million over the three year period (and average of $125 million/year), while maintaining the ability to ramp up after fiscal 2019 if warranted.

BC Hydro determined this level of demand-side management expenditure after considering the targets referenced above, the delayed system needs described in section 3.4.2, the need to meet the 2013 10 Year Rates Plan and a number of other factors, including opportunities to take advantage of new technologies and changing customer expectations. Details of the Demand-Side Management Plan are provided in Chapter 10 of this application.

[26] Subsection 2(b) of the *Clean Energy Act* is the British Columbia's energy objective "to take demand-side measures and to conserve energy, including the objective of [BC Hydro] reducing its expected increase in demand for electricity by year 2020 [by year fiscal 2021 from fiscal 2008] by at least 66 per cent".

The 2013 Integrated Resource Plan included a target of 7,800 GWh and 1,400 MW, which reflected cumulative energy and capacity savings with a fiscal 2013 start year. The corresponding equivalent amount to 7,800 GWh based on planned savings going forward from fiscal 2016 (the start year for analysis in this application) is 5,100 GWh whereas the corresponding equivalent of 1,400 MW is 900 MW. With the Demand-Side Management Plan in this application, BC Hydro anticipates electricity savings by year 2020 (fiscal 2021) to be 3800 GWh for energy and 700 MW for capacity (fiscal 2016 start year).

While lower than the target established in the 2013 Integrated Resource Plan, the Demand-Side Management Plan exceeds the 66 per cent objective of the *Clean Energy Act* and equates to approximately 106 per cent of BC Hydro's forecasted energy load increase by fiscal 2021 (refer to Chapter 10, section 10.3.4 for a discussion on this metric and its sensitivity). The 106 percent presented is based on the May 2016 Load Forecast without LNG. The figure would be 90 per cent if based on the May 2016 Load Forecast with LNG, still in excess of the *Clean Energy Act* objective.

The Minister has accepted the lower anticipated savings by fiscal 2021[27] and expects BC Hydro to consult on a new long-term target, beyond 2020, through the 2018 Integrated Resource Plan process.

The Demand-Side Management Plan, together with other Recommended Actions, is expected to provide sufficient resources to meet the forecast demand until fiscal 2034 for energy and fiscal 2029 for capacity as shown in the Load Resource Balances in Table 3-8 and Table 3-9. The Demand-Side Management Plan also maintains the ability to ramp-up after fiscal 2019, if warranted.

[27] Minister Bill Bennett has confirmed that government supports BC Hydro's demand-side management plans and expenditure levels for the fiscal 2017 to fiscal 2019 period by letter dated December 16, 2015 (attached in Appendix BB).

3.4.3.2 Recommended Action 2: Pursue Demand-Side Management capacity conservation

Recommended Action 2 in the 2013 Integrated Resource Plan was:

> Implement a voluntary industrial load curtailment program from fiscal 2015 to fiscal 2018 to determine how much capacity savings can be acquired and relied upon over the long term. Pilot voluntary capacity-focused programs (direct load) for residential, commercial and industrial customers over two years, starting in fiscal 2015.

Capacity focused demand-side management is potentially a cost-effective capacity option but is still being piloted to understand whether it can be a long term resource that is sufficiently reliable for deferring generation resources. Since the 2013 Integrated Resource Plan, BC Hydro has advanced its investigation of capacity focused demand-side management in two areas: load curtailment and demand response. Details on these activities are provided in Chapter 10, section 10.2.2.

3.4.3.3 Recommended Action 3: Explore more codes and standards

Recommended Action 3 in the 2013 Integrated Resource Plan was:

> Explore more codes and standards. Explore additional opportunities to leverage more codes and standards to achieve conservation savings at a lower cost beyond the current target and to gain knowledge and confidence about their potential to address future or unexpected load growth.

Activities undertaken by BC Hydro as part of this recommended action since the 2013 Integrated Resource Plan are described in Chapter 10, section 10.2.3.

3.4.3.4 Recommended Action 10 - Supporting Electrification (Demand-Side Management)

Recommended Action 10 in the 2013 Integrated Resource Plan included:

> With input from government policy signals on GHG reductions to incent electrification, BC Hydro will focus on

> advancing electrification with a focus on industrial, transportation and other sectors.

BC Hydro has positioned itself to respond to this recommended action through its approach to demand-side management as outlined in Chapter 10, section 10.3.3.

3.4.3.5 Recommended Action 4: Optimize existing portfolio of IPP Resources

Recommended Action 4 in the 2013 Integrated Resource Plan was:

> Optimize the current portfolio of IPP resources according to the key principle of reducing near-term costs while maintaining cost-effective options for long-term need

Actions taken to implement this recommendation included:

- **Termination, Downsizing or Deferral of Pre-Commercial Operation Date Electricity Purchase Agreements**: Since 2013, BC Hydro has implemented a number of actions to optimize the portfolio of IPP resources. BC Hydro has executed agreements with IPPs to terminate 14 Electricity Purchase Agreements, downsize and defer two Electricity Purchase Agreements, and defer the delivery of energy to BC Hydro from an additional 11 Electricity Purchase Agreements. As a result of these actions, BC Hydro has reduced electricity purchase commitments by $2.1 billion through:
  - Ongoing reductions representing 435 MW in nameplate capacity and approximately 1,890 GWh per year contracted energy through Electricity Purchase Agreement downsizing and terminations; and
  - One-time reductions in purchase commitments of approximately 2,050 GWh occurring between fiscal 2015 and fiscal 2018 through deferrals of commercial operations for Electricity Purchase Agreements.
- **Electricity Purchase Agreement renewals:** Consistent with the approved 2013 Integrated Resource Plan, BC Hydro continues to assume renewal of

50 percent of the energy and capacity contributions from biomass Electricity Purchase Agreements and 75 per cent from the run-of-river hydroelectric Electricity Purchase Agreements that are due to expire within the remaining years of the 2013 10 Year Rates Plan.

Renewal of Electricity Purchase Agreements with existing facilities has the long term benefit of delaying future greenfield resources. BC Hydro is targeting renewal of contracts for those facilities that have the lowest cost, greatest certainty of continued operation and best system support characteristics. Due to the fact that Electricity Purchase Agreement renewals are related to existing projects for which the IPPs initial capital investment has been fully or largely recovered during the term of the initial Electricity Purchase Agreement, BC Hydro expects to negotiate a lower energy price than the initial Electricity Purchase Agreement. In its Electricity Purchase Agreement renewal negotiations, BC Hydro will consider the IPPs' opportunity cost, the electricity spot market, the cost of service for the IPPs (including fibre supply costs for biomass facilities) and other factors such as the attributes of the energy produced and other non-energy benefits.
BC Hydro is not requesting any approvals in this application with respect to the renewal of Electricity Purchase Agreements. They will be subject to separate British Columbia Utilities Commission review pursuant to section 71 of the *Utilities Commission Act*. Any variances from forecast energy costs in this application as a result of the British Columbia Utilities Commission review of the section 71 filings will be captured in the Non-Heritage Deferral Account; and

- **New Electricity Purchase Agreements:** Consistent with the 2013 Integrated Resource Plan, with the exception of Standing Offer Program related Electricity Purchase Agreements, BC Hydro is not proposing to enter into any new Electricity Purchase Agreements for the test period. No projects associated with Impact Benefit Agreement commitments with First Nations are assumed to come into service during the test period.

3.4.3.6 Recommended Action 10: Support Clean Energy Sector (Standing Offer Program – Electricity Purchase Agreements and Renewals)

Recommended Action 10 in the 2013 Integrated Resource Plan was:

> Advance a set of actions that will support a healthy, diverse clean energy sector and promote clean energy opportunities for First Nations' communities.

This recommended action is the Clean Energy Strategy. Among other things, the Strategy consists of two actions that impact the Load Resource Balance after recommended actions:

1. Undertaking Electricity Purchase Agreement renewals (refer to section 3.4.3.5); and
2. The Standing Offer Program.

The Standing Offer Program is a legislated requirement pursuant to subsection 15(2) of the *Clean Energy Act*. Subsection 15(3) provides that BC Hydro may establish the terms and conditions of the offers under the Standing Offer Program. The Standing Offer Program annual target of 150 GWh/year was established in the 2013 Integrated Resource Plan to enable small-scale projects in communities throughout BC Hydro's service area, and to promote First Nations participation in the clean energy sector. A "Micro-Standing Offer Program" component, in the range of 100 kW to 1 MW, was introduced within the overall Standing Offer Program annual target on February 29, 2016. This new component has a streamlined process to reduce development costs and is available for First Nations and communities.

The current Standing Offer Program price was informed by the prices from the Clean Power Call in 2010. Since then:

- The cost for developing some new clean energy resources has declined (e.g., wind and solar);
- The Pacific Northwest, including BC Hydro, has become more constrained in operation during the freshet oversupply period; and
- BC Hydro is expecting to have greater need for new capacity resources over energy resources.

Accordingly, BC Hydro is going through an optimization process for the Standing Offer Program and Micro-Standing Offer Program. This process will help to ensure the Standing Offer Program and Micro-Standing Offer Program reflect future system needs, consider recent advancements in technology, and are aligned with the 2013 10 Year Rates Plan. To ensure that projects that are significantly advanced are not unduly impacted, any changes to the programs are expected to apply to projects allocated to the Standing Offer Program volume in calendar 2020 and beyond, and not during the current test period.

3.4.4 Long-Run Marginal Costs

This section discusses the updated energy and capacity long-run marginal costs and compares them that with those set out in the approved 2013 Integrated Resource Plan.

3.4.4.1 How Long-Run Marginal Cost is Used

Long-run marginal cost can be defined as the price for acquiring resources to meet incremental customer demand beyond existing and committed resources. A consideration in setting the long-run marginal cost is providing a steady and consistent price signal for determining/screening the cost-effectiveness of different resources. BC Hydro does not expect to acquire all available resources up to the long-run marginal cost, nor does it expect the long-run marginal cost to be the clearing price.

BC Hydro uses long-run marginal costs as a price signal to determine cost-effectiveness of the resources that it acquires in circumstances where portfolio analysis cannot be effectively undertaken. In particular, the long-run marginal costs are benchmarks in determining:

- The cost-effectiveness of demand-side management expenditures in this application;
- The cost-effectiveness of IPP Electricity Purchase Agreement renewals; and
- The level of efficiency to specify in acquiring electric system equipment.

The Long Run Marginal Cost also informs the setting of conservation rate structures as per the current 2015 Rate Design Application.

Determination of the long-run marginal costs is guided by the government approved Integrated Resource Plan, which ensures reliable and cost-effective electricity service both in the near and long-term while balancing multiple policy objectives.

3.4.4.2 Energy Long-Run Marginal Cost Determination and Application

For many years prior to the 2013 Integrated Resource Plan, BC Hydro had a forecast need to acquire energy from greenfield clean or renewable IPP projects and they were the marginal resource that set the long-run marginal cost. The estimated cost of energy from greenfield clean or renewable IPPs[28] was revised from $135/MWh (fiscal 2013$)[29] to $125/MWh (fiscal 2013)[30] in the 2013 Integrated Resource Plan. It is now estimated at $100/MWh (fiscal 2015$).[31] The need for energy from greenfield clean and renewable IPPs

[28] The costs shown are adjusted Unit Energy Costs including delivery cost to the Lower Mainland/Vancouver Island region.
[29] Based upon the Clean Power Call results, the most recent and broadly-based power acquisition process at the time of the 2013 Integrated Resource Plan.
[30] Based upon resource cost estimate at the time of the 2013 Integrated Resource Plan, reflecting cost reduction since the Clean Power Call.
[31] Based upon BC Hydro's most recent resource options updates, reflecting recent wind cost estimates.

shown in the updated Load Resource Balance in section 3.4.2 is not expected to occur until fiscal 2034.

The Greenfield clean or renewable IPP long-run marginal cost is still relevant in the case of:

- Demand-side management, reflecting "the authority's long-run marginal cost of acquiring electricity generated from clean or renewable resources in British Columbia for the purpose of section 4.1.1 of the *Demand Side Management Regulation*";[32]
- Longer term stable pricing signals for rates; and
- Long lived assets where electricity supply benefits extend to and beyond fiscal 2034.

A long-run marginal cost based on resources that have a lower cost than greenfield IPPs was introduced in the 2013 Integrated Resource Plan after lower Load Forecasts and modifications to *Clean Energy Act* self-sufficiency requirements reduced the need for new resources. Currently, and still consistent with the 2013 Integrated Resource Plan, BC Hydro's actions to meet future energy demand through to the late 2020's include the Site C Clean Energy Project and the Standing Offer Program, along with demand-side management and IPP Electricity Purchase Agreement renewals. Given that the Site C Clean Energy Project is a committed resource under construction and the Standing Offer Program is required pursuant to subsection 15(2) of the *Clean Energy Act*, they are not marginal resources. As a result, the marginal resources before the return of need for new resources from greenfield clean or renewable IPPs are

[32] Section 4.1.1 of the Demand-Side Management Regulation 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 long-run marginal cost in the Demand-Side Management Regulation to be the cost of acquiring greenfield clean or renewable IPP resources, which is estimated at $100/MWh (fiscal 2015$).

demand-side management programs and Electricity Purchase Agreement renewals.

Since the demand-side management and IPP renewal resource supply curves (price and volume relationship) are not easily visible until the actions have been undertaken, BC Hydro used a price signal (i.e., the Long Run Marginal Cost) to set the upper limit on these acquisitions. The long-run marginal cost set out in the 2013 Integrated Resource Plan was $85 to $100/MWh (fiscal 2013$). This was revised to $85/MWh based upon a reduced need for new resources and further information as set out in the Rate Design Application Evidentiary Update. BC Hydro expects it will be able to acquire sufficient resources to meet its need at or below this price.

- ***Electricity Purchase Agreement Renewals:*** As described in section 3.4.3.5., the cost of service for IPPs is one of the factors in Electricity Purchase Agreement renewal negotiations and could vary significantly among IPPs. BC Hydro is targeting renewal of contracts for those facilities that have the lowest cost, greatest certainty of continued operation and best system support characteristics. Due to the fact that Electricity Purchase Agreement renewals are related to existing projects for which the IPPs' initial capital investment has been fully or largely recovered during the term of the initial Electricity Purchase Agreement, BC Hydro expects to be able to negotiate a lower energy price than the initial Electricity Purchase Agreement. Since the 2013 Integrated Resource Plan, BC Hydro has carried out further analysis of the expected cost of service for existing projects. BC Hydro currently estimates that the renewal volumes in the plan can be acquired at or below $85/MWh (fiscal 2013$) although the relationship between price, volume, contract terms and other non-energy benefits has yet to be established through bilateral negotiations. As previously noted in this section, BC Hydro does not expect to acquire all available resources up to the long-run marginal cost nor does it expect the long-run marginal cost to be the clearing price;

- ***Demand-Side Management Plan:*** The $85/MWh amount was used to inform the development of the Demand-Side Management Plan including by ensuring that all demand-side management initiatives were cost-effective in a total resource cost test against the $85/MWh threshold.

Based on the updated load resource balances in section 3.4.2, the need for new energy resources beyond existing and committed resources is in fiscal 2022 (delayed from fiscal 2017 in the 2013 Integrated Resource Plan). Given planned resources pursuant to the 2013 Integrated Resource Plan Recommended Actions, greenfield IPPs will not be needed until fiscal 2034. The resulting marginal resources and related costs are as follows:

Table 3-10 Marginal Energy Resources and Related Cost

Marginal Resources	Period of Applicability	$/MWh
Demand-Side Management and Electricity Purchase Agreement renewals	fiscal 2022 to fiscal 2033	Less than: $87/MWh (fiscal 2016$) or $85/MWh (fiscal 2013$)
Greenfield IPPs	fiscal 2034 and beyond	$102/MWh (fiscal 2016$) or $100/MWh (fiscal 2015$)

3.4.4.3 Capacity Long-Run Marginal Cost Determination and Application

Consistent with the 2013 Integrated Resource Plan, the updated capacity Load Resource Balance continues to show a need to acquire additional capacity resources over and above the other resource acquisitions in the Plan. The next generation capacity resources that could be developed and are being advanced for contingency planning purposes are Revelstoke Unit 6 and natural gas-fired simple-cycle gas turbine generators. Revelstoke Unit 6 is the next most cost-effective generation capacity resource on a unit cost basis.

In the 2013 Integrated Resource plan, the long-run marginal cost for capacity was estimated at $50 to 55/kW-year based on Revelstoke Unit 6 and the unit capacity costs for simple-cycle gas turbine generators was estimated at $88/kW-year. These costs are both in fiscal 2013$ and are at point-of-interconnection. In BC Hydro's most recent resource options updates, the unit capacity costs of a simple-cycle gas turbine generators at point-of-interconnection has dropped to $79/kW-year (fiscal 2015$). To make the unit capacity costs comparable to the adjusted unit energy costs with delivery to Lower Mainland and to adjust for energy impacts, these unit capacity costs are adjusted to be $57/kW-year (fiscal 2015$) for Revelstoke Unit 6 and $115/kW-year (fiscal 2015$) for a simple-cycle gas turbine. The range of $50 to $55/kW-year (fiscal 2013$) continues to be reasonable for Revelstoke Unit 6.

As shown in the updated Load Resource Balance in section 3.4.2, "Peak Capacity Load Resource Balance after Planned Resources", there is still a small capacity need prior to the Site C Clean Energy Project coming fully into service in fiscal 2025. BC Hydro continues to plan to rely on the market to bridge this capacity need.

Revelstoke Unit 6 is the next capacity resource planned and is being advanced as either a contingency resource for its earliest in-service date in fiscal 2022 or for the need in the mid-level forecast in fiscal 2027. The next capacity resource after Revelstoke Unit 6 is not needed until fiscal 2029. The resulting marginal resources and related costs are as follows:

Table 3-11 Marginal Capacity Resources and Related Costs

Marginal Resources	Period of Applicability	$/kW-year
Revelstoke Unit 6	Fiscal 2020 to fiscal 2028	$50 - $55/kW-year (fiscal 2013$)
Simple-Cycle Gas Turbine	Fiscal 2029 and beyond	$117/kW-year (fiscal 2016$) or $115/kW-year (fiscal 2015$)

Fiscal 2017 to Fiscal 2019

Revenue Requirements Application

Chapter 4

Cost of Energy

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4.1 Introduction

This chapter discusses the components of BC Hydro's energy costs, including Heritage and Non-Heritage energy sources, and a detailed forecast of the expected cost of energy during the test period. Heritage Energy refers to energy or capacity associated with BC Hydro's 30 hydroelectric generation facilities, also known as BC Hydro's Heritage Resources. Non-Heritage Energy refers to energy from other sources, such as energy obtained through Electricity Purchase Agreements with Independent Power Producers (**IPPs**). The Cost of Energy does not include operating and maintenance costs associated with the Heritage Assets.

This chapter is organized as follows:

- Section 4.2 identifies the components of BC Hydro's Cost of Energy, includes a high-level summary of BC Hydro's forecast Cost of Energy during the test period, and identifies applicable deferral accounts;
- Section 4.3 explains BC Hydro's use of an Energy Study to optimize the dispatch of BC Hydro resources that impact components of the Cost of Energy. It also identifies water inflows, market prices and loads as the primary variable inputs to the Energy Study influencing the Cost of Energy; and
- Section 4.4 describes in greater detail BC Hydro's forecast Cost of Energy during the test period. The forecast Cost of Energy is driven primarily by IPP costs, and specifically those costs associated with agreements entered into prior to fiscal 2017, for which cost recovery is prescribed by Direction No. 7. Electricity Purchase Agreement renewals during the test period will be subject to British Columbia Utilities Commission review in separate section 71 processes.

Please note, in the tables in this Chapter, references to F2015 RRA or F2016 RRA signifies the Plan amount from the Fiscal 2015 - Fiscal 2016 Revenue Requirements Rate Application.

4.2 Cost of Energy Background

This section identifies the components of BC Hydro's Cost of Energy, provides a high-level summary of BC Hydro's forecast Cost of Energy during the test period, and identifies applicable deferral accounts.

4.2.1 Components of Cost of Energy

The Cost of Energy is the sum of the Cost of Heritage Energy and the Cost of Non-Heritage Energy.

The Cost of Heritage Energy is the cost that BC Hydro incurs to provide up to 49,000 GWh per year under the Heritage Contract to serve domestic load obligations.[33] As further described in section 4.4, the Cost of Heritage Energy is the sum of:

- Water rental fees associated with hydroelectric generation, capacity and storage from Heritage Resources;
- Market electricity purchases;
- The cost of natural gas and gas transportation for Heritage thermal generation;
- Electricity transmission costs;
- The financial impact of transactions associated with Columbia River Treaty related agreements;

less:

- Revenue from surplus sales; and
- Water rental remissions.

[33] BC Hydro's domestic load obligations include deliveries under the Skagit Valley Treaty. The Heritage Contract is Appendix A of Direction No. 7, which is included in Appendix C of the Application.

The Cost of Non-Heritage Energy is the cost that BC Hydro incurs to provide energy from Non-Heritage sources to serve domestic load. As further described in section 4.4.2, the Cost of Non-Heritage Energy is the sum of:

- Water rental fees associated with BC Hydro's one-third interest in the Waneta facility;
- Purchases from IPPs;
- The cost of energy for the Non-Integrated Areas;
- Non-Heritage natural gas transportation costs; and
- Net purchases (sales) from Powerex.

A breakdown of the components of the Cost of Energy is shown in Appendix A Schedule 4.0.

4.2.2 Cost of Energy Forecast

The Cost of Energy forecast is shown in Table 4-1. This forecast was prepared using the Energy Study process described in section 4.3, which includes consideration of a range of future water inflow sequences, market prices, and loads. The Cost of Energy forecast is the expected value of the distribution of possible outcomes from the Energy Study.

Table 4-1 Cost of Energy Forecast

Cost of Energy	F2015 RRA ($ million)	F2015 Actual ($ million)	F2016 RRA ($ million)	F2016 Actual ($ million)	F2017 Plan ($ million)	F2018 Plan ($ million)	F2019 Plan ($ million)
Heritage Energy	311.6	388.9	357.6	206.1	279.3	250.2	279.3
Non-Heritage Energy	1,072.9	1,123.6	1,034.1	1,269.5	1,270.0	1,407.6	1,483.6
Total	**1,384.5**	**1,512.5**	**1,391.7**	**1,475.6**	**1,549.3**	**1,657.8**	**1,762.9**

The changes in the Cost of Heritage Energy over the test period are primarily due to fluctuations in market electricity purchases and surplus sales. Please refer to section 4.4.1.7 for details.

The average annual cost of Non-Heritage Energy increases across the test period. The primary component of the cost of Non-Heritage Energy are IPP costs which increase to $1,439 million in the fiscal 2019 plan from $1,229 million fiscal 2016 actual costs, as more IPP projects achieve commercial operation. Please refer to section 4.4.2.3 for more details.

Please refer to Appendix K for an explanation of in the Cost of Heritage and Non-Heritage Energy for fiscal 2015 and fiscal 2016.

4.2.3 Cost of Energy Deferral Accounts

There are two deferral accounts for the Cost of Energy – the Heritage Deferral Account and the Non-Heritage Deferral Account. Certain differences between plan and actual Cost of Energy amounts are deferred to the Heritage Deferral Account[34] and the Non-Heritage Deferral Account. [35] Please refer to Chapter 7 for a more detailed description of these accounts.

4.3 Forecasting the Cost of Energy

BC Hydro uses proprietary Energy Study models to inform operational decisions on system storage operations, thermal dispatch, and purchases and sales of market electricity. The same models are used for BC Hydro's ongoing financial forecasting of the Cost of Energy. BC Hydro runs the energy studies monthly. The Energy Study underlies the forecasted Cost of Energy in this application. This section describes the Energy Study and its key drivers.

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[34] The Heritage Deferral Account captures certain differences between the forecast and actual Heritage Payment Obligation. The Heritage Payment Obligation is equal to the Cost of Heritage Energy described in section 4.4 adjusted for notional water rentals (refer to Schedule B, Note 1, of the March 31, 2016 Deferral Account Report), Skagit Valley Treaty and ancillary revenues, and certain load curtailment and other costs (refer to Appendix A Schedule 4.0).

[35] The "Non-Heritage Cost of Energy Subject to the Non-Heritage Deferral Account" is equal to the Non-Heritage Cost of Energy described in section 4.4.2 adjusted for foreign exchange gains/losses on the trade account, notional water rentals, load variance and other adjustments.

4.3.1 The Role of the Energy Study

The Energy Study informs BC Hydro's supply portfolio optimization and is reflected in financial forecasting of the Cost of Energy.

BC Hydro's supply portfolio includes its Heritage Resources (hydroelectric and thermal), IPP contracts, and contractual rights and obligations under its coordination agreements. The supply portfolio also includes transactions with Powerex under the Transfer Pricing Agreement.

BC Hydro optimizes its supply portfolio, in particular its dispatchable resources, to maximize the consolidated net revenue over a five-year forecasting horizon while satisfying domestic integrated system requirements and contractual obligations.[36] It does so in accordance with numerous operating parameters and constraints, as well as water licence and Water Use Plan requirements and obligations under several coordination agreements, including the Columbia River Treaty and Canal Plant Agreement.

BC Hydro's large storage reservoirs on the Peace River (Williston) and the Columbia River (Kinbasket) provide the majority of the flexibility in the optimization of the supply portfolio by allowing the seasonal and annual shift of energy production from periods of high inflows to periods of high demand and high market prices, and by enabling the seasonal integration of non-dispatchable Heritage and Non-Heritage resources such as wind and run-of-river hydro generation.

The optimization of the supply portfolio and resulting operation of the system is informed by BC Hydro's Energy Study, which is produced by a suite of decision support models. These are proprietary models developed specifically for the characteristics of the BC Hydro system. A key feature of the Energy Study models is

[36] Consolidated net revenue is the revenue from billed sales, plus revenue from market electricity sales, less cost of water rental energy payments, less cost of gas and associated taxes for thermal generation, less cost of IPP Electricity Purchase Agreements, less cost of market electricity purchases, less Net Purchases (Sales) from Powerex.

the explicit modeling of decision-making under uncertainty in future inflows, market prices, and loads.

The Energy Study models are used by BC Hydro to inform operational decisions on system storage operations, thermal dispatch, and purchases and sales of market electricity. The same models are used for BC Hydro's ongoing financial forecasting of the Cost of Energy, including the forecasts in this application.

Primary inputs to the Energy Study models include:

- The load forecast (as described in Chapter 3 and section 4.3.2.3) net of DSM savings, including the range[37] of values based on weather variability;
- The range of supply and seasonal shape of resources under contract to BC Hydro;
- The range of inflow conditions on the Peace and Columbia River basins as described in section 4.3.2.1;
- The range of market prices for both gas and electricity as described in section 4.3.2.2; and
- The range of supply expected from all of BC Hydro's Heritage Resources other than those in the Columbia and Peace River basins.

The above inputs describe the variable inputs; however, the unit availability and economic assumptions also influence the results. Using all of the inputs, the models develop risk-neutral operating strategies for the Peace and Columbia River plants, as well as information on the range and expected value of generation from thermal resources dispatchable by BC Hydro, and market sales and purchases that maximize consolidated net revenue. BC Hydro uses these outputs to build the Cost of Energy forecast, the components of which are described in this section.

[37] The inputs for which a range of values are forecast include variability by weather sequence, based on historic weather/inflow data for the period 1973 to 2015.

4.3.2 Energy Study Drivers

Sections 4.3.2.1 through 4.3.2.4 provide a summary of key system optimization variables - inflows, electricity and gas market prices, and load - and the resulting system storage through fiscal 2019.

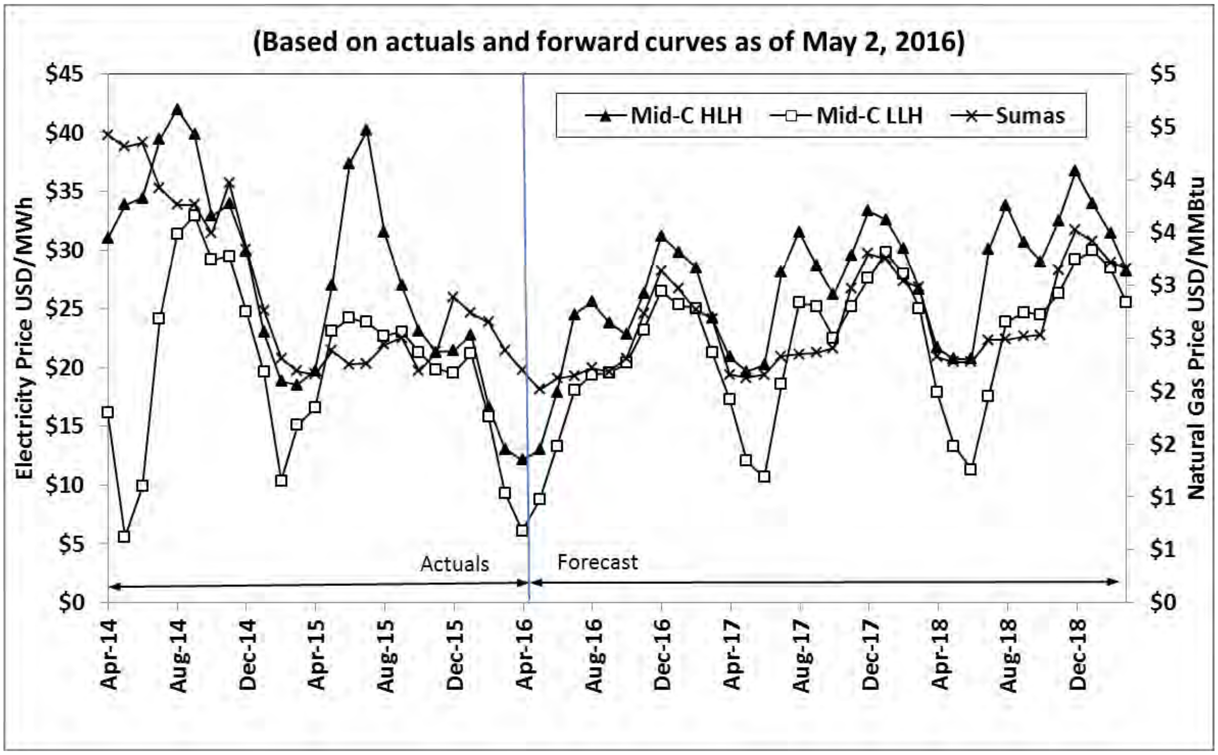
4.3.2.1 Inflows

The amount of energy available from hydroelectricity in any given year is variable and depends on inflows. In a high inflow year the available energy will be higher than in a low inflow year. Inflows in the Energy Study are based on the 43-year historical record of 1973 through 2015. For all years in the test period the reported model results are based on the average across these 43 years of record. The differences between years in the test period are due to expected changes in the use of storage as discussed in section 4.3.2.4. The fiscal 2017 results also include the snowpack forecast which should result in more accurate forecast of inflows for the spring and summer of 2016.

4.3.2.2 Electricity and Gas Market Prices

The value of surplus sales, the cost of market purchases, and the cost to run thermal generation are dependent on electricity and gas market prices. These prices are used within the Energy Study to make decisions about which resources to use to meet domestic load obligations in order to maximize the consolidated net revenue. Figure 4-1 shows the historical and forecast electricity (Mid-C) and gas (Sumas) market prices from the start of fiscal 2015 through to the end of fiscal 2019, as of May 2, 2016. Across the test period there is a general upward trend in both forecast gas and electricity prices.

Figure 4-1 Electricity and Gas Prices



4.3.2.3 Load

The Energy Study results inform the dispatching of resources as required to meet domestic obligations, primarily the domestic load. BC Hydro's load forecast used in the Energy Study is discussed in Chapter 3, adjusted for weather-related variability.

4.3.2.4 System Storage

The amount of energy available from hydroelectric generation in a given year depends on the amount of system storage at the beginning of that year. BC Hydro's reservoirs typically reach their annual minimum storage levels near the end of April, after the annual drawdown to serve the period of peak winter load, and refill to their annual maximum in the summer following the spring freshet.

However, as system storage is operated to maximize the consolidated net revenue (i.e., consolidated operations to support both domestic load obligations and trade) over a five year forecasting horizon, actual reservoir levels will differ from the historical average due to factors that change over time, such as loads, resource additions and resource upgrades, operating constraints such as those introduced through Water Use Plans, volume and timing of IPP deliveries, inflows and market prices.

System storage is expressed as an energy equivalent sum of the Williston and Kinbasket reservoirs.

The system storage forecast for the test period, along with the fiscal 2015 and fiscal 2016 actual system storage is shown in Table 4-2. At the end of fiscal 2015, BC Hydro's system storage was about 17,800 GWh, or about 5,400 GWh above the average of the previous ten years (i.e., the March 31 value from 2005 to 2014) of 12,400 GWh. The drivers for the high levels of system storage at the end of fiscal 2015 are discussed in Appendix K section 2.1. At the end of fiscal 2016, the system storage was 14,822 GWh, moving closer to BC Hydro's ten year average. The forecast for system storage is near to below average across the test period.

Table 4-2 End of Period System Storage

GWh	F2015 RRA	F2015 Actual	F2016 RRA	F2016 Actual	F2017 Plan	F2018 Plan	F2019 Plan
End of Period System Storage[38]	11,820	17,800	11,891	14,822	11,918	10,746	10,576

4.4 BC Hydro's Cost of Energy

Section 4.4 presents the detailed forecast information for Cost of Heritage Energy and Cost of Non-Heritage Energy as set out Appendix A, Schedule 4.0. BC Hydro explains that the overall increases in the Cost of Energy are driven primarily by IPP costs, and specifically those costs associated with agreements entered into prior to fiscal 2017 for which cost recovery is prescribed by Province's Direction No. 7 to the British Columbia Utilities Commission.

[38] System storage is the energy equivalent storage available at the end of each fiscal year at Williston and Kinbasket. The system storage forecast is calculated by taking the fiscal 2016 ending storage and adding the forecast net changes in storage year over year.

4.4.1 Cost of Heritage Energy

Table 4-3 provides the breakdown of the Cost of Heritage Energy. The planned costs represent the average of the expected value of a range of potential outcomes for each item.

Table 4-3 Cost of Heritage Energy

Cost of Energy	F2015 RRA ($ million)	F2015 Actual ($ million)	F2016 RRA ($ million)	F2016 Actual ($ million)	F2017 Plan ($ million)	F2018 Plan ($ million)	F2019 Plan ($ million)
Heritage Energy							
Hydroelectric (Water Rentals)	385.1	361.4	384.5	357.7	379.9	350.4	350.1
Market Electricity Purchases	44.7	6.0	56.6	2.8	8.6	30.2	35.9
Market Purchases to Non-Heritage	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Natural Gas for Thermal Generation	26.6	24.0	26.9	20.0	14.9	10.5	10.7
Domestic Transmission	30.5	18.4	25.7	52.6	54.5	57.7	52.0
Columbia River Treaty Related Agreements	(7.8)	13.7	(19.8)	(14.4)	(23.1)	(10.4)	(7.2)
Surplus Sales	(122.6)	(0.2)	(84.2)	(174.1)	(118.1)	(150.4)	(129.2)
Remissions and Other	(44.9)	(34.4)	(32.1)	(38.6)	(37.3)	(37.8)	(33.1)
Total	**311.6**	**388.9**	**357.6**	**206.1**	**279.3**	**250.2**	**279.3**

Each item in the table is discussed below. Refer to Appendix K, section 3, for an explanation of historical variances.

4.4.1.1 Hydroelectric Water Rental Fees

Water rental fees are payable to the Province under the *Water Sustainability Act* on the generation of energy and on the operating and construction capacity of a license holder.

Water rental fees on the generation of energy are calculated as the actual energy output of the licence holder from the prior calendar year times the current year rates. The current year rates are calculated as the previous year rate times the annual percentage change in B.C.'s Consumer Price Index. As shown in Table 4-4 below, there are three tiers of water rental rates charged by the government, which vary depending on the volume of energy produced.

The elimination of the higher Tier 3 water rental rates will be phased in over calendar 2017 with the rate being eliminated on January 1, 2018.

Water rental fees on operating capacity are calculated as the maximum sustained capacity observed over prior years times the current year rate. The current year rates are calculated as the previous year rate times the annual percentage change in B.C.'s Consumer Price Index. For new projects (e.g., Mica), turbine unit nameplate capacity[39] is used until a higher peak capacity is observed over a reporting year, and the water rental fees are calculated based on the observed/nameplate capacity times the current year rate.

Construction capacity is a portion of the nameplate capacity that has not been placed in service. Fees are calculated based on the observed/nameplate capacity times the current year rate.

The current year rates are calculated as the previous year rate times the annual percentage change in B.C.'s Consumer Price Index.

The actual and forecast water rental rates change each calendar year and are summarized for 2015 to 2019 in Table 4-4.

[39] The intended full-load sustained output of a generating facility.

Table 4-4 Water Rental Rates

	Calendar Year				
	Actual		Forecast		
Water Rental: General Power Use	2015	2016	2017	2018	2019
Output (Tier 1) ($/MWh) < 160,000 MWh	1.301	1.315	1.340	1.367	1.394
Output (Tier 2) ($/MWh) < 3,000,000 MWh	6.066	6.133	6.250	6.375	6.503
Output (Tier 3) ($/MWh) > 3,000,000 MWh	7.298	7.378	6.567[40]	6.375	6.503
Operating Capacity ($/kW)	4.334	4.382	4.465	4.554	4.645
Construction Capacity ($/kW)	0.433	0.438	0.446	0.455	0.464
B.C. CPI (%)	1.0	1.9	2.0	2.0	2.0

Total Heritage generation water rentals fees for fiscal 2017, fiscal 2018 and fiscal 2019 are forecast to be $379.9, $350.4 and $350.1 million (Appendix A Schedule 4.0) respectively, assuming average inflow conditions. The reduction in water rental fees for fiscal 2018 and fiscal 2019 is due to the elimination of the Tier 3 water rental rate, as pursuant to Part 2 of the *Water Sustainability Act*, which is valued at approximately $50 million on an annual basis.

4.4.1.2 Market Electricity Purchases

Planned electricity purchase costs in fiscal 2017 to fiscal 2019 are based on forward market prices as of May 2, 2016 (as shown in Figure 4-1). Market electricity purchases were 207 GWh and 122 GWh for fiscal 2015 and fiscal 2016. Market electricity purchases during the test period are expected to be 230 GWh, 747 GWh and 934 GWh for fiscal 2017, fiscal 2018 and fiscal 2019, respectively. The amount of electricity purchased or sold on the market varies depending on market prices, water inflows, and loads. Market electricity purchases are not net of surplus sales. Surplus sales are presented as a separate line item in Appendix A Schedule 4.0. Refer to section 4.4.1.7.

[40] The forecast Tier 3 rates for calendar year 2017 are: $7.518/MWh for January 1, 2017 to March 31, 2017 and $6.250/MWh from April 1, 2017 to December 31, 2017, this will be charged on a pro-rated basis for the calendar year as $6.567/MWh.

4.4.1.3 Market Purchases to Non-Heritage

Market electricity purchases allocated to the Cost of Heritage Energy are capped to maintain the volume of energy provided under the Heritage Contract at no more than 49,000 GWh/year. Any additional market electricity purchases are included in the Cost of Non-Heritage Energy.

In Appendix A Schedule 4.0, all market purchases are first shown in one line item, whether allocated to Cost of Heritage Energy or to Cost of Non-Heritage Energy. In a separate line item, the Non-Heritage allocation, if any, is separated out to maintain the distinction between the two categories of Cost of Energy. For fiscal 2017 to fiscal 2019, there are no forecast market purchases allocated to Non-Heritage Cost of Energy.

4.4.1.4 Natural Gas for Thermal Generation

Table 4-5 provides the forecasted costs of total natural gas commodity purchases in fiscal 2017 to fiscal 2019 at $4.5 million, $6.0 million and $6.2 million, respectively, compared with $4.2 million for fiscal 2016.

Table 4-5 Natural Gas for Thermal Generation

Costs	F2015 RRA ($million)	F2015 Actual ($million)	F2016 RRA ($million)	F2016 Actual ($million)	F2017 Plan ($million)	F2018 Plan ($million)	F2019 Plan ($million)
Total Natural Gas Purchases for Burrard	2.4	1.4	2.4	0.9	0.0	0.0	0.0
Total Natural Gas Purchases for Burrard (inclusive of Transportation and Taxes)	15.3	12.9	15.3	12.0	5.9	0.0	0.0
Total Natural Gas Purchases for Fort Nelson and Prince Rupert	7.2	6.9	7.3	3.4	4.5	6.0	6.2
Total Natural Gas Purchases for Fort Nelson and Rupert(inclusive of Transportation and Taxes)	11.3	11.1	11.6	8.0	9.0	10.5	10.7
Total Natural Gas Purchases	**9.5**	**8.3**	**9.7**	**4.2**	**4.5**	**6.0**	**6.2**
Total Natural Gas Purchases (inclusive of Transportation and Taxes) Appendix A Schedule 4.0, line 29	**26.6**	**24.0**	**26.9**	**20.0**	**14.9**	**10.5**	**10.7**

Total natural gas purchases, inclusive of transportation and taxes for fiscal 2017 to fiscal 2019, are expected to be $14.9 million, $10.5 million and $10.7 million, respectively, compared to $20.0 million for fiscal 2016. The $9.3 million decrease in fiscal 2019 relative to fiscal 2016 is largely due to the decommissioning of the Burrard generating units at the end of fiscal 2016. Note that during the test period the expected natural gas purchases for the Prince Rupert facility are zero.[41]

4.4.1.5 Domestic Transmission

Domestic Transmission costs include transmission costs associated with surplus sales, as well as transmission costs relating to BC Hydro's obligations under the Skagit Valley Treaty.[42] Transmission costs for domestic exports range from approximately $30 million to $35 million per year and variances are driven by the variation in surplus sales. Costs to deliver energy to Seattle under the Skagit Valley Treaty include approximately $16 million per year for wholesale transmission in

[41] The Prince Rupert facility only runs for testing or to supply area load when the transmission line to Prince Rupert is out of service, and is not modelled in the Energy Study that is used in preparing the Application.

[42] The Skagit Valley Treaty refers to a set of agreements that obliges BC Hydro to deliver from heritage energy an amount of 340 GWh annually to Seattle City Light.

British Columbia,[43] and approximately $6 million per year for wholesale transmission in the United States, based on current transmission tariffs.

4.4.1.6 Columbia River Treaty Related Agreements

The Non-Treaty Storage Agreement and the Libby Coordination Agreement are agreements related to the operation of the Columbia River Treaty reservoirs in Canada and provide for the release and storage of water to create mutual operational benefits in both Canada and the United States. The agreements are designed to create an average annual positive financial benefit to BC Hydro. The projected revenue for fiscal 2017 is greater than in succeeding years due to a forecast reduction in the accounts across fiscal 2017.

4.4.1.7 Surplus Sales

Surplus sales are expected to be 4,962 GWh, 5,556 GWh and 4,517 GWh for fiscal 2017, fiscal 2018 and fiscal 2019, respectively, as shown on Appendix A Schedule 4.0, line 6. Surplus sales are not net of market electricity purchases which, as mentioned in section 4.4.1.2 are expected to be 230 GWh, 747 GWh and 934 GWh for fiscal 2017, fiscal 2018 and fiscal 2019, respectively. High surplus sales across the test period are due to a combination of initial above average system storage which results in a forecast net draw from storage of 2900 GWh in fiscal 2017 and 1170 GWh in fiscal 2018 as well as annual energy surpluses.

4.4.1.8 Remissions and Other

Remissions and Other includes Water Use Planning Remissions of approximately $33 million to $37 million each year during the test period.

The Water Use Planning program was initiated in November 1998 at the direction of the Province. Ongoing delivery of the Water Use Plans regulatory requirements results in costs associated with the value of foregone energy and costs associated with the delivery of monitoring and physical works programs. Where these costs

[43] Refer to section 8.8 of the Application, Inter-Segment Revenues.

were not already required under BC Hydro's existing water licences, BC Hydro is entitled to recover them through a reduction in water licence rental costs. The reduction in water licence rentals otherwise payable is referred to as System Operations Fund Offsets, or Remissions.

Remissions are credited to the System Operations Fund and are capped by the Province at $50 million per calendar year, with any excess carried into a future year. Remissions associated with the value of foregone energy are used to offset BC Hydro's Cost of Energy. Remissions associated with the delivery of monitoring and physical works programs are shown as an offset to BC Hydro's operating costs (refer to section 5.4.8.1).

Total remissions for fiscal 2017 through fiscal 2019 credited to the System Operating Fund are provided in Table 4-6.

Table 4-6 Water Use Planning Remissions

	F2015 RRA ($ million)	F2015 Actual ($ million)	F2016 RRA ($ million)	F2016 Actual ($ million)	F2017 Plan ($ million)	F2018 Plan ($ million)	F2019 Plan ($ million)
Remissible portion for Monitoring and Physical Works (Operating Cost Offset)	17.9	15.6	17.9	12.8	15.3	18.4	10.7
Remissible portion for Value of Foregone Energy (Cost of Energy Offset)	44.9	34.5	32.1	38.6	37.3	37.8	33.1
Total Credited Remissions	62.8	50.1	50.0	51.4	52.6	56.2	43.8

4.4.2 Cost of Non-Heritage Energy

Table 4-7 presents the Cost of Non-Heritage Energy. Each item in the schedule is discussed below. The largest portion of the cost of Non-Heritage Energy is from IPPs and long-term commitments, as discussed in section 4.4.2.3.

Table 4-7 Cost of Non-Heritage Energy

Cost of Energy	F2015 RRA ($ million)	F2015 Actual ($ million)	F2016 RRA ($ million)	F2016 Actual ($ million)	F2017 Plan ($ million)	F2018 Plan ($ million)	F2019 Plan ($ million)
Non-Heritage Energy							
Market Purchases from Heritage	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydroelectric Water Rentals for Waneta	7.7	7.3	7.4	7.6	6.8	6.4	6.3
IPPs and Long-Term Commitments	1,028.6	1,064.0	975.5	1,228.9	1,234.4	1,369.7	1,439.3
Non-Integrated Area	32.9	25.5	34.3	22.6	24.6	27.4	31.1
Gas & Other Transportation	11.8	10.6	12.1	10.5	10.6	10.1	6.1
Net Purchases (Sales) from Powerex	(8.1)	16.2	4.8	(0.1)	(6.5)	(6.0)	0.7
Total	**1,072.9**	**1,123.6**	**1,034.1**	**1,269.5**	**1,270.0**	**1,407.6**	**1,483.6**

4.4.2.1 Market Purchases From Heritage

There are no market electricity purchases allocated to the Cost of Non-Heritage Energy for fiscal 2017 to fiscal 2019 because the total amount of Heritage Energy for fiscal 2017 to fiscal 2019, including all market purchases, is not forecast to exceed the Heritage Contract amount of 49,000 GWh. Refer to section 4.4.1.3.

4.4.2.2 Hydroelectric Water Rentals for Waneta

Water rental fees for BC Hydro's one third interest in Waneta are included in Non-Heritage Cost of Energy, Appendix A Schedule 4.0, line 10 at approximately $6 million per year.

4.4.2.3 IPP and Long-Term Commitments

BC Hydro has purchased electricity from IPPs since the mid-1980s. IPPs are a critical part of BC Hydro's self-sufficiency, a requirement under the *Clean Energy Act*. Without the energy and capacity supplied by IPPs, BC Hydro would have a shortfall. IPP projects are developed by companies specializing in power production as well as municipalities, First Nations and BC Hydro customers using resources such as wind, water, biomass, solar and waste heat.

IPPs help meet the electricity needs of BC Hydro's customers by developing and operating innovative, sustainable projects that add supply to the integrated system through Electricity Purchase Agreements. Under these long-term Electricity Purchase Agreements project development risks and costs are borne by the IPP. Once a project reaches commercial operations, the IPP bears risks and costs associated with factors such as project financing, operations and sustaining capital; thus, ratepayers are not exposed to market risk and price uncertainty. However, as resources, such as wind, solar and water, are subject to weather conditions, the volume of energy received through these contracts may vary from year to year.

BC Hydro's last major power call was the 2010 Clean Power Call, although BC Hydro completed Phase 2 of its Bioenergy Call in 2011 and negotiated several Electricity Purchase Agreements with pulp and paper customers from 2010 to 2013 under its Integrated Power Offer. These procurement processes were required to meet BC Hydro's energy shortfall that existed at that time. They were also aligned with the 2007 Energy Plan and the Clean Energy Act (enacted in June 2010), particularly the British Columbia energy objectives of achieving self-sufficiency and generating at least 93 per cent of electricity from clean or renewable resources.

BC Hydro has two active power procurement programs, namely the Standing Offer Program for clean power projects of 15 MW less and the Micro-Standing Offer Program for projects between 100 kW and 1 MW. Apart from the Standing Offer Program, the Micro-Standing Offer Program, and Electricity Purchase Agreement renewals as described below, no additional power acquisitions from IPPs are planned in the test period.

BC Hydro actively manages its rights and obligations under its Electricity Purchase Agreements with IPPs. Over the last three years, 14 Electricity Purchase Agreements have been terminated. In each case, the contracts were terminated by mutual agreement with the IPPs as a result of project challenges encountered by the

IPP related to the project costs, financing and permitting, as well as actions identified in BC Hydro's approved 2013 Integrated Resource Plan (refer to Chapter 3).

BC Hydro currently has 127 active Electricity Purchase Agreements for projects that are connected to, or plan to connect to, the integrated grid. As shown in Table 4-8, as of May 1, 2016, the 127 active Electricity Purchase Agreements includes 106 projects in commercial operation and delivering energy to the integrated grid and another 21 projects in various phases of development that have not yet reached their planned commercial operation date.

Additionally, BC Hydro has entered into six Electricity Purchase Agreements for projects in Non-Integrated Area communities, which are shown as a separate line item in Appendix A, Schedule 4.0.

Table 4-8 Electricity Purchase Agreement Summary[1]

	Post-COD		Pre-COD	
Project Type	**Number of EPAs**	**GWh/Year[2]**	**Number of EPAs**	**GWh/Year[2]**
Non-Storage Hydro	58	6,233	12	1,193
Storage Hydro	11	4,904	1	148
Biomass	17	3,160	2	578
Gas-Fired Thermal	3	3,205	1	82
Wind	4	1,365	5	798
Waste	5	307	0	0
Biogas	7	126	0	0
Solar	1	2	0	0
Total	**106**	**19,302**	**21**	**2,799**

1. As of May 1, 2016, for projects connected to the integrated grid.
2. Represents the sum of expected energy deliveries assuming all projects are in-service.

Storage and non-storage hydro projects account for roughly 60 per cent of the operational Electricity Purchase Agreements and contracted energy volumes. Biomass projects, including several Integrated Power Offer Electricity Purchase Agreements, represent 16 per cent of BC Hydro's IPP supply portfolio. Wind energy has also increased in prominence with four large projects now in operation.

With regard to the 21 Electricity Purchase Agreements for projects not yet in commercial operation, 18 are for hydro or wind projects awarded through the 2006 Open Call, Clean Power Call or Standing Offer Program and three are associated with the Bioenergy Phase 2 Call or negotiated Electricity Purchase Agreements.

For fiscal 2017 through fiscal 2019, IPPs are expected to provide about 23 per cent of BC Hydro's energy supply. Cost of energy for IPPs and long-term commitments after accounting adjustments as reflected in Table 4-10, makes up roughly 29 per cent of BC Hydro's revenue requirements, with an average cost of $93/MWh over this forecast period.

Table 4-9 outlines the projected energy purchases under the active Electricity Purchase Agreements and expected new Standing Offer Program Electricity Purchase Agreements over the test period, with comparative figures for fiscal 2015 and fiscal 2016.

Table 4-9 IPP and Long-Term Purchase Volumes

Call Process	Number of EPAs[1]	F2015 RRA (GWh)	F2015 Actual (GWh)	F2016 RRA (GWh)	F2016 Actual (GWh)	F2017 Plan (GWh)	F2018 Plan (GWh)	F2019 Plan (GWh)
Pre 2003 Electricity Purchase Agreements	32	3,502	3,577	3,493	3,210	3,307	3,350	3,139
2003 Green Power Generation Call	6	548	641	548	576	562	562	562
2006 Open Call	18	2,032	2,354	2,040	2,092	2,129	2,135	2,135
2008 Bioenergy Call - Phase 1	2	197	177	197	215	188	188	188
2008/10 Standing Offer Program	24	198	235	198	252	295	431	517
2010 Bioenergy Call - Phase 2	4	95	-	126	129	282	725	725
2010 Clean Power Call	20	1,180	1,141	1,247	1,323	1,818	2,705	2,863
2010 Integrated Power Offer	7	1,023	969	1,080	1,101	1,022	1,064	1,074
Negotiated Electricity Purchase Agreements	14	4,564	4,283	3,073	5,420	3,701	3,711	3,703
Expected Standing Offer Program Projects[(2)]	N/A	-	-	-	-	71	130	291
Total	**127**	**13,339**	**13,377**	**12,002**	**14,319**	**13,375**	**15,002**	**15,199**

1. As of May 1, 2016 for projects connected to or planned to connect to the integrated grid.
2. Includes one co-generation project.

BC Hydro's Electricity Purchase Agreement portfolio includes a significant number of hydro resources. The amount of generation under these contracts is driven by hydrology and other operational factors which may cause delivery to vary significantly from year to year. In fiscal 2016, actual volumes delivered from hydro IPPs exceeded the fiscal 2016 Plan amount, primarily because of changes in operations at Rio Tinto Alcan's Kemano facility that were linked to the start-up and commissioning of Rio Tinto Alcan's smelter modernization project. As a result of these changes, Rio Tinto Alcan's deliveries to BC Hydro were approximately $130 million more than forecast. However, this was partially offset by lower than forecast deliveries for several IPPs due to delays in achieving commercial operations and lower than planned thermal generation.

IPP purchase volumes in fiscal 2017 are expected to decrease to 13,375 GWh largely due to a return to expected volumes from Rio Tinto Alcan. This reduction in IPP purchase volumes in 2017 also reflects the offsetting impact of an increase in energy volumes due to the first full year of generation from projects that reached commercial operation in the prior fiscal year and from 12 projects expected to reach commercial operation in fiscal 2017.

For fiscal 2018, IPP purchase volumes are projected to increase by 12.3 per cent over fiscal 2017 to 15,002 GWh, due to the first full year of generation from the 12 projects that reached commercial operation in the prior fiscal year and a partial year of generation for projects expected to reach commercial operation in fiscal 2018.

For fiscal 2019, the increase is 1.3 per cent over fiscal 2018 to 15,199 GWh, largely due to the first full year of generation from the ten projects that are expected to commence commercial operation in fiscal 2018.

Energy volumes for new projects reaching commercial operation are partially offset by reductions that result from less than full renewal of expiring Electricity Purchase Agreements. Over the test period, Electricity Purchase Agreements for several small hydroelectric and biomass Electricity Purchase Agreements are expiring (see Chapter 3, section 3.4.3.5). For planning purposes, BC Hydro has assumed that 50 per cent of the energy contribution from expiring biomass Electricity Purchase Agreements will be renewed, and 75 per cent of the energy contribution from expiring run-of-river hydro projects will be renewed, consistent with the 2013 Integrated Resource Plan Recommended Action 4. These renewal assumptions are on an aggregate basis and do not reflect the particular circumstances for individual Electricity Purchase Agreements. Renewals of Electricity Purchase Agreements are subject to the review by the British Columbia Utilities Commission in separate processes pursuant to section 71 of the *Utilities Commission Act*. To the extent that the cost of energy purchases forecast from contracts are not approved under section 71, forecast costs would not be recovered from ratepayers. BC Hydro's actual energy costs related to any contracts that the British Columbia Utilities Commission does not approve will be lower than forecasted and this favorable difference will be credited to the Non Heritage Deferral Account as described in Chapter 7.

Certain Electricity Purchase Agreements are deemed to be capital leases for accounting purposes and therefore their costs are recorded as operating costs, taxes, amortization and finance charges and not as costs of energy. A table showing the reclassification of costs is provided in Chapter 8.

To allow reporting consistency with that shown in previous revenue requirement applications, Table 4-10 provides both the cost of IPP energy before and after accounting adjustments.

Table 4-10 IPP and Long-Term Purchase Costs

Call Process	Number of EPAs[1]	F2015 RRA ($ million)	F2015 Actual ($ million)	F2016 RRA ($ million)	F2016 Actual ($ million)	F2017 Plan ($ million)	F2018 Plan ($ million)	F2019 Plan ($ million)
Pre-2003 Electricity Purchase Agreements	32	268.2	275.6	273.0	252.4	277.2	281.0	261.6
2003 Green Power Generation Call	6	31.7	37.7	32.0	34.2	33.3	33.7	34.1
2006 Open Call	18	175.6	202.1	177.8	182.8	188.4	190.8	192.7
2008 Bioenergy Call - Phase 1	2	22.1	21.1	22.3	26.3	22.7	23.0	23.3
2008/10 Standing Offer Program	24	18.0	22.0	18.1	24.5	28.9	43.8	52.6
2010 Bioenergy Call - Phase 2	4	12.8	-	16.0	17.6	39.2	99.7	100.9
2010 Clean Power Call	20	158.4	151.2	169.3	171.9	242.0	336.0	358.3
2010 Integrated Power Offer	7	119.6	114.1	128.3	135.2	126.5	131.2	135.1
Negotiated Electricity Purchase Agreements	14	356.1	305.8	294.0	447.5	346.6	357.2	359.9
Expected Standing Offer Program Projects[(2)]	N/A	-	-	-	-	7.8	13.6	29.2
Total Payments to IPPs and Long-Term Commitments	**127**	**1,162.5**	**1,129.6**	**1,130.9**	**1,292.5**	**1,312.5**	**1,509.9**	**1,547.9**
Accounting Adjustments		(133.9)	(65.6)	(155.4)	(63.7)	(78.1)	(140.2)	(108.6)
IPPs and Long-Term Commitments		**1,028.6**	**1,064.0**	**975.5**	**1,228.9**	**1,234.4**	**1,369.7**	**1,439.3**

1. As of May 1, 2016 for projects connected to or planned to connect to the integrated grid.
2. Includes one co-generation project.

Total payments to IPPs in fiscal 2017 are projected to be $1.31 billion, which is a $182 million increase over the fiscal 2016 Plan levels. However, the cost increase in fiscal 2017 compared to fiscal 2016 actual costs is forecast at $20 million. The increase reflects the fact that cost increases largely attributable to new projects expected to reach commercial operation during fiscal 2017 are largely offset by declining purchases primarily due to changes in operations at Rio Tinto Alcan's Kemano Facility that were linked to the start-up and commissioning of Rio Tinto Alcan's Smelter Modernization Project.

Energy delivered under Electricity Purchase Agreement contracts has a different cost than both energy generated by BC Hydro and energy purchased or sold in energy markets. Therefore, as the proportion of Electricity Purchase Agreement contract energy changes, BC Hydro's average cost of energy changes.

In fiscal 2018, total payments to IPPs are projected to increase by 15 per cent to $1.51 billion largely due to a full year of production from the projects coming on-stream in fiscal 2017 and the ten additional projects reaching commercial operation during fiscal 2018.

In fiscal 2019, total payments to IPPs are expected to increase by 2.5 per cent over fiscal 2018 consistent with the outlook for IPP delivery volumes. The $38 million increase in IPP costs for fiscal 2019 arises due to an increase in volume and from contractual price escalation factors.

4.4.2.4 Non-Integrated Area

Non-Integrated Area communities are served by local generating facilities and distribution networks. Generating capacity in these areas is provided by a combination of diesel and hydro facilities. BC Hydro purchases approximately one-third of the energy supplied in these areas from IPPs. The cost of energy for the Non-Integrated Area is shown on line 39 of Appendix A Schedule 4.0. Forecast decreases to Non-Integrated Area cost of energy as compared to the fiscal 2016 Plan are largely due to lower fuel costs resulting from lower fuel prices and a lower load forecast including one IPP which is now connected to the grid.

4.4.2.5 Gas and Other Transportation

Gas transportation costs arise from a number of upstream gas transportation contracts entered into by BC Hydro. To enhance security of gas supply these contracts provide flexibility to acquire natural gas closer to the actual source of gas production. BC Hydro also incurs external transmission costs, related to the service of domestic load in Fort Nelson, such as its Demand Transmission Service contract with the Alberta Electric System Operator. Total gas and external transmission costs for fiscal 2017 to fiscal 2019 are $10.6 million, $10.1 million and $6.1 million, respectively, compared to the fiscal 2016 Plan of $12.1 million. For fiscal 2017 to fiscal 2019, the amounts which relate only to gas transportation are $9.1 million, $8.7 million and $4.7 million, respectively, compared to the fiscal 2016 Plan of

$10.9 million. The decrease over the test period is due to the gas transportation contracts expiring during fiscal 2018 and fiscal 2019 that are no longer necessary for BC Hydro to hold for thermal operations.

4.4.2.6 Net Purchases (Sales) from Powerex

Certain energy purchases by BC Hydro from Powerex under the Transfer Pricing Agreement create limited rights and obligations for Powerex to purchase energy back from BC Hydro for later use in electricity trade. These purchases by BC Hydro are allocated to the Trade Account. Net transfers to or from the Trade Account are shown as Net Purchases or Sales from Powerex. For fiscal 2017 and fiscal 2018, Net Sales from Powerex are forecast to be $~~6.0~~6.5 million and $~~6.5~~6.0 million, respectively. For fiscal 2019, net purchases from Powerex are forecast to be $0.7 million.

BC Hydro
Power smart

Fiscal 2017 to Fiscal 2019
Revenue Requirements Application

Chapter 5

Operating Costs

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5.1 Introduction

This chapter describes our planned operating costs and FTEs over the fiscal 2017 to fiscal 2019 test period.

In the most recent fiscal years prior to the test period, BC Hydro's base operating costs increased minimally following the Government Review and the introduction of the 2013 10 Year Rates Plan: average annual increases in base operating costs from fiscal 2013 through fiscal 2016 were 1.8 per cent per year. As most of BC Hydro's base operating costs are subject to inflationary pressures, limiting the rate increase to this level required careful management and ongoing efforts to find efficiencies.

As set out in this chapter, our iterative planning process successfully identified material cost savings and efficiencies to offset cost pressures. BC Hydro's base operating expenditures (excluding Smart Metering and Infrastructure Program costs which were previously deferred while the project was in implementation and are now being operationalized as the Program is complete), are forecast to increase by $11.7 million in fiscal 2017, $2.1 million in fiscal 2018 and $11.9 million in fiscal 2019, averaging approximately 1.2 per cent per year over the test period.

The ongoing costs (net of benefits) related to operationalizing the Smart Metering and Infrastructure Program are forecast to be $22.1 million in fiscal 2017, decreasing by $1.4 million in fiscal 2018 and decreasing by $0.1 million in fiscal 2019. These operating costs are a required element of achieving the net benefits of the Smart Metering and Infrastructure Program. A project completion report for the Smart Metering and Infrastructure Program is planned to be filed during the time period of this proceeding, and will show that the Program has a positive net present value benefit for ratepayers.

In addition to base operating costs and costs related to operationalizing the Smart Metering and Infrastructure Program, BC Hydro's total operating expenditures include IPP capital leases (long-term contracts) and ineligible capital overhead. These costs are excluded from base operating costs because they are driven by accounting rules and can vary significantly from year to year, either by way of an increase or decrease in operating costs. They are increasing in total by $16.9 million in fiscal 2017, $57.8 million in fiscal 2018 and $13.2 million in fiscal 2019.

Total operating expenditures are planned to increase by $50.7 million in fiscal 2017, $58.5 million in fiscal 2018 and $25.0 million in fiscal 2019 (before regulatory accounts). Overall, BC Hydro's operating costs and FTEs over the test period reflect a rigorous effort by BC Hydro to identify cost savings and efficiencies across the organization in order to meet the objectives of the 2013 10 Year Rates Plan and our priorities as outlined in Chapter 1.

The remainder of this chapter is organized as follows:

- Section 5.2 describes the changes to the organization and cost classification since the Fiscal 2015 - Fiscal 2016 Revenue Requirements Rate Application and BC Hydro's resulting organizational structure, as well as the iterative, bottom-up and top-down operating cost planning process undertaken for the test period;
- Section 5.3 describes initiatives to continue to improve the way we operate, including the sustainment costs and savings related to the Smart Metering and Infrastructure Program, the Work Smart program for continuous process improvement and the Workforce Optimization Program to ensure that BC Hydro has the right mix of internal and external resources. This section also provides an overview of BC Hydro's operating costs and FTEs over the test period, showing the cost pressures and cost savings and efficiencies identified by BC Hydro through its planning process. This section ends with a discussion of the Standard Labour Rate planning assumptions and a breakdown of operating costs and FTEs by business group.;

- Sections 5.4 to 5.7 provide a detailed description of planned operating costs and FTEs for each of BC Hydro's four business groups, explaining at a detailed level the necessary costs and FTEs to undertake the work of each business group and Key Business Unit; and
- Section 5.8 describes BC Hydro's post-employment benefit costs.

Please note, in the tables in this Chapter, references to F2015 RRA or F2016 RRA signifies the Plan amount from the Fiscal 2015 - Fiscal 2016 Revenue Requirements Rate Application.

5.2 Organization and Planning

5.2.1 Organization Changes and Cost Classifications

BC Hydro is organized into four business groups (not including Powerex):

- Training, Development and Generation Business Group;
- Transmission, Distribution and Customer Service Business Group;
- Capital Infrastructure Project Delivery Business Group, and
- Operations Support Business Group.

Each of the business groups is further broken down into Key Business Units, as summarized in Table 5-1.

Table 5-1 Summary of BC Hydro Business Groups and Key Business Units

Business Group	Key Business Unit
Training, Development and Generation	Training and Development
	Generation Operations
	Generation Resource Management
	Asset Management
	Generation Maintenance
	Business Unit Support
Transmission, Distribution, and Customer Service	Field and Grid Operations
	Asset Management and Distribution Engineering
	Program and Contract Management
	Customer Service and Distribution Design
	Technology
	Business Unit Support
Capital Infrastructure Project Delivery	Project Delivery
	Generation and Transmission Engineering
	Aboriginal Relations
	Environmental Risk Management
	Dam Safety
	Properties
	Site C Clean Energy Project
	Business Unit Support
Operations Support	Executive Office
	Finance and Supply Chain
	Corporate Affairs
	Safety, Security and Emergency Management
	General Counsel

As discussed in Chapter 1 of the Application, BC Hydro restructured in fiscal 2016 so that we are now in a better position to deliver on our capital plan, maintain safety and customer service, and find efficiencies. The restructuring in fiscal 2016 is described below.

- BC Hydro created the Project Delivery Key Business Unit (as part of the Capital Infrastructure Project Delivery Business Group) to be responsible for the execution of complex generation, transmission, substation, and major distribution projects. Prior to the reorganization, BC Hydro had capital delivery groups in both Generation and in Transmission and Distribution. This change has improved delivery of the projects and ensures consistency in project management. The Capital Infrastructure Project Delivery is also responsible for Dam Safety, Environmental Risk Management, Aboriginal Relations and Properties Key Business Units who provide their services to all business groups. A separate Key Business Unit within this business group has responsibility for delivering the Site C Clean Energy Project;

- BC Hydro has brought the planning and support for safety initiatives together under a Senior Vice President of Safety, Security and Emergency Management, reporting directly to the President and Chief Executive Officer. The change will provide a more unified approach to safety and meet the challenge of improving our safety record. The responsibility of this executive is to ensure that all parts of BC Hydro are prepared for emergencies and that we have taken appropriate steps to ensure the safety and security of our employees and the public;
- BC Hydro is moving to a more customer oriented culture and a renewed focus on our everyday interactions with our customers. The former Customer Care Key Business Unit has been integrated with the former Transmission and Distribution Business Group, and renamed the Transmission, Distribution and Customer Service Business Group; and
- BC Hydro has also created a new Corporate Affairs Key Business Unit to strengthen alignment across the organization and to further an already coordinated approach to planning and policy. This new Key Business Unit combines Conservation and Energy Management, Energy Planning, Business and Economic Development, Business Planning and Risk, Policy and Reporting, Regulatory, Communications and Human Resources under the Senior Vice President of Corporate Affairs and Chief Human Resources Officer.

A detailed summary of the restructuring by business groups and Key Business Units that occurred since the Fiscal 2015 - Fiscal 2016 Revenue Requirements Rate Application are shown in Appendix DD.

In addition to the restructuring described above, there were two cost classification changes since the Fiscal 2015 - Fiscal 2016 Revenue Requirements Rate Application that are reflected in the test period:

- Future Removal and Site Restoration – the Future Removal and Site Restoration Regulatory Account is expected to have a zero balance by the end of fiscal 2017 and the related expenses thereafter will be included in operating expenditures (specifically, within Provisions and Other); and
- Smart Metering and Infrastructure Program – pursuant to British Columbia Utilities Commission Order No. G-48-14, operating costs related to the Smart Metering and Infrastructure Program have been deferred in fiscal 2015 and fiscal 2016. Starting in fiscal 2017, these costs have been integrated within the relevant business groups.

In this Application, BC Hydro has re-stated its fiscal 2015 and fiscal 2016 operating costs to reflect the organization changes and cost classification changes discussed above. As a result, the operating costs for fiscal 2015 to fiscal 2019 in this Chapter and Appendix A (Schedules 5.0 Operating Costs and Provisions and Schedule 16.0 FTE) are presented on a comparable basis.

5.2.2 Planning Process – Key Steps

BC Hydro’s planning framework for fiscal 2017 to fiscal 2019 consisted of top-down and bottom-up elements with respect to operating expenditures and FTEs.

The top-down element, which is strategic in nature, was primarily driven by two considerations:

(a) A focus on investments required to align with BC Hydro's updated vision, key goals and priorities as outlined in Chapter 1, as well as the performance measures as described in BC Hydro's 2015/2016-2017/2018 Service Plan in Appendix E and also discussed in Chapter 2; and

(b) Alignment with the 2013 10 Year Rates Plan. BC Hydro is managing its overall costs to stay within the 2013 10 Year Rates Plan. Our operating cost framework maintains fiscal discipline while also providing the flexibility to support important priorities and improve service. BC Hydro continues to seek opportunities to reduce expenditures.

The bottom-up element involved each business group evaluating cost pressures and savings opportunities. Although cost pressures continue to be a challenge, BC Hydro's business groups were successful in identifying cost savings to help offset these pressures.

Following initial reviews at the business group level, the executive team engaged in an iterative review process. The result of the process was the approval of the planned operating costs proposed in this Application as discussed further in section 5.3 below.

5.3 Summary of Fiscal 2017 to Fiscal 2019 Operating Costs and FTEs

This section summarizes at an overall BC Hydro and business group level the fiscal 2017 to fiscal 2019 operating costs and FTEs presented in this Application. This section begins with a discussion of some of the new key factors affecting BC Hydro's operating expenses over the test period, then reviews the fiscal 2017 to fiscal 2019 operating plans and FTEs, Standard Labour Rate planning assumptions and, lastly, shows the operating cost and FTEs by business group, which are discussed in further detail in sections 5.4 to 5.7.

5.3.1 Initiatives To Continue To Improve The Way We Operate

This section discusses initiatives that will help continue to improve the way we operate. These include the Smart Metering and Infrastructure Program that was completed in fiscal 2016, which will provide information that will allow us to operate our system more effectively and provide better information to our customers, plus two company-wide efficiency and improvement programs, namely, the Work Smart Program and Workforce Optimization Program.

5.3.1.1 Smart Metering and Infrastructure Program

Beginning in fiscal 2012, actual operating costs related to the sustainment of Smart Metering and Infrastructure technologies, less actual benefits realized, were deferred into the Smart Metering and Infrastructure Regulatory Account. This deferral treatment continued in fiscal 2015 and fiscal 2016 pursuant to British Columbia Utilities Commission Order No. G-48-14. Section 7.5.19 provides more details with regard to the Smart Metering and Infrastructure Regulatory Account.

The Smart Metering and Infrastructure Program had an approved budget of $930 million and was implemented $150 million under budget at a final cost of $779.2 million. As of March 31, 2016, all sustainment activities related to the implemented Smart Metering and Infrastructure technologies have been integrated into the business groups to which they relate.

Table 5-2 below presents the planned incremental Smart Metering and Infrastructure operating costs, operating cost savings and FTEs for fiscal 2017 to fiscal 2019. These operating costs are a required element of achieving the net benefits of the Smart Metering and Infrastructure Program. A project completion report for the Smart Metering and Infrastructure Program is planned to be filed during the same time period as this proceeding and will show that the Program has a positive net present value benefit for ratepayers.

Table 5-2 does not include other benefits related to the implementation of Smart Metering and Infrastructure such as theft reduction as shown in Chapter 3, Table 3-6, Table 3-7, Table 3-8 and Table 3-9.

Table 5-2 Incremental Operating and Maintenance Costs, Operating Cost Savings and FTEs from Smart Metering and Infrastructure Sustainment Activities

	Fiscal 2017				Fiscal 2018				Fiscal 2019			
Business Group/Key Business Unit	Incremental Operating Costs	Operating Cost Savings	Total Net Incremental Cost	FTEs	Incremental Operating Costs	Operating Cost Savings	Total Net Incremental Cost	FTEs	Incremental Operating Costs	Operating Cost Savings	Total Net Incremental Cost	FTEs
Transmission Distribution and Customer Service												
Asset Management and Distribution Engineering	1.0		1.0	1	-	-	-	-	-	-	-	-
Customer Service and Distribution Design	14.4	(19.7)	(5.3)	2	(1.2)	(0.2)	(1.4)		0.1	(0.2)	(0.1)	
Field and Grid Operations	3.1	(1.4)	1.7	23	-	-	-	-	-	-	-	-
Technology	25.6	-	25.6	25	-	-	-	-	-	-	-	-
Operations Support												
Finance and Supply Chain	0.1	(1.0)	(0.9)		-	-	-	-	-	-	-	-
Totals	**44.3**	**(22.2)**	**22.1**	**51**	**(1.2)**	**(0.2)**	**(1.4)**	**-**	**0.1**	**(0.2)**	**(0.1)**	**-**

The impact of ongoing costs, savings and FTEs related to Smart Metering and Infrastructure sustainment can be found in the impacted Key Business Unit descriptions and tables throughout this chapter.

A total of 51 sustainment FTEs are required to sustain the technologies implemented under the Smart Metering and Infrastructure Program.

Ongoing sustainment costs, savings and FTEs that are related to Smart Metering and Infrastructure sustainment impact the following Key Business Units during the test period:

- Asset Management and Distribution Engineering Key Business Unit (within the Transmission, Distribution and Customer Service Business Group) - sustainment costs of $1.0 million in fiscal 2017 related to ongoing meter exchange work;
- Customer Service and Distribution Design Key Business Unit (within the Transmission, Distribution and Customer Service Business Group) – net savings of $5.3 million in fiscal 2017:
  - Reduced meter reading costs of $19.7 million in fiscal 2017, partially offset by $7.0 million of ongoing manual meter reading costs in fiscal 2017 related to meters that are unable to connect to the smart metering network. The number of non-communicating meters is expected to decrease in fiscal 2018, driving further reductions to operating costs of $1.2 million;
  - Costs of $2.0 million in fiscal 2017 related to customers who have chosen to participate in the Meter Choices Program. These costs are offset by related revenues (which are not included in operating costs); and
  - Energy diversion and theft reduction costs of $5.4 million in fiscal 2017. A portion of this amount, $0.7 million, is related to the Meter Choices Program and is offset by related revenues. These costs enable BC Hydro to monitor energy inventory imbalances across the distribution grid and initiate field

inspections in areas with higher than expected losses. Enabled by the Smart Metering and Smart Grid investments, the Revenue Assurance team identifies, shuts down and recovers revenue from thefts as well as other revenue leakage instances. Although theft levels have now been reduced from pre-Smart Metering and Infrastructure levels, a smaller, continuing revenue assurance program is still required to sustain these benefits, deter future thefts, and provide assurance that losses are being minimized.

- Field and Grid Operations Key Business Unit (within the Transmission, Distribution and Customer Service Business Group) – sustainment costs of $3.1 million in fiscal 2017 related to FTEs to support operations of program technologies, operations of metering systems, enhanced outage management capabilities, and data analysis, infrastructure and network performance, partially offset by $1.4 million of savings in fiscal 2017 attributed to fewer meters requiring manual reconnects;
- Technology Key Business Unit (within the Transmission, Distribution and Customer Service Business Group) – sustainment costs of $25.6 million in fiscal 2017. These costs support the technology environment, infrastructure and network, as well as enabling new capabilities such as billing from automated meter reads, remote disconnections and reconnections of meters, field metering and data analysis work, enhanced outage management capabilities, and the advanced connectivity to meters. These costs also include maintenance and support for new systems and devices, as well as integration to existing devices and systems, including the Advanced Metering System applications (e.g., network management system, metering data management system automated data collection system), energy analytics solutions and the energy visualization portal. These costs also include sustainment activities related to the telecommunications network that support the field area network and wide area network, which are critical to the communication of data from meters back to network applications and databases. Lastly, these costs support

the additional servers, storage and other infrastructure required to maintain the Smart Metering and Infrastructure environments, including securing it against internal or external threats, and maintaining compliance to North American Electric Reliability Corporation Critical Infrastructure Protection Plan requirements and security standards; and

- Finance and Supply Chain Key Business Unit (within the Operations Support Business Group) - net cost savings of $0.9 million related to vehicle cost savings due to the reduced requirement for meter readers and associated vehicles.

5.3.1.2 Work Smart Program

As part of our approach to continue to improve the way we operate, BC Hydro has implemented a Work Smart program for continuous process improvement that is based upon Lean principles. Lean is a business philosophy focused on the needs of the customer (internal and/or external) and includes streamlining work and identifying and eliminating non-value added activities. It applies the Lean principles that focus on customer needs and delivers business value by reducing variation, waste, and cycle time, while promoting the use of work standardization and flow.

Lean originated with the Toyota Production system in the 1930s and has since been implemented by major corporations such as General Electric, Ford, Boeing, and Bank of America. More recently, Lean has been implemented in North American public sector settings. Several US states have legislated Lean within their administrations, and in Canada, the governments of Saskatchewan and British Columbia have significant Lean programs.

The objectives of BC Hydro's Work Smart program include the following:

- Assisting BC Hydro in achieving its strategic priorities including "Continue to improve the way we operate";

- Improving employee engagement and empowerment by engaging employees throughout the process improvement cycle, from identifying processes that can be improved right through to designing and implementing the future state processes; and
- Reducing work effort on non-value added tasks enabling employees to focus on more critical, value added tasks.

A typical Work Smart initiative will include many steps, from stakeholder interviews and data collection about the current state, to “value stream mapping” where employees collaborate to create a visual representation and assess process steps, to developing and implement the future state process within 90 to 120 days. Some recommendations may include opportunities to optimize technology that supports the process; however, these are not required to be implemented within the 90 to 120 days and are considered in the longer-term.

WorkSmart initiatives completed to date include those shown in Table 5-3 below:

Table 5-3 Work Smart Initiatives

Project	Benefits
Generation Contract Approval	Reduced cycle time and work effort Appropriate review and approval
Asbestos Management - Generation Stations	Safer work environment Improved control of asbestos containing materials
Vegetation Management	Reduction in planning work and post work inspections without compromising quality
Customer Build	Improved customer satisfaction and reduced cycle time
Procurement	Reduced work effort in contract requisition
Safety Incident Investigation	Reduced cycle time and work effort
Aboriginal Engagement	Reduced work effort and rework Appropriate Aboriginal engagement

As noted above, a key objective of Work Smart is to “Continue to improve the way we operate” by creating efficiencies in the processes and time it takes to perform our work. One of the key benefits of Work Smart is streamlined processes and the elimination of non-value added activities which allows us to address workload issues and to shift the work effort to more critical and higher-value tasks.

Work Smart’s key measure is capacity hours gained. This measure is appropriate because the program seeks to enhance processes such that workload issues can be addressed enabling employees to focus on higher-value work. Estimated capacity hours gained from Work Smart initiatives as at the end of fiscal 2016 were 22,550 hours annually. Capacity hours gained is the difference between the work effort (touch time) of the process before the Work Smart initiative is undertaken and after implementation of the Work Smart recommendations.

5.3.1.3 Workforce Optimization

In July 2015, BC Hydro launched the Workforce Optimization Program to examine BC Hydro’s resourcing model to ensure that it has the right mix of internal and external resources.

Ensuring we have the right mix of internal and external resources is key to delivering on our business objectives. Since fiscal 2011, BC Hydro eliminated over 900 positions. These changes helped drive an efficiency mindset through the organization. In the effort to contain headcount, areas of the business where investment levels were growing significantly (particularly in our capital programs), were also constrained. This led to an increasing reliance on external resource providers. In some cases, these external resources came at a higher cost than internal resources and/or increased business risk (e.g., reduced internal knowledge, fluctuating costs, oversight requirements, turnover etc.).

Pursuant to the Workforce Optimization Program, Business Groups identified areas where cost and/or risk could be reduced or outcomes improved by shifting work from external contractors to internal employees. The merits and cost savings of each of these opportunities were reviewed and approved by the executive team.

At the end of October 2015, approximately 170 FTEs had been approved for hire through fiscal 2019 with offsetting reductions in the use of external resources. In accordance with our focus on delivering capital projects on time and on budget, approximately 70 per cent of these positions relate to capital construction (to be performed by the Capital Infrastructure Project Delivery Business Group) or the Technology Key Business Unit (within the Transmission, Distribution and Customer Service Business group).

The Workforce Optimization Program will result in net savings, since increased labour costs will be more than offset by a reduction in contractor costs. The financial benefits of the program are primarily capital savings as the majority of optimization opportunities pertain to resources executing capital work. Unlike contractors working on capital projects whose work for BC Hydro is solely related to the projects and thus whose costs can all be capitalized, BC Hydro employees working on capital projects spend some of their time on internal, non-project related activities (e.g., general training) which cannot be capitalized. Thus, some new BC Hydro employees added as part of this program result in an increase to operating costs, although a total cost reduction overall. The operating cost impacts have been reflected in BC Hydro's operating budgets in this Application.

In total, during the test period, BC Hydro plans to add the 170 FTEs related to Workforce Optimization as shown in Table 5-8. The operating cost increase associated with these FTEs is approximately $1.2 million per year as reflected in Table 5-5, while the related capital savings are $4.8 million in fiscal 2017, $7.4 million in fiscal 2018 and $7.6 million in fiscal 2019.

Additional Workforce Optimization positions will continue to be implemented in cases where cost savings and/or improved outcomes can be achieved.

5.3.2 Fiscal 2017 to Fiscal 2019 Operating Costs

This section summarizes the fiscal 2017 to fiscal 2019 operating costs presented in this Application as an outcome of the planning process described in section 5.2.2, including additional savings and efficiencies and cost increases compared to BC Hydro's fiscal 2016 Plan (i.e., the fiscal 2016 plan presented in the Fiscal 2015 - Fiscal 2016 Revenue Requirements Rate Application). These items are summarized below in the continuity tables shown in Table 5-4 and Table 5-5 discussed further in this section.

Rows two and three of Table 5-4 relate to restructuring impacts and budget transfers between groups, respectively. Both of these rows have a zero balance because on a consolidated basis, by themselves, they net to zero for the corporation. In other words, they do not result in a change in costs during the test period. However, in the business group continuity schedules the amounts related to the specific business groups are shown. As shown in row 15 of Table 5-4, the net operating costs presented for each year of the test period match those shown in Appendix A.

Table 5-4 Net Operating Costs Continuity Schedule

	($ million)		F2017 Plan	F2018 Plan	F2019 Plan
1	F2016 Revenue Requirement Application Plan / carry forward plan	A	826.9	877.6	936.1
2	Reorganization Impact		-		
3	Budget transfers between Business Groups		-		
4	Independent Power Producer Capital Leases	B	(5.6)	35.4	(9.2)
5	IFRS Ineligible Capital Overhead	C	22.4	22.4	22.4
6	**Test Period Savings/Efficiencies**	D	(33.2)	(0.3)	(0.2)
7	**Test Period Cost Increases:**				
8	Unavoidable Costs		10.1	7.6	9.3
9	Capital-Driven		19.0	(3.1)	2.6
10	Initiatives		6.5	(1.5)	-
11	Other Cost Pressures		9.3	(0.6)	0.2
12	Smart Metering and Infrastructure		22.1	(1.4)	(0.1)
13		E	67.0	1.0	12.0
14	**Net Increase/(Decrease)**	F=D+E	33.8	0.7	11.8
15	**Net Operating Costs (Schedule 5.0, line 12)**	A+B+C+F	**877.6**	**936.1**	**961.1**

The base operating cost continuity schedule shown in Table 5-5 provides a more detailed continuity schedule for the test period, including savings and efficiencies and cost increases for each year. Base operating costs is a measure used by BC Hydro in its Service Plans, which are filed annually with the Province. As noted in BC Hydro's 2015/16-2017/18 Service Plan, base operating costs are defined as "personnel, materials and external services expenses included in income that are incurred in the day-to-day operating of BC Hydro's electric utility, net of recoveries, capitalized costs and reclassification adjustments." As discussed in Chapter 1, BC Hydro considers base operating costs as the key measure for the assessment of BC Hydro's operating costs. The operating costs that are excluded from base operating costs, as shown in rows 2 and 3 of Table 5-6, are IPP capital leases (long-term contracts) and ineligible capital overhead. These costs are excluded from base operating costs because they are driven by accounting rules and can vary significantly from year to year, either by way of an increase or decrease in operating costs. IPP capital lease operating costs are impacted by any new Electricity Purchase Agreements that are accounted for as capital leases reaching commercial operation or expiring in a given fiscal year. IPP capital leases operating costs are $28.2 million, $63.6 million and $54.3 million in fiscal 2017, fiscal 2018, and fiscal 2019 respectively. Please refer to section 5.7.8 for further information on Independent Power Producer Capital Lease operating costs. IFRS ineligible capital overhead is a credit to operating costs and these costs are phased into operating costs over a 10-year period, resulting in an increase to operating costs of $22.4 million per year over the test period. Please refer to section 5.7.9 for further information on IFRS ineligible capital overhead.

Table 5-5 Base Operating Costs Continuity Schedule

			F2017	F2018	F2019
1	**($ million)**		**Plan**	**Plan**	**Plan**
2	F2016 Revenue Requirement Application Plan		826.9		
3	Less:				
4	IFRS Ineligible Capital Overhead		(80.5)		
5	Independent Power Producer Capital Leases (Schedule 5.1, line 15)		(33.8)		
6	Base Operating Cost	A	**712.7**	**746.5**	**747.2**
7	**Test Period Savings/Efficiencies**	B	**(33.2)**	**(0.3)**	**(0.2)**
8	**Test Period Cost Increases:**				
9	Unavoidable Costs				
10	- Labour (excluding Workforce Optimization)		4.9	8.4	9.1
11	- Mandatory fees		4.7	(0.8)	0.2
12	- Crane remediation		0.5	-	-
13	Total Unavoidable Costs	C	10.1	7.6	9.3
14	Capital-Driven				
15	- Maintenance		5.8	2.3	3.8
16	- Capital project dispute resolution costs		5.0	(5.0)	-
17	- Capital project investigation costs		7.0	(0.5)	(1.0)
18	- Workforce Optimization		1.2	0.1	(0.2)
19	Total Capital-Driven	D	19.0	(3.1)	2.6
20	Initiatives				
21	- Safety initiatives		5.0	-	-
22	- Customer Strategy		1.5	(1.5)	-
23	Total Initiatives	E	6.5	(1.5)	-
24	Other Cost Pressures				
25	- Inventory obsolescence		1.7	-	-
26	- Bad debt		1.0	-	-
27	- Storm restoration costs		2.8	-	-
28	- Technology software maintenance and support costs		1.2	-	-
29	- Electric system operating technology maintenance and support costs		0.8	-	-
30	- Direct charge to capital for Customer Connect costs		(4.9)	-	-
31	- Facility maintenance and identification phases of Properties' projects		0.5	0.2	0.2
32	- Category Management and other Procurement related costs		1.5	(1.0)	-
33	- Capital Overhead adjustments		3.4	0.2	0.0
34	- Other		1.3	-	-
35	Total Other	F	9.3	(0.6)	0.2
36	**Total Test Period Cost Increases**	G=C+D+E+F	**44.9**	**2.4**	**12.1**
37	Net Increase/(Decrease) excluding Smart Metering and Infrastructure	H=B+G	**11.7**	**2.1**	**11.9**
38	Total percentage increase excluding Smart Metering and Infrastructure	H/A	1.6%	0.3%	1.6%
39	Smart Metering and Infrastructure	I	22.1	(1.4)	(0.1)
40	Net Increase/(Decrease) including Smart Metering and Infrastructure	J	**33.8**	**0.7**	**11.8**
41	Total percentage increase including Smart Metering and Infrastructure	J/A	4.7%	0.1%	1.6%
42	**Base Operating Costs**	A+J	**746.5**	**747.2**	**759.0**

BC Hydro sought significant savings and efficiencies to mitigate cost increases and looked at all areas of the organization. As result of this process, and as shown on row 7 of Table 5-5, savings and efficiencies of $33.2 million are planned in fiscal 2017. These savings are to continue throughout the test period with minor additional savings in fiscal 2018 and fiscal 2019. The savings in fiscal 2017 include the following:

- $15.0 million in the Transmission, Distribution and Customer Service Business Group. These annual savings are from an initiative in the Transmission, Distribution and Customer Service Business Group which is further described in section 5.5.1.5. The key themes in this initiative include: inspections frequency optimization, technology functional reviews, work coordination and optimization, customer service cost savings improvements, vegetation management tools implementation and trouble response process improvements;
- $7.0 million related to the partial decommissioning of the Burrard Thermal Plant and its conversion to operating as a synchronous-condense facility (please refer to section 5.4.2 for further details). The savings are primarily related to labour;
- $6.9 million of savings in various other areas including consultants, donations and sponsorships, property lease savings and the cancellation of BC Hydro's membership in the Canadian Electricity Association; and
- $4.3 million in company-wide savings from ongoing efforts to find cost savings and efficiencies.

Cost increases during the test period are required to support key priorities, initiatives and ongoing operations. Cost increases are shown in the following four categories in Table 5-5:

(a) Unavoidable costs – this category includes primarily mandatory fees imposed by third-parties, as well as expenditures related to labour, including BC Hydro's collective agreements with its unions, as well as similar increases for management and professional staff:

- Mandatory fees of $4.7 million in fiscal 2017. External regulators such as the Western Electricity Coordinating Council, Peak Reliability and the North American Electric Reliability Corporation are increasing their fees by $3.7 million in fiscal 2017 (this includes exchange rate impacts as these fees are billed in US dollars). BC Hydro is required to be a member of the Western Electricity Coordinating Council due to its oversight of Mandatory Reliability Standards. Implementing reliability standards and ensuring compliance supports the reliability of the North American interconnected grid and the BC Hydro system. Also included in this category are $1.0 million related to higher Canada Post rates and printing costs for customer bills and correspondence;
- Labour costs (excluding Workforce Optimization) of $4.9 million in fiscal 2017. These expenditures cover increases under BC Hydro's collective agreements, which mirror those provided under the Province's bargaining mandate. Salary increases for management and professional staff have been limited and targeted in recent years, and are planned to increase at the same rate as the collective agreements during the test period; and
- Crane remediation costs of $0.5 million in fiscal 2017. These costs are for inspections and assessments required for compliance with a WorkSafeBC order related to certification of BC Hydro's non-mobile cranes;

(b) Capital-driven – this category includes costs related to BC Hydro's capital program. Cost increases are required both at the front-end of projects (e.g., planning and other pre-capitalization phases – these expenditures are referred to as capital project investigation costs) and the back end (e.g. maintenance on constructed assets):

- Capital project investigation costs of $7.0 million in fiscal 2017. These costs support early phases of capital projects being delivered through the Capital Infrastructure Project Delivery Business Group, and technology projects being delivered through the Transmission, Distribution and Customer Service Business Group. By increasing its investment in resources early in the project life cycle, we can ensure that we better define and scope projects, which will result in more on-time and on-budget project delivery;
- Maintenance costs of $5.8 million in fiscal 2017. As a result of BC Hydro's increasing asset base, additional maintenance expenditures are needed. These include expenditures related to the vehicle fleet, the Generation civil maintenance program (further details can be found in section 5.4.7.1) and vegetation maintenance. In fiscal 2019, there are new costs related to the operation of the John Hart facility after completion of the upgrade project in accordance with a public private partnership agreement (further details can be found in section 5.4.4.1);
- Capital project dispute resolution costs of $5.0 million in fiscal 2017 (but not in subsequent years); and
- Workforce Optimization costs of $1.2 million in fiscal 2017. As previously mentioned, these costs support capital savings and result in overall cost savings for BC Hydro. See section 5.3.1.3 and Appendix F.

(c) Initiatives – this category includes costs related to initiatives that are not expected to be permanent expenditures. For example, BC Hydro is investing in its Customer Strategy in fiscal 2017, but these expenditures will not be required in future years and accordingly are reduced as appropriate:

- Safety initiative costs of $5.0 million in fiscal 2017. BC Hydro is investing in safety initiatives to target high priority areas to improve its safety record. During the test period, planned initiatives include those related to compliance with regulatory requirements (e.g., asbestos and confined space) and implementing safety systems. Further details on these initiatives can be found in section 5.7.6;

- Customer Strategy costs of $1.5 million in fiscal 2017 (but not in subsequent years). BC Hydro has maintained a high customer satisfaction ranking; however, expectations are evolving and we must continue to enhance our customer service to meet customer needs. The Customer Strategy is discussed further in section 5.5.1.1.

(d) Other cost pressures – this category includes all other cost pressures, including storm restoration costs, expenditures related to technology, as well as capital overhead adjustments:

- Storm restoration costs of $2.8 million in fiscal 2017. BC Hydro continues to budget for storm restoration costs using a five-year average of normal weather years. In recent years, we have experienced higher storm-related expenditures, which has caused the five-year average to increase;
- Technology-related costs of $2.0 million in fiscal 2017. These costs reside in the Field and Grid Operations and Technology Key Business Units in the Transmission, Distribution and Customer Service Business Group. The additional costs relate to software maintenance and support costs for new enterprise and business applications, and for existing applications an increased cost of renewals and US currency fluctuations;
- Category management and other procurement related costs of $1.5 million in fiscal 2017 (reduced by $1.0 million in fiscal 2018). BC Hydro is developing and implementing category management strategies and processes for key operational procurement categories to better meet BC Hydro's requirements for quality, safety, and reliability of goods and services procured by BC Hydro to achieve a lower total lifecycle cost. Category management is further discussed in section 5.7.4.2; and

- Other cost pressures shown in Table 5-5, including those related to inventory obsolescence provisions and increases in facility services costs.

As shown on row 38 in Table 5-5, base operating costs before sustainment costs related to the Smart Metering and Infrastructure Program are increasing by 1.6 per cent in fiscal 2017, 0.3 per cent in fiscal 2018 and 1.6 per cent in fiscal 2019 for an average increase of 1.2 per cent over the three years. Sustainment costs related to the Smart Metering and Infrastructure Program are shown separately on row 39 of Table 5-5 as these are not new expenditures; rather, these expenditures were deferred in fiscal 2015 and fiscal 2016 pursuant to British Columbia Utilities Commission Order No. G-48-14, as discussed above.

Lines four and five of Table 5-5 show the reconciling items between the fiscal 2016 Plan and base operating costs – namely, IFRS ineligible capital overhead and IPP capital leases which are excluded from base operating costs.

Table 5-6 below shows the reconciliation of base operating costs back to the net operating costs shown in Appendix A.

Table 5-6 Reconciliation of Base Operating Costs to Net Operating Costs

	($ million)	F2017 Plan	F2018 Plan	F2019 Plan
1	Base Operating Cost	746.5	747.2	759.0
2	Independent Power Producer Capital Leases (Schedule 5.1, line 15)	28.2	63.6	54.3
3	IFRS Ineligible Capital Overhead	102.9	125.3	147.7
4	**Net Operating Costs (Schedule 5.0, line 12)**	**877.6**	**936.1**	**961.1**

Further details regarding BC Hydro's planned operating expenditures and savings can be found in the Business Group and Key Business Unit sections in sections 5.4 to 5.7.

5.3.3 Fiscal 2017 to Fiscal 2019 FTEs

BC Hydro's planned FTEs, including overtime and Site C Clean Energy Project FTEs, are 6,296 for fiscal 2017, 6,344 for fiscal 2018 and 6,365 for fiscal 2019.

FTEs are calculated by taking the total number of hours (regular and overtime) worked in a given year divided by the average number of hours a full time employee would work per year. These averages differ by affiliation and, for the test period, are 1,621 hours for Management and Professional employees (including Executive), 1,535 hours for MoveUP employees and 1,461 hours for International Brotherhood of Electrical Workers employees.

FTEs represent the employee workforce which performs operating, capital and deferred work across the company. Table 5-7 provides the breakdown of FTEs by these work functions. FTEs related to capital overhead are shown within the Operating category, as it is not possible to separate these FTEs. For further details on FTEs see Appendix A, Schedule 16.0.

Table 5-7 Total FTEs by Function (Operating, Capital and Deferred)

FTEs (including Overtime)	F2016 RRA	F2016 Actual	F2017 Plan	F2018 Plan	F2019 Plan
Operating					
Transmission, Distribution and Customer Service	1,735	1,795	1,695	1,701	1,707
Training, Development and Generation	837	863	777	777	777
Capital Infrastructure Project Delivery	420	459	463	467	463
Operations Support	942	925	937	937	937
Total (Schedule 16 line 90)	3,935	4,042	3,872	3,881	3,884
Percentage Change			-4%	0%	0%
Capital					
Transmission, Distribution and Customer Service	1,118	1,020	1,206	1,219	1,224
Training, Development and Generation	196	225	233	233	233
Capital Infrastructure Project Delivery	773	634	778	806	819
Operations Support	64	56	53	53	53
Total (Schedule 16 line 91)	2,150	1,934	2,269	2,311	2,329
Percentage Change			17%	2%	1%
Deferred					
Transmission, Distribution and Customer Service	107	95	21	21	21
Training, Development and Generation	-	0	-	-	-
Capital Infrastructure Project Delivery	3	6	3	3	3
Operations Support	170	156	132	129	129
Total (Schedule 16 line 92)	280	257	155	152	152
Percentage Change			-40%	-2%	0%
Total					
Transmission, Distribution and Customer Service	2,960	2,910	2,922	2,941	2,952
Training, Development and Generation	1,033	1,088	1,010	1,010	1,010
Capital Infrastructure Project Delivery	1,196	1,099	1,243	1,275	1,285
Operations Support	1,175	1,137	1,121	1,119	1,119
Total (Schedule 16 line 93)	6,365	6,234	6,296	6,344	6,365
Percentage Change			1%	1%	0%
Regular Hour FTEs	5,781	5,635	5,721	5,769	5,785
Overtime Hours FTEs	583	599	575	575	580
Total	6,365	6,234	6,296	6,344	6,365

As shown in Table 5-7, BC Hydro's total FTEs increase about 1 per cent each year, from fiscal 2016 actual FTEs, in fiscal 2017 and fiscal 2018 Plan and less than 1 per cent in fiscal 2019 Plan. Table 5-7 also shows the following:

- Overall, planned FTEs at the end of the test period, when compared to fiscal 2016 actual FTEs, are higher in capital, and lower in operating and deferred. This reflects BC Hydro's focus on its capital program;
- Within Operating, key FTE changes include the reduction of FTEs in Transmission, Distribution and Customer Service partially related to distribution designers charging directly to capital programs rather than being allocated to capital overhead. Further details can be found in section 5.5.6.3. Reductions in Training, Development and Generation relate to the Burrard Thermal facility, as it has transitioned from a generating facility to a synchronous-condense facility and a reduction in the intake of apprentices and trainees due to recent success in addressing forecasted future resourcing requirements in fiscal 2015 and fiscal 2016. Further details can be found in section 5.4.2. This is partially offset by an increase in Operations Support primarily related to Safety, Security and Emergency Management Workforce Optimization additions and more operating work by the Materials Management department;
- Within Capital, key FTE changes include increases in Transmission, Distribution and Customer Service related to distribution designers charging directly to capital programs rather than being allocated through capital overhead and increases in the Capital Infrastructure Project Delivery Business Group related to Site C Clean Energy Project and Workforce Optimization; and
- Within Deferred, key changes include reduced FTEs in:
  - The Conservation and Energy Management Key Business Unit and the Customer Service and Distribution Design Key Business Unit related to changes to demand-side management programs; and
  - The Transmission, Distribution and Customer Service Business Group, as a result of FTEs related to the sustainment of the Smart Metering and Infrastructure Program transitioning from Deferred to Operating.

Table 5-8 below is a continuity schedule of planned changes in FTEs during the test period and descriptions of the drivers for the change. The only additions planned for fiscal 2017 to fiscal 2019 relate to the Workforce Optimization Program and additions for the Site C Clean Energy Project.

Table 5-8 Continuity Schedule of Planned FTEs

FTE's (including Regular and Overtime hours)	Training, Development and Generation	Transmission, Distribution and Customer Service	Capital Infrastructure Project Delivery	Operations Support	Total
F2016 Actual	**1,088**	**2,910**	**1,099**	**1,137**	**6,234**
Workforce Optimization	6	26	67	11	110
Site C Clean Energy Project			77		77
Burrard Generating Station reductions	(47)				(47)
Reductions resulting from changes in the demand-side management program		(5)		(13)	(18)
Reductions in Training and Development	(34)				(34)
Miscellaneous Changes	(3)	(9)	-	(14)	(26)
F2017 Plan	**1,010**	**2,922**	**1,243**	**1,121**	**6,296**
Workforce Optimization		19	28	2	49
Reductions resulting from changes in the demand-side management program				(4)	(4)
Site C Clean Energy Project			4		4
F2018 Plan	**1,010**	**2,941**	**1,275**	**1,119**	**6,344**
Workforce Optimization		11	-	-	11
Site C Clean Energy Project			10		10
F2019 Plan	**1,010**	**2,952**	**1,285**	**1,119**	**6,365**

The following provides additional information with regards to Table 5-8:

- For increases from Workforce Optimization, refer to section 5.3.1.3;
- The Site C Clean Energy project is ramping up in fiscal 2017 with an increase of 77 FTEs. In fiscal 2018 there are four additional FTEs planned with a further 10 in fiscal 2019;
- Burrard Generating Station reductions relate to the partial decommissioning of the Burrard Generating station and its conversion to operating as synchronous-condense facility (refer to section 5.4.2 for further details);
- During the test period there is a change to demand-side management programs which will achieve cost savings and reduce the average cost of programs. These changes have also resulted in a reduction in FTEs required to deliver the

program. Refer to Chapter 10 for BC Hydro's demand-side management expenditures during the test period;

- Reduction in Training and Development primarily due to a reduction in apprentice and trainee intakes in fiscal 2016 and also from the timing of graduations and intakes that occur throughout fiscal 2017.

Further details regarding BC Hydro's planned FTEs during the test period can be found in the Business Group and Key Business Unit sections in sections 5.4 to 5.7.

5.3.4 Standard Labour Rates

Table 5-9 outlines the planning assumptions for Standard Labour Rates. Standard Labour Rates are used by BC Hydro to assign payroll and benefits costs (including current service pension costs), and vacation and flex day entitlements to work activities, projects, and work orders. The rates are calculated at the beginning of the budgeting cycle to support budgeting based on standard work hours and are based on forecasts of wage and salary increases, job classification, current service pension costs, gainsharing under our union contracts, sick days, annual vacation, and flex day entitlements. The rates are a weighted average across each affiliation.

Table 5-9 Planning Assumptions - Standard Labour Rates ($ per hour)

Affiliation	F2016	F2017	F2018	F2019	Source
MoveUP (formerly COPE)	55.33	58.89	60.10	61.40	Refer to Table 5-10
International Brotherhood of Electrical Workers	69.90	73.97	75.36	76.85	Refer to Table 5-10
Management and Professionals	93.88	96.73	98.33	100.05	Refer to Table 5-10

The changes in the weighted average Standard Labour Rates by affiliation are detailed in Table 5-10, and are largely due to the following:

- The Standard Labour Rates shown in Table 5-9 are fully loaded Standard Labour Rates. The benefit loading rate is added to the base Standard Labour

Rate to get a fully loaded Standard Labour Rate. The forecast benefits loading rates have changed from 29.2 per cent in the fiscal 2016 Plan, to 29.8 per cent for fiscal 2017, 30.1 per cent for fiscal 2018 and 30.5 per cent for fiscal 2019. The benefit loading rate is the total expected cost of benefits divided by total base pay. The largest component of benefit cost increase relates to current service pension cost which has increased from $76.5 million in the fiscal 2016 Plan to $87.0 million for fiscal 2017, $88.3 million for fiscal 2018 and $89.7 million for fiscal 2019. This increase is mainly due to a decrease in the discount rates used to calculate current service pension costs. A decrease in the discount rate results in an increase in BC Hydro's pension obligation and an increase in current service pension costs. Further details regarding the calculation of current service pension costs can be found in section 5.8. Effective January 2016, BC Hydro changed the cost sharing model related to its registered defined benefit pension plan such that employees and BC Hydro each contribute fifty per cent of the annual cost of contributions. Previously, BC Hydro's share was higher. Benefit costs also include the employer portion of Canada Pension Plan, Employment Insurance, health and dental premiums, long term disability and workers' compensation premiums; and

- An increase of 1.9 per cent per year is included in base pay for MoveUP and International Brotherhood of Electrical Workers. It consists of a 1.5 per cent general wage increase per the collective agreements and an estimate of 0.4 per cent for the Economic Stability Dividend. The Dividend is a component of the collective agreements that is in accordance with the Government's bargaining mandate. It provides for additional increases in wage rates if actual British Columbia real Gross Domestic Product growth exceeds a Government forecast. An Economic Stability Dividend wage increase of 0.45 per cent was provided effective February 1, 2016 consistent with the Union collective agreements. Also included in the Standard Labour Rates is a 1.5 per cent per year assumption for Management and Professionals compensation increases.

1 Table 5-10 Weighted Average Standard Labour
2 Rates by Affiliation

F2017 Plan			
($ per hour)	MoveUp	IBEW	M and P
Standard Labour Rates F2016 Plan	55.33	69.90	93.88
Forecast weighted average base pay increase/(decrease)	2.20	1.91	1.43
Benefit Costs			
Forecast current pension costs increase/(decrease)	1.09	0.75	1.38
Forecast other benefit costs increase/(decrease)	0.16	(0.18)	(0.08)
Forecast premium and allowance increase/(decrease)	0.03	1.53	(0.11)
Forecast gainsharing/results pay increase/(decrease)	0.08	0.07	0.23
Total Rate Increase/(Decrease)	**3.56**	**4.08**	**2.85**
Standard Labour Rates F2017 Plan	**58.89**	**73.97**	**96.73**

F2018 Plan			
($ per hour)	MoveUp	IBEW	M and P
Standard Labour Rates F2017 Plan	58.89	73.97	96.73
Forecast base pay increase	0.82	0.93	1.10
Benefit Costs			
Forecast current pension costs increase	0.14	0.14	0.17
Forecast other benefit costs increase	0.23	0.24	0.33
Forecast premium and allowance increase	0.01	0.04	(0.00)
Forecast gainsharing/results pay increase	0.03	0.03	0.00
Total Rate Increase	**1.21**	**1.39**	**1.60**
Standard Labour Rates F2018 Plan	**60.10**	**75.36**	**98.33**

F2019 Plan			
($ per hour)	MoveUp	IBEW	M and P
Standard Labour Rates F2018 Plan	60.10	75.36	98.33
Forecast base pay increase	0.83	0.95	1.11
Benefit Costs			
Forecast current pension costs increase	0.15	0.16	0.19
Forecast other benefit costs increase	0.28	0.30	0.42
Forecast premium and allowance increase	0.01	0.04	(0.00)
Forecast gainsharing/results pay increase	0.03	0.03	0.00
Total Rate Increase	**1.30**	**1.48**	**1.72**
Standard Labour Rates F2019 Plan	**61.40**	**76.85**	**100.05**

5.3.5 Operating Costs and FTEs by Business Group

The overall operating costs and FTEs by business group are presented below in Table 5-11 and Table 5-12. The operating costs for the Operations Support Business Group include IPP capital lease costs and IFRS ineligible capital overhead.

The variances for fiscal 2015 Plan (i.e., the fiscal 2015 plan presented in the Fiscal 2015 - Fiscal 2016 Revenue Requirements Rate Application) to fiscal 2015 actual costs and fiscal 2016 Plan to fiscal 2016 actual costs are explained in Appendix K, section 4. In summary, the business group operating costs overall were within $4.4 million (0.55 per cent) of the fiscal 2015 Plan for fiscal 2015 and within $2.4 million (0.29 per cent) of the fiscal 2016 Plan. The business groups work together to meet the annual operating cost target for BC Hydro. When some business groups encounter unforeseen or unavoidable costs the other business groups look at their programs for areas where they can reduce costs to offset these additional costs. This facilitates meeting the overall corporate target but results in variances at the business group level.

The fiscal 2017 to fiscal 2019 operating costs and FTEs are discussed in further detail in the sections that follow. The operating costs changes are discussed relative to the fiscal 2016 Plan and the FTE changes relative to the fiscal 2016 actual FTEs.

Table 5-11 Operating Costs by Business Group

	($ million)	F2015 RRA	F2015 Actual	F2016 RRA	F2016 Actual	F2017 Plan	F2018 Plan	F2019 Plan
		1	2	3	4	5	6	7
1	Training, Development and Generation	132.9	134.0	131.3	136.3	136.4	139.2	146.2
2	Transmission, Distribution and Customer Services	513.4	517.6	510.9	513.6	536.0	536.0	537.2
3	Capital Infrastructure Project Delivery	48.7	52.7	48.7	61.0	56.3	51.8	52.1
4	Operations Support	98.2	93.3	136.0	118.4	148.9	209.1	225.6
5	Business Group Net Operating Costs	793.2	797.6	826.9	829.3	877.6	936.1	961.1
6	Regulatory Account Recoveries	176.0	175.9	162.9	162.9	203.2	182.6	182.7
7	Total (5.0 L47)	969.1	973.5	989.9	992.2	1,080.8	1,118.8	1,143.7

Table 5-12 FTEs by Business Group

	(FTEs)	F2015 RRA	F2015 Actual	F2016 RRA	F2016 Actual	F2017 Plan	F2018 Plan	F2019 Plan
		1	2	3	4	5	6	7
1	Training, Development and Generation	1,033	1,050	1,033	1,088	1,010	1,010	1,010
2	Transmission, Distribution and Customer Services	3,010	2,978	2,960	2,910	2,922	2,941	2,952
3	Capital Infrastructure Project Delivery	1,157	1,088	1,196	1,099	1,243	1,275	1,285
4	Operations Support	1,190	1,196	1,175	1,137	1,121	1,119	1,119
5	Total (16.0 L72)	6,390	6,312	6,365	6,234	6,296	6,344	6,365

5.4 Training, Development and Generation Business Group

The Training, Development and Generation Business Group is responsible for the management, including operation, maintenance and reinvestment in BC Hydro's generation Heritage Assets. The business group also coordinates agreements such as the Columbia River Treaty and the Canal Plant Agreement, directs market purchases and sales for domestic needs, and makes any surplus capability of the generating system available to Powerex for earning Trade Income. In addition, the business group provides effective training and development opportunities to build our internal capacity to meet strategic goals and position us for the future.

Training, Development and Generation is organized into the following Key Business Units:

- Training and Development;
- Generation Operations;
- Generation Resource Management;
- Generation Asset Management;
- Generation Maintenance; and
- Business Unit Support.

The responsibilities, staffing levels and expenditures for these Key Business Units are discussed further below in section 5.4.3 to 5.4.8.

In fiscal 2016, the previous Generation Business Group was restructured:

- The Dam Safety Key Business Unit and the Environmental Risk Management Key Business Unit moved from the previous Generation Business Group to Capital Infrastructure Project Delivery Business Group;
- The Energy Planning department moved from the Generation Business Group to the Corporate Affairs Key Business Unit within the Operations Support Business Group; and
- The Training and Development department moved from Human Resources and Safety to the Training, Development and Generation Business Group.

5.4.1 Training, Development and Generation – Business Priorities

Over the test period, Training, Development and Generation will be focusing on the following company-wide priorities:

- Continue to improve the way we operate:
  - ▶ Improving safety performance and managing of safety risks;
  - ▶ Managing the life cycle of generation assets through the implementation of our maintenance and reliability programs by striking the right balance between investment in capital and maintenance; and
  - ▶ Exercising fiscal responsibility and maintaining structures and equipment integrity by leveraging technology and work smart process improvements.
- Strengthen our proud and valued workforce:
  - ▶ Attracting, retaining and developing skilled employees.

These business priorities are expanded on further in the following sections.

5.4.1.1 Improving Safety Performance and Managing Safety Risks

Training, Development and Generation is accountable for managing the safety of employees, contractors and members of the public at and around our generation facilities, which are hazardous environments. Managers and supervisors in Training, Development and Generation are supported by the Safety department when planning and executing their work and whenever safety issues arise in order to meet regulatory requirements and improve safety performance.

Training, Development and Generation will support achievement of BC Hydro's Safety Vision and Goals (refer to section 5.7.6) together with the Safety department through a number of initiatives, making a significant investment in additional training for the group's managers and professional and trades employees, as well as implementing and sustaining other improvements as described below:

- **Completing Safety Taskforce recommendations** – The business group will continue to implement and sustain the 2011 Safety Taskforce recommendations (refer to Appendix FF, Attachment 3). The taskforce was initiated following an employee fatality in 2010 and brought together a dedicated team of employees from different operational backgrounds and business groups to determine why serious safety incidents had been occurring and to develop recommendations to improve BC Hydro's safety performance. This work produced 21 recommendations;
- **Improving practices for electrical safety, asbestos and confined space management** –The business group will continue to participate in BC Hydro-wide projects and programs to close gaps and improve performance in managing areas of high risk to employee and contractor safety including electrical hazards, asbestos and confined spaces in order to ensure employee and contractor safety and compliance with regulations;
- **Improving access to safety information** – the business group will participate in the continued development of BC Hydro's Safety Management Framework, including improving workforce access to safety standards, rules and procedures to support competency, compliance with regulations, efficiency, and ultimately

fewer safety incidents. (For additional information on BC Hydro's Safety Management Framework refer to section 5.7.6.1);

- **Ensuring compliance with crane regulations** – in fiscal 2016, in response to a WorkSafeBC order related to the certification and testing of cranes, the business group reviewed compliance with Occupational Safety and Health regulations for its 107 cranes. From that review, the business group has prepared a plan to upgrade cranes, resolve deficiencies in crane documentation, and improve crane operator training;
- **Improving emergency preparedness** – In fiscal 2015, Training, Development and Generation along with the Emergency Management department began work to improve the quality of emergency response plans in preparation for emergencies including major seismic, fire, flood or other events. In addition, the business unit is implementing more frequent and structured emergency exercises for generation assets. This work will continue implementation into fiscal 2017 and enter into sustainment in fiscal 2018; and
- **Improving safety training** – reviewing and planning safety training based on employee exposure to hazards and risks as well as regulatory and compliance requirements and determining training requirements for employees on new and existing equipment, technology and work procedures based on the focus areas in the Five-Year Safety Plan (refer to section 5.7.6).

5.4.1.2 Managing the Life Cycle of Generation Assets

Training, Development and Generation manages the ongoing risks associated with BC Hydro's generation facilities through asset management and maintenance programs. The business group has taken steps to enhance its approach for managing assets across their full life cycle. An established approach to lifecycle asset management is in place, which is well aligned with PAS 55.[44] ISO 55000[45] is

[44] PAS 55 is the British Standards Institution's Publicly Available Specification for the optimized management of physical assets.

based on PAS 55, but is a recent evolution of the standard. Given that ISO 55000 is based on PAS 55 the business group is already aligned with much of the ISO 55000 methodology, and will be working to ensure more complete alignment in the future.

BC Hydro's generation facilities were constructed over many decades with the largest capacity generating units built in the late 1960s, 1970s and 1980s. Smaller capacity units were constructed as early as the 1920s. As assets age and ultimately approach their expected end of life, asset performance declines, the risks associated with the assets increase, and maintenance requirements to preserve operation also increase.

Maintenance Programs

Training, Development and Generation has adopted the following maintenance types:

- **Preventive Maintenance** is work performed to documented maintenance programs to reduce the risk of equipment failure. Preventive maintenance programs are set up in the work management system to automatically generate work orders when pre-established triggers are met;
- **Condition-Based Maintenance** is work triggered by the condition of equipment as determined by preventive maintenance inspections, tests, maintenance bulletins, and/or operational readings and occurs before equipment fails. Condition–based maintenance is performed only when the work needs to be done (for example, equipment clearances are outside specification, operational readings trigger required maintenance or component condition has deteriorated), and is scheduled at the first practical opportunity once the need has been identified;
- **Corrective Maintenance** is work done in response to a breakdown that occurs while equipment is in service. This includes when equipment must to be taken

[45] ISO 55000 is an international standard covering management of physical assets.

out of service for repair. Corrective maintenance includes all work done due to any type of forced outage; and

- **Facility Maintenance** is work performed to upkeep a facility and is not maintenance on the power system. This includes items such as maintenance and minor repair of building roof and structure, lighting, domestic water and sewer as well as roads and landscaping maintenance and snow removal.

The preventive maintenance programs for major generating equipment (turbines, generators, governors, exciters, circuit breakers and unit transformers) are developed following reliability centered maintenance methodology. The business group looked at best practices in electric utilities and other capital intensive industries such as airlines, pulp and paper and refining; and based on that review, adopted reliability centered maintenance.

The basis of reliability centered maintenance is failure modes and effects analysis. This risk-based analysis determines the way in which critical components can fail and what the effect of such failure is on the major equipment. Reliability centered maintenance determines preventive maintenance such that the total cost of maintenance (including all direct maintenance costs plus outage opportunity costs) plus the cost of forecast outages (including all costs of returning the unit to service plus opportunity costs) is minimized. This leads to a recommendation of the maintenance tasks to be done, that balances cost and reliability.

The objectives of reliability centered maintenance -based maintenance are to:

- Increase the effectiveness of maintenance spending;
- Reduce the risk of forced outages; and
- Ensure equipment meets reliability needs.

The result is a documented, logic-based, maintenance program that can be revised as circumstances change. Preventive maintenance programs are reviewed periodically to continually improve the effectiveness and efficiency of maintenance. These maintenance program reviews are led by Generation Maintenance and include subject matter experts and facility managers, maintenance engineers and trades.

Preventive maintenance programs for ancillary equipment and all equipment at older smaller facilities (see Available Energy facilities below) are based on manufacturers' recommendations modified by historical practices, regulatory requirements, engineering judgment and field experience within the business group and throughout the electrical utility industry.

Facility Asset Plans and Prioritization of Assets

Training, Development and Generation has developed Facility Asset Plans for BC Hydro's hydroelectric generation facilities and is in the process of developing Facility Asset Plans for thermal generation facilities and dams with no generation. The purpose of a Facility Asset Plan is to document a robust understanding of the issues, risks and opportunities at a specific facility and the proposed long term investment strategy in the context of BC Hydro's strategic objectives.

The generation facilities are categorized into Key, Strategic and Available Energy facilities. Key facilities include the seven largest facilities each with a capacity greater than 200 MW which together provide 90 per cent of the annual average electricity generated by BC Hydro. The eighteen Strategic facilities are plants with multiple facilities on a river system, those on Vancouver Island and those providing voltage support to the system. The Strategic facilities together generate 9 per cent of BC Hydro's average annual energy. Lastly, the seven remaining Available Energy facilities generally represent the smallest facilities, which together provide 1 per cent of BC Hydro's average annual electricity production.

The generation function uses its equipment condition assessment methodology – Equipment Health Rating – results as an indicator of the reliability risk associated with generating equipment. The generation function periodically evaluates the condition of its major assets (turbines, generators, governors, exciters, transformers, and circuit breakers) based on the latest available maintenance test and inspection data. Health assessments are based primarily on asset condition but also consider safety and environmental issues, reliability, design deficiencies, asset age and industry expected life as well as availability of spare parts and technical expertise (Appendix R provides additional information on Equipment Health Rating).

As reflected in the 10-Year Capital Forecast in Appendix G, the Training, Development and Generation Business Group, with the exception of dam safety projects and maintenance, has prioritized capital investment in Key facilities, with a lower level of investment in the Strategic facilities. With the exception of Whatshan Generating Station and Aberfeldie Generating Station, the business group will continue to operate and maintain Available Energy facilities with limited proactive and minimal reactive capital investment until all units at a facility are forced out of service indefinitely. Investment at any facility will be limited to a multi-year expenditure cap that results in a positive net present value until redevelopment. When a facility is forced out of service, and on an individual basis, plans will be developed for the economic refurbishment or redevelopment of the facility or decommissioning.

The business group uses forced outage factor as a measure of reliability; a lower forced outage factor indicates a more reliable unit or facility. The forced outage factor results over the 11-year period from fiscal 2005 to fiscal 2016 reflects the Training, Development and Generation Business Group's investment strategy. The five year rolling forced outage factor for Key facilities has remained relatively constant. The five year rolling forced outage factor for Strategic facilities has also remained relatively constant over this period, excluding Alouette Generating Station which is at end-of-life and has not been redeveloped. However, the five year rolling forced outage factor for Available Energy facilities has increased from 5 per cent at the start of the period to slightly over 9 per cent as of end of fiscal 2015.

Integration of Civil Preventive Maintenance – During fiscal 2017 to fiscal 2019, the business group also plans to further integrate preventive maintenance of civil assets with the existing program for electrical and mechanical equipment such that ongoing risks associated with all assets are managed effectively and with lowest life cycle costs. Since fiscal 2012, the business group has allocated a specific operating and maintenance budget to increase the focus on civil asset corrective maintenance based on risk assessment priority. Corrective and condition-based civil maintenance is now prioritized in the same way as all other corrective and condition-based maintenance. Over the test period and beyond, BC Hydro will allocate additional budget to implement the preventive maintenance civil inspection tasks and condition-based repairs expected from these tasks.

Mandatory Reliability Standards – North American Electric Reliability Corporation standards became mandatory and enforceable under the *Utilities Commission Act* in 2009. The North American Electric Reliability Corporation standards have imposed more frequent and more extensive testing and maintenance on certain generating station components as well as additional management processes as part of a North American-wide program to improve electrical system reliability and security. Under the *Utilities Commission Act*, BC Hydro must annually determine cost impacts of new or revised standards. On May 15, 2015, BC Hydro filed Mandatory Reliability Standards Assessment Report No. 8 summarizing the cost impacts of 37 new and revised reliability standards. The standards include:

- Enhanced protective relay maintenance and testing standards;
- New requirements for verification of models and data for generating equipment that is provided for planning and reliability studies of the bulk electric system; and
- Enhanced standards for cyber security of industrial networks within generating stations.

Each of these enhanced standards add to the cost of operating and maintaining the assets the business group manages.

5.4.1.3 Exercising Fiscal Responsibility through Working Smarter

Training, Development and Generation has implemented, and continues to seek, opportunities to increase productivity.

Improved Workforce Utilization – Training, Development and Generation's approach has been to absorb generating facility cost pressures by offsetting them with productivity improvements achieved through better work planning and scheduling and optimization of unit planned outage intervals. Examples of productivity improvements are outlined below to demonstrate how the business group offsets some of these incremental requirements with productivity improvements:

- In fiscal 2008, the business group began an initiative called "Back to Basics" to improve and standardize maintenance management. A major focus has been on planning and scheduling that has led to more work completed with existing resources. The first phase of Back to Basics, "Bronze", measured and assessed adequacy and consistency of practices across Generation facilities for identifying, planning, executing and reviewing work. The "Silver" phase began in fiscal 2010 and has been refined over time with the present framework requiring managers of Key and Strategic facilities to demonstrate full compliance with 12 mandatory maintenance process requirements and achieve 80 per cent compliance with a remaining 30 other requirements. Efforts to continue to meet these requirements will continue through the test period;
- To improve the reliability of flood discharge systems the business group started in fiscal 2010 an enhanced testing and maintenance program for spillways. This program resulted in significant additional labour hours for added preventive maintenance tasks as well as required condition-based maintenance identified by preventive maintenance. Through the improved planning and scheduling

achieved in Back to Basics, the business group was able to absorb the additional flood discharge system maintenance and testing within existing budgets;

- In fiscal 2010, a fifth unit (524 MW) was added at Revelstoke and in fiscal 2015, a fifth unit (520 MW) was added at Mica, with a sixth unit at Mica (520 MW) in fiscal 2016. The addition of these units has resulted in an overall increase in hydroelectric generation capacity of 15 per cent; however, the cost of maintaining these additional units has been largely absorbed within pre-existing budgets. By re-applying the reliability-centered maintenance methodology to new and existing units at Revelstoke and Mica with the knowledge gained from using the initial maintenance program developed using reliability centered maintenance, the business group was able to extend the maintenance intervals on existing units to offset the maintenance costs of the new units; and
- In fiscal 2016 an Equipment Health Rating Work Smart review was initiated to examine the existing Equipment Health Rating processes of field data collection, centralized subject matter assessment and the recommendation review and acceptance process to improve process efficiency and reduce assessment cycle time.

5.4.1.4 Attracting, Retaining and Developing Skilled Employees

Training, Development and Generation relies on a highly skilled, educated and experienced technical workforce to fulfill its mandate. The development of technical and leadership skills is critical for employee retention. Management has committed resources and funding to develop and deliver training using internal and contracted trainers to employees in all roles.

Development of Skilled Trades and Professional Employees: The skills which are difficult to attract and needed for the business group are:

- Trades: Communication, Protection and Controls Technologists and Electricians; and
- Professionals: Electrical and Mechanical Engineers, Maintenance and Operations Managers; and Specialists (enterprise specific knowledge that is not readily available in the marketplace must be developed on the job over several years to support key functions within the organization).

In fiscal 2014, the business group implemented regionally-based training and advisory groups consisting of management and trades staff to identify and plan annual technical training for trades employees. We have also developed leadership training for front line managers and trades crew leaders which began in fiscal 2015 and will continue throughout the test period.

Learning and development opportunities are also provided to support ongoing career and professional development of our management and professional employees. The selection of professional development course offerings is regularly reviewed, expanded and adjusted to reflect the evolving business needs. In addition, the Information Technology Education Centre provides training and development to address changing technology needs, the Internal Coaching program supports the development of managers and professionals through informal coaching relationships and the Learning Plans for Frontline Leaders specifically outline all of the skill and development areas required for frontline leaders in the areas of Safety, Technical, People leadership and Management Skills.

Attraction and Retention in the North – A particular workforce concern for Training, Development and Generation is attracting and retaining employees in the Northern Operations region. BC Hydro has implemented a recruiting strategy to increase the intake of local residents into BC Hydro's apprenticeship program with the intent that these apprentices, once graduated as journeypersons and hired into positions, will be more likely to remain in the region to improve the stability of the workforce.

5.4.2 Three-Year Operating Cost and FTE Summaries

The operating costs for Training, Development and Generation are shown on Table 5-13 and Table 5-14 below:

Table 5-13 Training, Development and Generation Operating Costs Before Regulatory Account Transfers, Net of Recoveries – By Key Business Unit

	($ million)	F2015 RRA	F2015 Actual	F2016 RRA	F2016 Actual	F2017 Plan	F2018 Plan	F2019 Plan
		1	2	3	4	5	6	7
1	Training and Development	24.3	25.8	24.3	25.3	25.9	25.9	26.3
2	Generation Operations	85.0	86.2	85.1	85.3	81.2	81.7	88.0
3	Generation Resource Management	13.2	12.9	13.3	13.9	14.5	14.7	14.8
4	Generation Asset Management	2.3	1.8	2.3	1.9	2.2	2.2	2.3
5	Generation Maintenance	4.7	3.9	4.7	4.3	6.0	8.0	8.1
6	Business Unit Support	3.4	3.4	1.6	5.6	6.6	6.6	6.7
7	Total (5.2 L15)	132.9	134.0	131.3	136.3	136.4	139.2	146.2

Table 5-14 Training, Development and Generation Operating Costs Continuity Schedule

	($ million)		F2017 Plan	F2018 Plan	F2019 Plan
1	**F2016 Revenue Requirement Application Plan (Generation)**		**298.5**		
2	Reorganization Impacts		(167.2)		
3	**F2016 Revenue Requirement Application Plan (Training, Development and Generation)**		131.3	136.4	139.2
4	Budget transfers between Business Groups		8.8		
5	**Adjusted F2016 Revenue Requirement Application Plan (Training, Development and Generation)**		140.1		
6	**Test Period Savings/Efficiencies:**				
7	Productivity/Efficiencies				
8	- Burrard decommissioning		(7.0)		
9	- Workforce reductions		(0.1)		
10		A	(7.1)	-	-
11	**Test Period Cost Increases:**				
12	Unavoidable Costs				
13	- Labour (excluding Workforce Optimization)		0.6	2.1	2.2
14	- Crane remediation		0.5		
15	- Mandatory fees				
16	▪ North American Electric Reliability Corporation mandatory reliability standards		0.4	-	
17	▪ Waneta maintenance		0.2		
18	▪ Contractor cost escalation for operations and maintenance		0.7	(0.9)	-
19	Capital-Driven				
20	- Maintenance				
21	▪ Generation Civil Program implementation		0.5	2.0	
22	▪ Mica additional operating and maintenance costs		0.5		
23	▪ Payments under John Hart operating agreement				4.8
24	- Workforce Optimization		(0.1)	(0.4)	(0.0)
25	Other				
26	- Other		0.1		
27		B	3.4	2.8	7.0
28	Net Increase/(Decrease)	A+B	(3.7)	2.8	7.0
29	**Net Operating Costs Plan (Schedule 5.2, line 15)**		**136.4**	**139.2**	**146.2**

The FTEs for Training, Development and Generation are shown on Table 5-15 below.

Table 5-15 Training, Development and Generation FTEs

	(FTEs)	F2015 RRA	F2015 Actual	F2016 RRA	F2016 Actual	F2017 Plan	F2018 Plan	F2019 Plan
		1	2	3	4	5	6	7
1	Training and Development	404	435	404	469	434	434	434
2	Generation Operations	493	488	493	494	447	447	447
3	Generation Resource Management	67	64	67	65	64	64	64
4	Generation Asset Management	9	9	9	8	9	9	9
5	Generation Maintenance	58	50	58	50	52	52	52
6	Business Unit Support	3	3	3	3	3	3	3
7	Total (16.0 L15)	1,033	1,050	1,033	1,088	1,010	1,010	1,010

Operating expenditures for Training, Development and Generation Business Group are increasing by $5.1 million in fiscal 2017 compared to fiscal 2016 Plan, primarily due to:

- $8.8 million in budget transfers to fund work program changes, training and development delivery, and increased Standard Labour Rates;
- $1.5 million in unavoidable costs for Standard Labour Rate increases, crane remediation and North American Electricity Reliability Corporation reliability standards;
- $1.1 million in maintenance for the generation civil maintenance program implementation and additional maintenance costs at Mica and $0.7 million for contractor cost escalation; and
- These increases are partially offset with $7.0 million in savings in operating and maintenance costs at Burrard Generating Station. With the completion of the Interior to Lower Mainland transmission line, installation of Mica Units 5 and 6 and the third transformer at the Meridian substation, Burrard's generating capacity is no longer required to meet critical loads in the Lower Mainland. Accordingly, Burrard will no longer be operated to generate electricity and will instead be operated in synchronous-condense to provide voltage support for the transmission and distribution systems in the Lower Mainland, saving operating and maintenance costs.

Operating costs in fiscal 2018 are planned to increase by $2.8 million compared to fiscal 2017 due to an increase of $2.0 million for implementation of the civil maintenance program and $2.1 million for Standard Labour Rate increase.

Operating costs in fiscal 2019 are planned to increase by $7.0 million compared to fiscal 2018 due to $4.8 million for John Hart operating agreement payments relating to the operations of the redeveloped John Hart Generating Station and $2.2 million for Standard Labour Rate increase.

FTEs in Training, Development and Generation are decreasing by 79 FTE in fiscal 2017 compared to fiscal 2016 actual FTEs with a 47 FTE decrease in Generation Operations primarily due to the change in operations at Burrard Generating station and 35 FTE decrease in Training and Development primarily due to a reduction in apprentice/trainee intakes in fiscal 2016 and also from the timing of graduations and intakes that occur throughout fiscal 2017. The reduction in apprentice/trainee intakes in fiscal 2016 is due to the success in addressing forecasted future resourcing requirements in fiscal 2015 and 2016. FTEs from fiscal 2017 to fiscal 2019 are planned to remain constant.

The following sections describe the six Key Business Units in Training, Development and Generation Business Group.

5.4.3 Training and Development

This Key Business Unit determines, manages and implements strategies and programs to train and develop employees as well as manages the Trades Training Centre. The Trades Training function focuses on the delivery of training specific to the front line workforce and manages all apprenticeship programs, including the operating costs and FTEs.

Trades Training will:

- Conduct critical skills competency assessments and training for electrical workers, including Life Saving Rules related to electrical work;
- Coordinate SafeStart training (refer to section 5.7.6) to develop employee safety skills;
- Complete Safety Taskforce recommendations related to training; and
- Manage the Training Advisory Groups that plan and implement technical and trades training across all operational areas.

The Work Methods department develops safe work procedures for working on the electrical system in compliance with electrical safety regulations, BC Hydro safety standards and rules, and industry best practice. The Enterprise Learning department is responsible for the budget, design and delivery of leadership, professional and non-technical programs, orientation and onboarding, and also provides solution sourcing for employee training as well as professional and career development. Enterprise Learning also manages the Engineer-in-Training program, Graduate Technologist in Training program and Distribution Design and Customer Care Trainee program including the operating costs and FTEs.

Training Operations provides program support for Trades Training and Enterprise Learning, scheduling and logistics for enterprise-wide training requests, instructional design and managing the Trades Training Centre.

Training Performance Services provides metrics, reporting, analytics, contract management, and training governance.

5.4.3.1 Three-Year Operating Cost and FTE Summary

Differences are discussed in reference to Table 5-13 and Table 5-15.

Operating expenditures for the Training and Development Key Business Unit increase by $1.6 million in the fiscal 2017 compared to the fiscal 2016 Plan and remain relatively constant in fiscal 2018 and fiscal 2019.

The increase of $1.6 million in the fiscal 2017 Plan is primarily due to growth in the technical, trades and leadership training programs at BC Hydro. This growth took place in fiscal 2015 and fiscal 2016 when the program was ramped up which is reflected in the actual costs exceeding the plan in both fiscal years. This was due to increases in apprentices and trainees and additions to the Training Delivery teams at a cost of $2.2 million partially offset by reduced apprentice and trainee costs of $1.0 million due to less time charged to training and more time charged to work programs. In fiscal 2017 the only increase compared to fiscal 2016 actual costs is $0.4 million related to additions under Workforce Optimization.

When compared to the fiscal 2015 and 2016 Plans, Training and Development actual FTEs increased by 31 in fiscal 2015 and an additional 34 in fiscal 2016. This was due to increased intakes into the apprentice and trainee programs to ramp up the program to address forecasted future resourcing requirements. As a result of the success in addressing forecasted future resourcing requirements in fiscal 2015 and 2016, the FTEs decrease by 35 in the fiscal 2017 Plan compared to the fiscal 2016 actual FTEs primarily due to a reduction in apprentice and trainee intakes in fiscal 2016 and planned intakes in 2017. This is partially offset by three FTE additions related to Workforce Optimization.

The FTEs are planned to remain constant in fiscal 2018 and fiscal 2019 compared to fiscal 2017.

5.4.4 Generation Operations

Generation Operations is responsible for the maintenance and protection of BC Hydro's dams and generation facilities and for performing local operating functions such as completing visual and audible checks in accordance with prescribed daily and weekly checklists. Facilities-based engineering staff, supported by centrally-located Generation Maintenance equipment specialists, are responsible for technical review and changes to the maintenance program, equipment repairs and upgrades. Generation Operations is divided into three areas: Northern Operations, Columbia Operations, and Coastal Operations.

Generation Operations performs or manages both maintenance and capital work at the facilities in accordance with Generation's asset management strategy.

5.4.4.1 Three-Year Operating Cost and FTE Summary

Differences are discussed in reference to Table 5-13 and Table 5-15.

Generation Operations has the largest component of Training, Development and Generation's operating costs with a fiscal 2017 budget of $81.2 million, about 60 per cent of Generation's fiscal 2017 Plan operating costs. Generation Operations is also the largest group by staffing with 447 FTEs.

Operating expenditures are planned to decrease from fiscal 2016 Plan by $3.9 million due to the change in operation of Burrard Generating Station which will save $7.0 million, partially offset by an increase in funding for civil maintenance and Mica units 5 and 6 maintenance, and Standard Labour Rate increases. Operating expenditures in fiscal 2018 are planned to increase by $0.5 million compared to fiscal 2017 due to Standard Labour Rate increases. Operating expenditures in fiscal 2019 are planned to increase by $6.3 million compared to fiscal 2018 mainly due to John Hart operating agreement payments of $4.8 million to the InPower BC General Partnership who is responsible for the asset availability, performance and condition for the first 15 years the new assets are in service as well as Standard Labour Rate increases.

FTEs for the Generation Operations Key Business Unit have decreased by 47 FTEs in fiscal 2017 from fiscal 2016 actual FTEs primarily due to the change in operations at Burrard Generating Station. FTEs are planned to remain constant from fiscal 2017 to fiscal 2019.

5.4.5 Generation Resource Management

Generation Resource Management is responsible for planning the operation of the BC Hydro generation system, and for integrating other provincial resources into those operations, to reliably meet load obligations in an economical, sustainable and open manner, and with direct consideration of uncertainties. As part of this responsibility, Generation Resource Management plans short to mid-term (hourly up to three years) operation of the Heritage Assets and dispatchable Non-Heritage generating resources by considering a number of variable inputs such as loads, inflows, outages, and market prices, while at the same time making any surplus system capability available to Powerex for trade. Generation Resource Management is also involved in the management of water licenses, the Columbia River Treaty, Canal Plant Agreement, Keenleyside Entitlement Agreement and the Waneta Co-ownership and Operating Agreement with Teck.

5.4.5.1 Three-Year Operating Cost and FTE Summary

Differences are discussed in reference to Table 5-13 and Table 5-15.

Operating expenditures for the Generation Resource Management Key Business Unit are planned to increase in fiscal 2017 from fiscal 2016 Plan by $1.2 million due to a change in the labour mix and Standard Labour Rate increases and increases to various contracts and licenses. Operating costs in fiscal 2018 are planned to increase by $0.2 million compared to fiscal 2017 due to Standard Labour Rate increases. Operating costs in fiscal 2019 are planned to increase by $0.1 million compared to fiscal 2018 due to Standard Labour Rate increases.

FTEs for Generation Resource Management are planned to remain relatively constant during fiscal 2017 to fiscal 2019 compared to the fiscal 2016 actual FTEs.

5.4.6 Generation Asset Management

Generation Asset Management is responsible for providing an over-arching strategic asset management framework for the business group and an understanding of the risks and opportunities associated with the generation assets to recommend the best value strategies and portfolio investments that will preserve BC Hydro's generating capabilities. Asset management is a set of systematic and coordinated activities and practices through which an organization manages its physical assets and their associated performance, risks, and expenditures over their lifecycles for the purpose of achieving its organizational strategic plan. BC Hydro uses asset management methodologies to guide decisions regarding the management of and investment in its generating facilities.

5.4.6.1 Three-Year Operating Cost and FTE Summary

Differences are discussed in reference to Table 5-13 and Table 5-15.

Operating expenditures for the Generation Asset Management Key Business Unit are planned to remain relatively constant with fiscal 2016 Plan during fiscal 2017 to fiscal 2019.

FTEs for Generation Asset Management are also planned to remain relatively constant during fiscal 2017 to fiscal 2019 compared to the fiscal 2016 actual FTEs.

5.4.7 Generation Maintenance

Generation Maintenance is responsible for developing maintenance programs to preserve equipment functionality, manage asset risk, and minimize the life cycle costs associated with the assets. They work closely with Generation Operations, Generation Asset Management, and the Generation Resource Management Key Business Units to develop these programs.

With subject matter expertise on generating equipment, Generation Maintenance's key functions are to carry out equipment condition assessments and determine Equipment Health Ratings, to provide reliability engineering services and to support plant-based engineering staff in resolving equipment problems and recommending maintenance program changes, repairs and upgrades.

5.4.7.1 Three-Year Operating Cost and FTE Summary

Differences are discussed in reference to Table 5-13 and Table 5-15. Operating expenditures for the Generation Maintenance Key Business Unit are planned to increase in fiscal 2017 from fiscal 2016 Plan by $1.3 million due to increases in crane remediation of $0.5 million and civil maintenance programs. Operating expenditures in fiscal 2018 are planned to increase by $2.0 million compared to fiscal 2017 due to an increase in civil maintenance program implementation. Operating costs in fiscal 2019 are planned to increase by $0.1 million due to a Standard Labour Rate increase.

FTEs in Generation Maintenance are increasing by three in fiscal 2017 compared to fiscal 2016 actual FTEs with the additions related to the Workforce Optimization Program. FTEs from fiscal 2017 to fiscal 2019 are planned to remain constant.

5.4.8 Training, Development and Generation Business Unit Support

Business Unit Support includes the Training, Development and Generation Office of the Senior Vice President, the budget for apprentices and trainees for the time they are working on generation work activities, and the budget and costs for Waneta maintenance.

The Training, Development and Generation Office of the Senior Vice President is responsible for providing strategic direction and leadership for the Training, Development and Generation Business Group and business unit support.

5.4.8.1 Three-Year Operating Cost and FTE Summary

Differences are discussed in reference to Table 5-13 and Table 5-15. Operating expenditures for the Business Unit Support Key Business Unit increase in fiscal 2017 from fiscal 2016 Plan by $5.0 million. This budget increase was partially required to fund apprentices and trainees working in the business group with the remainder relating to budget transfers from other business groups.

Business Unit Support's FTEs remain constant from fiscal 2016 through the test period.

5.5 Transmission, Distribution and Customer Service Business Group

The Transmission, Distribution and Customer Service Business Group is responsible for planning, designing, building (except for larger, complex capital projects that are managed by the Capital Infrastructure Project Delivery Business Group), operating and maintaining the majority of BC Hydro's systems and assets needed to deliver electricity safely and reliably to BC Hydro's customers. In addition, the business group is responsible for the customer service operations serving BC Hydro's four million customers, as well as building and sustaining all technology and telecommunications systems.

Transmission, Distribution and Customer Service functions are delivered through six Key Business Units as follows:

- Field and Grid Operations;
- Asset Management and Distribution Engineering;
- Program and Contract Management;
- Customer Service and Distribution Design;
- Technology; and
- Business Unit Support.

The responsibilities, staffing levels and expenditures for these Key Business Units are discussed further below in section 5.5.3 to 5.5.8. The maintenance programs for transmission and distribution assets are described in section 5.5.9.

In fiscal 2016, the previous Transmission and Distribution Business Group was restructured:

- The Customer Service Key Business Unit was combined with the Transmission and Distribution organization;
- The Technology Key Business Unit was combined with the Transmission and Distribution organization;
- The Smart Metering and Infrastructure Program was completed in fiscal 2016 and the operationalization of the sustainment functions in Transmission, Distribution and Customer Service commenced in fiscal 2017. Refer to sections 5.3.1.1, 5.5.3.6, 5.5.4 and 5.5.6 or further details; and

- Aboriginal Relations has been reallocated from the previous Transmission and Distribution Business Group to the Capital Infrastructure Project Delivery Business Group.

5.5.1 Transmission, Distribution and Customer Service – Business Priorities

Over the test period, Transmission, Distribution and Customer Service will be focusing on the following company-wide priorities:

- Make It Easy For Customers To Do Business With Us:
  - Implement our Customer Strategy to strengthen our service foundation, build a customer-centric culture and proactively build to meet the needs of our customers in the future.
- Continue To Improve The Way We Operate:
  - Manage the safety of employees, contractors and members of the public across our transmission and distribution system;
  - Plan and manage the transmission and distribution system assets to ensure the safe, reliable and cost-effective delivery of power; and
  - Effectively plan, design, support and manage BC Hydro's information and telecommunications technologies; and
  - Continue to identify operational efficiencies and savings.
- Deliver capital projects on time and on budget:
  - Effectively deliver distribution capital projects and replacement programs for distribution and transmission electrical equipment and infrastructure.
- Strengthen our proud and valued workforce:
  - Continue efforts to improve employee engagement.

These business priorities are expanded on further in the following sections.

5.5.1.1 Implement Our Customer Strategy to Provide a Better and Smarter Experience for Our Customers

BC Hydro formed a new Customer Strategy anchored around a simple customer promise of "We make doing business with BC Hydro easy for you". This is driven by three strategic objectives, which are shown below along with the related customer strategy initiatives that are planned over the test period to meet each objective:

1. Strengthen our customer service foundation: Improve the delivery of our core services:
   - Improvements to how customers receive bills and how they can make payments;
   - Introductions of new service capabilities across mobile and App platforms; and
   - Making it easier to get in touch with BC Hydro over the phone (single phone number).
2. Shape a customer-centric culture: Shift the culture at BC Hydro to understand the benefits and necessity of adopting a customer-centric culture and shift our behaviors and actions accordingly:
   - Enabling employees as ambassadors for helping service customers; and
   - Providing improved customer service training.
3. Proactively Build for Tomorrow: Make investments in capabilities, products and services that will continue to enhance our ability to deliver customer service in our evolving market:
   - Take an active role in the province with respect to Electric Vehicles;
   - Develop new products, services and rates that help meet the needs of our customers; and
   - Build a more integrated view of our customers across our various teams.

We have already started to work towards implementing the Customer Strategy in fiscal 2016 and will continue the initiatives during the test period to provide a better and smarter experience for our customers.

5.5.1.2 Manage the Safety of Employees, Contractors and the Public Across Our Transmission and Distribution System

Safety is a top priority for BC Hydro. Transmission, Distribution and Customer Service is accountable for managing the safety of employees, contractors and members of the public across our transmission and distribution system. Managers and supervisors in Transmission, Distribution and Customer Service are supported by the Safety business unit when planning and executing their work and whenever safety issues arise in order to meet regulatory requirements and improve safety performance.

In alignment with BC Hydro's safety vision and goals in section 5.7.6, Transmission, Distribution and Customer Service is focused on eliminating serious and fatal incidents. Transmission, Distribution and Customer Service will continue to participate in BC Hydro-wide projects and programs to close gaps and improve performance in managing areas of high risk to employee and contractor safety including electrical hazards, asbestos and confined spaces in order to ensure employee and contractor worker safety and compliance with regulations.

Transmission, Distribution and Customer Service will continue to implement the Safety Taskforce recommendations (Appendix FF, Attachment 3) and is taking further steps to integrate safety into the everyday actions and the behaviours of employees and contractors (see section 5.7.6. for further details). Transmission, Distribution and Customer Service's objective is to have the right number of engaged employees, with the right tools and skills to safely perform their work.

5.5.1.3 Plan and Manage the Transmission and Distribution System Assets to Ensure the Safe, Reliable and Cost-Effective Delivery of Power

Aging Infrastructure

A large portion of the transmission system was built in the 1960s and 1970s and is reaching or exceeding end of life condition. Similarly, a large portion of the distribution system has, or soon will, exceed design life. For example, over 87,000 distribution wood poles are more than 50 years old and over half of all circuit breakers are greater than 30 years old. Based on asset health, approximately 12 per cent of the approximately four million transmission and distribution assets are in Poor to Very Poor condition, which indicates either remediation work or replacement, would be required within the next 10 years, depending on the criticality of the asset. BC Hydro evaluates the condition of the transmission and distribution assets based primarily on the latest available maintenance test and inspection data, and assigns an Asset Health Index to each asset. Asset Health Index is a recently developed methodology that assigns ratings of Very Good, Good, Fair, Poor, or Very Poor, which in turn can be grouped and analyzed by asset class and/or criticality. An overview of the new Asset Health Index methodology, together with summary ratings for transmission, distribution and substation assets are provided in Appendix S.

Aging infrastructure is driving the required level of expenditures to maintain and replace these assets. Investments to address aging infrastructure are necessary to maximize the life cycle value of transmission and distribution assets and protect the investment in the electric system as well as to maintain the reliability and safe operation of the system.

BC Hydro has a number of programs designed to extend asset life or replace assets as their condition deteriorates. The programs are managed to ensure the long term sustainability of the asset and consider constraints such as resource and system outage availability and the impact on customer reliability (planned outages). The planning criteria for capital expenditures are described in section 6.3.

Load Growth and System Expansion

Demand for electricity continues to increase in the province, and many parts of the BC Hydro system are reaching capacity. Growth in some sectors of the economy is driving the need to reinforce the system in areas that do not have the infrastructure to meet these needs. New investments are required in both distribution and transmission infrastructure to meet customer demand growth and to connect new supply resources.

Managing Reliability Performance

Aging infrastructure and prolonged use of the system at or near capacity have combined to put pressure on system reliability. Investments in system reliability often take a number of years to have an impact on performance. In recent years, BC Hydro has increased expenditures for reliability initiatives and such investments have had a demonstrated positive impact on current performance measures. Further information on performance measures is provided in Appendix N. There remains a need for continued investment in order to maintain long-term reliability system-wide.

5.5.1.4 Effectively Plan, Design, Support and Manage BC Hydro's Information and Telecommunications Technologies

For over 50 years, BC Hydro has delivered reliable and affordable electricity to its customers, safely. Customer expectations, however, are changing and BC Hydro must respond by modernizing and automating the electricity grid, optimizing grid and field operations, and creating a culture of customer service that crosses all groups in the company.

For the last few years, BC Hydro has been designing and building a more advanced grid, especially with the implementation of Smart Metering and Infrastructure, distribution automation devices, and new telecommunications technologies. Over the next 10 years, BC Hydro's grid will need to become more dynamic, more flexible, and more responsive to manage the increasing bi-directional flow and variable distribution of both power generation and loads.

BC Hydro is developing a long-term strategy that lays out the future requirements for BC Hydro and its customers to respond effectively to this changing nature of the electricity grid. A list of programs and initiatives are being identified to help BC Hydro with the modernization of its grid over the next 10 years.

It is expected that during the test period, BC Hydro will be working on various programs and initiatives related to grid optimization, enablement and innovation.

5.5.1.5 Continue to Identify Operational Efficiencies and Savings

In the fall of 2015, Transmission, Distribution and Customer Service Senior Management and Executives initiated a Transmission, Distribution and Customer Service Efficiency Initiative to seek ideas from all employees for improved means to conduct our business while still achieving our desired results. Employees were asked for suggestions on how we might be able to perform our business more efficiently, or differently, without sacrificing the needs of our customers. As a result of this call for ideas, multiple suggestions were made. These ideas were prioritized to determine the most appropriate cases to bring forward for further in-depth review, and if warranted, implementation.

As a result of this work, over 20 projects, with six core themes, were prioritized and are being undertaken in fiscal 2017 and fiscal 2018 to drive further operational efficiencies and savings throughout the business. The key themes in this initiative include: inspections frequency optimization, technology functional reviews, work coordination and optimization, customer service cost savings improvements, vegetation management tools implementation and trouble response process improvements.

Project plans for the implementation of this work are currently in development. While this work is still being refined, the Application includes $15 million of sustainable annual savings for fiscal 2017 and subsequent years as shown on line 11 of Table 5-17.

5.5.1.6 Effectively Deliver Distribution Capital Projects and Replacement Programs for Distribution and Transmission Electrical Equipment and Infrastructure

The Program and Contract Management group in Transmission, Distribution and Customer Service is responsible for the project delivery (through project managing or overseeing the external project management) of capital work programs and maintenance work programs on the Transmission and Distribution systems, as well as smaller scale system improvement and customer driven projects on the Distribution system.

Program and Contract Management manage large volumes of electrical equipment inspections, maintenance and replacements and measure delivery success on a cost per unit basis and work completion to unit completion targets with a focus on safety, environment, efficiency, risk management and quality. Program and Contract Management combine project and portfolio management concepts and factory production management concepts in a tailored fashion to manage the work being delivered.

5.5.1.7 Continue Efforts to Improve Employee Engagement

Employee engagement is an area that Transmission, Distribution and Customer Service will continue to focus on over the coming years. The annual employee engagement survey is a tool to gauge the areas that are working well and areas that need more focus to make further improvements. Other tools include face to face meetings as well as mid-year and year-end performance and career development discussions.

The current main areas of focus include:

- Collaboration – making sure we improve how well the groups within Transmission, Distribution and Customer Service work together and how well we work with other groups within BC Hydro;
- Leadership and Integrity – sharing the vision, reviewing how decisions are made and making sure we communicate our decisions well, and
- Workload – focusing on tasks that meet our priorities.

5.5.2 Three-Year Operating Cost and FTE Summaries

The operating costs for Transmission, Distribution and Customer Service are shown on Table 5-16 and Table 5-17.

Table 5-16 Transmission, Distribution and Customer Service Operating Costs Before Regulatory Account Transfers, Net of Recoveries – By Key Business Unit

	($ million)	F2015 RRA	F2015 Actual	F2016 RRA	F2016 Actual	F2017 Plan	F2018 Plan	F2019 Plan
		1	2	3	4	5	6	7
1	Field and Grid Operations	138.0	138.9	137.7	140.1	146.4	147.9	149.6
2	Asset Management and Distribution Engineering	152.8	162.3	151.7	155.1	158.1	158.6	158.1
3	Program and Contract Management	12.2	11.8	12.2	10.9	12.9	13.1	13.3
4	Customer Service and Distribution Design	90.1	92.9	90.1	94.5	88.0	85.7	86.2
5	Technology	108.4	108.9	110.1	107.2	139.5	139.7	138.9
6	Business Unit Support	11.9	2.9	9.0	5.8	(8.9)	(8.9)	(8.9)
7	Total (5.4 L18)	513.4	517.6	510.9	513.6	536.0	536.0	537.2

Table 5-17 Transmission, Distribution and Customer Service Operating Costs Continuity Schedule

	($ million)		F2017 Plan	F2018 Plan	F2019 Plan
1	**F2016 Revenue Requirement Application Plan (Transmission and Distribution)**		**335.4**		
2	Reorganization Impacts		175.5		
3	**F2016 Revenue Requirement Application Plan (Transmission, Distribution and Customer Service)**		510.9	536.0	536.0
4	Budget transfers between Business Groups		4.4		
5	**Adjusted F2016 Revenue Requirement Application Plan (Transmission, Distribution and Customer Service)**		515.4		
6	**Test Period Savings/Efficiencies:**				
7	Productivity/Efficiencies				
8	- Reduction in use of consultants and contractors		(0.3)		
9	- Membership cancellations		(0.3)		
10	- Workforce reductions		(0.7)	(0.1)	
11	- Transmission, Distribution, and Customer Service Efficiency Initiative		(15.0)		
12		A	(16.3)	(0.1)	-
13	**Test Period Cost Increases:**				
14	Unavoidable Costs				
15	- Labour (excluding Workforce Optimization)		2.0	3.1	3.3
16	- Mandatory fees				
17	- Canada Post		1.0		
18	- Western Electrical Coordination Council, Peak Reliability		2.4	0.1	0.2
19	Capital-Driven				
20	- Technology capital project investigations costs		4.0		(1.0)
21	- Maintenance				
22	▪ Vegetation maintenance		1.0		(1.0)
23	- Workforce Optimization		0.2	(0.2)	(0.2)
24	Initiatives				
25	- Customer Strategy		1.5	(1.5)	
26	Other Cost Pressures				
27	- Bad debt		1.0		
28	- Storm restoration costs		2.8		
29	- Technology software maintenance and support costs		1.2		
30	- Electric system operating technology maintenance and support costs		0.8		
31	- Direct charge to capital for Customer Connect costs		(4.9)		
32	- Other		0.9		
33	Smart Metering and Infrastructure		23.0	(1.4)	(0.1)
34		B	37.0	0.1	1.2
35	Net Increase/(Decrease)	A+B	20.6	0.1	1.2
36	**Net Operating Costs Plan (Schedule 5.4, line 18)**		**536.0**	**536.0**	**537.2**

The FTEs for Transmission, Distribution and Customer Service are shown on Table 5-18 below.

Table 5-18 Transmission, Distribution and Customer Service FTEs

	(FTEs)	F2015 RRA	F2015 Actual	F2016 RRA	F2016 Actual	F2017 Plan	F2018 Plan	F2019 Plan
		1	2	3	4	5	6	7
1	Field and Grid Operations	1,903	1,881	1,907	1,809	1,817	1,817	1,817
2	Asset Management and Distribution Engineering	280	282	280	281	273	273	273
3	Program and Contract Management	180	181	180	186	208	212	212
4	Customer Service and Distribution Design	424	425	421	447	458	458	458
5	Technology	166	153	168	158	162	177	188
6	Smart Metering and Infrastructure	53	53	0	25	0	0	0
7	Business Unit Support	4	3	4	4	4	4	4
8	Total (16.0 L32)	3,010	2,978	2,960	2,910	2,922	2,941	2,952

Transmission, Distribution and Customer Service operating costs are forecast to increase by $20.6 million in fiscal 2017 from fiscal 2016 Plan primarily due to:

- Operationalization of Smart Metering and Infrastructure which totals $23.0 million net of savings (Smart Metering and Infrastructure costs were previously being recorded in a deferral account during the Program's implementation stage but must now be recorded as operating costs as the Programs complete);
- $2.0 million in Standard Labour Rate increases;
- $1.0 million in postage and printing increases;
- $2.4 million in Western Electricity Coordinating Council and Peak Reliability fees;
- $5.2 million in capital-driven costs primarily due to additional Technology capital project investigation costs;
- $1.5 million for the Customer Strategy; and
- $1.8 million in other cost pressures.

These increases have been partially offset by:

- $16.3 million in productivity and efficiency savings. Operating costs in fiscal 2018 and fiscal 2019 are planned to remain relatively constant as cost increases for labour are offset by savings in other areas.

A more detailed explanation of operating costs has been provided in the individual Key Business Unit descriptions.

From fiscal 2016 actual FTEs to fiscal 2017 Plan, FTEs are increasing by 12 mainly due to additions under the Workforce Optimization in Program and Contract Management and Technology as well as small changes in other Key Business Units partially offset by a decrease of 25 in Smart Metering and Infrastructure with the operationalization of the project and integration of the FTEs in the various Key Business Units. Further discussion of FTE changes are found in the individual Key Business Unit descriptions.

The following section describes the six Key Business Units in Transmission, Distribution and Customer Service.

5.5.3 Field and Grid Operations

Field and Grid Operations is responsible for the real time operation of the BC Hydro generation, transmission, distribution and telecommunication systems and the operation and maintenance of the transmission and distribution systems . This Key Business Unit is also responsible for responding to unplanned outages, supporting and implementing emergency management preparedness plans, and safety and environmental programs for transmission and distribution. Grid Operations also facilitates fair and open access to the transmission grid for all customers, through administration of the Open Access Transmission Tariff and operation of the wholesale transmission market.

The Field and Grid Operations Key Business Unit consists of seven departments:

- Regional Operations;
- Trouble and Operations Support;
- Non-Integrated Areas;
- Construction Services;
- Real Time Operations;
- Smart Technology Operations and Restoration; and
- Office of the Vice President of Field and Grid Operations.

The operating costs and FTEs for the seven departments in Field and Grid Operations are shown on Table 5-19 and Table 5-20 below.

Table 5-19 Field and Grid Operations Operating Costs

	($ million)	F2015 RRA	F2015 Actual	F2016 RRA	F2016 Actual	F2017 Plan	F2018 Plan	F2019 Plan
		1	2	3	4	5	6	7
1	Regional Operations	37.5	39.7	37.6	40.4	40.2	40.7	41.3
2	Trouble and Operations Support	36.9	38.1	36.4	35.9	37.6	37.7	37.8
3	Non-Integrated Areas	11.0	10.9	11.0	10.6	11.1	11.1	11.2
4	Construction Services	14.3	12.5	14.3	12.3	13.5	13.7	13.9
5	Real Time Operations	30.3	28.7	30.3	31.7	31.5	32.0	32.6
6	Smart Technology Operations and Restoration	6.6	7.6	6.6	8.1	11.3	11.4	11.6
7	Office of the Vice President Field and Grid Operations	1.5	1.4	1.5	1.0	1.2	1.2	1.2
	Total	138.0	138.8	137.7	140.1	146.4	147.9	149.6

Field and Grid Operations executes the maintenance and capital work orders issued by other Key Business Units and charges into the work programs, where applicable, its labour costs, contractor invoices and material costs.

Table 5-20 Field and Grid Operations FTEs

	(FTEs)	F2015 RRA	F2015 Actual	F2016 RRA	F2016 Actual	F2017 Plan	F2018 Plan	F2019 Plan
		1	2	3	4	5	6	7
1	Regional Operations	1,000	977	1,000	966	1,012	1,012	1,012
2	Trouble and Operations Support	110	86	110	88	95	95	95
3	Non-Integrated Areas	58	55	58	57	57	57	57
4	Construction Services	478	521	478	454	404	404	404
5	Real Time Operations	148	146	148	140	137	137	137
6	Smart Technology Operations and Restoration	105	93	109	102	109	109	109
7	Office of the Vice President Field and Grid Operations	5	3	5	2	2	2	2
8	Total	1,903	1,881	1,907	1,809	1,817	1,817	1,817

Recruiting and retaining qualified workers in some specialized trades continues to be a challenge. Field and Grid Operations and Human Resources are addressing these challenges in a number of ways as discussed in BC Hydro's Workforce Plan Appendix F.

Operating Costs and FTE changes over the test period are explained in section 5.5.3.8.

One of the key focus areas of the Field and Grid Operations Key Business Unit is supporting implementation of BC Hydro's safety vision and goals (section 5.7.6) by:

- Implementing the Learning Plans for Frontline Leaders developed to improve the quality of supervision of front-line managers and crew leaders. The Learning Plans for Frontline Leaders provide a road map for front-line leaders to develop and prioritize their professional development by identifying the knowledge and skills they need for effective management and safe decision making in four key areas: Safety, Technical, Management and People;
- Adding front-line supervisors, skilled trades and support staff where insufficient resources might be impacting employee and contractor safety;
- Collaborating with both the Safety department and the Training, Development and Generation Business Group to update the Safety Practice Regulations to

make it easier for employees and contractors to identify the critical information they need to ensure their safety;

- Improving the timeliness and quality of information used by senior managers to evaluate the effectiveness of and compliance with job pplanning and job observation requirements; and
- Improving employee and contractor engagement to create a culture where all workers identify and resolve issues that could lead to safety incidents. We will engage employees and, as appropriate, contractors, to strengthen our safety culture through and not limited to: tailboards; Safe Work Observations; job planning; safety conference calls; incident investigations; near miss incident reporting; and Joint Health and Safety Committees.

5.5.3.1 Regional Operations

Regional Operations is responsible for all regional stations, distribution and transmission crews, and is organized into two groups. The first group is Distribution and Stations Operations which is further organized in five regions – Lower Mainland North, Lower Mainland South, Vancouver Island, North Interior and South Interior. The second group is Transmission Line Operations.

Distribution and Stations Operations manages the operating, maintenance and some construction activities on approximately 56,000 km of distribution lines. Distribution and Stations Operations is responsible for emergency response and restoration of the system, including routine and major storm damage to the system; construction of customer connections; and improvement and routine maintenance of the system. Power line technicians are the largest trade within this group. Other trades include electricians, cable splicers, communication protection and control technicians, and line truck operators.

Distribution and Stations Operations also provides inspection, maintenance, and outage response services to approximately 400 indoor and outdoor substations and telecommunication sites. This group is comprised predominantly of communication protection and control technicians and electricians.

Transmission Line Operations manages the operating, maintenance and some construction activities on approximately 18,000 km of overhead, underground, and submarine transmission lines operating at 60 kV or higher, as well as the underground distribution lines. Maintenance work includes visual inspections, testing, repair, and replacement of transmission and distribution underground equipment. The group is comprised predominantly of power line technicians, line truck operators, cable splicers, and technologists.

5.5.3.2 Trouble and Operations Support

Trouble and Operations Support is a group within Field and Grid Operations that has responsibility for three major areas: Trouble Response, Storm Response, and Support Services.

- **Trouble Response** – management, oversight, and continuous improvement of day-to-day outage restoration;
- **Storm Response** – management, oversight, and continuous improvement of restoration of outages associated with major storms; and
- **Support Services** – consists of three functional groups that support BC Hydro Operations Business Units:
  - Aircraft Operations - manage the risks that are present in helicopter use;
  - Operational Cost Recovery - recover costs arising from third-party damages to BC Hydro assets; and
  - Processing Center – planned outage notifications, centralized administration for International Brotherhood of Electrical Workers work and work order closing.

5.5.3.3 Non-Integrated Areas

Non-Integrated Areas is responsible for the generation and distribution of electricity in 18 small communities that are not connected to the integrated system. Electricity generated for these communities is supplied by local BC Hydro-owned diesel generating sources or by local hydro generating sources that are owned and operated by BC Hydro or IPPs.

5.5.3.4 Construction Services

Construction Services provides a range of construction services supporting the capital replacement, maintenance and capital expansion of transmission, distribution, station, and generation assets. The group is made up of full time managers, and International Brotherhood of Electrical Workers crew leaders, supporting a scalable workforce of approximately 300 International Brotherhood of Electrical Workers full time temporary trade employees. Construction Services contributes to the objectives of BC Hydro by delivering an integrated bundle of services with on-demand skilled construction trades including power line technicians, electricians, general trades, winders, and equipment operators. They also provide specialized asbestos abatement services for the energized environment.

In addition to increasing BC Hydro's operational flexibility, Construction Services adds value and reduces risk to BC Hydro by:

- Quickly deploying resources in response to urgent and emergent work;
- Providing solutions to complex, multi-disciplinary projects, particularly when safety challenges exists or when the construction risk cannot be transferred to contractors;
- Using First Nations contracted services and labour to support Construction Services projects, and
- Providing timely access to scarce, skilled trades (e.g., winders and specialized civil).

5.5.3.5 *Real Time Operations*

The Real Time Operations department is responsible for managing the real time operation of the BC Hydro generation, transmission and distribution systems through operation of the System Control Centres utilizing the Energy Management System. Real Time Operations also facilitates fair and open access to the transmission grid for all customers, through administration of the Open Access Transmission Tariff and operation of the wholesale transmission market.

Real Time Operations is composed of four groups described below.

- ***Operations Planning***

  The Operations Planning group studies and plans the operation of the electrical grid and coordinates operations with other utilities connected to BC Hydro. This involves examining the impact of planned outages of generation and transmission facilities, the addition of new facilities, and undertaking seasonal studies to ensure that the appropriate contingency analysis has been performed and that operating staff are prepared to manage the grid each day. This group is also responsible for supporting compliance with the North America Electric Reliability Corporation Transmission Operations Standards. The core staff are power system engineers, one of whom is stationed in the control room to provide engineering advice to operators.

- ***System Control and Outage Scheduling***

  The System Control and Outage Scheduling group controls and monitors in real time more than 18,000 kilometers of transmission circuits and associated substations, over 20 generating plants and over 56,000 kilometers of distribution circuits all from the Fraser Valley Control Centre and the Southern Interior Control Centre. The control centres dispatch generation, restore service when faults occur on the power system and provide normal monitoring and controlling of equipment for maintenance and operating purposes. The function is performed 24 hours per day, every day of the year.

This group also performs the outage scheduling function which ensures coordination amongst the planned outages of generation, transmission, and distribution facilities that are necessary for maintenance and for the commissioning of new facilities.

- ***Real Time Systems***

  The Real Time Systems group supports the Energy Management System and Supervisory Control and Data Acquisition systems, used for electric system monitoring and control by Real Time Operations. The group is also responsible for compliance with the North American Electric Reliability Corporation Critical Infrastructure Protection Standards as they apply to the Energy Management System and Supervisory Control and Data Acquisition systems. The staff in this group provides onsite support to the control room during business hours and on call support at all other times.

- ***Market Policy and Operations***

  The Market Policy and Operations department is the point of contact for BC Hydro's Open Access Transmission Tariff customers and is responsible for wholesale transmission market policies, contracts, the Open Access Transmission Tariff, and the administration of wholesale transmission services, including transmission pre-scheduling, settlements and billing, revenue reporting and forecasting. The department also develops, executes, and manages the interconnection services and operating agreements with other utilities, generators and customers.

5.5.3.6 Smart Technology Operations and Restoration

Smart Technology Operations and Restoration is responsible for operating BC Hydro's telecommunications and smart metering networks, as well as provincial metering and restoration activities on the transmission and distribution systems.

Smart Technology Operations and Restoration was formed as a result of an amalgamation between existing operational and program groups with Transmission, Distribution and Customer Service along with the transitioning of the smart metering program from installation to operation. The smart metering program has been operationalized and the responsibility for operations, maintenance and support of the smart metering information technology systems are a part of this department.

Smart Technology Operations and Restoration is comprised of the following departments:

- Provincial Metering Operations maintains the Meter Shop facility and provides testing as well as field activity such as installations and replacements;
- Field Device Operations is responsible for the day-to-day operation of the smart metering system. The group is responsible for meter data collection, smart metering device operations and network operations for close to 2 million end-points devices;
- Operations Program Office works closely with the Technology Group to deliver operational technology solutions to support the safe, reliable and efficient operations of BC Hydro's bulk electricity system;
- Restoration Centre provides support for power system restoration activities. The team dispatches field crews based on information from various systems including customer calls, smart meter information and other source systems in order to respond to customer outages; and
- Transmission Network Operations is responsible for the telecommunications in support of critical infrastructure throughout the BC Hydro electrical system. The network is an integral part of the grid, providing system protection, visibility and control to the system control centre.

5.5.3.7 Office of the Vice President of Field and Grid Operations

The Office of the VP of Field and Grid Operations is responsible for setting strategic direction for Field and Grid Operations and providing executive leadership.

5.5.3.8 Three-Year Operating Cost and FTE Summary

Differences are discussed in reference to Table 5-16, Table 5-18, Table 5-19 and Table 5-20.

Field and Grid Operation's net operating expenditures increase in fiscal 2017 by $8.7 million from fiscal 2016 Plan, by a further $1.5 million in fiscal 2018 and by $1.7 million in fiscal 2019. The increases for fiscal 2017 are described below while the increases for fiscal 2018 and fiscal 2019 relate primarily to Standard Labour Rate increases.

In Regional Operations there is a decrease in the reconnect/disconnect work program of $1.1 million as a result of the implementation of the Smart Metering and Infrastructure Program resulting in the reduction of manual reconnect/disconnect work. This is offset by an increase of $2.7 million relating to Standard Labour Rate increases, a change in the labour mix, as well as an increase in tool testing costs of $0.6 million and other minor cost increases.

In Trouble and Operations Support there is an increase of $1.2 million due to an increase in storm response costs of $2.8 million. This increase is based on the average of the most recent five normal weather years, consistent with past practice. This is partially offset by a transfer of $1.3 million to the vegetation trouble maintenance program in Asset Management and Distribution Engineering (section 5.5.4.8) and $0.3 million in outage management savings with the implementation of the Smart Metering and Infrastructure Program.

In Real Time Operations there is an increase in Western Electricity Coordinating Council and Peak Reliability annual fees of $2.4 million. BC Hydro has been a member of the Western Electricity Coordinating Council and its predecessor organizations since 1967 and actively participates with other members to develop reliability standards and coordinate operating and planning activities. Peak Reliability is the organization responsible for complying with the North American Electric Reliability Corporation standards associated with the Reliability Coordinator function in the Western Interconnection and was established in 2014 by separating this functional role from the Western Electricity Coordinating Council. The increase in cost is due partially to Peak Reliability's bifurcation from Western Electricity Coordinating Council and the impact of U.S. exchange rates. This increase is partially offset by a transfer of $0.9 million to Asset Management and Distribution Engineering for the Duck Lake Wheeling Agreement between BC Hydro and FortisBC.

Smart Technology Operations and Restoration increase relates to Smart Metering and Infrastructure sustainment cost of $3.1 million which was previously charged to the regulatory account (refer to section 5.3.1.1 for more information). With the completion of the Smart Metering and Infrastructure project in fiscal 2016, and operationalization of the program, Field and Grid Operations is responsible for the daily operation of the smart metering system. There is also $1.8 million increase for system maintenance, support and licensing fee costs in operating technology systems used for electric system monitoring, protection and control as well as Standard Labour Rate increases.

From fiscal 2016 actual FTEs to fiscal 2017 Plan there is an increase of eight FTEs with no change in fiscal 2018 and fiscal 2019. In Regional Operations there is an increase of 46 FTEs due to the return of employees that worked on the Interior to Lower Mainland Project from Construction Services and vacancies to be filled in fiscal 2017. Also as part of the return of employees working on the Interior to Lower Mainland Project, there is a decrease in Construction Services International Brotherhood of Electrical Workers employees of 50 FTEs. There is an increase of seven FTEs in Trouble and Operations Support mainly due to filling of vacancies. There is a decrease of three FTEs in Real Time Operations due to attrition and the

BC Hydro reorganization. In Smart Technology Operations and Restoration there is an increase of seven FTEs due to the transfer in of key resources from the Smart Metering and Infrastructure Program.

5.5.4 Asset Management and Distribution Engineering

Asset Management and Distribution Engineering is responsible for the planning and management of the transmission and distribution system assets to ensure the safe, reliable and cost-effective delivery of power. Specifically, Asset Management and Distribution Engineering is responsible for developing capital and maintenance plans for the transmission and distribution system stemming from growth and sustainment needs.

Asset Management and Distribution Engineering has asset management practices in place for the development of capital and maintenance plans. These asset management practices cover integrated planning, risk management, portfolio and program development and prioritization, performance evaluation and structured decision-making processes. An external review of asset management practices in Asset Management and Distribution Engineering was conducted in 2013 and concluded that practices were forward looking and among the leaders in the industry. Asset Management and Distribution Engineering is improving its asset management practices in a number of areas including the ongoing updating of policies and strategies; strengthening communication and consultation across the organization; improving asset information management; and strengthening safety considerations during the asset planning stage. Asset Management and Distribution Engineering also has a variety of other initiatives that will improve the asset management practices, such as increasing the use of Smart Meter Infrastructure data for asset planning purposes, streamlining the tools for the use of the Asset Health Index that describes the condition of assets, and improving asset data quality.

Asset Management and Distribution Engineering is comprised of seven departments as follows:

- Distribution Planning and Reliability;
- Distribution Engineering and Standards;
- Transmission and Stations Planning;
- Asset Sustainment;
- Interconnections and Shared Assets;
- Resource Strategy and Management; and
- Office of the Vice President Asset Management and Distribution Engineering.

The operating costs for the seven Asset Management and Distribution Engineering departments noted above are shown in line 1 of Table 5-21 and the changes during the test period are explained in section 5.5.4.8. Lines 2 and 3 of Table 5-21 show the maintenance costs that the Field and Grid Operations and Program and Contract Management Key Business Units charge to Asset Management and Distribution Engineering and that are not included in the costs of those Key Business Units. Other costs in line 4 primarily relate to costs for managing secondary revenue, house moves, temporary connections and cover ups (i.e., when a customer is working close to a power line, a power line technician is required on site to ensure the site is safe and may cover up the line to ensure safety). These costs are offset by revenue collected from customers for these services.

The maintenance costs are described in section 5.5.9.

Table 5-21 Asset Management and Distribution Engineering Operating Costs

	($ million)	F2015 RRA	F2015 Actual	F2016 RRA	F2016 Actual	F2017 Plan	F2018 Plan	F2019 Plan
		1	2	3	4	5	6	7
1	Asset Management and Distribution Engineering Department Costs	41.6	44.9	41.9	43.8	43.7	44.2	44.8
2	Transmission Maintenance	64.2	66.6	62.3	61.6	63.3	63.3	62.6
3	Distribution Maintenance	43.7	45.9	43.3	43.9	46.6	46.6	46.3
4	Other Costs	3.3	4.9	4.2	5.8	4.5	4.5	4.4
5	Total	152.8	162.3	151.7	155.1	158.1	158.6	158.1

5.5.4.1 Distribution Planning and Reliability

Distribution Planning and Reliability develops strategies and plans for the distribution system to accommodate load growth and new distributed energy resource interconnections, and to manage the reliability and integrity of the system. This involves setting planning criteria and strategies, and the development of short and long term system plans. Proposed connections of distributed energy resources are carefully evaluated to ensure that system operation and safety are not compromised, identified risks are mitigated, and necessary distribution system upgrades are identified and implemented. This department also manages BC Hydro’s revenue metering system by planning the supply, testing, and maintenance of BC Hydro’s revenue meters to ensure accurate customer energy metering and compliance with Measurement Canada’s revenue metering requirements. Compliance with Measurement Canada regulations is required to maintain electricity seller status in the Canadian electricity market. In addition, the department provides business and reliability performance analysis and reporting, asset condition assessments and corresponding data management, as well as facilitating and disseminating reliability studies and surveys.

5.5.4.2 Distribution Engineering and Standards

The Distribution Engineering and Standards department has overall engineering accountability for all distribution work performed on the BC Hydro system. This department provides services and expertise to the Program and Contract Management Key Business Unit, the Capital Infrastructure Project Delivery Business

Group, Customer Service and Distribution Design Key Business Unit, Field and Grid Operations Key Business Unit, and partners within the Asset Management and Distribution Engineering Key Business Unit to support BC Hydro's distribution electrical infrastructure. These services and expertise include engineering, design, estimating, standards, specifications and operations support.

Distribution Engineering and Standards also provides review and technical oversight of all work from service providers to ensure the externally designed and built infrastructure meets BC Hydro's Technical Standards, safety requirements, and standards of quality.

5.5.4.3 Transmission and Stations Planning

Transmission and Stations Planning plans the long term growth of the transmission system, including substations and the connections of new transmission load and generation customers. This involves defining reliability requirements by establishing a planning methodology and criteria; forecasting and planning for investments to address growth; and conducting planning studies associated with new transmission load and generators connecting to the transmission system as well as Point-to-Point service requests.

The Transmission and Stations Planning department also monitors and improves performance of the existing grid through short-term planning to determine operational limits and to solve system operational problems. To conduct the planning studies, Transmission and Stations Planning manages all data for power system modelling and analysis, and maintains specialized and custom technology applications needed to undertake the planning processes. This department interacts with neighboring utilities on planning issues related to the interties and facilitates discussion on behalf of BC Hydro customers.

5.5.4.4 Asset Sustainment

Asset Sustainment develops the asset strategies, standards and plans to inspect, maintain, repair and undertake the end-of-life replacements of transmission, substation and distribution system assets to optimize asset lifecycle costs. This requires an understanding of system operation, asset performance, asset condition, risk and business support systems. This department also develops the strategies, standards and plans to inspect and maintain vegetation and hazard trees on transmission line rights of way, distribution line corridors and substations.

5.5.4.5 Interconnections and Shared Assets

The Interconnections and Shared Assets department manages customer requests to interconnect, supply or receive electrical services from the transmission and distribution system. Types of interconnection requests include generators, transmission loads and major distribution loads (defined as loads with greater than 5 megavolt amperes and/or $1 million in interconnection costs). Activities include managing interconnection tariffs; developing and applying interconnection policies; and managing interconnection queues, processes and agreements. The department also manages initial and ongoing customer life-cycle relationships and commitments while ensuring compliance with all tariff requirements, interconnection agreement obligations and system technical needs. Third-party requests to relocate BC Hydro transmission and distribution infrastructure are also managed by this department.

The Interconnections and Shared Assets department also manages the joint ownership and use agreement with Telus (co-owner of 80 per cent of distribution poles) and third-party co-location requests which generate additional revenue by leveraging existing transmission and distribution infrastructure. Examples of this include facilitating attachments to poles of cables and antennae telecommunication carriers. This includes activities such as establishing contractual agreements, managing agreements and billings, conducting contract compliance reviews and working with other groups within BC Hydro to deliver on contractual obligations and resolve issues that arise. The department also ensures the effective operation of the BC Hydro system is not compromised by the co-location of third-party assets.

The interconnection of residential and small commercial load customers on the distribution system is managed by the Distribution Design and Customer Connections department within Customer Service and Distribution Design Key Business Unit, as discussed in section 5.5.6.2.

5.5.4.6 Resource Strategy and Management

Resource Strategy and Management is accountable for forecasting Transmission, Distribution and Customer Service labour and equipment resource demand and assessing any risk to the capital and operating and maintenance plans. The department also facilitates the development of mitigating strategies for these risks. In so doing, Resource Strategy and Management balances two objectives: ensuring there is sufficient labour and equipment to execute planned work, and ensuring that the planned use of resources optimizes overall productivity, safety, and quality over both the short and long term. Resource Strategy and Management is an important partner in the development and execution of BC Hydro's Workforce Plan.

5.5.4.7 Office of the Vice President, Asset Management and Distribution Engineering

The Office of the Vice President, Asset Management and Distribution Engineering is responsible for setting strategic direction for transmission and distribution assets and plans, as well as providing executive leadership. The Office also includes the Asset Investment Optimization group, which ensures transmission and distribution asset investment decisions are optimized by balancing risk with financial and human resource constraints. The group ensures the capital work plans meet the strategic direction and objectives of BC Hydro through the use of a common approach to planning and prioritizing investments in the Asset Management and Distribution Engineering Key Business Unit.

5.5.4.8 Three-Year Operating Cost and FTE Summary

Differences are discussed in reference to Table 5-16, Table 5-18, and Table 5-21.

Asset Management and Distribution Engineering's net operating costs increase by $6.4 million from fiscal 2016 Plan to fiscal 2017, then remain relatively constant for fiscal 2018 and fiscal 2019. Of the total increase in fiscal 2017, $4.5 million relates to an increase in maintenance expenditures which is primarily due to additional funding of $1.0 million for vegetation maintenance ($0.8 million for transmission vegetation and $0.2 million for distribution vegetation), a transfer of $1.3 million from Trouble and Operations Support in Field and Grid Operations to vegetation maintenance for trouble maintenance, $1.1 million in additional meter maintenance related to the operationalization of the Smart Metering and Infrastructure Program, and $0.7 million mainly due to increases in inspections. These changes are explained in more detail as part of the maintenance year over year analysis in section 5.5.9.

The remaining $1.9 million is primarily due to:

- A transfer of $0.9 million from Field and Grid Operations to Transmission and Stations Planning for the Duck Lake Wheeling Agreement with FortisBC Inc.;
- $1.2 million to fund positions that were vacant when the fiscal 2016 Plan was developed and were not included in the plan, and were subsequently filled and included in the fiscal 2017 plan; and
- Standard Labour Rate increases.

The above increases are partially offset by the transfer of the underground locate team from Distribution Engineering to Customer Service, workforce reductions, and a reduction in membership fees.

There is an overall decrease of eight FTEs in Asset and Investment Management from fiscal 2016 actual FTEs to fiscal 2017 Plan. This decrease is primarily due to the transfer of the Underground Locate team from Distribution Engineering and Standards to Customer Service and Distribution Design and workforce reductions of two in Distribution Planning and Reliability. There is no anticipated FTE change in fiscal 2018 and fiscal 2019.

5.5.5 Program and Contract Management

Program and Contract Management is responsible for the project delivery (through project managing or overseeing the external project management) of capital work programs and maintenance work programs on the Transmission and Distribution systems, as well as smaller scale system improvement and customer driven projects on the Distribution system. These programs and projects are managed within five departments:

- Distribution Program Delivery;
- Distribution Project Delivery;
- Transmission Program Delivery;
- Vegetation and Access Management; and
- Contract Management.

Program and Contract Management manages large volumes of electrical equipment inspections, maintenance and replacements and measures delivery success on a cost per unit basis and work completion to unit completion targets with a focus on safety, environment, efficiency, risk management and quality.

5.5.5.1 Distribution Program Delivery

Distribution Program Delivery is responsible for the management of electrical equipment maintenance and replacement delivery programs for distribution electrical equipment which includes the conductor lines, underground cables, and support structures such as wood poles, platforms, concrete poles, and associated equipment.

5.5.5.2 Distribution Project Delivery

Distribution Project Delivery is responsible for the delivery of the capital distribution projects from definition through implementation. The department delivers internally initiated system improvement projects with approximately 300 projects and $100 million annually, which includes growth projects to provide increased system capacity and sustainment projects that improve reliability. Also, there are currently around 30 customer initiated projects totaling approximately $15 million annually. Finally, the group delivers interconnection projects for distribution-connected IPPs within project timelines.

5.5.5.3 Transmission Program Delivery

Transmission Program Delivery provides program and project management for the delivery of capital and maintenance programs on transmission infrastructure. This includes the transmission conductor lines, underground and submarine cables, steel towers, wood poles and all facilities within a substation and as well as the telecommunication system.

5.5.5.4 Vegetation and Access Management

Vegetation and Access Management is responsible for the execution of all vegetation and access management on the transmission and distribution systems including:

- Transmission, substation, and distribution vegetation management maintenance programs and right of way access maintenance programs;
- Vegetation management, right-of-way clearing, and access management planning and construction in support of transmission and distribution capital projects;
- Storm response to aid in the removal of vegetation to reduce overall system restoration time; and

- Management of the relationship with, and contract management in respect of, vegetation management and access contractors.

5.5.5.5 Contract Management

The Contract Management department is responsible for contracting work to third-parties to ensure external construction work is completed by engineering, design, line, civil and vegetation contractors.

The department undertakes the following work:

- Contractor evaluation;
- Work allocation;
- Work delivery;
- Quality assurance and performance management; and
- Transaction, information and document management.

5.5.5.6 Three-Year Operating Cost and FTE Summary

Differences are discussed in reference to Table 5-16 and Table 5-18.

Operating expenditures in the Program and Contract Management group are increasing during the three year test period by $0.7 million in fiscal 2017 from fiscal 2016 Plan, an additional $0.2 million in fiscal 2018, and an additional $0.2 million in fiscal 2019. In fiscal 2017 $0.5 million of the increase is due to FTE additions under the Workforce Optimization Program as contractors are being replaced with employees to manage work programs and reduce overall capital costs. The other $0.2 million increase in each of the three years relates to Standard Labour Rate increases.

FTEs in the Program and Contract Management Key Business Unit are increasing by 22 in fiscal 2017 from fiscal 2016 actual FTEs, and a further four in fiscal 2018.

The increases relate to Workforce Optimization as contractors are being replaced with employees to manage work programs and reduce overall capital costs.

5.5.6 Customer Service and Distribution Design

In fiscal 2016, BC Hydro amalgamated the Customer Service and Distribution Design groups to provide a single focused organization responsible for customer-facing activities. Customer Service and Distribution Design Key Business Unit provide the following functions:

- Designs new residential and small commercial distribution customer connections and other distribution work programs;
- Manages the revenue cycle, including rate administration, billing, payments, and collections;
- Manages the customer contact channels, including call centres, online self-service, key accounts, and claims;
- Leads cross-organizational initiatives to make it easy for customers to do business with us, and provide consistent customer experience across different channels and customer groups;
- Engages with customers in support of BC Hydro's demand-side management objectives;
- Investigates potential electricity theft and pursues recovery of lost revenues; and
- Develops models and analyzes data for purposes such as load forecasting, customer segmentation, and theft detection.

During the test period, operational cost pressures are expected in the following areas:

- Overall costs for revenue cycle and call centre operations will increase with customer growth, as a result of increasing volumes. Cost increases will be offset by a reduction in manual meter reading costs and increased participation in electronic billing reducing postage and printing costs;
- Postage and print costs continue to increase in excess of the rate of inflation; and
- Bad debts are expected to increase as a result of a formula output which takes into account customer growth and an increase in general rates.

The operating cost and FTE requirements are shown in the operating cost and FTE tables in section 5.5.2 and explained below.

Customer Service and Distribution Design will provide resources for a number of key initiatives that fall under BC Hydro's company-wide priority of making it easy for customers to do business with us, such as:

- Strengthening BC Hydro's customer service foundation:
  - Continue to operationalize Smart Metering and Infrastructure intelligence and capabilities to support business planning and network management;
  - Integrate and realign customer service channels to reduce telephone wait times, inconsistent service, impacts of planned outages, high bill complaints, and to improve bill presentation leading to an overall improvement in customer experience; and
  - Implement improved services for larger, more complex customers not served by Key Accounts (e.g., small municipalities, property management firms).
- Shape a customer-centric culture:
  - Increase emphasis on customers across the organization; and

- ▶ Measure customer experience through an integrated customer performance metrics.
- Proactively build for tomorrow:
  - ▶ Expand the public access to electric vehicle charging infrastructure facilitating future adoption of emission free transportation;
  - ▶ Continue investment into building a single customer system of record where all customer interactions are recorded and accessible within a comprehensive view; and
  - ▶ Further expand customer service channels to take advantage of emerging capabilities in Apps, social media and other digital forms, growing BC Hydro's ability to meet the changing needs of our customers

5.5.6.1 Customer Service

Customer Service is part of Customer Service and Distribution Design and is comprised of four departments as follows:

- Customer Analytics, Revenue and Risk Management;
- Customer Service Operations;
- Customer Strategy Delivery and Partnerships; and
- Key Account Management.

Customer Analytics, Revenue and Risk Management

Customer Analytics, Revenue and Risk Management is responsible for the reduction of electricity theft and other non-theft revenue leakage through Distribution System Metering and business intelligence tools inclusive of Smart Meter Infrastructure and an enhanced field inspection team. This department also includes the load analysis function, which organizes and manages historical energy and billing data, undertakes residential customer end-use sampling, and performs specialized analysis to provide hourly load profiling and localized consumption data. This business intelligence is used throughout BC Hydro for purposes such as the development of BC Hydro's load forecast, analytical support for creation of Transmission, Distribution and Customer Service distribution plans, development of demand-side management initiatives, review of the Electric Tariff and rates, and development of operational policies and business practices.

Customer Service Operations

Customer Service Operations is responsible for day-to-day management of core customer services processes including the revenue cycle (billing, payments, and collections) and customer contact channels (primary call centre, MyHydro web portal, escalations and enhanced services). The group also manages manual meter reading services (for non-automated meters); rate operations (Electric Tariff application; Transmission Service Stepped Rate; Large/Medium General Service Rates), claims investigation and resolution, and the Underground Locate Centre (part of the BC One Call organization). These services are provided through a partnership of internal and external resources, including Accenture Business Services.

Customer Strategy Delivery and Partnerships

Customer Strategy Delivery and Partnerships provides planning and management of the Customer Strategy initiatives delivery, as well as governance of BC Hydro's outsourcing agreement with Accenture Business Services[46]. This team creates and manages key customer metrics.

Key Account Management

Key Account Management is the single point of contact for BC Hydro's largest customers and is responsible for working with these transmission, large commercial

[46] The current outsourcing contract with Accenture Business Services expires on April 30, 2018.

and institutional customers, government agencies, municipalities and communities to identify and take advantage of energy conservation opportunities. In addition, this group is responsible for the ongoing relationship management of these large customer accounts which includes responding to billing and rate inquiries, dispute resolution, outage notification and scheduling, and facilitating load interconnections.

Key Account Managers interact with approximately 750 customers, which total 59,000 accounts and consume half of BC Hydro's domestic energy sales. These customers also comprise approximately half of the energy savings forecast within demand-side management programs.

5.5.6.2 Distribution Design and Customer Connections

The Distribution Design and Customer Connection part of Customer Service and Distribution Design is organized as a single department.

Distribution Design and Customer Connections supports the electrical connection of residential and small commercial customers, and provides design and technical services for other distribution system work programs, including system improvement, maintenance and end of life asset replacement projects. The customer connection work includes: the planning, design, and project coordination for complex connections to BC Hydro's distribution system; responding to over 35,000 customer requests each year for simple new service connections, upgrades, and service disconnects; and supporting customers and developers in the design and construction of underground residential distribution electrical infrastructure through BC Hydro approved professional electrical engineering firms. These functions are performed by design staff located in facilities throughout the province, as well as in centralized Express Connect operations centres.

5.5.6.3 Three-Year Operating Cost and FTE Summary

Differences are discussed in reference to Table 5-16 and Table 5-18.

Customer Service and Distribution Design operating costs are planned to decrease by $2.1 million in fiscal 2017 compared to fiscal 2016 Plan, then decrease by a further $2.3 million in fiscal 2018 and increase by $0.5 million in fiscal 2019. The differences are described below.

Customer Service operating costs are planned to decrease by $0.6 million in fiscal 2017 compared to fiscal 2016 Plan. This is due to Smart Metering and Infrastructure savings related to reduced manual meter reading costs of $10.7 million, partially offset by $5.4 million of operationalized Smart Metering and Infrastructure sustainment costs related to energy diversion, theft, and field investigations. Other cost increases are for postage and printing of $1.0 million as a direct result of Canada Post rate increases, forecasted bad debt expense increase of $1.0 million primarily as a result of a formula output which takes into account customer growth and increased revenue, and one-time funding of $1.5 million for various customer focused initiatives, as described in section 5.5.6. Additionally, the transfer of the Underground Locate team from Distribution Engineering in Asset Management and Distribution Engineering to Customer Service results in the transfer of $1.0 million to Customer Service operating costs.

Customer Service operating costs are planned to decrease by $2.6 million in fiscal 2018 compared to fiscal 2017. The decrease is primarily due to the reduction of the one-time funding for customer focused initiatives of $1.5 million and further reductions in manual meter reading costs of $1.2 million by reducing the number of meters that are unable to connect to the smart metering network, partially offset by Standard Labour Rate increases. There is a slight increase in fiscal 2019 compared to fiscal 2018 of $0.2 million mainly due to Standard Labour Rate increases.

Distribution Design operating costs are planned to decrease by $1.5 million in fiscal 2017 compared to fiscal 2016 Plan. This decrease is primarily due to a $4.9 million reduction in operating costs resulting from direct charging the Distribution Design labour costs to the capital program rather than allocating through the capital overhead model across all distribution capital projects. This change more accurately captures the labour effort and costs associated with the specific capital program and projects the group supports. The above decrease is partially offset by $2.8 million to fund positions that were vacant when the fiscal 2016 Plan was developed and were not included in the plan. Subsequently, they have been filled and are included in the fiscal 2017 plan, and $0.6 million due to Standard Labour Rate increases. There is a slight increase of $0.3 million in operating costs from the fiscal 2017 to fiscal 2018 and $0.4 million from fiscal 2018 to fiscal 2019 primarily due to Standard Labour Rate increases.

Customer Service and Distribution Design FTEs are planned to increase by 11 in the fiscal 2017 Plan compared to fiscal 2016 Actual FTEs and will remain constant thereafter. The increase in Customer Service is eight FTEs in fiscal 2017 primarily due a transfer of two from Smart Metering and Infrastructure related to operationalization of the project, an increase of eight related to supporting the Customer Strategy and four FTEs related to the transfer of the underground locate centre where there were eight headcount transferred about halfway through fiscal 2016. These increases are partially offset by a decrease of five FTEs in Key Account Management due to changes to demand side management programs discussed further in Chapter 10.

Distribution Design FTEs are planned to increase by three in fiscal 2017 compared to fiscal 2016 actual FTEs, and will remain constant in fiscal 2018 and fiscal 2019. Two of these additions are graduate trade trainee FTEs.

5.5.7 Technology Group

The Technology Group is responsible for the planning, design, delivery, operations, support and management of BC Hydro’s information and telecommunications technologies. It is also responsible for the security of data and digital information, records management, as well as digital and physical library assets.

The Technology Group provides the following functions for BC Hydro:

- Business Partner Services;
- Technology Planning and Performance;
- Security and North American Electric Reliability Corporation Critical Infrastructure Protection Compliance Planning;
- Enterprise Application Services;
- Telecommunications and Infrastructure; and
- Project Management Office and Business Management.

The operating costs and FTEs are shown in Table 5-16 and Table 5-18 and the changes during the test period are explained in section 5.5.7.7.

5.5.7.1 Business Partner Services

Technology works directly with BC Hydro business groups to address their technology needs. There are three teams, organized functionally, delivering services to internal business partners in:

- Transmission and Distribution Technology Services Delivery;
- Generation and Site C Technology Services Delivery; and
- Corporate and Customer Technology Services Delivery.

For each technology project, these teams develop statements of objectives, business cases, and help initiate the work, and also ensure business needs and objectives are met. For existing systems and applications, they monitor issues, identify and prioritize enhancements, and oversee sustainment program delivery. This function also provides records management and data access support services for employees.

5.5.7.2 Technology Planning

Technology Planning is an integrated planning and reporting function for the Technology group. It includes activities such as technology plan development, enterprise architecture, capital planning, finance and resource management as well as risk management, business continuity planning, performance reporting and technology regulatory compliance related to North American Electric Reliability Corporation.

5.5.7.3 Security and North American Electric Reliability Corporation Critical Infrastructure Protection Compliance Planning

The Cyber Security and North American Electric Reliability Corporation Critical Infrastructure Protection Compliance Strategy and Planning team provides planning and oversight to ensure the security and integrity of BC Hydro’s business data, customer and employee information, and technical systems. They ensure that cyber security controls and processes align with BC Hydro's Technology and Business solutions, while minimizing risk and cost.

5.5.7.4 Enterprise Application Services

Enterprise Applications Services supports various technology applications that are cross-organizational or used by multiple business groups. Activities include maintaining, sustaining, upgrading and optimizing applications such as financial, procurement and Human Resource systems.

Expenditures include maintenance and sustainment of enterprise-wide and business group applications as well as management and funds for multiple supplier contracts providing application support services.

5.5.7.5 Telecommunications and Infrastructure

Telecommunications and Infrastructure consist of two planning and operations teams:

- Telecommunications Planning and Operations; and

- Infrastructure Planning and Operations.

Telecommunications Planning and Operations provides telecommunications services (e.g., data network and Wi-Fi, telephony, mobility and radio) that enable BC Hydro employees and systems to connect and communicate.

Infrastructure Planning and Operations provides services to employees and contractors including personal computing equipment and mobile devices, networks, central data systems, and facilities (e.g., video conferencing). This includes Cyber Security Planning and Operations and Help Desk and Business Applications.

This team is also responsible for the maintenance and sustainment of software and hardware related to data centers, including disaster recovery sites; personal computing and mobile devices; networks and other telecommunications equipment and systems; and cybersecurity.

5.5.7.6 Project Management Office and Business Management

This function is responsible for overseeing delivery of the technology capital portfolio including defining project management standards, processes and procedures and includes support for technology and cybersecurity capital project delivery. These projects are described in Chapter 6 and Appendices I and J. Operating expenditures related to capital initiatives typically include early stage planning, project identification, analysis of alternatives, requirements analysis, change management, training, and data migration.

The business management function provides vendor and contract management including vendor relationship management, financial management and contract oversight including the managed service provision contracts.

5.5.7.7 Three-Year Operating Cost and FTE Summary

Differences are discussed in reference to Table 5-16 and Table 5-18.

Technology operating costs are planned to increase by $29.4 million in fiscal 2017 compared to fiscal 2016 Plan primarily due to costs related to the Smart Metering and Infrastructure Program for metering and analytics applications and supporting technology, security, network and telecom costs of $25.6 million which were previously deferred while the project was in implementation. Other increased costs in fiscal 2017 compared to fiscal 2016 Plan include capital project investigation costs of $4.0 million, and $1.2 million for additional software maintenance and support costs for new enterprise and business applications, and for existing applications an increased cost of renewals and U.S. currency fluctuations. The increases are partially offset by savings through the Workforce Optimization Program and a budget transfer post re-organization.

Operating costs increase in fiscal 2018 compared to fiscal 2017 by $0.2 million mainly due to Standard Labour Rate increases. There is a reduction in fiscal 2019 compared to fiscal 2018 for capital project investigation costs of $1.0 million with a partially offsetting increase for the change in labour costs of $0.2 million mainly due to Standard Labour Rate increases.

FTEs increase by four across the group from fiscal 2016 actual FTEs compared to fiscal 2017 plan and increase by 15 in fiscal 2018 and 11 in fiscal 2019. These changes relate to the Workforce Optimization Program and will reduce overall capital costs as well as decrease our dependence on contractors to manage capital projects and maintain and support BC Hydro systems.

5.5.8 Transmission, Distribution and Customer Service Business Unit Support

Business Unit Support holds the budget for the Office of the Executive VP Transmission, Distribution and Customer Services and for business group costs that are not specifically related to any single Key Business Unit.

The Office of the Executive VP is responsible for providing strategic direction and leadership for the business group.

The business group costs that are budgeted in Business Unit Support include First Nations community payments in lieu of taxation, exempt materials, as well as business group initiatives such as business process reviews and efficiency projects. These costs are offset in the test period by the savings to be realized through the Transmission, Distribution and Customer Service Efficiency Initiative (refer to section 5.5.1.5 for description) which currently are not allocated to individual Key Business Units.

5.5.8.1 Three-Year Operating Cost and FTE Summary

Differences are discussed in reference to Table 5-16 and Table 5-18.

Business Unit Support costs have decreased by $17.9 million from fiscal 2016 Plan to fiscal 2017 primarily due to $15.0 million of planned savings from the Transmission, Distribution and Customer Service Efficiency Initiative and $3.1 million due to the completion of prior year's efficiency initiatives.

5.5.9 Transmission and Distribution Maintenance Programs

This section describes the maintenance programs for transmission and distribution assets. The different types of maintenance activities are described in section 5.5.9.1. Details of transmission and distribution expenditures are provided in sections 5.5.9.2 and 5.5.9.3 respectively.

Maintenance expenditures are included in the operating plans of the Field and Grid Operations, Asset and Investment Management and Program Contract Management Key Business Units above (sections 5.5.3, 5.5.4 and 5.5.5 respectively). However the maintenance programs are presented below in order to consolidate the information.

5.5.9.1 Types of Transmission and Distribution Maintenance

Transmission and distribution maintenance activities include monitoring, inspection, condition assessment, preventive action, corrective action and the environmental programs and practices used to maintain transmission and distribution corridors, substations and transmission and distribution lines and cables. Maintenance activities are developed using a reliability-centred maintenance methodology to optimize equipment reliability, maintenance cost and outages.

The main types of work performed within the maintenance programs are preventive maintenance, condition based maintenance, and corrective maintenance.

Preventive Maintenance

The majority of preventive maintenance work is planned and scheduled work, including a variety of inspections and condition assessments, such as general and detailed inspections, infrared inspections, and special inspections as required. The frequency of each type of inspection is dictated by the asset criticality, age and component condition in accordance with transmission and distribution maintenance standards. Cycle times between inspections vary by asset class and as a result the inspection work is cyclical and not uniform year over year. Preventive maintenance also includes specific sampling and testing programs, such as the wood pole test and treat program, that verify asset condition and track deterioration of specific key components. Maintenance standards are reviewed on a regular basis to ensure that optimal work is being performed to maintain the assets. The Asset Sustainment department is responsible for updating the transmission and distribution maintenance standards. The Asset Sustainment department is described in section 5.5.4.4 above.

Condition Based Maintenance

The majority of condition based maintenance work consists of annually planned repairs or replacements of defective or damaged components of the transmission and distribution system. Condition based maintenance work is required when a component has experienced damage, wear or decay but has not failed completely. Condition based maintenance is prioritized by considering the component's condition assessment, the component criticality, and due diligence (in accordance with the

BC Hydro's risk framework). Each of these three considerations is analysed to determine whether the work will be done within days, months, or next fiscal year, or whether the component condition will continue to be monitored on a regular basis. The analysis will consider whether the component should be replaced under a sustaining capital program. The condition based work items that require attention within days or months are incorporated and prioritized into the current year's maintenance work plan.

Condition based maintenance expenditures could also include engineering, including specialized geotechnical hazard reviews, design studies, development and improvement of design and maintenance standards, and the maintenance of essential records and drawings related to the transmission and distribution system.

Corrective Maintenance

Corrective maintenance consists of any unplanned repairs or replacements of failed transmission and distribution equipment and systems. As this work is unplanned, it is not specifically identified in the annual work plan and the budget is established based on recent trends. The budget does not include replacement of failed equipment and systems that are capitalized, which occur when the expenditure meets the capitalization rules. Transmission maintenance expenditures greater than $1 million and related to single events such as major equipment failure, extreme weather, wildfires, are recorded in the Non-Heritage Deferral Account, as approved by British Columbia Utilities Commission Order No. G-16-11.

Table 5-22 shows the planned cost of transmission and distribution maintenance activities in the test period by asset type. The expenditures are further detailed in the following sections.

Table 5-22 Maintenance Expenditures - Transmission, Distribution, Non-Integrated Area and Polychlorinated Biphenyls

	($ million)	F2015 RRA	F2015 Actual	F2016 RRA	F2016 Actual	F2017 Plan	F2018 Plan	F2019 Plan
		1	2	3	4	5	6	7
	Maintenance							
1	Transmission Maintenance	64.2	66.6	62.3	61.6	63.3	63.3	62.6
2	Distribution Maintenance	43.7	45.9	43.3	43.9	46.6	46.6	46.3
3	NIA Maintenance	7.4	7.6	7.4	8.2	8.5	8.5	8.5
4	PCB Mitigation	14.0	10.0	13.4	18.0	18.5	16.3	15.3
5	Distribution Emergency Response	30.2	31.9	29.7	29.1	31.3	31.3	31.3
6	**Total Maintenance**	159.5	162.1	156.1	160.9	168.2	165.9	163.9

5.5.9.2 *Transmission Maintenance Programs*

Maintenance expenditures planned on transmission assets are summarized in Table 5-23.

Table 5-23 Transmission Maintenance Expenditures

	($ million)	F2015 RRA	F2015 Actual	F2016 RRA	F2016 Actual	F2017 Plan	F2018 Plan	F2019 Plan
		1	2	3	4	5	6	7
	Transmission System Circuit Maintenance							
1	Transmission Preventive Maintenance	12.7	11.0	12.3	11.7	10.9	10.9	10.9
2	Transmission Condition Based Maintenance	4.1	4.5	4.0	4.0	4.1	4.1	4.1
3	Transmission Corrective Maintenance	1.2	4.3	1.1	2.3	2.5	2.5	2.5
4	**Total Transmission System Circuit Maintenai**	18.0	19.8	17.5	17.9	17.5	17.5	17.5
	Transmission Station Maintenance							
5	Stations Condition Based Maintenance	2.0	3.7	2.0	3.0	2.7	2.8	2.9
6	Stations Corrective Maintenance	9.0	6.0	9.0	6.9	6.7	6.7	6.9
7	Stations Engineering Work	2.0	2.1	2.0	1.8	1.9	1.8	1.9
8	Stations Facilities Maintenance	2.4	5.0	2.4	4.1	4.2	4.3	4.4
9	Stations Preventive Maintenance	10.3	9.2	10.3	10.3	10.4	10.4	9.8
10	**Total Transmission Station Maintenance**	25.7	26.1	25.7	26.1	25.9	25.9	25.9
	Vegetation and ROW Maintenance							
11	Vegetation Edge Tree	2.5	2.2	1.9	1.9	2.3	2.3	2.0
12	Vegetation Pest Management	0.4	0.3	0.4	0.4	0.4	0.4	0.4
13	Vegetation ROW	15.6	16.5	15.2	13.9	15.4	15.4	15.1
14	Vegetation Facilities	0.6	0.5	0.6	0.6	0.7	0.7	0.6
15	ROW and Access	1.4	1.2	1.1	0.9	1.1	1.1	1.1
16	**Total Vegetation and ROW Maintenance**	20.5	20.6	19.1	17.6	19.8	19.8	19.1
17	**Total Transmission Maintenance**	64.2	66.6	62.3	61.6	63.3	63.3	62.6

Transmission System Circuit Maintenance

Transmission circuits carry energy over the distance between generators and load centres. The transmission network has over 18,800 circuit km of lines; approximately

500 km of subterranean and submarine cables; 23,000 lattice steel and steel pole structures and 116,000 wood poles.

Transmission system circuit asset health data are provided in Appendix S.

Annual transmission maintenance expenditures are primarily directed at regularly inspecting and assessing the transmission system, recording defects and performing planned and unplanned repairs. The inspections provide condition assessment and defect information, which is the basis for the short-term and long-term condition based maintenance and capital programs. The inspections also focus on public safety and right-of-way encroachments. All structures are inspected at least once a year.

Total annual transmission system circuit maintenance expenditures over the test period are planned to remain at the fiscal 2016 Plan level. Preventive maintenance expenditures are planned to be lower following the optimization of maintenance intervals while corrective maintenance expenditures are planned to be higher based on recent trends of unplanned repairs and replacements.

Transmission Station Maintenance

The transmission system consists of 306 substations and an integrated enterprise telecommunication system.

Substations are required to link generators and transmission and distribution lines into the electrical grid. Substation infrastructure includes switchgear, circuit breakers, transformers, buswork, series capacitors, reactive support equipment, fencing, land, buildings and protection and control equipment.

The protection and control assets comprise all protective relaying and control systems at the transmission stations. Protection and control assets, together with circuit breakers, protect the energized transmission equipment from being damaged from unplanned electrical events. Protection and control assets also help ensure system stability and electrical service reliability during disturbances, assist in the control of energy flows throughout the electrical grid, ensure electrical safety for employees, contractors and the public, and provide information to control centres via the integrated telecommunication system.

The power system provides information to control centres and the telecommunication system is used to interconnect commercial offices with corporate data services and voice services. The integrated telecommunications system is comprised of several integrated telecommunications systems, including microwave radio, fibre optic, power line carrier, satellite, UHF/VHF radio, WiMAX, and third-party leased line circuits. The telecommunications system also includes ancillary infrastructure components, such as batteries and chargers, diesel generators and fuel tanks, towers and buildings, access roads, bridges, and helipads.

Station asset health data are provided in Appendix S.

Transmission Station Maintenance work is broken down into preventive, corrective and condition based maintenance as well as the following two additional categories:

- Facilities Maintenance encompasses the work required to maintain the station grounds and enclosure, such as fences, cable trenches, janitorial service, landscaping, etc.; and
- Engineering Services provides support in the form of special reports, root cause analysis, and special investigations required to sustain the assets.

Station equipment is maintained to minimize the life cycle cost of the equipment, ensure safe operation, sustain existing reliability and mitigate negative impacts to the environment.

Total annual transmission stations maintenance expenditures are planned to be higher by $0.2 million during the test period compared to fiscal 2016 Plan. The stations facilities maintenance program is higher during the test period due to the addition of new substations to the system and the uniform application of minimum maintenance level for buildings and fences. The condition based maintenance program is also planned to be higher, mainly due to overall aging substations. The increases are offset by lower station corrective work, predominantly due to increased management control and the development of new capital replacement programs to address assets experiencing increasing failure rates.

Transmission Vegetation and Right of Way Maintenance

The overhead transmission lines cover over 79,000 hectares of land in rights-of-way. Transmission corridor vegetation and access management includes both the work required to manage vegetation along the transmission corridors and the work required to maintain access to the transmission corridors. The goal of vegetation management is to ensure employee, contractor and public safety and system reliability at the least possible long-term cost while ensuring compliance with regulatory requirements pertaining to Mandatory Reliability Standards, fish and wildlife, species at risk, environment, wildfire, and herbicide use. Maintenance of approximately 5,000 hectares of rights-of-way per year is required to meet that goal.

Transmission access programs support the work of both vegetation and overhead transmission maintenance by providing access to work sites. This program helps to ensure public and worker safety and environmental protection on roads and related infrastructure that BC Hydro needs and has the responsibility to maintain, while addressing land management objectives set by stakeholder groups.

Transmission and distribution optimizes its vegetation maintenance program by employing integrated vegetation management program strategies which are consistent with the North American Electric Reliability Corporation Transmission Vegetation Management Program standard FAC-003-1. BC Hydro Transmission Vegetation Management Program was audited by North American Electric Reliability Corporation in 2015 and found fully compliant with FAC-003-1. On August 1, 2015, a revised version of the North American Electric Reliability Corporation standard, FAC-003-3 came into force in British Columbia. BC Hydro vegetation maintenance practices are now operating under the provisions of the revised North American Electric Reliability Corporation standard.

Total annual transmission vegetation and right-of-way maintenance expenditures are planned to increase by $0.7 million in fiscal 2017 compared to fiscal 2016 Plan, followed by a $0.7 million decrease from fiscal 2018 to fiscal 2019. The increase is mainly driven by additional edge tree maintenance on a number of circuits, particularly 69 kV and 138 kV circuits on Vancouver Island and the Lower Mainland, which experienced unusual damage during the storms in late August and November 2015 on the south coast.

5.5.9.3 Distribution Maintenance

Distribution maintenance comprises the Distribution Line, Distribution Vegetation, and Distribution Meters Maintenance Programs. The expenditures on these programs are summarized in Table 5-24.

Table 5-24 Distribution Maintenance Expenditures

	($ million)	F2015 RRA	F2015 Actual	F2016 RRA	F2016 Actual	F2017 Plan	F2018 Plan	F2019 Plan
		1	2	3	4	5	6	7
	Distribution Line							
1	Overhead Maintenance	5.2	6.21	5.7	4.8	3.5	3.5	3.5
2	Underground Maintenance	3.1	3.34	3.9	3.4	3.5	3.7	3.7
3	Inspections	5.2	5.14	3.3	4.5	5.8	5.6	5.6
4	Distribution Poles	3.6	3.72	3.3	3.6	3.7	3.7	3.7
5	Street Light Maintenance	0.7	1.55	0.7	1.7	1.1	1.1	1.1
6	**Total Distribution Line**	17.9	20.0	16.9	18.1	17.6	17.6	17.6
	Distribution Vegetation Maintenance							
7	Vegetation	16.7	21.7	20.7	20.5	21.6	21.6	21.3
8	Mountain Pine Beetle	2.7	1.9	0.2	0.0	-	-	-
9	Hazard Tree	3.3	0.3	2.2	3.6	3.1	3.1	3.1
10	**Total Distribution Vegetation Maintenance**	22.7	23.9	23.2	24.1	24.7	24.7	24.5
11	**Distribution Meter Maintenance**	3.2	2.1	3.2	1.8	4.2	4.2	4.2
12	**Total Distribution Maintenance**	43.7	45.9	43.3	43.9	46.6	46.6	46.3

Distribution Line Maintenance

The distribution system has approximately 58,600 km of overhead lines; 5,000 circuit km of underground lines; 900,000 wood poles; 8,000 concrete poles; 278,000 overhead transformers, 91,000 street lights, 60,000 underground transformers and 5,900 manholes.

The Distribution Line Maintenance program is intended to keep the system safe for the public and workers; maintain reliability of the system at intended levels; and ensure that the Distribution Line assets are maintained at lowest cost and reach expected life. Key Distribution Line Maintenance programs include: public safety inspections of the overhead and underground system; inspections and repairs of the overhead and underground distribution system; test and treat inspections of wood pole complete with follow-up detailed inspections and repairs; inspections and repairs of specific distribution equipment such as re-closers; and street light repairs. Distribution asset health data is provided in Appendix S.

Total annual distribution line maintenance expenditures are planned to be higher by $0.7 million during the test period compared to fiscal 2016 Plan. The increase is mainly due to increases in inspections, pole maintenance and street light maintenance needed as the assets on average are getting older. The increase is partially offset by lower overhead and underground condition based maintenance.

Distribution Vegetation Maintenance

This program addresses vegetation affecting overhead distribution lines. The goal of the program is to ensure employee, contractor and public safety and system reliability at the least possible long-term cost.

The Hazard Tree program focuses on preventing trees from falling onto the distribution system and causing power outages and damage. The program deals with off-corridor hazardous trees, including mountain pine beetle infested trees that are dead or dying.

Total annual distribution vegetation maintenance expenditures are planned to increase by $1.5 million in fiscal 2017 compared to fiscal 2016 Plan and then decrease by $0.2 million in fiscal 2019. The increase is mainly due to a cost transfer of $1.3 million from Field and Grid Operation's trouble budget to the vegetation and hazard tree programs.

Distribution Meter Maintenance

BC Hydro must comply with the *Electricity and Gas Inspection Act* administered by Measurement Canada, as well as with Measurement Canada's compliance sampling regulations to maintain a meter tester accreditation. To meet these requirements, BC Hydro has programs to sample and test meters, and exchange failed and time-expired meter groups.

Total annual distribution metering maintenance expenditures are planned to increase by $1.0 million during the test period compared to fiscal 2016 Plan level due to the operationalization of Smart Metering and Infrastructure. The Smart Metering and Infrastructure Program is discussed in section 5.3.1.1.

5.5.9.4 Non-Integrated Area Maintenance Programs

Maintenance work in Non-Integrated Areas consists of routine, scheduled and corrective work at diesel generating stations and Clayton Falls (hydro) generating station. The work includes maintenance of all the systems within the station fence and includes the diesel engine and generator, substation, station fuel system, station control and protection systems. Non-Integrated Area maintenance is summarized in Table 5-25.

Table 5-25 Non-Integrated Area Maintenance Expenditures

	($ million)	F2015 RRA	F2015 Actual	F2016 RRA	F2016 Actual	F2017 Plan	F2018 Plan	F2019 Plan
		1	2	3	4	5	6	7
1	NIA Generation Maintenance	7.4	7.6	7.4	8.2	8.5	8.5	8.5
2	**Total NIA Maintenance**	7.4	7.6	7.4	8.2	8.5	8.5	8.5

Total annual Non-Integrated Area maintenance expenditures are planned to increase by $1.1 million during the test period compared to fiscal 2016 Plan. The increase is due to the addition of new generating stations and additional maintenance activities required at existing stations.

5.5.9.5 Polychlorinated Biphenyls Mitigation

More stringent Federal Polychlorinated Biphenyls regulations were enacted in September 2009 and in response to the changes, BC Hydro conducted an asset condition assessment to mitigate issues related to oil-filled equipment with varying Polychlorinated Biphenyls concentrations. BC Hydro identified actions to detect equipment containing Polychlorinated Biphenyls, to mitigate releases, monitor leaks and prioritize equipment for replacement. The planned activities during the test period will identify (sampling and testing), reduce environmental impact (leak repairs, oil replacement, site remediation) and dispose of Polychlorinated Biphenyls contaminated equipment. Any new oil-filled equipment added to the transmission and distribution systems is required to be Polychlorinated Biphenyls-free. The following Polychlorinated Biphenyls Mitigation expenditures are planned in the test period as shown in Table 5-26 below:

Table 5-26 Polychlorinated Biphenyls Mitigation Expenditures

	($ million)	F2015 RRA	F2015 Actual	F2016 RRA	F2016 Actual	F2017 Plan	F2018 Plan	F2019 Plan
		1	2	3	4	5	6	7
1	PCB Mitigation	14.0	10.0	13.4	18.0	18.5	16.3	15.3

Polychlorinated Biphenyls mitigation gross expenditures in fiscal 2017 are planned to increase by $5.1 million compared to fiscal 2016 Plan largely due to planned increased volumes of Polychlorinated Biphenyls related leak repairs, the purchase of materials to contain equipment during transport and the one-time purchase of purpose-built containment trays. Expenditures in fiscal 2018 are planned to decrease by $2.3 million from fiscal 2017 mainly due to lower planned disposal costs and the completion mid-way through the year of the work to develop a hazardous waste long-term strategy. Expenditures in fiscal 2019 decrease $1.0 million from the fiscal 2018 level largely due to the completion of the hazardous waste long-term strategy during fiscal 2018.

Please refer to Chapter 7, section 7.5.23 for an explanation on Polychlorinated Biphenyls mitigation costs and associated regulatory account balances.

5.5.9.6 Distribution Emergency Response

Transmission, Distribution and Customer Service has three programs related to distribution emergency response maintenance. The first is routine trouble, which is day to day restoration of power outages. The second is storms, which are events causing outages over a large geographic area or affecting a large number of customers, or of extended duration. The third is damage to plant, which are events where a third-party may be liable for the cost of the system repairs. Distribution emergency expenditures are based on historical levels. Expenditures for storms are planned based on the five year average as explained in Chapter 7, section 7.5.2. A summary of the costs are shown in Table 5-27.

Table 5-27 Distribution Emergency Response Maintenance Expenditures

	($ million)	F2015 RRA	F2015 Actual	F2016 RRA	F2016 Actual	F2017 Plan	F2018 Plan	F2019 Plan
	Distribution Emergency Response	1	2	3	4	5	6	7
1	Routine Trouble	25.0	25.4	24.5	22.8	22.4	22.4	22.4
2	Storm	3.9	3.9	3.9	3.9	6.7	6.7	6.7
3	Damage to Plant	1.3	2.6	1.3	2.4	2.3	2.3	2.3
4	**Total**	30.2	31.9	29.7	29.1	31.3	31.3	31.3

BC Hydro and contractor crews respond to about 55,000 dispatched calls per year regarding the distribution system.

Total distribution emergency response expenditures are planned to increase by $1.6 million during the test period compared to fiscal 2016 Plan. The increase is primarily due to $2.8 million higher plan spending for storms and damage to plant, offset by lower historical routine trouble and the $1.3 million transfer of vegetation trouble work to the distribution vegetation maintenance program.

5.5.9.7 Asbestos Management

WorkSafe BC requires that an asbestos management plan be in place for all workplaces that have asbestos containing materials. As asset owners of equipment and infrastructure, Transmission, Distribution and Customer Service is required to: maintain asbestos inventories; conduct asbestos risk assessments; ensure effective identification of friable asbestos; conduct regular formal risk reassessments; and remove or encapsulate all friable asbestos. Transmission, Distribution and Customer Service's more recent asbestos management efforts, initiated in December 2011, cover: transmission and distribution underground infrastructure; station infrastructure and equipment, station buildings, microwave and repeater sites; and in the Non-Integrated Area, plant and substation infrastructure, equipment and buildings. Identification and abatement activities are in progress for each facility group with total plan completion by the end of fiscal 2018.

Please refer to Chapter 7, section 7.5.7 for an explanation on Asbestos costs and associated regulatory account balances.

5.6 Capital Infrastructure Project Delivery Business Group

The Capital Infrastructure Project Delivery Business Group was formed in fiscal 2016 to better manage the size and complexity of BC Hydro's capital program. With the addition of the Site C Clean Energy Project to the overall capital plan, BC Hydro is planning to invest an average of $2.3 billion every year through to the end of the 2013 10 Year Rates Plan.

The Capital Infrastructure Project Delivery Business Group, which is led by the Deputy Chief Executive Officer, is organized into the following Key Business Units:

- Project Delivery;
- Generation and Transmission Engineering;
- Aboriginal Relations;

- Environmental Risk Management;
- Dam Safety;
- Properties;
- Site C Clean Energy Project; and
- Business Unit Support.

The responsibilities, staffing levels and expenditures for these Key Business Units are discussed further below in section 5.6.3 to 5.6.10.

To be successful, BC Hydro needs to be thoughtful, coordinated and disciplined in the delivery of its capital plan. The projects delivered by this group employ a unified and systematic approach based on industry project management practices. Business units with the primary function of supporting the execution of capital infrastructure projects, were assembled into a single business group reporting to the Deputy Chief Executive Officer:

- Formerly separate business units of Generation Project Delivery, Transmission and Distribution Major Projects, and Transmission Programs, into a single business unit;
- Formerly separate business units of Generation Engineering and Transmission Engineering, into a single business unit;
- Aboriginal Relations, responsible for establishing and implementing a corporate wide approach to developing and sustaining long term relationships with First Nations;
- Environmental Risk Management, responsible for eliminating, mitigating or compensating environmental and social risk and impact of projects and operations; and

- Site C Clean Energy Project, responsible for the construction of the $8.3 billion Site C dam and powerhouse by fiscal 2025.

Also included in the Capital Infrastructure Project Delivery Business Group are:

- The Dam Safety Key Business Unit which is responsible for the monitoring of all water retaining and conveyance structures, undertaking periodic comprehensive dam safety reviews, and the identification and prioritization of dam safety issues. The group also initiates and provides technical oversight to dam safety investigations and capital improvement projects when required; and
- The Properties Key Business Unit which is responsible for acquiring and managing property and property rights, reservoir rights and agreements, and managing BC Hydro's headquarters and field offices, to support BC Hydro's electric and non-electric system assets.

The Capital Infrastructure Project Delivery Business Group executes over 70 per cent of the total BC Hydro capital plan, which includes the majority of the generation, stations, and transmission projects, some larger distribution projects, and properties projects. These infrastructure projects generally exceed $1 million, and typically have higher complexity and risk. This business group does not oversee technology projects, fleet projects, and small and less complex distribution projects.

5.6.1 Capital Infrastructure Project Delivery – Business Priorities

Over the test period, the Capital Infrastructure Project Delivery Business Group will be focusing on the following company-wide priorities:

- Deliver capital projects on time and on budget:
  - Apply a unified and systematic project delivery practice.
- Continue to improve the way we operate:
  - Building trusting and mutually-beneficial relationships with First Nations.

These business priorities are expanded on further in the following sections.

5.6.1.1 Apply a Unified and Systematic Project Delivery Practice

BC Hydro will continue to implement a project delivery framework and associated processes that reflect industry leading practices and are understood by everyone working on the projects. To achieve this, BC Hydro will:

- Continue to enhance a unified and systematic set of project management practices so we have a consistent approach to delivering projects;
- Ensure the right mix of employees, contractors and resources to complete the work;
- Work with our contractors to improve safety and ensure good records and metrics are in place to track progress (for additional information on contractor safety management, refer to section 5.7.6); and
- Continue to deploy a formal lessons-learned approach to help us plan future projects and include industry feedback on our practices.

5.6.1.2 Building Trusting and Mutually-Beneficial Relationships with First Nations

BC Hydro recognizes that building relationships that address the interests of First Nations is critical to successfully fulfilling BC Hydro's mission to provide our customers with reliable, affordable, clean electricity throughout BC, safely. As we make capital investments, we are mindful of First Nations communities around the province. BC Hydro is committed to remaining a leader in aboriginal relations by continuing to build and strengthen relationships with First Nations.

Through early engagement and emphasizing collaboration, respect and mutually beneficial relationships, First Nations will see improved transparency and their interests incorporated into BC Hydro operations and the delivery of our capital projects. These interests can include employment, environmental stewardship, and business development.

5.6.2 Three-Year Operating Cost and FTE Summaries

The operating costs for Capital Infrastructure Project Delivery Business Group are shown on Table 5-28 and Table 5-29. The tables do not include the costs of the Site C Key Business Unit which are capitalized. The Project Delivery and Generation and Transmission Engineering Key Business Units also capitalize the majority of the work they do on capital projects, and to a lesser extent some of the other Key Business Units also capitalize work on capital projects.

Table 5-28 Capital Infrastructure Project Delivery Operating Costs Before Regulatory Account Transfers, Net of Recoveries, by Key Business Unit

	($ million)	F2015 RRA	F2015 Actual	F2016 RRA	F2016 Actual	F2017 Plan	F2018 Plan	F2019 Plan
		1	2	3	4	5	6	7
1	Project Delivery	12.7	12.1	12.7	12.0	13.4	14.2	14.3
2	Generation and Transmission Engineering	12.3	13.3	12.4	12.3	14.0	14.2	14.4
3	Aboriginal Relations	5.0	5.5	5.1	6.2	6.1	6.1	6.1
4	Environmental Risk Management	25.6	26.8	25.6	26.4	27.2	27.5	27.8
5	Dam Safety	9.5	9.4	9.5	9.7	8.8	8.9	9.0
6	Properties	33.2	32.9	33.0	32.9	32.2	32.5	32.8
7	Business Unit Support	(49.6)	(47.4)	(49.6)	(38.6)	(45.3)	(51.6)	(52.3)
8	Total (5.5 L9)	48.7	52.7	48.7	61.0	56.3	51.8	52.1

Table 5-29 Capital Infrastructure Project Delivery Operating Costs Continuity Schedule

	($ million)		F2017 Plan	F2018 Plan	F2019 Plan
1	**F2016 Revenue Requirement Application Plan**		-		
2	Reorganization Impacts		48.7		
3	**F2016 Revenue Requirement Application Plan (Capital Infrastructure Project Delivery)**		48.7	56.3	51.8
4	Budget transfers between Business Groups		(1.4)		
5	**Adjusted F2016 Revenue Requirement Application Plan (Capital Infrastructure Project Delivery)**		47.3		
6	**Test Period Savings/Efficiencies:**				
7	Productivity/Efficiencies				
8	- Reduction in use of consultants and contractors		(0.2)		
9	- Workforce reductions		(0.3)		
10	- Reduction in property lease costs		(1.9)		
11	- Centralization of dam safety review investigations		(0.3)		
12	- General reductions		(0.8)		
13		A	(3.5)	-	-
14	**Test Period Cost Increases:**				
15	Unavoidable Costs				
16	- Labour (excluding Workforce Optimization)		2.1	0.9	0.9
17	Capital-Driven				
18	- Capital project investigation costs		3.0	(0.5)	
19	- Capital project dispute resolution costs		5.0	(5.0)	
20	- Workforce Optimization		1.4	0.6	
21	Other				
22	- Facility maintenance and identification phases of Properties' projects		0.5	0.2	0.2
23	- Capital Overhead adjustment		0.2	(0.8)	(0.8)
24	- Other		0.3		
25		B	12.5	(4.5)	0.3
26	Net Increase/(Decrease)	A+B	9.0	(4.5)	0.3
27	**Net Operating Costs Plan (Schedule 5.5, line 9)**		**56.3**	**51.8**	**52.1**

The FTEs for Capital Infrastructure Project Delivery are shown on Table 5-30 below:

Table 5-30 Capital Infrastructure Project Delivery FTEs

	(FTEs)	F2015 RRA	F2015 Actual	F2016 RRA	F2016 Actual	F2017 Plan	F2018 Plan	F2019 Plan
		1	2	3	4	5	6	7
1	Project Delivery	318	306	318	284	340	368	368
2	Generation & Transmission Engineering	422	429	422	429	443	443	443
3	Aboriginal Relations	35	36	35	48	47	47	47
4	Environmental Risk Management	80	78	80	85	83	83	83
5	Dam Safety	35	36	35	37	35	35	35
6	Properties	110	106	110	104	106	106	106
7	Site C Clean Energy Project	158	97	198	109	186	189	199
8	Business Unit Support	0	0	0	3	3	3	3
9	Total (16.0 L71)	1,157	1,088	1,196	1,099	1,243	1,275	1,285

Operating expenditures for the Capital Infrastructure Project Delivery Business Group, which was formed in fiscal 2016, include transferred-in costs of $48.7 million that were previously reflected in the fiscal 2016 Plan in other business groups. There is an increase of $7.6 million in fiscal 2017 Plan compared to the initial costs transferred-in when the business group was formed. The increase primarily relates to Capital Project Investigations costs and capital project dispute resolution costs partially offset by a reduction in property lease costs. From fiscal 2017 to fiscal 2018, operating expenditures decrease by $4.5 million primarily due to a planned reduction of capital project dispute resolution costs. From fiscal 2018 to fiscal 2019, operating expenditures remain relatively constant. Further year-to-year discussions at the Key Business Unit level are included in the sections that follow.

FTEs in Capital Infrastructure Project Delivery are planned to increase by 144 FTEs in fiscal 2017 compared to fiscal 2016 actual FTEs, 32 FTEs in fiscal 2018 compared to fiscal 2017 and 10 FTEs in fiscal 2019 compared to fiscal 2018. The primary drivers for the increase in FTEs relates to the Workforce Optimization Program and the delivery of BC Hydro’s capital plan, in particular the Site C Clean Energy Project. Discussion of the changes are found in the Key Business Unit sections that follow.

The following section describes the seven Key Business Units in the Capital Infrastructure Project Delivery Business Group.

5.6.3 Project Delivery

Project Delivery is responsible for leading the planning and execution of a multi-billion dollar portfolio of generation, transmission, substation, and large distribution projects. In the organizational restructuring in fiscal 2016, the project delivery functions for generation and transmission infrastructure projects were consolidated into a single Key Business Unit. This Key Business Unit is a fully integrated project delivery group, providing overall project and portfolio management, schedule/cost management, construction management, contract management, risk management, performance management, project controls and standards. The Project Delivery team consists of employees and contractors with diverse roles and backgrounds, working together with internal and external partners to safely deliver quality projects, on scope, on budget, and on schedule. At any time, Project Delivery is managing approximately 600 projects in various phases, from early identification through implementation, ranging in cost from $1 million to $1 billion, with durations from one year to more than six years.

Project Delivery uses a unified and robust system of delivery that includes industry leading practices for project, program and portfolio management, ensuring meaningful consultation and engagement with First Nations and stakeholders, and identifying and responding to key project and portfolio risks, while ensuring flexibility to respond to changing priorities.

Project Delivery is made up of project and program managers, managing six portfolios, which are supported by two departments (Capital Construction and Project, Program and Portfolio Services). Project managers are accountable to project initiators in other business groups and manage project definition, scope, schedule, resources and costs. Project support staff are responsible for the scheduling, cost control, and monitoring, as well as associated commercial, regulatory, environmental, stakeholder engagement and communications activities. Capital construction staff are responsible for planning and managing construction and commissioning activities on site and ensuring all contractual requirements are met.

Projects managed by Project Delivery typically require analysis of multiple design alternatives, and multiple methods of execution, and will have multiple engineering disciplines involved. A designated project manager is assigned to be accountable for leading the planning, execution, and close-out of the project.

Each of the groups within Project Delivery is described below. There are three transmission portfolio teams that consist of project and program managers to deliver transmission, substation, and larger distribution projects throughout the province. The overall portfolio comprises capital projects driven by growth, sustainment and customer interconnection needs. The three regionally organized teams are:

- Northern Interior and Southern Interior Transmission Portfolio;
- Lower Mainland Transmission Portfolio; and
- Vancouver Island and BC Transmission Portfolio.

The three generation portfolio teams consist of project and program managers to deliver generation projects for hydroelectric and thermal plants as well as deliver projects focused on mitigating risks associated with the dams and other water control and conveyance structures in BC Hydro’s system. The overall portfolio comprises capital projects driven by growth, sustainment, and dam safety needs. The two hydroelectric and thermal teams are organized regionally, with the third team focused on dam safety projects:

- Columbia and Vancouver Island Generation Portfolio;
- Northern, Thermal, Bridge, and Lower Mainland Generation Portfolio; and
- Dam Safety Portfolio.

The Capital Construction team consists of construction managers, contract managers, and contract administrators. Construction managers who are typically located at the construction site are accountable for managing site safety, as well as site environmental and social, quality, schedule and cost risks. Contract managers and administrators ensure that all contractual requirements are being met by the contractor and that the work has been commissioned and is accepted. The Capital Construction team is supported by the Safety department when planning and executing their work.

The Project, Program and Portfolio Services team is organized as follows: Project Services includes scheduling and cost control; Portfolio and Commercial

Management includes developing business cases, performance and resource reporting (which includes providing important inputs into BC Hydro's Workforce Plan); Project Controls and Standards includes project compliance and standards development; and Regulatory, Environment, Stakeholder Engagement and Properties and Document Control includes regulatory, environmental, and social issues as well as properties support, and document control and archiving support.

5.6.3.1 Three-Year Operating Cost and FTE Summary

Differences are discussed in reference to Table 5-28 and Table 5-30.

Operating expenditures for the Project Delivery Key Business Unit from fiscal 2016 to fiscal 2017 Plan are expected to increase by $0.7 million mainly due to $1.3 million from Workforce Optimization changes and $0.5 million due to increased use of ABS Tempworks. This is partially offset by a $1.0 million decrease due to higher utilization rates on capital projects and a $0.8 million budget transfer due to FTE transfers to other business groups. From fiscal 2017 to fiscal 2018 Plan, operating costs are expected to increase by $0.8 million due to $0.6 million from Workforce Optimization changes with the remainder primarily due to Standard Labour Rate increases. From fiscal 2018 to fiscal 2019, operating costs are planned to remain relatively constant.

Compared to the fiscal 2016 Actual FTEs the fiscal 2017 FTEs are expected to increase by 54 with a further increase of 28 in fiscal 2018 due to Workforce Optimization. From fiscal 2018 to fiscal 2019 Plan FTEs will remain constant.

5.6.4 Generation and Transmission Engineering

Generation and Transmission Engineering is responsible for engineering and quality management services to support capital projects for generation, transmission, and dam safety, as well as engineering expertise to asset management, operations and resource management groups across BC Hydro. This Key Business Unit also provides maintenance engineering support as needed for the generation and transmission systems and also assists with analysis of equipment failures and emergency outage support.

In the fiscal 2016 organizational restructuring, the engineering functions for generation and transmission projects were consolidated into a single Key Business Unit within the Capital Infrastructure Project Delivery Business Group.

Generation and Transmission Engineering consists of a general manager and six engineering teams and the Estimating, Project Engineering and Quality Management team:

Engineering Teams

- Transmission Lines;
- Stations;
- Protection and Control and Telecommunications;
- Generation Civil;
- Generation Electrical and Protection and Control; and
- Generation Mechanical Engineering.

The services these teams provide include engineering studies and design, technical support during procurement, manufacturing, construction, testing, commissioning and ongoing maintenance.

Estimating, Project Engineering and Quality Management

The Estimating teams develop cost estimates for projects. The Project Engineering teams provide engineering resources to lead the engineering on the more complex projects. Quality Management provides support for quality systems, stock material procurement and quality assurance throughout the project lifecycle including procurement, manufacturing and construction.

The delivery model for engineering services uses a combination of internal staff and external consultants. This model is internally known as the Owner's Engineer Plus model. In the Owner's Engineer Plus model, a portion of the engineering work is completed by external service providers, with review and oversight of that work being performed by internal BC Hydro resources. The level of oversight varies depending on the contractual arrangement, type of project, project risk and phase of project implementation. The "Plus" part of the model ensures that BC Hydro retains its capability as a knowledgeable owner through employees having the opportunity to build their skill sets by working directly on projects. BC Hydro must remain a knowledgeable owner to ensure the system will meet the needs of BC Hydro and its customers and stakeholders.

5.6.4.1 Three-Year Operating Cost and FTE Summary

Differences are discussed in reference to Table 5-28 and Table 5-30.

Operating expenditures for the Generation and Transmission Engineering Key Business Unit are planned to increase by $1.6 million in fiscal 2017 from fiscal 2016 Plan, $0.2 million from fiscal 2017 to fiscal 2018, and $0.2 million from fiscal 2018 to fiscal 2019. The fiscal 2017 increase is primarily due to higher FTEs due to Workforce Optimization, along with a lower utilization on capital projects as a result of an increased focus by managers and team leads on developing their teams in technical, leadership and Owner's Engineer skills. The fiscal 2018 and fiscal 2019 increases are due to an increase in the Standard Labour Rate.

FTEs are planned to increase by 15 in fiscal 2017 from fiscal 2016 actual FTEs. The increase in fiscal 2017 relates to Workforce Optimization. FTEs are planned to remain constant for fiscal 2018 and fiscal 2019.

5.6.5 Aboriginal Relations

Aboriginal Relations is responsible for establishing and implementing a corporate-wide approach to developing and sustaining long term relationships with

First Nations. BC Hydro seeks to better understand First Nations' interests so that those priorities can be incorporated, where possible, into BC Hydro's capital programs and business operations. This approach aligns with BC Hydro's Statement of Aboriginal Principles as well as its legal obligation to consult with First Nations. Aboriginal Relations responsibilities with First Nations include:

- Developing and sustaining meaningful relationships;
- Engaging and consulting on BC Hydro's activities;
- Negotiation and implementation of agreements; and
- Pursuing opportunities for Aboriginal employment and business development.

BC Hydro's commitment to Aboriginal relations is summarized by its Statement of Aboriginal Principles, introduced in 2015.

OUR COMMITMENT

At BC Hydro, we exist to serve British Columbians with clean, reliable and affordable energy. We recognize that this system has impacts on the lives and interests of First Nations communities. We are committed to working together and to building relationships that respect these interests.

Through our Statement of Aboriginal Principles, we commit that:

1. We will always operate safely and protect the safety of individuals.
2. We will inform First Nations communities, to the best of our ability, of our multi-year planning, identifying potential projects and works as early as possible for discussion.
3. We will strive to provide the most clear, accessible and transparent information possible.
4. We will seek advice on First Nations perspectives on how to best reduce or avoid impacts on the environment, cultural heritage and social needs.
5. We will be accessible and open to understanding the unique interests of First Nations in relation to our operations.
6. We will respect that our perspectives may be based on different world views.
7. Where we are refurbishing existing facilities and assets, or building new infrastructure, we will seek opportunities for meaningful benefit to local First Nations communities.
8. We will seek solutions to improving the accessibility of clean reliable and affordable power to First Nations communities in remote areas of the province.
9. We will deliver leading employment and training programs to attract and support First Nations individuals to become an increasing part of the BC Hydro workforce.
10. We will deliver on our commitments and we will be open and transparent if something is standing in the way of our mutual success.

BC Hydro is sincere in its commitment to ensure these principles are understood and acted upon by everyone in our organization, including contractors.

Aboriginal Relations is structured as follows:

- Three regional teams - Southwest, Southeast, and North;
- Project Management Office and Business Operations; and
- Aboriginal Employment and Business Development.

The three regional teams are responsible for managing BC Hydro's overall business relationships with 203 First Nations in B.C. With some of these First Nations, BC Hydro seeks a deeper level of engagement as a result of its existing infrastructure and planned projects in some areas of the province. Responsibilities include early and transparent engagement and consultation for capital projects, maintenance and operations, as well as negotiation and implementation of agreements with First Nations.

The Project Management Office and Business Operations team is responsible for managing Aboriginal Relations practices that support capital project delivery and operations. Responsibilities include: adherence with BC Hydro's engagement and consultation practices, including assessment of adequacy of BC Hydro's activities in this regard; updates to engagement and consultation practices as new legal precedents emerge; and coordination of the Aboriginal Relations component in regulatory filings, including assessments of the adequacy of consultation.

The Aboriginal Employment and Business Development team provides direct support to First Nations and businesses at a community level to enable Aboriginal opportunities with BC Hydro. This support includes community engagement and awareness, training and apprenticeships. Through this approach, BC Hydro is able to attract and retain Aboriginal employees and businesses.

5.6.5.1 Three-Year Operating Cost and FTE Summary

Differences are discussed in reference to Table 5-28 and Table 5-30.

Operating expenditures for the Aboriginal Relations Key Business Unit are planned to increase in fiscal 2017 from fiscal 2016 Plan by $1.0 million. An increase of $1.2 million is attributable to the transfer of the Aboriginal Employment and Business Development group to Aboriginal Relations from Human Resources. This is partially offset by a reduction of external contractor costs. Operating costs are planned to remain constant from fiscal 2017 through fiscal 2019.

FTEs for Aboriginal Relations are planned to remain relatively constant during fiscal 2017 to fiscal 2019 compared to the fiscal 2016 actual FTEs.

5.6.6 Environmental Risk Management

Environmental Risk Management is responsible for managing environmental risk in all phases of life for BC Hydro’s assets to protect BC Hydro’s consent to operate. This objective is accomplished by eliminating, mitigating or compensating environmental, regulatory, and social risk that results from BC Hydro operations and infrastructure.

The Environmental Risk Management Key Business Unit is responsible for all strategic, project and operational environmental issues. The team creates and implements policies, standards, and strategies, and manages a risk analysis and review process to ensure environmental and related social risks are addressed. The group is also accountable for the Water License Requirements Program, the Fish and Wildlife Compensation Program, real time field support, company and contractor environmental training, environmental performance reporting and analytics, project support and regulatory compliance strategies on files such as, species at risk, reservoir archeology and fish and aquatic issues.

Environmental Risk Management is organized into five main groups:

- Environmental Field Services;
- Project Environmental Risk Management;

- Land Management;
- Water Management; and
- Fish and Wildlife Compensation Program.

Risks and impacts are managed effectively by:

- Avoiding, preventing, mitigating or compensating environmental impacts in projects and operations;
- Meeting regulatory obligations and legislative requirements;
- Making decisions about environmental risk and opportunity in a structured and systematic way; and
- Building and maintaining relationships with the public, regulators, First Nations and other stakeholders.

5.6.6.1 Three Year Operating Cost and FTE Summary

Differences are discussed in reference to Table 5-28 and Table 5-30.

Operating expenditures for the Environmental Risk Management Key Business Unit are planned to increase by $1.6 million in fiscal 2017 from fiscal 2016 Plan, $0.3 million from fiscal 2017 to fiscal 2018, and $0.3 million from fiscal 2018 to fiscal 2019. The fiscal 2017 increase is due to $0.6 million budget transfer to fund resources and work transferred from the former Safety, Health and Environment Key Business Unit, $0.5 million budget increase to accommodate the increase in the Consumer Price Index for the Fish and Wildlife Compensation Program, a $0.5 million increase in field monitoring and mitigation work, and a $0.4 million increase for archaeology management funding along with a Standard Labour Rate increase. The increase from fiscal 2016 Plan to fiscal 2017 is partially offset by a $1.0 million decrease in the non-remissible portion of the Water License requirements. The fiscal 2018 and fiscal 2019 increases are due to an increase in the Standard Labour Rate.

FTEs for Environmental Risk Management are planned to remain relatively constant during fiscal 2017 to fiscal 2019 compared to the fiscal 2016 actual FTEs.

5.6.7 Dam Safety

BC Hydro currently owns, operates, and maintains dams at many sites in B.C., as a major part of its generating system. BC Hydro is accountable to the Government of British Columbia, and to the Comptroller of Water Rights, for ensuring the safety of BC Hydro dams in accordance with the British Columbia Dam Safety Regulation. As a dam owner, BC Hydro manages risks to employee, contractor and public safety, the environment, reliability of electricity supply. To manage these risks, BC Hydro has a comprehensive dam safety program, which has been compared favourably to the leading programs around the world.

The objective of the dam safety program is to manage the safety of physical features and structures that retain the reservoirs and control passage of flows through, around and beyond dams that are operated by BC Hydro, thus protecting both the public and the corporation.

BC Hydro develops and maintains world-class capability in risk assessment and dam safety engineering, and is committed to providing the resources to meet or exceed dam safety guidelines. BC Hydro representatives communicate regularly with the Comptroller of Water Rights, who represents the Government of British Columbia in relation to dam safety matters.

The Dam Safety Program includes a staff of about 35, which includes seven dam safety area engineers supported by eleven instrumentation technologists, most of whom reside in the generating regions, and are involved in all dam safety activities at the dams. Coordination and support related to instrumentation systems, regulatory requirements, risk management, and the program of dam safety investigations and capital upgrades, is provided by staff who report directly to the Director of Dam Safety.

BC Hydro's overall approach to managing safety risks from dams can be found on BC Hydro's Dam Safety website.

5.6.7.1 Three-Year Operating Cost and FTE Summary

Differences are discussed in reference to Table 5-28 and Table 5-30.

Operating expenditures for the Dam Safety Key Business Unit are planned to decrease by $0.7 million in fiscal 2017 from fiscal 2016 Plan. A decrease of $1.0 million is attributable to project funding for the large embankment dam initiative which will be funded through Capital Infrastructure Project Delivery Business Unit Support beginning in fiscal 2017. The offsetting additional increase in operating costs is due to Standard Labour Rate increases and changes in labour mix. Operating costs are planned to remain relatively constant from fiscal 2017 through fiscal 2019.

FTEs for Dam Safety are planned to remain relatively constant during fiscal 2017 to fiscal 2019 compared to the fiscal 2016 actual FTEs.

5.6.8 Properties

The Properties Key Business Unit provides property and real estate leadership and services required to support BC Hydro's electric and non-electric system assets. Properties' services include acquiring and managing property for generation, transmission and distribution and reservoir rights and agreements, managing BC Hydro's headquarters and field offices, and leading BC Hydro's real estate sales, leasing, and planning needs.

Properties is comprised of the following departments:

- Property Acquisition and Rights Services manages the property related functions associated with the life cycle of BC Hydro's electrical assets including acquiring and actively managing property rights over Crown and private lands in support of the electrical infrastructure, managing generation property interests, and managing requests from the public and the Crown regarding generation facilities and water usage. This group also acquires, negotiates, and provides strategic advice on property rights and matters related to First Nations property, acquires and manages property interest on First Nation reserves, and ensures BC Hydro property interests are considered during the provincial treaty process;

- Facility Services and Capital Projects manages BC Hydro's field and office facilities assets, including planning the capital investments, delivery of associated capital projects, and maintaining the existing facilities. The standard BC Hydro project lifecycle approach is followed for managing projects; and
- Real Estate Services administers BC Hydro's property tax portfolio, provides business services (properties information and records management, mapping, switchboard, mail distribution, layout, graphics, copy centre, travel and parking, and conference centre), provides workspace planning services (workstation moves, workspace design, and space reconfigurations for all of BC Hydro), manages the leases of both BC Hydro's assets and externally leased space, manages telecom agreements, leads the sales of surplus property, and provides real estate subject matter expertise.

5.6.8.1 Three-Year Operating Cost and FTE Summary

Differences are discussed in reference to Table 5-28 and Table 5-30.

Operating expenditures for the Properties Key Business Unit are planned to decrease by $0.8 million in fiscal 2017 from fiscal 2016 Plan. A decrease of $1.9 million is attributable to a reduction in lease costs. An additional decrease of $0.2 million in labour is associated with a reduction in FTEs. Offsetting increases of $1.3 million include project identification phase and move costs associated with Properties capital projects, operating costs for new facilities, and inflation. Operating costs are planned to remain relatively constant from fiscal 2017 through fiscal 2019

FTEs for Properties are planned to remain relatively constant during fiscal 2017 to fiscal 2019 compared to the fiscal 2016 actual FTEs.

5.6.9 Site C Clean Energy Project

The Site C Clean Energy Project will be the third dam and hydroelectric generating station on the Peace River in northeast B.C. Site C is being built to help meet B.C.'s long-term electricity needs. It will provide 1,100 megawatts of capacity, and produce about 5,100 gigawatt hours of electricity each year – enough energy to power the equivalent of about 450,000 homes per year. Given the size and duration of the Site C project, Site C has been set up as its own Key Business Unit with a complement of key resources to support all components of successful project execution. Functional resources on Site C coordinate closely with their counterparts in BC Hydro to ensure BC Hydro practices are employed on the Site C project.

5.6.9.1 Three-Year Operating Cost and FTE Summary

Differences are discussed in reference to Table 5-28 and Table 5-30.

The Site C Clean Energy Project has no planned operating expenditures over the test period as all Site C costs are being charged to capital.

Planned FTEs for Site C Clean Energy Project Key Business Unit will increase by 77 in fiscal 2017 from fiscal 2016 actual FTEs as the project staffs up to a full complement of resources to manage and administer the project. In fiscal 2018 an increase of three and in fiscal 2019 an increase of 10 FTEs primarily related to increases for overtime as the project team takes on all implementation activities. All Site C Clean Energy Project FTEs are charged to capital.

5.6.10 Capital Infrastructure Project Delivery Business Unit Support

The Capital Infrastructure Project Delivery Business Unit Support Key Business Unit holds the budget for the Office of the Deputy Chief Executive Officer and for business group costs that are not specifically related to any single Key Business Unit.

The Office of the Deputy Chief Executive Officer is responsible for providing strategic direction and leadership for the business group.

The business group costs that are budgeted in Business Unit Support include capital project investigation costs, capital project dispute resolution costs, First Nations community payments in lieu of taxation, dam safety investigation costs and capital overhead.

Capital project investigation costs are those that are incurred to determine or confirm a need or opportunity for a capital project, and to develop, review and recommend conceptual alternatives to address that need (refer to Chapter 6, section 6.4.1.3 for project lifecycle).

The budget for capital overhead was consolidated under the Capital Infrastructure Project Delivery Business Group at the time of the fiscal 2016 reorganization and resides in Business Unit Support. Capital overhead is planned as a credit of $68.2 million, $69.0 million, and $69.7 million in fiscal 2017, fiscal 2018 and fiscal 2019 respectively and the breakdown by function is 13 per cent Generation, 62 per cent Distribution and 25 per cent Transmission.

5.6.10.1 Three-Year Operating Cost and FTE Summary

Differences are discussed in reference to Table 5-28 and Table 5-30.

Planned operating expenditures for the Capital Infrastructure Project Delivery Business Unit Support Key Business Unit have increased from fiscal 2016 Plan to fiscal 2017 by $4.3 million, comprised of $3.0 million for capital project investigation costs and $5.0 million for capital project dispute resolution costs, partially offset by consolidation of capital overhead under the Capital Infrastructure Project Delivery with the balance being other reductions.

Costs are decreasing from fiscal 2017 to fiscal 2018 by $0.5 million for capital project investigation costs and $5.0 million for capital project dispute resolution costs, and remaining constant from fiscal 2018 to fiscal 2019.

FTEs for Business Unit Support are planned to remain relatively constant during fiscal 2017 to fiscal 2019 compared to the fiscal 2016 actual FTEs.

5.7 Operations Support Business Group

The Key Business Units included into the Operations Support Business Group provide enterprise-wide support services to the business. This section describes the activities and costs of the following Key Business Units:

- Executive Office;
- Finance and Supply Chain;
- Corporate Affairs;
- Safety, Security and Emergency Management; and
- General Counsel.

The responsibilities, staffing levels and expenditures for these Key Business Units are discussed further below in section 5.7.3 to 5.7.7. In addition Independent Power Producer capital lease operating costs (section 5.7.8) and Corporate Costs (section 5.7.9) are included as part of the Operations Support Business Group.

In fiscal 2016 previously decentralized parts of Finance, Human Resources, Safety and Business Planning were centralized to:

- Drive consistency and standardization in delivery of services;
- Deliver cost savings through reduced FTEs, the elimination of redundant and/or duplicative services and/or improved utilization of resources; and
- Focus and deliver on the company objectives and key priorities.

5.7.1 Operations Support – Business Priorities

Over the test period the Key Business Units are collectively focused on the following three company-wide priorities:

- Explore the full potential of energy conservation:
  - Continue to help our residential, commercial and industrial customers conserve energy while looking at new ways to save energy and encourage all of our customers to be smarter with their power.
- Strengthen our proud and valued workforce:
  - Attract and retain skilled employees across the organization. BC Hydro has developed a Workforce Plan to meet the resource requirements of the 10-Year Capital Forecast and maintain core operations.
- Continue to improve the way we operate:
  - Improving safety performance to reduce injuries and the associated costs and impacts on the lives of employees, contractors and the public;
  - Continuing with the implementation of category management;
  - Creating and executing Work Smart projects;
  - Managing costs to reduce the impact to ratepayers and creating efficiencies; and
  - Planning to meet the long-term electricity needs of our customers.

These business priorities are expanded on further in the Key Business Unit sections below.

5.7.2 Three-Year Operating Cost and FTE Summaries

The operating costs for Operations Support are shown in Table 5-31 and Table 5-32 below.

Table 5-31 Operations Support Operating Costs Before Regulatory Account Transfers, Net of Recoveries – By Key Business Unit

	($ million)	F2015 RRA	F2015 Actual	F2016 RRA	F2016 Actual	F2017 Plan	F2018 Plan	F2019 Plan
		1	2	3	4	5	6	7
1	Executive	0.7	0.8	0.7	0.8	0.9	1.0	1.0
2	Finance and Supply Chain	108.2	104.5	108.1	112.6	119.4	120.2	121.6
3	Corporate Affairs	53.7	50.4	53.8	51.1	53.1	53.3	53.9
4	Safety, Security, Emergency Management	25.6	24.4	25.7	29.2	30.0	30.0	30.0
5	General Counsel	12.2	11.6	12.2	11.0	12.2	12.3	12.3
6	IPP Capital Lease Operating Costs	29.4	29.4	33.8	34.2	28.2	63.6	54.3
7	Corporate Costs	(131.6)	(127.9)	(98.3)	(120.6)	(94.8)	(71.2)	(47.5)
8	Total (5.1 L19)	98.2	93.3	136.0	118.4	148.9	209.1	225.6

Table 5-32 Operations Support Operating Costs Continuity Schedule

	($ million)		F2017 Plan	F2018 Plan	F2019 Plan
1	**F2016 Revenue Requirement Application Plan (Corporate Groups)**		**193.1**		
2	Reorganization Impacts		(57.1)		
3	**F2016 Revenue Requirement Application Plan (Operations Support)**		136.0	148.9	209.1
4	Budget transfers between Business Groups		(11.8)		
5	**Adjusted F2016 Revenue Requirement Application Plan (Operations Support)**		124.2		
6	Independent Power Producer Capital Leases		(5.6)	35.4	(9.2)
7	IFRS Ineligible Capital Overhead		22.4	22.4	22.4
8	**Test Period Savings/Efficiencies:**				
9	Productivity/Efficiencies				
10	- Reduction in use of consultants and contractors		(0.6)	-	-
11	- Reduction in corporate donations and sponsorships		(0.6)	-	-
12	- Membership cancellations		(0.4)	-	-
13	- Workforce reductions		(0.6)	-	-
14	- Efficiency savings to be identified		(4.0)	(0.2)	(0.2)
15		A	(6.2)	(0.2)	(0.2)
16	**Test Period Cost Increases:**				
17	Unavoidable Costs				
18	- Labour (excluding Workforce Optimization)		0.1	2.3	2.8
19	Capital-Driven				
20	- Maintenance				
21	▪ Fleet - increase in number of vehicles		3.8	0.3	
22	- Workforce Optimization		(0.3)	(0.0)	
23	Initiatives				
24	- Safety initiatives		5.0		
25	Other Cost Pressures				
26	- Category Management and other Procurement related costs		1.5	(1.0)	
27	- Inventory obsolescence		1.7		
28	- Capital Overhead adjustments		3.1	0.9	0.8
29	- Other		0.0		
30	Smart Metering and Infrastructure		(0.9)	-	-
31		B	14.0	2.6	3.5
32	Net Increase/(Decrease)	A+B	7.8	2.4	3.3
33	**Net Operating Costs Plan (Schedule 5.1, line 19)**		**148.9**	**209.1**	**225.6**

Planned operating costs have increased by $12.9 million in fiscal 2017, compared to fiscal 2016 Plan. The increase is primarily related to $22.4 million in IFRS ineligible capital overhead being phased into operating expenses over a 10-year period (refer to section 5.7.9), $3.8 million in capital-driven maintenance related to the increase in the size and aging of the vehicle fleet, $5.0 million in initiative costs for Safety, and $6.4 million for category management, inventory obsolescence, capital overhead changes, and Standard Labour Rate increases, partially offset by savings and efficiencies of $6.2 million, a $5.6 million decrease in capital leases and net budget transfers to other business groups of $11.8 million.

The FTEs for Operations Support are shown on Table 5-33 below:

Table 5-33 Operations Support FTEs

	(FTEs)	F2015 RRA	F2015 Actual	F2016 RRA	F2016 Actual	F2017 Plan	F2018 Plan	F2019 Plan
		1	2	3	4	5	6	7
1	Executive	2	3	2	3	4	4	4
2	Finance and Supply Chain	593	604	586	584	579	579	579
3	Corporate Affairs	419	425	412	389	369	365	365
4	Safety, Security, Emergency Management	137	126	137	125	131	133	133
5	General Counsel	38	38	38	37	37	37	37
6	Total (16.0 L62)	1,190	1,196	1,175	1,137	1,121	1,119	1,119

Planned operations Support FTEs are decreasing by 17 in fiscal 2017 due to labour efficiencies realized with the centralization of support services and changes to demand-side management programs. The FTEs will remain relatively constant in fiscal 2018 and fiscal 2019.

The organization changes, benefits achieved to date, and expected outcomes over the test period are summarized below in each group section.

5.7.3 Executive Office

Differences are discussed in reference to Table 5-31 and Table 5-33.

The Executive Office comprises the President and Chief Executive Officer and support staff. The Chief Executive Officer leads the executive management team, and is responsible for the day-to-day leadership and management of the corporation.The Chief Executive Officer is also responsible for developing BC Hydro’s strategy, and thereafter for BC Hydro’s performance in executing on that strategy.

5.7.4 Finance and Supply Chain

Finance and Supply Chain is led by the Executive Vice President, Finance and Supply Chain and Chief Financial Officer. The Executive Vice President and Chief Financial Officer is responsible for providing strategic direction and financial leadership across the company and within the Finance and Supply Chain Key Business Unit specifically and for reporting on BC Hydro's financial and operating results to the Board of Directors and BC Hydro's shareholder.

The operating costs and FTEs for Finance and Supply Chain are shown in the Table 5-34 and Table 5-35 below and the changes during the test period are explained in section 5.7.4.3.

Table 5-34 Finance and Supply Chain Operating Costs

	($ million)	F2015 RRA	F2015 Actual	F2016 RRA	F2016 Actual	F2017 Plan	F2018 Plan	F2019 Plan
		1	2	3	4	5	6	7
1	Chief Financial Officer	0.8	0.8	0.8	0.8	0.8	0.8	0.8
2	Finance	27.7	25.2	27.8	26.0	26.8	27.3	27.7
3	Supply Chain	79.7	78.4	79.5	85.9	91.8	92.2	93.0
4	Total	108.2	104.5	108.1	112.6	119.4	120.2	121.6

Table 5-35 Finance and Supply Chain FTEs

	(FTEs)	F2015 RRA	F2015 Actual	F2016 RRA	F2016 Actual	F2017 Plan	F2018 Plan	F2019 Plan
		1	2	3	4	5	6	7
1	Chief Financial Officer	3	3	3	3	3	3	3
2	Finance	188	177	188	174	174	174	174
3	Supply Chain	402	423	395	407	402	402	402
4	Total	593	604	586	584	579	579	579

Sections 5.7.4.1 and 5.7.4.2 describe further the activities of Finance and Supply Chain.

5.7.4.1 Finance

Our focus during the test period will be to continue the development of consistent financial processes and reporting and continue to monitor and manage financial risks for BC Hydro. This will improve the way BC Hydro operates.

Finance is also responsible for BC Hydro's Work Smart program which is focused on finding ways the company can work smarter. This is a structured methodology to process improvement based on Lean principles. The program is being utilized in several areas of the company.

The Finance group is responsible for financial management of the company including financial reporting and analysis, budget and forecasting, treasury and audit and for management of the 2013 10 Year Rates Plan. In order to increase efficiency and improve consistency and standardization of financial processes and reporting, BC Hydro centralized the Finance groups under the Chief Financial Officer in fiscal 2016.

The Finance group consists of the following departments:

- Business Support Services;
- Financial Reporting and Policy;
- Financial Planning and Forecasting;
- Treasury; and
- Audit Services.

Business Support Services

This team provides support to the business for many finance functions including operating and capital budgeting, monthly spend analysis and comparison to budgets, forecasting and management reporting. The team also manages capital expenditure authorization request reviews and approvals, reviews of major contracts, and asset accounting.

Financial Reporting and Policy Team

This team delivers monthly, quarterly and annual financial reporting to the business including Executive Team and Board of Directors, operates and supports the financial system, provides technical accounting and tax support to the business, and ensures a proper internal control environment is in place and is adhered to.

Financial Planning and Forecasting

This team is responsible for forward looking quarterly financial forecasts, regulatory accounting and reporting, and coordinating the annual budgeting process. They are also responsible for the Work Smart program, leading preparation of budgets and the financial model for the Plan, and supporting execution of the 2013 10 Year Rates Plan by identifying potential risks and mitigating actions.

Treasury

This team is responsible for cash management and banking, debt management, insurance management, credit risk management and pension plan management. This involves ensuring that BC Hydro has sufficient financial resources to fund its operations, maintaining credit facilities, developing and implementing debt management strategies, forecasting finance charges, procuring and managing operational and construction insurance programs, evaluating, monitoring and reporting credit exposures as well as managing investments associated with BC Hydro's Pension Plan and non-pension post-retirement benefits.

Audit Services

This team provides assurance that appropriate controls and effective risk management processes are in place to support BC Hydro Board of Directors and management to achieve the Company's business objectives through the development and execution of the Audit Plan. Audit Services has a functional reporting relationship to the Audit and Finance Committee of the BC Hydro Board of Directors.

5.7.4.2 Supply Chain

In fiscal 2013, the procurement organizations that were part of the previous Generation, Transmission and Distribution, and Corporate Business Groups, together with the Materials Management and the Fleet groups were centralized into a single Supply Chain organization. This followed the development of a Supply Chain and Fleet Services Business Model which identified the supply chain requirements of BC Hydro's business units and the capabilities required within the organization to meet their supply chain needs. Implementation of the business model includes people, process and technology changes, and the transition from the current state to the new business model is a multi-year undertaking. The centralization of the Supply Chain organization resulted in FTE reductions and further standardization of processes to improve efficiencies.

Some of the key changes that have been implemented to date include:

- Implementation of a segmented approach for procurement related to capital projects based on the project's risk profile, value and complexity;
- Initial development of category management processes and tools as well as the implementation of category management strategies for some operational procurement categories. Category management is an approach that focuses on the organization's expenditures on goods and services with third-party suppliers. It is a process-based approach and segments the main areas of the organization's expenditures into discrete groups/categories and incorporates strategy development, business process change, sourcing, contract management and supplier management;

- Initiation of technology changes to provide effective supply chain management tools; and
- Standardization of inventory working stock items and a reduction in the number of catalogue items from approximately 1,000 to 300. This has resulted in better inventory management and reduced number of transactions.

The focus during the test period will be:

- Continued implementation of category management with the goal of having 50 per cent of BC Hydro's expenditure categories managed under the new business model; and
- The design and implementation of new business processes and SAP information technology for the supply chain through the Supply Chain Applications Project. BC Hydro will file a separate application with the Commission for the Supply Chain Applications Project.

Supply Chain is comprised of the following three departments:

- Procurement;
- Materials Management; and
- Fleet Services.

Procurement

The Procurement department's functions include developing and executing purchasing strategies and sourcing programs, and monitoring compliance with procurement policies and guidelines. More than 30,000 transactions a year flow through the department including approximately 200 public competitions and up to 500 secondary sourcing processes for suppliers pre-qualified through public competitions.

The department is also responsible for implementing category management across BC Hydro with a focus on 40 to 50 operational categories totaling approximately 80 to 90 per cent of BC Hydro's procurement expenditures. Examples of expenditure categories include power transformers, line construction, safety clothing, vegetation maintenance, electrical components and distribution transformers. The accounts payable relationship and contract with Accenture Business Services for Utilities, BC Hydro's e-commerce program and the administration of the corporate credit card are also managed within this department.

Materials Management

Materials Management provides services, including inventory forecasting and planning, material distribution and transportation, field warehouse operations and waste transformer oil management. Materials Management handles approximately 220,000 transactions annually in inventory materials that support operations and capital projects as well as maintenance items.

Fleet Services

Fleet Services is responsible for the procurement and life-cycle management of BC Hydro's approximately 3,200 fleet assets, including vehicles, trailers and other pieces of equipment such as forklifts. The life-cycle management of the fleet assets include fleet asset planning, acquisition, maintenance and repair, vehicle fueling, disposal, and fleet supplier and contract management.

5.7.4.3 Three-Year Operating Cost and FTE Summary

Differences are discussed in reference to Table 5-31 and Table 5-33.

Operating expenditures for Finance are planned to decrease by $1.1 million in fiscal 2017 compared to fiscal 2016 Plan. This is primarily due to labour cost savings of $1.0 million as a result of efficiencies realized during the centralization of the Finance groups. Operating expenditures in fiscal 2018 and fiscal 2019 are planned to remain relatively constant with fiscal 2017. The small increases are due to Standard Labour Rate increases.

Operating expenditures for Supply Chain are planned to increase by $12.4 million from $79.4 million in fiscal 2016 Plan to $91.8 million in fiscal 2017.

These increases are mainly due to:

- An increase in Fleet costs of $3.8 million largely due to vehicle maintenance cost increases as a result of an aging fleet, changes in the size and mix of the fleet (more heavy and medium-sized work trucks) and higher parts costs due to the impact of the weakening of the Canadian dollar on parts purchased in US dollars;
- An increase of $1.7 million to provide for an appropriate provision for inventory obsolescence for Active and Spares inventory. The provision is based on the average write-offs experienced over the last two years;
- An increase of $3.3 million for incremental expenditures related to developing and implementing category strategies and providing ongoing management of strategic and key operational spend categories that will better meet BC Hydro's requirements for quality, safety, reliability in what BC Hydro buys for a lower total lifecycle cost resulting in savings in capital spend and in other parts of the business; and
- Standard Labour Rate increases.

Operating costs for Supply Chain are expected to increase by $0.4 million in fiscal 2018 from fiscal 2017 and by $0.8 million in fiscal 2019 from fiscal 2018 due largely to Standard Labour Rate increases.

FTEs for Finance and Supply Chain are planned to remain relatively constant during fiscal 2017 to fiscal 2019 compared to the fiscal 2016 actual FTEs.

5.7.5 Corporate Affairs

The Corporate Affairs group was created in fiscal 2016 to ensure a coordinated approach to the delivery of BC Hydro's vision and priorities in order to:

- Meet the long term electricity needs of our customers cost effectively through the design and delivery of conservation and energy management programs and managing our third-party contracts for electricity supply;
- Look to the future and set out our long-term and short-term plans based on the needs and expectations of our customers and our mandate from the government;
- Effectively and proactively manage our relationship with government, and the regulator, and influence key policy decisions;
- Monitor progress on implementing our plans while identifying and managing key risks;
- Manage internal and external communications; and
- Ensure that we have the right people with the right skills to execute our plans, and also that we have an engaged, productive workforce.

The creation of the Corporate Affairs group strengthens alignment across the organization and furthers an already coordinated approach to planning and policy. This structure also supports decision making within the broader organization to deliver on the 2013 10 Year Rates Plan and achieve corporate objectives and priorities. Corporate Affairs has the situational context required to respond to changes in the external environment and organization by supporting informed, measured decision making for the organization as a whole.

Corporate Affairs brings together existing departments and two new departments, listed below:

- Senior Vice President of Corporate Affairs and Chief Human Resources Officer;

- Human Resources;
- Energy Planning;
- Business and Economic Development;
- Regulatory and Rates;
- Conservation and Energy Management;
- Business Planning and Risk **(**new Key Business Unit that brings together the Enterprise Risk Management Key Business Unit previously part of Corporate Finance and the Operations Performance Reporting Key Business Unit previously part of the previous Transmission and Distribution Business Group);
- Policy and Reporting, (new Key Business Unit that includes the environment policy team previously part of Safety, Health and the Environment Key Business Unit); and
- Communications.

The operating costs and FTEs for Corporate Affairs are shown in the Table 5-36 and Table 5-37 below and the changes during the test period are explained in section 5.7.5.10**.**

Table 5-36 Corporate Affairs Operating Costs

	($ million)	F2015 RRA	F2015 Actual	F2016 RRA	F2016 Actual	F2017 Plan	F2018 Plan	F2019 Plan
		1	2	3	4	5	6	7
1	SVP Corporate Affairs	1.4	1.1	1.4	1.5	1.1	1.1	1.2
2	Human Resources	23.5	21.8	23.5	20.4	22.1	22.2	22.5
3	Energy Planning	4.4	4.0	4.4	3.7	4.1	4.2	4.2
4	Business and Economic Development	4.4	4.0	4.4	4.3	4.6	4.7	4.8
5	Regulatory and Rates	5.6	5.2	5.6	5.6	6.0	6.1	6.2
6	Conservation and Energy Management	0.3	0.4	0.3	0.6	0.6	0.6	0.6
7	Business Planning and Risk	1.8	1.5	1.9	1.7	1.7	1.8	1.8
8	Policy and Reporting				1.2	1.4	1.4	1.5
9	Communications	12.3	12.4	12.2	12.2	11.4	11.1	11.3
10	Total	53.7	50.4	53.8	51.2	53.1	53.3	53.9

Table 5-37 Corporate Affairs FTEs

	(FTEs)	F2015 RRA	F2015 Actual	F2016 RRA	F2016 Actual	F2017 Plan	F2018 Plan	F2019 Plan
		1	2	3	4	5	6	7
1	SVP Corporate Affairs	4	4	4	5	4	4	4
2	Human Resources	101	94	101	84	89	89	89
3	Energy Planning	18	18	18	17	18	18	18
4	Business and Economic Development	21	22	21	23	23	23	23
5	Regulatory and Rates	27	26	27	26	28	27	27
6	Conservation and Energy Management	146	137	142	128	115	112	112
9	Business Planning and Risk	9	7	9	7	7	7	7
8	Policy and Reporting				4	6	6	6
9	Communications	94	117	91	94	80	80	80
10	Total	419	425	412	389	369	365	365

Sections 5.7.5.1 to 5.7.5.9 describe further the activities of each of these Key Business Units.

5.7.5.1 Senior Vice President Corporate Affairs and Chief Human Resources Officer

The Office of the Senior Vice President of Corporate Affairs and Chief Human Resources Officer includes the budget for Senior Vice President and support staff as well as the Ethics Office.

The Office of the Senior Vice President of Corporate Affairs and Chief Human Resources Officer is responsible for providing strategic direction and leadership for the Corporate Affairs Group and business unit support. The Ethics office is responsible for the Code of Conduct, the Respectful Workplace Program and the Ombuds Program. The Ethics Office provides support to all BC Hydro employees as well as contractors with workplace related conduct issues.

5.7.5.2 Human Resources

Human Resources functions from across the organization have been consolidated. The centralization has resulted in the elimination or streamlining of work processes and functions.

Over the test period Human Resources is responsible for the programs supporting the company-wide priority to strengthen our proud and valued workforce. Human Resources will continue to focus on attracting and retaining qualified workers as well as developing their capacity through:

- Targeted recruitment initiatives for difficult to attract locations and positions;
- Targeted development, succession and career path opportunities;
- Performance management, total compensation and recognition programs that contribute to employee engagement and productivity;
- Health management and return to work programs that maintain employees at their productive best; and
- Strong and effective relationships with our unions.

These activities support the development and execution of BC Hydro's Workforce Plan (refer to Appendix F).The Human Resources Key Business Unit is comprised of three departments:

- People Services and Systems;
- Organizational Effectiveness; and
- Client Services.

People Services and Systems

This department is comprised of the following functions: Employee Relations, Total Rewards, HR Systems and People Analytics, and Recruitment.

Employee Relations manages BC Hydro's overall labour relations strategy, as well as leads all contract negotiations with BC Hydro's bargaining units (International Brotherhood of Electrical Workers, MoveUP, Allied Hydro Council).

The Total Rewards function ensures that BC Hydro has a competitive mix of base pay, union gainsharing, benefits, pensions and related programs necessary to attract, retain and motivate appropriately qualified employees within Public Sector Employers' Council Guidelines. The department also manages BC Hydro's relationship with third-party vendors related to benefits and pension as well as provides prevention services that support employee health and facilitates employee return to work following sick leave or occupational injury.

The HR Systems and People Analytics function manages the human resources related information system (SAP Human Capital Management) including the learning management system and performance management system. The department also manages BC Hydro's relationship with Accenture Business Services for human resource services (payroll, recruitment administrative services, relocation services and temporary staffing services).

The Recruitment function manages BC Hydro's internal and external recruitment as well as broader partnerships with educational institutions.

Organizational Effectiveness

The Organizational Effectiveness department is responsible for managing the design, governance and operation of the enterprise diversity strategy and the employee performance program, as well as the talent management and succession planning programs. This department also provides employee engagement support including the annual employee engagement survey, the recognition program and facilitation for employee councils. This team also provides governance, coaching and change management expertise for change initiatives.

Client Services

The Client Services department provides Human Resources support to the entire organization through the implementation of programs and policies developed by the People Services and Systems and Organizational Effectiveness departments. This includes organizational design; change management; leadership coaching; leadership talent and succession planning; and rewards, recognition and performance management.

5.7.5.3 Energy Planning

Energy Planning is responsible for undertaking long-term resource planning and for assisting senior managers in strategic supply and demand-related resource decisions. These plans are periodically reflected in BC Hydro's Integrated Resource Plan. The Energy Planning team is responsible for the development, consultation and submission of the Integrated Resource Plan to government. The Integrated Resource Plan is a contextual document for a variety of regulatory applications including demand-side management expenditure requests, project approvals and acquisition processes. The team also provides analytical and witness support during related regulatory processes.

Energy Planning includes the key function of load and market forecasting. The load forecast is developed on an annual basis and is an important input to the Revenue Requirements Application and long-term resource planning. BC Hydro's load forecast is discussed in Chapter 3.

Energy Planning is also responsible for managing several transmission service agreements. As part of working with the transmission service provider, Energy Planning coordinates the bulk transmission system impacts in the Integrated Resource Planning process, provides load/resource assumptions used in transmission system planning studies, and undertakes analysis on alternatives (non-wire) to potential transmission projects as part of regional transmission planning initiatives. Energy Planning leads several aspects of BC Hydro's interregional planning efforts within the western interconnection system.

5.7.5.4 Business and Economic Development

The Business and Economic Development Team is responsible for procuring electricity from IPPs and third-party suppliers in B.C., in accordance with the Integrated Resource Plan.

Activities include managing the Net Metering Program, the Standing Offer Program, and the Micro-Standing Offer Program along with commitments made under several First Nations Impact Benefits Agreements.

The team manages cost commitments from electricity purchase agreements with IPPs, ensuring the rights and obligations of both parties are administered in a way that maximizes benefits to ratepayers. The team also conducts commercial negotiations with IPPs, manages invoice verification for IPPs that have commenced commercial operations, files new contracts with the commission for review, and analyzes the potential renewals of expiring contracts.

The team also provides analysis of BC Hydro's portfolio of IPP projects in support of corporate financial planning and regulatory filings.

5.7.5.5 Regulatory and Rates

The Regulatory and Rates department is responsible for managing all of BC Hydro's regulatory filings and proceedings with the British Columbia Utilities Commission. This department is the main interface between the British Columbia Utilities Commission and BC Hydro. The team also manages the relationships with our interveners.

The Regulatory and Rates department also interacts with the National Energy Board for regulation of BC Hydro activities that cross provincial and international boundaries. BC Hydro is the holder of certificates for four National Energy Board-regulated international power lines.

The Regulatory and Rates department provides interpretation and support with regard to compliance with BC Hydro's Electric Tariff, the Open Access Transmission

Tariff, the Standards of Conduct and Commission decisions and directives as well as the Mandatory Reliability Standards. The design and development of BC Hydro rates are also undertaken by the Regulatory and Rates department.

5.7.5.6 Conservation and Energy Management

The Conservation and Energy Management department (previously referred to as the Power Smart department) is responsible for conservation and energy management activities, including the planning, development, implementation and administration of various initiatives to achieve the company's energy and capacity objectives. Conservation and Energy Management is responsible for executing on one of the five company priorities to explore the full potential for energy conservation. Specific activities performed within this group include the following:

- Identifying the electricity conservation potential within the province;
- Developing and updating conservation and energy management options for the Integrated Resource Plan and long term conservation and energy management plan;
- Engaging customers, stakeholders and advisory groups with respect to conservation and energy management;
- Working with government and standards organizations on the research and development of new regulations, codes and standards; and
- Identifying new energy efficient technologies and practices, and working with stakeholders to advance their adoption.

Conservation and Energy Management utilizes its own resources and resources from other Key Business Units, to achieve conservation and energy management targets. For example, as described in section 5.5.6.1, the Customer Services department works directly with BC Hydro's largest customers through the Key Account Management group to deliver conservation and energy management programs.

Nearly all of Conservation and Energy Management's costs are classified as deferred operating expenditures as they are demand-side management related. See Chapter 10 for BC Hydro's demand-side management expenditures during the test period, pursuant to section 44.2 of the *Utilities Commission Act*.

Conservation and Energy Management also incurs operating expenditures, such as administrative costs, training and other activities that do not directly support Conservation and Energy Management targets, and are therefore classified as current operating expenditures, shown in Table 5-34.

5.7.5.7 Business Planning and Risk

The Business Planning and Risk Key Business Unit partners with other areas of the organization to support enterprise-wide business planning, workforce planning, and enterprise risk management activities, ensuring alignment with BC Hydro's vision and priorities. Specific activities that this group performs include the following:

- Support the development and roll-out of longer-term vision and priorities to guide business planning activities;
- Development of corporate work plans to support the vision and priorities, including the identification of related strategic and tactical risk;
- Development of a 10-year Workforce Plan to support BC Hydro's planned activities. The Workforce Plan forecasts BC Hydro's workforce requirements based on planned operating and capital work and identifies labour demand-supply gap risks based on internal and external factors. The Workforce Plan is provided in Appendix F and will be refreshed annually;
- Oversight of enterprise risk management which includes compiling and reporting out a view of top risks and operational risk areas, including reports where the Board has oversight; and
- Support the business groups in their development of their business plans aligned with the corporate strategy overview plan.

5.7.5.8 Policy and Reporting

Policy and Reporting is responsible for centralizing and coordinating policy development to support the achievement of BC Hydro's vision and company-wide priorities as well as government objectives. The department also provides strategic direction and advice to business groups across BC Hydro in response to emerging public policy developments and oversees the preparation of reports, such as the Annual Report and Service Plan and compliance reports on greenhouse gas emissions and low carbon fuel credits.

5.7.5.9 Communications

Communications is responsible for leading the development and delivery of information to the public and employees about BC Hydro's programs, projects and initiatives such as BC Hydro operations, capital projects, safety programs, emergency preparedness, customer service and conservation programs. The group also leads relationships with local governments, the media and other stakeholders. The group consists of the following departments:

Community Relations

Community Relations interacts with mayors, councillors and regional district officials and community leaders in over 160 communities. In addition, it is the primary local contact for all 85 Member of the Legislative Assembly constituency offices and maintains relationships with regional media. This team also works with other stakeholders including business groups, other utilities and crown corporations, customers and community organizations when there is an interest in or concern about BC Hydro activities.

During significant storms or emergency events, staff will become immediately involved in the emergency response process to ensure that elected officials and the community understands the impacts to the electrical system and BC Hydro's plans to restore power. They also facilitate communication and action between BC Hydro technical groups to prioritize critical response.

Local relationships with elected officials and the media are built throughout the province by representatives located in the Lower Mainland, Vancouver Island, Northern B.C., the Thompson Okanagan Columbia and East Kootenay.

This group also manages BC Hydro's community programs, including donations and sponsorships, activities in schools and three visitor centres located in Hudson's Hope, Revelstoke and Stave Falls.

Media Relations and Issues Management

Media Relations and Issues Management works with provincial and community media throughout B.C. to provide information about BC Hydro programs and initiatives as well as respond to emergency events and operational issues.

This group also responds to incoming inquiries on various topics about BC Hydro and its subsidiaries and provides reporters with information about BC Hydro projects, programs and activities. The group works closely with internal subject matter experts and senior managers to provide information to the public, through the media.

Marketing Communications

Marketing Communications develops proactive customer campaigns and supports a range of communications activities to build public awareness and understanding of key topics including electrical safety, customer service offerings, conservation and energy management programs and emergency and outage preparedness. The group manages digital communications channels (website, mobile, social media), face-to-face education and outreach programs for communities and schools and all customer-facing marketing communications activities, including integrated advertising campaigns across paid (i.e., advertising) and owned (i.e., website and newsletters) channels.

Capital Projects Communications

Capital Projects Communications works closely with community stakeholders, leading communications and consultation work on BC Hydro's large capital projects. This group delivers consultation with stakeholders, property owners, and the broader community. They gather input and local knowledge to inform the decision-making process on large projects that span BC Hydro's transmission, distribution and generation work across the province. The group communicates early and often to provide consultation, gather feedback, and share project information, regulatory requirements and construction schedules. By undertaking public consultation and by sharing information, the group aims to support public understanding of new infrastructure through transparency and open dialogue.

Employee Communications

Employee Communications connects BC Hydro's company-wide messages to all employees through a variety of communications platforms such as the employee intranet, employee newsletters, executive email/messages and company-wide conference calls. The group provides internal communications support to executive, as well as to specific business groups and/or cross-department projects.

5.7.5.10 Three-Year Operating Cost and FTE Summary

Differences are discussed in reference to Table 5-31, Table 5-33, Table 5-36 and Table 5-37.

Corporate Affairs operating costs decrease by $0.7 million in fiscal 2017 compared to fiscal 2016 Plan, then increase by $0.2 million for fiscal 2018 and by $0.6 million for fiscal 2019. The differences are described below.

The Corporate Affairs group was created in fiscal 2016 and brings together existing Key Business Units with two new Key Business Units created by transferring budget and FTEs from other areas of the business. The $0.7 million reduction in operating costs from fiscal 2016 Plan to fiscal 2017 is primarily related to reductions in Communications due to a decrease in the BC Hydro corporate donations and sponsorships program of $0.6 million, elimination and transfers of positions to Aboriginal Relations from Human Resources of $1.1 million, $0.4 million reduction in the Ethics Office and other efficiencies and cost reductions of $0.6 million. This is partially offset by the reorganization and transfers of budget and FTEs from other areas of the business of $2.1 million.

Operating costs increase by $0.2 million in fiscal 2018 and by a further $0.6 million in fiscal 2019 primarily due to Standard Labour Rate increases.

FTEs decrease by 20 in fiscal 2017 compared to fiscal 2016 actual FTEs primarily due to the changes in the demand-side management plan initiatives (as described in section 10.5 of the Application) resulting in a decrease of 14 FTEs, and a reduction of 14 in Communications primarily due to a reduction of outreach representatives as well as department reorganization and efficiencies, partially offset by some small FTE additions in other departments.

FTEs decrease by four in fiscal 2018 compared to fiscal 2017, due to the changes in the demand-side management plan initiatives as described in section 10.5. FTEs remain constant in fiscal 2019 compared to fiscal 2018.

5.7.6 Safety, Security and Emergency Management

In fiscal 2016, BC Hydro consolidated its safety functions under the Senior Vice-President of Safety, Security and Emergency Management. The reorganization brings together safety, security and emergency management to improve effectiveness of these three related business processes. This Key Business Unit provides leadership, direction and oversight of all three functions that span across

BC Hydro, enabling improved performance through consistent focus, programming, and messaging. Safety of employees, contractors, the public and BC Hydro’s assets is a key outcome in all three functions.

The Case for Safety and the Safety Priorities

Although our safety performance has improved over 2010, we must do better. Serious incidents where our employees are permanently disabled or killed occur on average every 20 months. High numbers of safety incidents impact our workers and their families and drive costs associated with lost-time injuries, investigations, WorkSafeBC premiums and penalties. Incidents negatively affect the organization’s culture, productivity and reputation and impact its ability to attract talent and maintain public consent to operate.

BC Hydro’s safety vision is ‘Everyone goes home safe every day’ and we believe ‘100 per cent of all injuries can be prevented.’ BC Hydro has five goals to realize this vision:

- Goal 1: Zero fatalities and zero disabling injuries;
- Goal 2: Year-over-year reduction in Lost Time Injuries and Medical Aid Injuries;
- Goal 3: Achieve regulatory compliance;
- Goal 4: Build culture to achieve excellence in safety; and
- Goal 5: Build corporate systems and tools supporting excellence in safety.

A strong safety culture and supporting systems and tools are essential to enable the outcome goals of zero serious injuries, a reduction in lost time and medical aid injuries and improving regulatory compliance in the management of safety risk.

BC Hydro is following a Five-Year Safety Plan, led by Safety and endorsed by the Executive Team that will see us developing and delivering programs and tools to help achieve BC Hydro’s vision and goals as shown in Appendix FF, Attachment 1.

The Five Year Safety Plan contributes to everyone getting home safe and is aligned with BC Hydro's Safety Policy in Appendix FF, Attachment 2.

BC Hydro has identified a list of safety improvement priorities and will monitor and measure its annual performance over the years with safety metrics and analytics including BC Hydro's Service Plan metrics in Appendix FF, Attachment 4. Improvement projects under these priorities are scheduled in fiscal 2017 to fiscal 2019 and have been included in the Safety operating and capital budgets. Priorities that must be implemented and sustained through fiscal 2017 to fiscal 2019 include:

- Developing seen and felt leadership through training and work observations, and supporting 'courage to intervene' if workers do not feel safe;
- Increasing awareness and learning from analysis and communication of safety metrics and data;
- Increasing the number of Safety Advocates[47] to support and guide workers and managers;
- Providing front-line workers with clear, concise and easily understood rules, procedures and drawings, and providing tools to easily access this information;
- Building one consistent place to store, access and update information on hazards and barriers;
- Conducting critical skills competency assessments and training for electrical workers, including Life Saving Rules related to electrical work, and SafeStart;[48]
- Improving job planning and identification of critical hazards and use of multiple barriers for high risk work;

[47] Safety Advocates – Safety leaders from the trades who provide safety support, guidance and direction to plant and field workers and managers.
[48] SafeStart – An externally-provided safety training program for developing personal 24/7 safety skills. It is being reintroduced to address injury rates and employee demand.

- Identifying new tools and procedures to reduce injuries from cuts;
- Maximizing opportunities to design out hazards with 'safety by design' early in the design process and project identification stage;
- Completing safety risk assessments early in asset management planning to meet all business objectives related to safety, cost, schedule, reliability and customer satisfaction;
- Completing and sustaining all corrective actions after injury and near miss incidents; and,
- Completing and sustaining improvements from asbestos and confined space risk management projects.

Many of these priorities are underway, with phased completion dates reflecting the effort, resources and degree of change required for the organization.

Regulatory Safety Priorities

BC Hydro is working with WorkSafeBC to ensure procedures and processes meet current and new regulations. Regulatory priorities in fiscal 2017 that must be sustained through fiscal 2017 to fiscal 2019 include:

(a) Streamlining the investigation and incident management process to support timely learning and effective corrective actions;

(b) Improving protection for all workers in relation to asbestos and when accessing confined spaces in stations, plants and underground facilities;

(c) Developing a comprehensive arc flash program to ensure effective management of this electrical hazard; and

(d) Implementing a program to inventory, test and certify cranes.

BC Hydro's efforts to improve asbestos and confined space management are company-wide and significant, as are our efforts to support capital project and contractor safety.

Asbestos Management

WorkSafeBC regulations require that an asbestos management plan be in place for all workplaces that have asbestos containing materials. Safety is working with the business groups to improve asbestos inventories and labelling for all generation, transmission and distribution facilities and manholes. BC Hydro's Asbestos Management Program will be updated to improve governance and standardization, and asbestos management activities will be embedded in asset management and work issuance processes to ensure inventories and labels are sustained and asbestos containing materials hazards are consistently identified for workers. Finance will develop asbestos retirement estimating guidelines and liability reporting expectations for all business groups.

Confined Space Management

To address deficiencies and gaps in our management of work involving confined space, Safety is working with all business groups to implement the Confined Space Management Program by ensuring the following are in place: comprehensive inventories and hazard assessments of confined spaces; procedures to identify hazards to employees and contractors; standardized equipment to improve efficiency and effectiveness across the organization; and training to support programs and workers for entry into confined spaces and rescue requirements.

Capital Project Safety and Contractor Safety Management

To support BC Hydro's capital program every year through the end of the 2013 10 Year Rates Plan, BC Hydro has augmented safety support for fiscal 2017 and going forward through fiscal 2017 to fiscal 2019 to capital projects. BC Hydro is developing a Contractor Safety Management program to provide comprehensive policies, procedures and tools for end-to-end safety management from initial planning and procurement to conclusion and evaluation of contract work. This will improve contractors' ability to perform BC Hydro work safely and support BC Hydro employees who oversee contractor work.

Sections 5.7.6.1 to 5.7.6.3 describe the activities and costs of each department in Safety, Security and Emergency Management.

5.7.6.1 Safety Department

The Safety department is responsible for providing centralized safety leadership, oversight, services, programs, tools and technical expertise in concert with and in support of all business groups in order to meet regulatory requirements and improve safety of employees, contractors and the public.

While managers and supervisors throughout the company are directly accountable for the safety of the workers they lead and for compliance with safety regulations, the mandate of the Safety department is to work with groups across the company to improve safety performance. Managers and supervisors rely on the Safety team for its expertise when planning and executing their work, and when safety issues arise. Through planned means such as participation or leadership in planning, coordination or governance meetings, or through direct requests from the field as issues arise, the Safety department is fully integrated into BC Hydro's operations.

Safety employs Occupational Safety and Health Specialists, engineers and other subject matter experts to provide support directly to: managers and crew leads in the operational groups; project groups managing contractors; asset management; corporate groups; and indirectly to the public, including first responders (police, fire, paramedics) across B.C. Key activities include:

- Providing expertise and oversight in health and safety, safety engineering, safety-by-design and risk analysis;

- Coordinating annual safety planning;
- Advising employee Joint Health and Safety Committees across BC Hydro;
- Leading development and sustainment of safety standards and programs to ensure consistent application and support compliance across the company;
- Analyzing data and reporting lessons from incidents and auditing processes; and
- Leading serious incident investigations and safety audits and supporting investigations and checking activities conducted by managers.

These services drive compliance and safety performance. Team members are located across the province to build working relationships, develop strong understanding of safety hazards and issues, and to optimize safety services based on client needs in 32 generating stations, over 70 Transmission and Distribution field and district offices, Materials Management, Fleet Services, and for over 1,000 mobile workers.

The following section describes the four groups within the Safety department.

Safety Projects and Program Management

This group designs, develops and executes safety projects and programs to integrate solutions for improved safety performance into the business. Projects and programs address specific safety risk management priorities identified through the Safety team's work with regulators and/or safety analytics. Work includes:

- 17 of the 21 Safety Taskforce recommendations have been implemented and transferred to sustainment. The four remaining recommendations to be implemented have been incorporated into the Five-Year Safety Plan.(see Appendix FF, Attachment 3). Some recommendations are being led and implemented by other business groups. The taskforce was initiated following an employee fatality in 2010;

- Developing processes and programs to meet regulations and improve protection of all workers managing asbestos and accessing confined spaces;
- Developing a program to effectively manage Power System Safety Protection authorizations, audits and training for employees and contractors; and
- Improving our Safety Management Framework to make it easier for employees and contractors to get the information and support they need to work safely, and to provide reliable information and processes to effectively manage safety risks. Work on the Safety Management Framework will also improve clarity of safety roles and responsibilities, define safety risk assessment, and processes required to ensure continuous improvement of BC Hydro's safety performance.

Safety Engineering

This group includes three teams: Safety Engineering, Public Safety, and Fire Marshal.

Safety Engineering specializes in Safety by Design, electrical safety, human factors, and other technical safety disciplines. The team provides ongoing Safety by Design support and process improvement to engineering and design work in capital projects, engineering standards and equipment specifications development.

Public Safety is responsible for increasing public awareness of electrical safety at home, at work and in the community as well as implementing public safety control measures at our dams and public use management areas.

The Fire Marshal provides general oversight, support and governance functions related to fire risk management, including wildfire, and serves as the authority having jurisdiction for topics that would otherwise fall under the BC Fire Commissioner mandate but do not due to provisions in the *Hydro and Power Authority Act*.

Field Safety Services

This group delivers core safety programs and advice to all of BC Hydro's operational and administrative areas. The expertise ensures work at the frontline is conducted safely and meets regulatory requirements. The group assists with safety program implementation and responds to safety issues raised by employees and managers. Field Safety Services employs Occupational Safety and Health Specialists and Safety Advocates.

Occupational Safety and Health Specialists support work involving protection from all workplace hazards, including asbestos, confined space, and working from heights. They are involved in all aspects of work planning and execution, hazard identification, risk assessment and safe work procedure development, and inspections to ensure compliance. During construction projects, they ensure site safety coordination takes place and inspect job sites and work activities. They work with contractors and hold them accountable for meeting safety obligations. Safety Advocates provide leadership for safe work across operations and capital programs. They are highly trained, experienced electrical tradespeople who observe work practices as well as coach and mentor plant and field workers and managers on topics including safety leadership, safe work procedures, job planning, and interpretation of rules.

Safety Strategy and Compliance

This group establishes, monitors and reports on safety strategy, policy, standards, metrics and targets to inform safety program development, implementation and sustainment across the company. It comprises three teams.

The Regulation, Policy and Standards team monitors, interprets and translates regulatory changes and emerging issues that impact BC Hydro's operations and require program development. It builds BC Hydro's safety strategy, policy and standards to meet regulations and business requirements, and provides safety and hygiene expertise to safety professionals, programs and operations, as well as engages with regulatory agencies.

The Safety Assurance team oversees, manages and assures quality of the incident management system, leads and supports investigations, and designs and conducts Safety audits. It supports corrective action development and learning from incidents.

The Safety Systems and Analytics team analyses data to inform decisions that impact safety. It conducts trend analysis, metric and target development, external benchmarking with peer utilities, and reporting to management and the Board.

5.7.6.2 Security

The Security department is responsible for the protection and security our people, infrastructure, assets and operations. To do so, we provide:

- Security solutions and systems based on industry best practices;
- Centralized security intelligence gathering, monitoring, reporting and planning; and
- Coordinated security operations with key vendors, suppliers, security and law enforcement agencies.

Priorities in fiscal 2017 that must be sustained through fiscal 2017 to fiscal 2019 and beyond include:

- Design and implementation of security solutions and systems as required by the North American Electric Reliability Corporation, Critical Infrastructure Protection; and
- Continuing to protect facilities and/or assets based on changing security requirements or increased threats.

Security services are provided through the following teams:

Security Operations

Security Operations secures and protects BC Hydro's assets, people and operations (i.e., substations, generating facilities, microwave sites, field offices and information systems). Security Operations delivers:

- Service through day-to-day management of a guard workforce, a central Security Command Center and contracted services when gaps in service delivery arise;
- Subject matter expertise on both security and non-security initiatives and projects;
- Security incident management, including managing security response, implementation of corrective actions, and reporting; and
- A variety of other services and guidance to senior management and operational groups on matters such as workplace violence.

Security Investigations

The Security investigation team consists of two investigators who are responsible for all security investigations across BC Hydro. Approximately 1,700 incidents are received each year by Security Command Center and reviewed by the investigation team. They conduct investigations into high risk files such as theft, criminal organizations and marijuana grow operations. The investigators liaise with law enforcement and intelligence agencies to gather key threat risk assessment information. The investigation team provides assistance to Human Resources, Employee Relations, Ethics, Safety and Legal on sensitive investigations or matters of concern, and the investigators work with provincial government agencies on enforcement and regulatory projects and issues such as the newly created *Metal Dealers and Recyclers Act* to help combat theft of copper.

Security Analysts

The Security Analyst team consists of two criminal analysts who gather security data from investigations, complaints and other related sources. The analysts collate and analyse these data and create reports, informing Security on emerging security trends and allowing for effective operational response planning. The analysts work with the investigators to support evidence collection and report creation as part of an overall investigation team. The analysts create and disseminate daily, weekly and monthly reports at the direction of the Security managers.

Security Engineering/Capital Projects

The Security engineer and technical advisors lead security aspects of capital projects planning, delivery and support for various transmission, distribution and generation capital projects. They are also subject matter experts for specific areas, such as access control, security systems (e.g., cameras, alarms, card swipes, etc.) and installation and oversight of these projects. They also have a very specific skill set to act as planners for North American Electric Reliability Corporation Critical Infrastructure Protection expansion and implementation.

5.7.6.3 Emergency Management

Emergency Management is responsible for ensuring the creation of plans through which the company reduces vulnerability to hazards and the impacts that incidents or emergencies have on the public, our people, our services and operations, our assets and infrastructure, the environment and our reputation in accordance with the *Provincial Emergency Program Act*, the *Water Act*, Dam Safety Regulations, and WorkSafeBC's Occupational Health and Safety Regulations. Emergency Management ensures appropriate risk management processes are developed and implemented across BC Hydro, incorporating international best practices. Emergency Management undertakes key activities including:

- Risk and hazard identification and management;

- Identification of critical business processes and functions (i.e., business continuity or continuity of operations); and
- Planning and preparedness, including training and exercises, and response and recovery.

5.7.6.4 Three-Year Operating Cost and FTE Summary

Differences are discussed in reference to Table 5-31 and Table 5-33.

Security and Emergency Management operating costs during fiscal 2017 to fiscal 2019 are planned to remain constant with fiscal 2016 Plan.

Safety Operating costs will increase by a $4.3 million in fiscal 2017 and remain at that level for fiscal 2018 and fiscal 2019. This increase relates to $5.0 million of additional funding to implement Safety Improvement Projects that address the four remaining BC Hydro Safety Taskforce recommendations, comply with regulatory arc flash and confined space requirements set out for us by WorkSafeBC and build corporate systems and tools supporting excellence in Safety (e.g., Field Access to Safety Information).

Safety, Security, and Emergency Management will increase by seven FTEs in fiscal 2017 compared to fiscal 2016 actual FTEs with a further two in fiscal 2018. These additions are related to the Workforce Optimization Program and will replace contractors supporting Capital work.

5.7.7 General Counsel

This group includes Legal Services, Corporate Secretary's Office and Freedom of Information Coordinating Office.

Legal Services provides legal advice and representation, through internal and external counsel, on matters such as rates and regulatory, commercial transactions, First Nations issues and major civil claims by and against BC Hydro. External legal services are utilized particularly in areas requiring specialized expertise or larger scale legal resourcing, like intellectual property, labour and tax law, complex regulatory hearings, major commercial transactions, and litigation.

The Corporate Secretary's Office serves as the records and registered office for BC Hydro and its subsidiaries and ensures that corporate governance principles and practices are adhered to, in accordance with the requirements of legislation, corporate policies, and shareholder expectations.

The Freedom of Information Coordinating Office is responsible for administering BC Hydro's compliance with the (B.C.) *Freedom of Information and Protection of Privacy Act*. The Freedom of Information Coordinating Office administers *Freedom of Information and Protection of Privacy Act* compliance through various BC Hydro policies and procedures.

5.7.7.1 Three-Year Operating Cost and FTE Summary

Differences are discussed in reference to Table 5-31 and Table 5-33.

Operating expenditures for the General Counsel Key Business Unit during fiscal 2017 to fiscal 2019 are planned to remain relatively constant with the fiscal 2016 Plan costs.

The General Counsel FTEs during fiscal 2017 to fiscal 2019 are also planned to remain relatively constant with the fiscal 2016 actual FTEs.

5.7.8 Independent Power Producer Capital Leases

The Operations Support Business Group includes the operating costs in relation to Electricity Purchase Agreements that are being accounted for as capital leases. In the fiscal 2016 Plan these costs were $33.8 million and will decrease by $5.6 million in fiscal 2017, as one of the Electricity Purchase Agreements expected to be a capital lease in the fiscal 2016 Plan did not meet the capital lease accounting criteria when it began commercial operations. Costs will then increase by $35.4 million in fiscal 2018, due to two additional Electricity Purchase Agreements coming into service during fiscal 2017 that will be accounted for as capital leases effective late-fiscal 2017. These costs will then decrease by $9.2 million in fiscal 2019 due to the expiry of one Electricity Purchase Agreement accounted for as a capital lease.

5.7.9 Corporate Costs

Corporate Costs is a category of general expenses that are not specifically related to any single Business Group or Key Business Unit and are managed centrally under the Operations Support Business Group. The primary costs in this category include insurance costs, corporate membership dues and fees, and IFRS ineligible capital overhead.

Insurance costs are based on the assets covered by the policies and the risks associated with the operations of the respective business groups. The costs are for various insurance policies including property, corporate general liability, directors' and officers' liability, fiduciary liability and several other smaller, miscellaneous insurance policies.

Annual Commission fees, National Energy Board fees, and various other smaller memberships are also planned in Corporate Costs. BC Hydro cancelled its membership in the Canadian Electricity Association as part of our cost saving initiatives.

Costs no longer eligible as capitalized overhead under IFRS are included in Corporate Costs. The IFRS ineligible capital overhead amount determined at the time of the transition to IFRS is being phased in to operating expenses over a 10-year period in accordance with the IFRS Property, Plant and Equipment regulatory account approved in British Columbia Utilities Commission Order No. G-77-12A for BC Hydro's Fiscal 2012-Fiscal 2014 Revenue Requirements Application. The annual credits planned in Corporate Costs are the annual amounts transferred to the IFRS Property Plant and Equipment regulatory account. The reduction in the annual amounts reflects the phase in to eliminate the transfers over a 10-year period. Over the test period, the annual reduction is $22.4 million per year, which drives the key change in Corporate Costs for each year of the test period.

5.8 Post-Employment Benefit Costs

Post-employment benefit costs are comprised of current service costs and non-current service costs. This section has been prepared under International Accounting Standard 19, except that the expected return on plan assets is determined based on the expected long term rate of return rather than the liability discount rate as specified by International Accounting Standard 19. This forecast methodology is consistent with previous revenue requirement applications.

5.8.1 Current Service Costs

Current service costs are the annual costs of accruing employees' post-employment benefits. It is the recognition of the cost of the future benefits earned by the employees in the current year. These costs are included in the Standard Labour Rates and charged to current work (capital and operating), and are therefore reflected in the costs presented throughout the Application.

The actuarial valuation for accounting purposes determines the cash flow stream of all the future benefit payments of the post-employment benefit plans. For accounting purposes, the present value of the costs of those future payments is allocated to the year in which those future benefit payments were earned.

The costs are allocated to specific years using an actuarial cost method called the projected accrued benefit method prorated on service. An actuarial valuation is required to be performed at least once every three years. Actuarial projections are performed in between actuarial valuation years. The last actuarial valuation was performed as at December 31, 2012, and an actuarial valuation is currently being performed as at December 31, 2015 which will be completed by September 2016.

Current service costs are sensitive to changes in the discount rate. A decrease in the discount rate will increase current service costs while an increase in the discount rate will decrease current service costs.

The forecast for current service costs is shown in Table 5-38. The increase in the planned current service costs for fiscal 2017 to fiscal 2019 compared to fiscal 2016 Plan is primarily due to a decrease in the forecast discount rate.

For the fiscal 2017 to fiscal 2019 Plan, BC Hydro has used a discount rate based on the average of the actual discount rates used in the calculation of actual Current Service Pension costs of the previous five fiscal years (fiscal 2012 to fiscal 2016). Please see Chapter 7, section 7.5.12 for a discussion of the approach for determining the discount rate for the fiscal 2017 to fiscal 2019 Plan and BC Hydro's application for approval of current service cost variances to plan.

Table 5-38 BC Hydro Current Service Costs

($ million)	F2015 Plan	F2015 Actual	F2016 Plan	F2016 Actual	F2017 Plan	F2018 Plan	F2019 Plan
Current Service Costs	76.5	89.8	76.5	113.4	87.0	88.3	89.7

5.8.2 Non-Current Service Costs

The non-current service costs and the components of the costs for fiscal 2017 to fiscal 2019 are shown in Table 5-39. The table separates the portion relating to the BC Hydro registered pension plan and other post-employment benefit plans which include post-retirement medical, extended health, dental benefits and the supplemental pension plan.

Non-current service costs are charged to operating expenses of the Operations Support Business Group, as shown in Table 5-31.

Table 5-39 Non Current Service Costs, Fiscal 2017 to Fiscal 2019

	F2016 Plan			F2017 Plan			F2018 Plan			F2019 Plan		
($ million)	**Pension Benefit**	**OPEB**	**Total**	**Pension Benefit**	**OPEB**	**Total**	**Pension Benefit**	**OPEB**	**Total**	**Pension Benefit**	**OPEB**	**Total**
Plan Income	(203.1)	N/A	(203.1)	(234.1)	N/A	(234.1)	(243.9)	N/A	(243.9)	(254.1)	N/A	(254.1)
Interest Expense	180.0	23.2	203.2	198.8	25.7	224.5	205.1	26.7	231.8	211.7	27.8	239.5
Total	(23.1)	23.2	0.1	(35.3)	25.7	(9.6)	(38.8)	26.7	(12.1)	(42.4)	27.8	(14.6)

A description of the components of non-current service costs follows in sections 5.8.2.1 and 5.8.2.2.

5.8.2.1 Plan Income

Plan income is estimated using the expected long term rate of return on the actual asset allocation of the BC Hydro registered pension plan. The market value of the plan is provided by the British Columbia Investment Management Corporation, BC Hydro's external investment manager.

The plan income is calculated by multiplying the expected long-term rate of return by the market value of the plan assets at the beginning of the fiscal year, adjusted for expected contributions and benefit payments during the year. A decrease in the expected long-term rate of return on pension plan assets will decrease the amount of plan income recognized. Other post-employment benefit plans (OPEB) income are not applicable as these are unfunded plans with no assets and do not earn income.

5.8.2.2 Interest Expense

Interest expense, also known as interest accretion, relates to the expected increase in the discounted pension benefit obligation to recognize the passage of time.

Interest expense is calculated by multiplying the discount rate by the amount of the pension obligation at the beginning of the fiscal year adjusted for the accrual of current service costs and expected benefit payments during the year.

A decrease in the discount rate will decrease the amount of interest expense (a rate variance). At the same time, a decrease in the discount rate will increase the accrued benefit obligation and thereby increase the interest expense (a volume variance). However, a decrease in the discount rate will result in a net overall decrease in interest expense.

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Fiscal 2017 to Fiscal 2019
Revenue Requirements Application

Chapter 6

Capital Expenditures and Additions

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6.1 Introduction

This chapter addresses BC Hydro's planned capital expenditures and additions over the test period, and the measures in place to ensure effective budgeting and efficient and timely delivery of capital projects and programs. The material in this chapter demonstrates that BC Hydro has undertaken a comprehensive capital planning process that balances the need for important investments and achieving the targets of the 2013 10 Year Rates Plan. BC Hydro's capital additions and expenditures for fiscal 2017 to fiscal 2019 will enable BC Hydro to continue to provide safe, reliable and responsive service to customers across the province. The forecast capital expenditures will address system requirements to meet customer growth and needs, address issues related to aging infrastructure, safety and security, and meet environmental and other regulatory requirements and our commitments to First Nations and other stakeholders.

This chapter is structured as follows:

- Section 6.2 summarizes BC Hydro's planned capital expenditures and additions for the fiscal 2017 to fiscal 2019 test period;
- Section 6.3 describes BC Hydro's corporate wide capital investment planning process, including the comprehensive planning processes in place for the Generation, Transmission and Distribution, Technology, Properties and Fleet/Other capital asset categories;
- Section 6.4 addresses capital project and program delivery processes used to implement BC Hydro's capital projects and programs in an efficient and timely manner; and
- Section 6.5 describes BC Hydro's forecast capital expenditures and additions for fiscal 2017 to fiscal 2019 for each of the Generation, Transmission and Distribution, Technology, Properties, and Fleet/Other asset categories, as well as the Site C Clean Energy Project.

Note that tables with financial information presented in this chapter may not add due to rounding. Please also note, in the tables in this Chapter, references to F2015 RRA or F2016 RRA signifies the Plan amount from the Fiscal 2015 - Fiscal 2016 Revenue Requirements Rate Application.

The information in Chapter 6 is supplemented by the following capital related information in the Appendices of the Application.

Table 6-1 Capital Related Information Provided in the Fiscal 2017 - Fiscal 2019 Revenue Requirements Application

Document	Content
Appendix A, Schedule 13.0	Revenue Requirements Application Model, schedule of Capital Expenditures, Additions and Amortization for fiscal 2017 to fiscal 2019, and historical information
Appendix G	BC Hydro 10 Year Capital Forecast - Including years fiscal 2017 to fiscal 2026
Appendix H	BC Hydro Organizational Chart
Appendix I	Projects and programs capital addition information for projects greater than $5 million with both capital expenditures and capital additions in the test period (Technology projects and programs greater than $2 million).
Appendix J	Project descriptions as of March 2016 for projects with planned total capital expenditures >$20 million and with capital expenditures in the test period, including project description, key drivers, issues addressed by the project, and a discussion of alternatives where relevant.
Appendix K	Fiscal 2015 - Fiscal 2016 Revenue Requirements Application Plan vs Actual results and explanations of major variances
Appendix M	Uniform System of Accounts – includes Fiscal 2015 - Fiscal 2016 Revenue Requirements Application Plan and Actual and Fiscal 2017 – Fiscal 2019 Plan - Property, Plant and Equipment Schedule
Appendix O	Technology Group 5 Year Strategic Plan

6.2 Description of BC Hydro's Planned Capital Expenditures and Additions for Fiscal 2017 to Fiscal 2019

This section summarizes BC Hydro's planned capital expenditures and additions for the fiscal 2017 to fiscal 2019 test period. The difference between expenditures and additions, which are addressed separately below, is as follows:

- Expenditures directly attributable to capital projects or programs are capitalized in accordance with International Financial Reporting Standards. In general, capital project expenditures are eligible for capitalization when the leading alternative is selected, management has made the decision to proceed with the project, the project is technically feasible and necessary approvals are likely to be obtained. Capital expenditures do not impact rates until the project is placed into service and they become capital additions. A discussion of capital project phases is provided in section 6.4.1.3; and
- Capital additions refer to the cost of capital projects or programs that come into service and are made available for use within a particular time period. Capital additions are amortized into rates over the life of the asset.

6.2.1 Capital Expenditures

BC Hydro's forecast capital expenditure portfolio is divided into the main asset categories of Generation, Transmission and Distribution, and ~~Operations~~ Business Support, which includes Technology, Properties, and Fleet/Other. The Site C Clean Energy Project is part of Generation, but because of its size and scope, is shown separately in certain sections where appropriate, and discussed in section 6.5.9.

BC Hydro's actual and planned capital expenditures for fiscal 2015 - fiscal 2019 are provided in Table 6-2, below. A discussion of the major variances for historical plan to actual capital expenditures is provided in Appendix K.

Table 6-2 BC Hydro Actual and Planned Capital Expenditures Fiscal 2015 to Fiscal 2019

($ million)	F2015 RRA	F2015 Actual	F2016 RRA	F2016 Actual	F2017 Plan	F2018 Plan	F2019 Plan
Generation (including Site C Clean Energy)	632.6	551.4	607.0	987.5	1,292.5	1,253.0	1,254.2
Transmission & Distribution	1,329.8	1,361.4	1,101.2	1,034.9	1,082.3	941.8	936.8
Business Support							
Technology (Schedule 13, Line 19)	164.1	115.2	109.3	122.3	83.9	93.4	78.8
Properties (Schedule 13, Line 22)	96.3	83.9	85.1	78.8	85.7	75.0	88.3
Fleet/Other (Schedule 13, Line 25)	29.7	47.9	36.6	72.5	49.7	48.6	39.6
Total	2,252.5	2,159.8	1,939.2	2,296.0	2,604.0	2,411.8	2,424.6
Less: Contribution in Aid	(85.1)	~~(333.9)~~ (334.4)	(124.1)	~~(135.5)~~ (133.8)	(86.4)	(100.2)	(106.4)
TOTAL	2,167.4	~~1,825.9~~ 1,825.4	1,815.1	~~2,160.5~~ 2,162.2	2,517.6	2,311.6	2,318.2

The planned capital expenditures include expenditures to sustain existing BC Hydro assets as well as growth expenditures to meet new customer requirements for supply.

The business drivers for each of these expenditures types are discussed below.

6.2.1.1 Expenditures to Sustain Existing Assets

Sustaining investments address safety and security, reliability, end-of-life, regulatory and environmental issues associated with existing assets. BC Hydro makes sustaining investment decisions that are aligned with good practices with other asset management focused industries. Important factors and considerations in determining sustaining these investments and their timing include:

- Asset and operational safety and security;
- Asset condition or health;
- Asset demography;
- Resource availability;

- Outage availability;
- Changing regulations and standards; and
- Procurement lead times.

6.2.1.2 Growth Driven Expenditures

Growth projects meet anticipated customer demand and increase supply-side efficiency. Important factors and considerations in determining growth investments and their timing include:

- BC Hydro's 2013 Integrated Resource Plan;
- Load Forecast; and
- Customer requirements

BC Hydro's actual and planned capital expenditures for fiscal 2015 to fiscal 2019, classified by sustaining and growth driven expenditures are provided in Table 6-2 and Table 6-3, below. Note that Table 6-3 includes planned capital expenditures for the Site C Clean Energy Project in order to align with Schedule 13 of Appendix A, which provides all of BC Hydro's capital expenditures and additions for fiscal 2017 to fiscal 2019. There are no planned capital additions for the Site C Clean Energy Project in the test period and therefore Table 6-4 does not include any additions related to the Site C Clean Energy Project.

Table 6-3 BC Hydro Actual and Planned Growth and Sustaining Capital Expenditures Fiscal 2015 to Fiscal 2019

($ millions)	F2015		F2016		F2017	F2018	F2019
	RRA	Actual	RRA	Actual	Plan	Plan	Plan
Generation							
Growth (Schedule 13, Line 4)	116.1	108.0	71.2	61.2	20.0	2.4	0.7
Growth - Site C Clean Energy (Schedule 13, Line 15)	-	25.2	-	489.4	742.5	716.5	829.2
Sustaining (Schedule 13, Line 5)	516.5	418.2	535.7	436.8	530.0	534.0	424.3
Transmission & Distribution							
Growth	972.2	1,029.0	679.8	607.4	641.8	455.4	402.2
Sustaining	357.6	332.4	421.4	427.5	440.5	486.4	561.6
Business Support[1]							
Technology (Schedule 13, Line 19)	164.1	115.2	109.3	122.3	83.9	93.4	78.8
Properties (Schedule 13, Line 22)	96.3	83.9	85.1	78.8	95.7	75.0	88.3
Fleet / Other (Schedule 13, Line 25)	29.7	47.9	36.6	72.5	49.7	48.6	39.6
Total	2,252.5	2,159.8	1,939.2	2,296.0	2,604.0	2,411.8	2,424.6
Less: Contribution in Aid	(85.1)	~~(333.9)~~ (334.4)	(124.1)	~~(135.5)~~ (133.8)	(86.4)	(100.2)	(106.4)
TOTAL	2,167.4	~~1,825.9~~ 1,825.4	1,815.1	~~2,160.5~~ 2,162.2	2,517.6	2,311.6	2,318.2

Note 1 Business Support expenditures are considered sustaining.

6.2.2 Capital Additions

As with capital expenditures, BC Hydro's forecast capital additions can be divided into the main asset categories of Generation, Transmission and Distribution, and ~~Operations~~ Business Support, which includes Technology, Properties, and Fleet/Other. There will be no additions for the Site C Clean Energy Project during the test period.

Planned capital additions in any year are impacted by the lifecycles of the capital projects and in particular project implementation dates. For example, in fiscal 2019 Generation capital additions are forecast to increase by approximately $1 billion compared to fiscal 2018, primarily due to the John Hart Generating Station Replacement coming into service.

BC Hydro's actual and planned capital additions for fiscal 2015 to fiscal 2019, classified by sustaining and growth driven additions are provided in Table 6-4, below. A discussion of the major variances for fiscal 2015 and fiscal 2016 Plan (i.e., the fiscal 2015 and 2016 plan presented in the Fiscal 2015 - Fiscal 2016 Revenue Requirements Rate Application) to actual capital additions is provided in Appendix K.

Table 6-4 BC Hydro Actual and Planned Growth and Sustaining Capital Additions Fiscal 2015 to Fiscal 2019

($ millions)	F2015		F2016		F2017	F2018	F2019
	RRA	Actual	RRA	Actual	Plan	Plan	Plan
Generation							
Growth	298.4	293.4	298.7	245.4	26.6	0.9	0.2
Sustaining	314.8	189.7	305.6	289.0	486.4	386.2	1,332.0
Transmission & Distribution							
Growth	1,313.3	1,137.9	1,627.0	1,486.8	581.9	472.8	442.8
Sustaining	330.0	340.5	400.3	431.5	437.4	374.6	429.0
Business Support[1]							
Technology (Schedule 13, Line 45)	113.7	82.3	103.0	145.2	81.6	91.1	112.6
Properties (Schedule 13, Line 53)	113.4	83.6	92.4	160.9	68.3	118.1	25.5
Fleet / Other (Schedule 13, Line 56)	28.0	26.5	35.2	23.7	55.3	46.1	45.7
Total	2,511.6	2,153.8	2,862.2	2,782.6	1,737.6	1,489.9	2,387.8
Less: Contribution in Aid	~~(162.7)~~ (85.1)	~~(333.2)~~ (388.3)	~~(129.3)~~ (124.1)	~~(110.9)~~ (111.1)	~~(89.8)~~ (90.1)	(88.0)	~~(84.4)~~ (84.6)
TOTAL	~~2,348.9~~ 2,426.5	~~1,820.6~~ 1,765.5	~~2,732.9~~ 2,738.1	~~2,671.7~~ 2,671.5	~~1,647.8~~ 1,647.5	1,401.9	~~2,303.4~~ 2,303.2

Note 1 Business Support additions are considered sustaining.

Additional information on planned fiscal 2017-fiscal 2019 capital expenditures and capital additions for each category is provided in section 6.5.

6.3 BC Hydro's Capital Investment Planning Process

This section describes BC Hydro's corporate wide capital investment planning process for Generation, Transmission and Distribution, Technology, Properties and Fleet/Other capital investments. BC Hydro has planning and oversight structures in place across the organization to ensure that the capital expenditures required to sustain, expand and operate its system and meet information technology requirements are appropriate and that capital projects and programs are delivered on time and on budget.

6.3.1 Overview of BC Hydro Assets

BC Hydro's system is composed of a large number of complex and diverse assets and infrastructure, which are located across the province, over a varied and challenging geography. Generation assets include 82 generating units at BC Hydro's 30 hydroelectric generating stations, three gas–fired units at BC Hydro's two thermal generating stations and four synchronous condenser units at a dedicated synchronous condenser station. BC Hydro's large generation assets are situated considerable distances from load centers, requiring significant infrastructure to deliver electricity to customers. BC Hydro has over 18,500 circuit km of transmission overhead lines, approximately 500 km of transmission subterranean and submarine cables, 306 substations, an integrated telecommunication system, approximately 48,600 circuit km of distribution overhead lines, 10,000 circuit km of distribution underground lines, and distribution facilities in 18 non-integrated areas. Overall, BC Hydro has approximately four million individual transmission and distribution assets.

BC Hydro has close to $520 million in information technology (**IT**) assets including $360 million in software, $110 million in hardware, and $50 million in telecommunications assets. Thousands of computers and other devices are used by a diverse workforce to access hundreds of applications and databases on a regular basis.

Vehicle Fleet and Equipment includes close to 3,200 vehicles, trailers and other equipment assets used by field crews and staff across the province. Properties assets include close to 100 office and field facilities across the province that supports field crews and a wide range of critical and operational functions.

6.3.2 Integrating Capital Planning and Delivery

In the context of capital investments, planning refers to the activities to identify investments in response to needs or opportunities and to rank the investments into portfolios that align with financial and labour resource availability. Delivery activities refers to the execution of a project through the project delivery lifecycle, or through the ongoing activities within a recurring capital program.

BC Hydro integrates the capital planning and capital delivery processes to effectively and efficiently deliver projects, so that the projects are executed by the appropriate delivery groups. This includes processes and governance structures so that projects are planned for release with the appropriate resource analysis, and scoped to meet business requirements. Collaboration between planning and delivery activities allows information to be shared. The project delivery processes and integration with the capital planning function are described in more detail in section 6.4 Capital Project and Program Delivery.

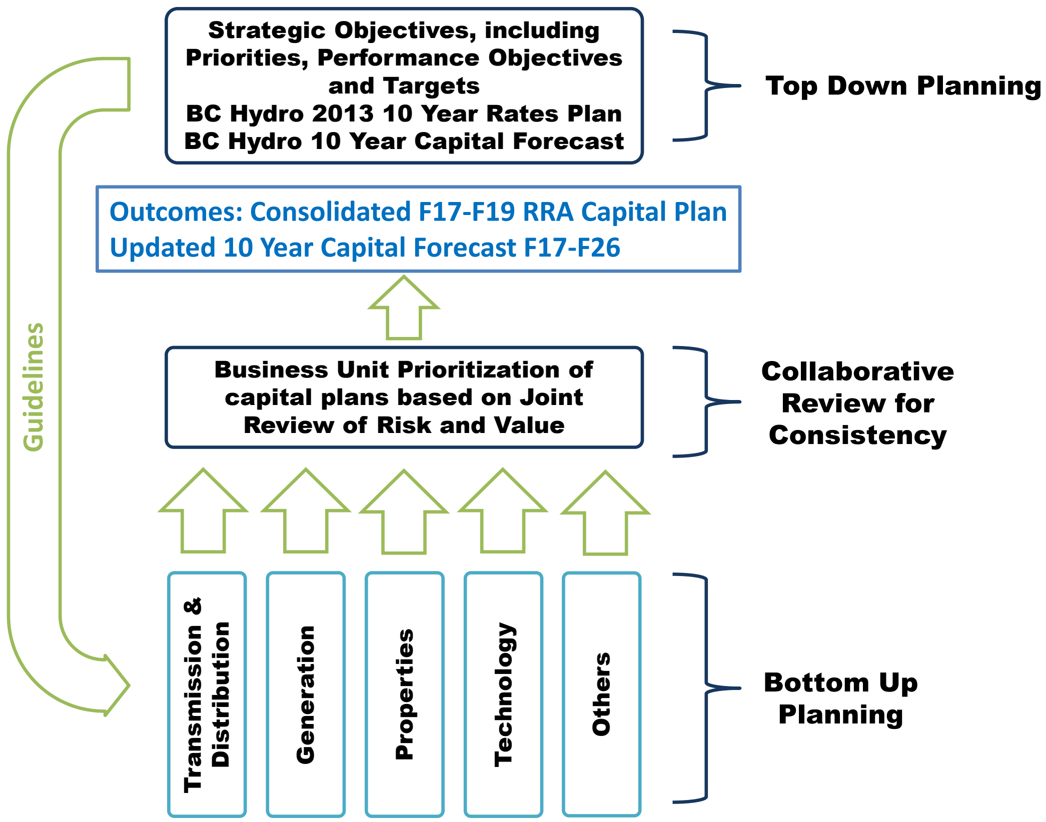
The planning and delivery of the forecast capital expenditures for fiscal 2017 to fiscal 2019 is aligned with the following priorities:

- Operating prudently and efficiently, providing safe, reliable, affordable, and clean electricity, now and in the future;
- Adhering to our 2013 10 Year Rates Plan, and successfully expanding, upgrading and rehabilitating our aging assets,to support the province’s growing economy and population, and to meet customers’ evolving needs; and
- Undertaking ongoing engagement and building effective relationships with stakeholders and First Nations.

6.3.3 Planning Process: Top Down, Bottom Up and Collaborative Prioritization

BC Hydro utilizes both a top-down and bottom-up approach to capital planning, including collaborative reviews so that its short and long term capital plans are appropriate and aligned with the overarching targets and strategic objectives of the corporation. Figure 6-1, below outlines this capital planning process and each step of the process is described in the following discussion.

Figure 6-1 Capital Planning Process



1. Top Down Planning and Guidelines

BC Hydro's top-down planning process refers to the guidance and direction to the planning process provided by the executive team, and also refers to the impact of two key documents which provide ongoing strategic direction and financial targets for the corporation's planning activities, namely the 2013 10 Year Rates Plan and the 10 Year Capital Plan prepared in 2014. This top-down direction and the key documents provide guidance for the preparation of the capital expenditure portfolios for each of the key capital asset categories, which are prepared annually and consolidated to provide an annual updated 10 Year BC Hydro Capital Plan (note the 10 Year BC Hydro Capital Plan was renamed the 10 Year Capital Forecast in fiscal 2016). These considerations are reflected in the capital plan for the fiscal 2017 to fiscal 2019 test period, and also the updated fiscal 2017 to fiscal 2026 10 Year Capital Forecast. The fiscal 2017 to fiscal 2026 10 Year Capital Forecast is provided in Appendix G.

- The 2013 10 Year Rates Plan provided the upper bound for capital expenditures from fiscal 2015 to fiscal 2024, so that capital additions would be such that rate increases would be within the targets;
- The updated 2014 10 Year Capital Forecast was developed in alignment with the 2013 10 Year Rates Plan, and established high level targets for annual capital expenditures for the organization as well as identifying key strategic projects and programs planned for the ten-year period. Each year the expenditure limits within the 10 Year Capital Forecast are reviewed with the business units responsible for capital planning, to provide guidance in developing their capital plan portfolios. While the 10 Year Capital Forecast establishes annual limits for capital expenditures, there may be some movement of expenditures between years as long as the overall limits of the 2013 10 Year Rates Plan are not exceeded; and
- In addition, other company-wide guidelines regarding business objectives, priorities and performance targets are provided by the executive team as part of the business planning process, which are also reflected in annual planning.

2. Bottom up Planning

The business units that undertake planning for each of the main asset categories develop their respective ten year capital expenditure portfolios through established planning processes within their units, in alignment with top-down guidance and targets, and in consideration of the issues, risks and opportunities associated with the assets and infrastructure of the respective asset category. The capital investment portfolios are informed by the need to extend the assets and infrastructure based on forecast growth in demand. In addition, all the business units use asset lifecycle management practices to inform their capital investment portfolios. This approach considers maintenance and investment decisions for sustaining assets and can result in decisions to maintain, upgrade or replace assets.

The business units developed their ten year capital expenditure portfolios, including the fiscal 2017 to fiscal 2019 capital expenditure forecast, during fiscal 2016 and updated the forecast in early fiscal 2017, based on new information as discussed in Chapter 1, section 1.5. The planning processes for the Generation, Transmission and Distribution, Technology, Properties and Fleet/Other asset categories are discussed throughout the Chapter.

The outcome of the bottom-up planning process is a capital planning portfolio for each of the respective asset categories, including capital projects and programs identified to meet requirements. These are prioritized by use of the collaborative ranking of investments, explained in step 3 below.

3. Collaborative Ranking of Capital Investments

BC Hydro has a corporate investment framework which is applied by the business units to identify, assess and rank risk and value driven capital expenditures in a consistent way.[49] The framework was developed jointly by the business units so that it could be used over highly diverse types of investments and provide consistent and comparable assessments using common criteria and defined ranges. The framework provides methodologies to assess risk-based and the few strictly value-based investments included in the portfolios. The assessments are used by the business units to prioritize which projects in their capital plan portfolios should proceed over

[49] BC Hydro informed the British Columbia Utilities Commission during the Fiscal 2012 - Fiscal 2014 Amended Revenue Requirements Application proceeding that it was in the process of developing an enterprise-wide framework for capital prioritization.

the short term, (i.e., three-year test period), and which projects can be delayed or moved to later periods.

BC Hydro uses the term risk-based capital expenditures to refer to investments made primarily for the purpose of reducing operational risk. Most of BC Hydro's capital investments are risk based. The methodology to assess risk-based capital expenditures is based on BC Hydro's corporate risk matrix, which has measures under the categories of safety, reliability, financial performance, environmental performance and reputation. The collaborating business units determined that additional reliability, reputation and environmental measures were needed to capture their diverse investments, including measures of asset condition, customers experiencing multiple interruptions and regulatory violations. The corporate risk matrix was also augmented with additional consequence and severity levels to provide more differentiation between investments.

The framework also provides a methodology to assess the few strictly value-based investments included in the portfolios. A value-based capital expenditure is one that provides economic benefits such as cost reductions or avoided future costs, or one that provides qualitative benefits such as improved service quality or alignment with business goals. The methodology to assess value-based capital expenditures measures the economic benefits such as increased revenue, cost savings, and avoided costs for those investments that seek to create positive net cash flow or other benefits for BC Hydro.

The application of the risk framework provides a numeric scoring and ranking of projects within each asset category, based on project characteristics and risks the project addresses, which provides guidance within the respective asset category capital portfolio on which projects should proceed in the planning period under consideration, in this case the fiscal 2017 to fiscal 2019 test period.

As part of the annual planning process, potential capital investments within the asset category capital portfolios are reviewed within the framework to identify and consider the risks and impacts associated with potentially delaying an investment. The framework recognizes that some investments should not be delayed. These include mandatory investments required to meet minimum legal, regulatory or tariff compliance, and investments that have proceeded to the implementation stage and are substantially committed. Also as part of the annual planning process, the business units representing each of the asset categories meet to collaboratively review the proposed investments in their respective capital investment portfolios to ensure the framework has been applied consistently.

Outcomes

The outcomes of the three step process described above are the short-term and long-term capital plans for each of the asset categories. These plans are in turn consolidated and form the updated BC Hydro 10 Year Capital Forecast for fiscal 2017 to fiscal 2026. The first three years of the updated 10 Year Capital Forecast is reflected in the fiscal 2017 to fiscal 2019 capital plan in this application.

Another outcome of the process is the consistent application of the corporate risk framework by the business units in the development and prioritization of their specific capital plans. This ensures capital investment decisions are subject to similar risk-based review across the organization. The risk framework is discussed further in Appendix G – BC Hydro 10 Year Capital Forecast.

Annual Review by Senior Management

The annual capital expenditure planning process includes several steps as part of both the Top-Down and Bottom Up stages, where senior management review capital expenditure portfolios and also the consolidated BC Hydro expenditure forecast. For example, the capital expenditure portfolios that are developed by the individual business units during their respective annual bottom-up planning process undergo a review process with the business unit's senior management to ensure the portfolio meets the objectives, strategies and priorities of the capital asset category. Once all the asset category capital expenditure portfolios are developed and have been subject to the corporate risk framework review for prioritization they are consolidated into the BC Hydro 10 Year Capital Forecast. Our executive team and Board of Directors reviews the 10 Year Capital Forecast to ensure it meets the overall corporate business objectives, provides a consistent and appropriate management of risk and targets, and is aligned with the 2013 10 Year Rates Plan.

6.3.4 Reductions to Fiscal 2017 to Fiscal 2019 Capital Plan

As discussed in Chapter 1, section 1.5.4, BC Hydro undertook to prioritize its capital plan in response to the reduced rate of forecast load growth, and to meet the targets within the 2013 10 Year Rates Plan.

Over the fiscal 2017 to fiscal 2019 period, planned capital expenditures were reduced by $381.2 million and planned capital additions were reduced by $392.5 million from initial plans. These reductions were achieved after a careful review of system requirements and current information. Most changes resulted in delaying investments, as opposed to cancelling them. BC Hydro's capital prioritization framework was incorporated where possible, with prioritization decisions based on the impact of delay of the investments, including financial, customer reliability, safety, environment, and reputational risks. Table 6-5 provides a breakdown of the reductions to planned capital expenditures and additions by asset category.

Table 6-5 Fiscal 2017 to Fiscal 2019 Reduction of Capital Expenditures and Capital Additions

	F2017 to F2019 Reductions to Capital Expenditures ($ million)	F2017 to F2019 Reductions to Capital Additions ($ million)
Generation	(200.7)	(17.3)
Site C	75.6	0
Transmission and Distribution	(99.0)	(167.2)
Technology	(75.5)	(25.8)
Properties	(77.5)	(177.1)
Fleet	(3.0)	(3.0)
Other	(1.1)	(2.1)
Totals	(381.2)	(392.5)

Generation reduced planned capital expenditures by $200.7 million and planned capital additions by $17.3 million over the test period. The primary objective was to first protect the reliability of the key facilities that produce 90 per cent of BC Hydro's average annual energy, and then protect the reliability of strategic facilities, which produce 9 per cent of average annual energy. Consideration was given to also minimizing impacts on safety, financial, reputational and environmental risks. The majority of changes were associated with delaying projects in the sustaining capital portfolio.

Transmission and Distribution reduced planned capital expenditures by $99 million and planned capital additions by $167.2 million over the test period. In considering possible reductions to the capital plan the primary objective was to protect customer reliability. Expenditures were considered for delay based on risk assessments. The planned reductions will not materially impact customer reliability during the rate period, but will have some impact on Asset Health during the test period compared to the original plan.

Technology reduced planned capital expenditures by $75.5 million and planned capital additions by $25.8 million over the test period. In considering possible reductions to the capital plan, the priorities were to maintain key programs such as Cyber Security and Safety, maintain and sustain current IT services, make appropriate investments in foundational platforms, and support the implementation of strategic business initiatives within the constraints. Reductions include delay or cancelation of asset refresh or enhancement programs, and reprioritization of system resilience programs to an as-needed basis. The technology portfolio is dynamic due to shifting business priorities and other factors and therefore identified reductions over the test period may be achieved through other programs as appropriate.

Properties reduced planned capital expenditures by $77.5 million and planned capital additions by $177.1 million over the test period. Reductions were achieved due to delay or reduction in scope of building development projects at support facilities, based on risk prioritization, consideration of critical safety, code and operational requirements, and consideration of mitigation strategies to enable the continuation of service. Building improvement expenditures to sustain existing facilities were prioritized and maintained where possible.

6.3.5 Overview of Bottom Up Planning Processes for Asset Categories By Business Units

The capital plans for each major asset category are developed by separate business units within the Business Groups in BC Hydro. Each business unit uses its own planning process to develop the capital expenditure portfolio for their respective asset category, within BC Hydro’s top-down planning guidelines. Each planning process considers the factors relevant to the specific functional areas of the business unit, including:

- The function, criticality, volume and complexity of the different assets or infrastructure;
- The magnitude of the risks and/or opportunities;
- The size, scope, complexity and costs of capital investments; and

- The number of stakeholders that need to be involved.

The processes used by the business units are scaled as needed. The largest and most complex portfolios such as Generation or Transmission and Distribution generally require more complex and detailed planning processes, and involve a larger number and broader spectrum of stakeholders. A high-level discussion of the considerations and planning processes used by the functional areas follows.

6.3.5.1 Generation Capital Investment Planning

Generation assets include 82 generating units at BC Hydro's 30 hydroelectric generating stations, 79 dams, three gas-fired generating units at BC Hydro's two thermal generating stations and four synchronous condenser units at one dedicated synchronous condenser station. During the test period, capital investments in these facilities include both asset sustainment and growth investments. Generation capital expenditures represent approximately 20 per cent of the overall BC Hydro capital portfolio during the fiscal 2017 to fiscal 2019 test period, excluding the Site C Clean Energy Project.

Generation manages and maximizes the lifecycle value of BC Hydro's Heritage Generation Assets by:

- Maintaining Heritage Assets so that they perform safely and reliably throughout their operating lives;
- Investing in Heritage Assets to extend their operating lives, enhance capability, manage risk, and increase efficiency and cost-effectiveness;
- Managing public and worker safety risks associated with facilities, especially around reservoirs and dams; and
- Demonstrating high standards of financial responsibility, integrity and efficiency.

Planning processes are in place to support these objectives and also so that the proposed portfolio of investments effectively manages risk and customer needs, within financial and human resource constraints.

6.3.5.2 Generation Portfolio Characteristics

During the test period, excluding the Site C Clean Energy Project, the majority of capital investments in the Generation portfolio are driven by the need to address issues and risks associated with existing facilities. Capital investments which are needed to preserve and sustain BC Hydro's existing generation assets over the fiscal 2017 to fiscal 2019 test period are broadly characterised as Asset Sustainment and Dam Safety. In addition, capital investment in Mica Generating Station Units 5 and 6 and Revelstoke Unit 6 is required during the test period to meet BC Hydro's expected load. Each of these is described in more depth in the following sections.

6.3.5.3 Asset Sustainment Capital Investments

Aging Assets

Construction of BC Hydro's Key generating facilities occurred in the 1960s, 1970s and 1980s, while the majority of BC Hydro's Strategic facilities were constructed in the 1950s. The age of BC Hydro's generating units ranges from less than 1 year (Mica generation station Unit 6) to 92 years (Elko generating station Units 1 and 2, which are currently not operational), with the average age being 49 years. From asset health assessments, a significant number of generating assets are now at end of life based on the actual condition of the assets.

Generating Equipment Condition

The condition of assets across BC Hydro's aging Generation fleet is a foundational input to the planning process. Generation periodically evaluates the condition of its major equipment (turbines, generators, governors, exciters, transformers, and circuit breakers) based on the latest available maintenance test and inspection data following BC Hydro's Equipment Health Rating methodology. This provides a systematic, objective, repeatable, and transparent assessment of equipment condition. Factors influencing the Equipment Health Rating include:

- Equipment condition;
- Maintenance history;
- Equipment reliability;
- Availability of spare parts;
- Availability of technical support; and
- Known type problems.

The equipment health or condition information is used to assess and manage risk and help prioritize the need to make investments to preserve and sustain the generating units.

Each health assessment results in a rating of Good, Fair, Poor, or Unsatisfactory. In general, as explained in Appendix R, assets that have a Poor or Unsatisfactory rating are considered for capital investment or replacement within five to twelve years. Thirty-five per cent of the equipment at Generation's key and strategic plants have been assessed as in either Poor or Unsatisfactory condition. For assets in this condition, there is a higher likelihood of failure: however, planned capital investments reduce this risk. The need to address the deteriorating health of BC Hydro's aging Generation assets has been identified and explored in previous BC Hydro applications to the British Columbia Utilities Commission, and BC Hydro's fiscal 2017 to fiscal 2019 capital plans reflect the continuing importance of reinvesting in these assets. However, there are a number of factors limiting BC Hydro's work to improve the health of our assets over the next three years, including the ability of BC Hydro to maintain operational requirements necessary to meet system needs and keep the lights on while simultaneously undertaking capital projects as well as the long lead times associated with many projects.

Please refer to Appendix R for a summary of the Equipment Health Ratings as at March 31, 2016.

The capital investments proposed in the fiscal 2017 to fiscal 2019 test period will continue to mitigate or resolve the highest risks identified with BC Hydro's generation assets. Over the test period sustaining capital expenditures will largely be focused at G.M Shrum, Bridge River 1 and 2, Mica, Peace Canyon, John Hart and Ruskin generating stations. While increased maintenance or other risk mitigation strategies may also be possible on an interim basis, BC Hydro's strategy over the longer term is to make capital investments in existing assets to:

- Replace assets that are at end-of-life;
- Enhance assets to maintain or improve reliability or to meet evolving regulatory standards; and
- Upgrade assets to mitigate risks including safety, environmental, security and seismic risks.

BC Hydro strives to prevent in-service failures of major generation equipment as such failures can result in significant safety, reliability, environmental, financial, and reputational risk consequences. However, a 'run-to-failure' strategy is adopted for equipment where the impacts of in-service failures are low. Currently, Alouette and Elko generating stations and Shuswap Unit 1 have been forced out of service due to unsatisfactory equipment condition and will remain out of service for an extended period. Significant capital investments proposed in the test period will focus on the highest priority major equipment rated as being in Poor or Unsatisfactory condition, as these assets have a higher likelihood of failure.

Dam Safety Investments

Dam Safety risks are associated with safe storage and passage of water under normal conditions, the ability to pass floods (from the annual freshet to extreme events), and the ability to withstand a major seismic event without any harmful release of water. Dam Safety risks generally have a relatively low probability of occurrence but a very high consequence if realized. Capital investments in the test period will focus on the highest priority Dam Safety issues and risks.

A number of issues and risks related to Dam Safety have been identified, and require remediation through capital investments in the fiscal 2017 to fiscal 2019 test period:

- ***Condition of Civil Structures*** There are a number of facilities where the integrity or degradation of the existing civil structures pose a risk to the ability to store or pass water safely. For example, since construction of the WAC Bennett Dam in the 1960s wind generated waves, ice loading and freeze-thaw actions have damaged the existing rip-rap which protects the internal zones of the dam. Investigations have concluded that a large portion of the existing rip-rap has eroded and the protective layers on the dam face need to be rebuilt on the upper portion of the dam face.
- ***Reliability of Spillway Gates*** Spillway gates are built into a dam and designed to enable the controlled release of water from the reservoir into the river below and are usually used when reservoir levels exceed or are expected to exceed normal maximum reservoir levels. Across the generation fleet, the lack of operational reliability of certain existing spillway gate equipment has been identified as a major risk.
- ***Seismic Risk*** The seismic performance at a number of dams is known to be significantly below current Canadian guidelines for major dams. For example, the John Hart Dam is classified as an extreme consequence dam and therefore the expected seismic performance under the 2007 Canadian Dam Association Guidelines is for no uncontrolled release of the reservoir for the Maximum Design Earthquake period. Seismic upgrades to the dam and spillway are required.

Additional information on BC Hydro's generation asset sustainment investments is provided in Appendix I and Appendix J.

Generation Growth Capital Investments

Based on information from Facility Asset Plans and as part of BC Hydro's integrated resource planning process, Generation advises BC Hydro Energy Planning of opportunities to enhance the capability or increase the efficiency of existing facilities. Generation integrates growth capital investments into the Generation capital plan only on direction from Energy Planning, which determines the need for, and timing, of such investments.

Given the long lead time associated with new generation, work on preparing for the installation of Revelstoke Unit 6 is needed in the test period in order to meet a required in-service date.

Additional information on BC Hydro's Generation growth investments is provided in later in this Chapter and in Appendix I and Appendix J.

6.3.5.4 Generation Capital Planning Process

Generation utilizes a number of established and integrated processes in developing its bottom-up capital investment plans for sustaining and growth expenditures, as discussed in the following sections.

Generation Asset Sustainment Capital Planning

The Generation annual planning process follows a five-step bottom-up/top-down approach that is part of the planning process used for the preparation of BC Hydro's 10 Year Capital Forecast as described in this Chapter. This planning process is founded on Generation's Facility Asset Planning process.

Step 1 - Facility Asset Plans

BC Hydro has developed Facility Asset Plans for its hydroelectric generating facilities and is currently developing plans for its thermal generating and synchronous condenser stations. Working with facility staff, Regional Asset Managers formulate and document the recommended ten-year investment strategy for each facility, with particular focus on the earlier years. The strategy takes into account the facility's role, Equipment Health Ratings, performance levels and targets, risks, and growth opportunities within the context of BC Hydro's strategic objectives.

As they are developed, each Facility Asset Plan is presented to the Generation Asset and Risk Planning Committee for agreement in principle and endorsement. This committee includes all members of the Training, Development and Generation Leadership Team; the VP, Project Delivery; the Director, Dam Safety; the General Manager, Engineering; the Process Lead, Operational Safety; and the Manager, Generation Asset Management. This ensures that there is input to the Facility Asset Plan on all issues and risks and proposed investments from key internal partners.

Facility Asset Plans are updated periodically to reflect the latest information, including changes in priorities and strategies which influence the scope and timing of facility plans and investments. A Facility Asset Plan may also be updated if new information emerges that affects the investment strategy for the facility. Between updates, Generation Asset Management continues to monitor the risks and issues associated with the facilities and makes adjustments if needed.

Step 2 - Generation 10 Year Capital Forecast

Generation consolidates the investment plans for each facility, including generating stations, dams and growth into a 10 Year Capital Forecast. This is undertaken annually, typically in May through August, to ensure that a forward looking 10 Year Capital Forecast is maintained. As part of the consolidation, investments are reviewed to ensure that the facility asset planning process has been applied consistently, that the data quality is sufficient and that investments are appropriately prioritized and timed. The Training, Development and Generation Leadership Team then reviews the 10 Year Capital Forecast and any 'top-down' direction, as described in section 6.3.3, is incorporated into the forecast.

As part of the annual update, typically in September and October, Generation's 10 Year Capital Forecast is reviewed by Generation Asset Management and various partners including Generation Engineering, Generation Resource Management and Capital Investment and Project Delivery to identify potential constraints (including financial, human resource, and outage availability). Where constraints exist, the timing of sustaining investments is modified to ensure that higher priority investments occur first, while relatively lower priority investments are moved into the future. This is an iterative process which continues until all constraints are satisfied.

As described in section 6.3.3, representatives from the business units responsible for capital planning meet to review the proposed investments in their respective capital investment portfolios, to ensure the corporate investment framework has been applied in a consistent way.

Step 3 – 10 Year Capital Forecast - Business Group Approval

The 10 Year Capital Forecast is reviewed by the Training, Development and Generation Leadership Team (which includes the Senior Vice-President, Training, Development and Generation and his direct reports); the Director of Dam Safety; the VP Project Delivery; and the General Manager, Engineering. The purpose of this review, which typically takes place in November, is to provide an opportunity for senior leaders to provide input and ensure the portfolio aligns with corporate and business group goals and objectives and can be implemented.

Step 4 – Capital Investment Plan BC Hydro Approval

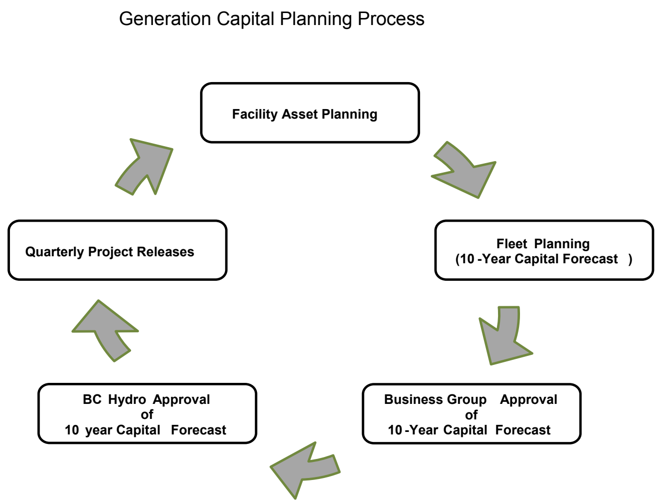
Finally, the 10 Year Capital Forecast from all business units responsible for capital planning is consolidated and reviewed by the BC Hydro executive team and BC Hydro's Board of Directors, to ensure the plan meets overall corporate business objectives, provides a consistent and appropriate management of risks and targets across all business groups and will achieve BC Hydro's 2013 10 Year Rates Plan.

The portfolio of investments that make up the 10 Year Capital Forecast are the basis for more detailed short to medium term investment plans that support this application.

Step 5 –Short Term Quarterly Project Releases

The approved 10 Year Capital Forecast is the basis for initiating new projects. On an annual basis, prior to the start of a new fiscal year, Generation Asset Management works closely with Capital Infrastructure and Project Delivery to establish a quarterly release schedule for projects proposed to start in the upcoming fiscal year. This looks at resource availability across multiple disciplines to determine the appropriate time to start new work, considering the portfolio of work proposed as well as projects that are already underway. The following Figure 6-2 illustrates the Generation capital planning process.

Figure 6-2 Generation Capital Planning Process



Generation Growth Capital Planning

Generation integrates growth capital investments into the Generation capital plan which is guided by the 2013 Integrated Resource Plan, which determines the need for, and timing of such investments. Growth projects in Generation are limited to Heritage Assets as defined by the *Clean Energy Act*. When growth projects are incorporated into the Generation 10 Year Capital Forecast, the timing of sustaining investments may need to be modified to accommodate the growth projects. This is accomplished as described in Step 2, above.

Other than the Site C Clean Energy Project, over the fiscal 2017 to fiscal 2019 test period Generation's growth related expenditures total $23 million and represent less than 2 per cent of Generation's total capital portfolio. These are expenditures primarily related to the completion of Mica Units 5 and 6 installation (fiscal 2017) and work on the Revelstoke Unit 6 project, which is in the Definition Phase.

6.3.6 Transmission and Distribution Capital Investment Planning

The Transmission and Distribution capital expenditures represent approximately 40 per cent of BC Hydro's gross planned capital expenditures (before Contributions In Aid) over the fiscal 2017 to fiscal 2019 test period. There are established planning processes in place in the Transmission Distribution Customer Service Business Group to ensure:

- Safe and reliable delivery of power;
- The timely connection of new customers and generators;
- The expansion of the networks required by load growth;
- Asset performance;
- Regulatory requirements are met; and
- Capital expenditures are optimized to effectively manage risk and customer needs within financial and human resource constraints.

6.3.6.1 Transmission and Distribution Portfolio Categories

The transmission and distribution capital forecast over the test period includes investments in both sustainment and growth.

Asset Sustainment Capital Investments

Approximately 50 per cent of transmission and distribution planned capital expenditures for fiscal 2017 to fiscal 2019 is sustaining expenditures driven by the need to address the issues and risks associated with the existing assets. Sustainment expenditures aim to ensure the assets perform throughout their lifecycle. Investments in existing assets include activities such as:

- Replacement of assets that are at end of life;
- Enhancements to maintain or improve reliability;

- Upgrades to mitigate risks including safety, environment, security and seismic;
- Improvements to meet evolving regulatory standards; and
- Relocations to address third party requests.

There are a number of issues and risks driving the capital investments to sustain BC Hydro's transmission and distribution assets over the fiscal 2017 to fiscal 2019 test period.

Aging Asset Demographic

A large portion of the transmission system was built in the 1960s and 1970s, and is reaching or exceeding end-of-life condition. Similarly, a large portion of the distribution system has, or soon will, exceed its design life, which is the expected life of the asset. For example, over 87,000 distribution wood poles are more than 50 years old and over half of all circuit breakers are greater than 30 years old. Based on asset health, approximately 12 per cent of the approximately 4 million transmission and distribution assets are in poor to very poor condition, which indicates either remediation work or replacement would be required within the next ten years, depending on the criticality of the asset. An overview of transmission, distribution and substation asset health is provided in Appendix S.

End-of-life replacement is needed when the equipment can no longer be maintained to an acceptable level of reliability due to comparatively high cost or due to lack of parts and inadequate manufacturer support. Replacement at end-of-life is also needed to mitigate increasing public and worker safety risks and environmental risks that result from increasing asset failures.

The replacement of assets at end-of-life represents 75 per cent of the sustainment expenditures, or approximately $1.1 billion over the test period. This level of expenditure is below the rate of replacements needed to maintain the condition and average age of the assets. BC Hydro evaluates the condition of the transmission and distribution assets based primarily on the latest available maintenance test and inspection data, and assigns an Asset Health Index to each asset. Asset Health Index is a recently developed methodology that assigns ratings of Very Good, Good, Fair, Poor, or Very Poor, which in turn can be grouped and analyzed by asset class and/or criticality. At the forecast level of expenditures, the number of assets in Poor or Very Poor condition is expected to increase and the average age of assets will continue to rise over the fiscal 2017 to fiscal 2019 test period. Therefore the reliability risk associated with some components of the transmission and distribution system is also expected to increase. Transmission, Distribution and Customer Service will minimize this risk by targeting investments to critical assets and the highest asset risks to improve the condition of those assets, and by monitoring system reliability to determine whether the level of end-of-life replacements needs to be adjusted. The new Asset Health Index methodology together with summary ratings for transmission and distribution assets are provided in Appendix S.

The end-of- life expenditures are managed to maximize the life cycle value of the transmission and distribution assets. While in most instances end-of-life replacements are done through proactive replacements, in some asset classes ‘run to failure’ is used to minimize the life cycle costs of managing the assets where the associated impacts upon asset failure are low. Examples of asset classes that are ‘run to failure’ include overhead distribution transformers and transmission line insulators.

Customer Reliability

Continued focus and investment on reliability is required over the test period to maintain current levels of reliability. These needs form the basis of customer reliability expenditures totaling approximately $125 million over the test period. This is in addition to the $1.1 billion forecast expenditures over the test period on end-of-life replacements, which also impacts customer reliability.

Safety

The safety of employees, contractors and the public is a top priority for BC Hydro. Achieving a good safety record requires assets that can be safely worked on and do not represent undue safety risk to our employees, contractors and the public. Safety risks may prevent maintenance activities from being carried out and may even require the removal of the asset from service until the risk is mitigated. In addition to investments to mitigate the safety risks associated with aging assets, investments are needed to remedy situations not related to aging assets that could escalate into serious safety hazards for employees, contractors and the public. Expenditures totaling approximately $140 million over the fiscal 2017 to fiscal 2019 test period are planned to address employee and public safety concerns not related to aging assets.

Transmission and Distribution Growth Capital Investments

The transmission and distribution capital investment plan includes growth related expenditures, which represent approximately 50 per cent of the transmission and distribution capital forecast for fiscal 2017-fiscal 2019. Growth expenditures are required to expand the transmission and distribution system to accommodate load growth and the connection of new load and generators. Investments to expand the assets include:

- Upgrades and additions of station equipment;
- Upgrades and additions of transmission lines and distribution feeders; and
- Provisions of new service connections and upgrades.

There are a number of issues and risks associated with the capital investments to expand the transmission and distribution assets over the fiscal 2017 to fiscal 2019 test period.

Demand for electricity continues to increase in the province, and certain parts of the BC Hydro system are reaching capacity. Growth in some sectors of the economy is driving the need to reinforce the system in areas that do not have the infrastructure to meet these needs. This includes actual and potential growth in the oil and gas sector in the Peace and North Coast regions. New investments continue to be required in both distribution and transmission infrastructure to meet customer demand growth and to connect new supply of electricity.

Growth investments and their timing are informed by the forecast load growth and resource supply additions. The growth investments in the fiscal 2017 to fiscal 2019 test period are based on BC Hydro's Updated 2012 System Demand Load Forecast, the 2013 Integrated Resource Plan, the 2015 Substation Load Forecast, and requests from Independent Power Producer (**IPP**) and load customers.

Large transmission projects require long lead times and work needs to be initiated accordingly. A number of growth projects will start during the test period in order to meet customer needs in the future.

The uncertainty of load forecasts represents a risk to planning for capital expenditures, especially when long lead time projects are required to address the forecast need. In some cases, load increases can occur faster than planned in areas experiencing unprecedented growth and where the system is reaching capacity. This is currently the case in the Northeast of the province where the Taylor Capacitor Bank Project is now required ahead of the Peace Region Electricity Supply projects to address a load connection request. BC Hydro mitigates the risk associated with forecast uncertainty through the regular review and update of its load forecasts and its capital investment plans. The Taylor Capacitor Bank Project and Peace Region Electricity Supply projects are included in Appendix I, page 6 of 12 and Peace Region Electricity Supply Project is described in Appendix J, page 47.

The capital expenditures required to interconnect transmission load customers or IPPs is difficult to forecast. Due to the uncertainty of their timing, location and scope, only known transmission load customers or IPPs interconnection projects are included in the forecast capital expenditures. As a result, the level of expenditures for this type of projects becomes more uncertain beyond the first year of the capital forecast (beyond fiscal 2017). These projects are non-discretionary and BC Hydro re-directs funding to emerging transmission interconnection projects from within its capital budgets. This may require adjustment of the timing or scope of other projects and programs in the BC Hydro capital investment plan. The distribution interconnection costs are more stable and are forecast based on historical levels. The ongoing management of Transmission and Distribution portfolio of capital investments is discussed in section 6.5.2.

6.3.6.2 Transmission and Distribution Asset Capital Planning Process

The Transmission and Distribution planning process follows a four-step bottom-up approach that is aligned with the planning process used for the preparation of the BC Hydro's 10 Year Capital Forecast described in section 6.3.3.

Step 1

The first step of the process is to identify system and asset needs that should be considered for remediation. This assessment includes regular reviews and studies of existing assets to identify assets that are: reaching end of life; represent safety or other risks; are at risk; do not perform adequately; or do not meet regulatory requirements. System and substation load forecasts are also developed and studied to identify areas across the system requiring reinforcement. These reviews and studies are conducted by planners who each focus on different aspects of the transmission and distribution system and assets, and involve consultations with stakeholders. The planners assign a timeline for remediation and a risk of deferral of the identified needs.

These reviews and studies are performed throughout the year and new needs are regularly identified. The reviews and studies used to identify system and asset needs are as follows:

- ***Asset Health and Performance:*** BC Hydro evaluates the condition of the Transmission and Distribution assets based primarily on the latest available maintenance test and inspection data, and, using a recently developed methodology, assigns an Asset Health Index to each asset. The methodology provides assessments that are objective, repeatable, and consistent across entire asset classes. Asset Health Index assigns ratings of Very Good, Good, Fair, Poor, or Very Poor. Assets with an Index of Very Poor or Poor are generally considered for reinvestment within three or ten years respectively after consideration of the asset's criticality. The new Asset Health Index methodology together with summary ratings for transmission and distribution assets is provided in Appendix S.
- ***Customer reliability:*** Reliability statistics are reviewed and poor performing assets are identified for improvement.
- ***Risk:*** BC Hydro assesses the potential severity and likelihood for a range of risks including safety, seismic, environment, fire, extreme weather and security. High risks, as determined by the Enterprise Risk Management Framework, are considered for remediation.
- ***Regulatory Requirements:*** The assets are also evaluated to ensure they meet all applicable regulations including WorkSafeBC, B.C. and Canadian Environmental laws, Mandatory Reliability Standards, Measurement Canada and Transport Canada. Deviations are addressed within the requirements of each regulation.
- ***Load and Energy Forecasts:*** The transmission and distribution system is assessed to ensure it can meet peak demand and accommodate load and

generation additions. The assessments are informed by the Updated 2012 System Demand Load Forecast, 2013 Integrated Resource Plan, 2015 Substation Load Forecast prepared by the Transmission Distribution and Customer Service business group, and studies for IPPs and load customers.

Step 2

The second step of the process is to manage the identified needs to ensure efficient planning and optimized solutions. This step in the process ensures that multiple needs impacting the same parts of the system within a similar time frame proceed through the next stages of the planning process as one integrated bundle. In this step, the identified needs are reviewed by cross-functional teams of planners to determine bundling opportunities by considering how needs relate to each other together with the timelines for remediation and risk of delay. Each cross-functional team is regionally focussed and meets on a quarterly basis to capture new needs as they are identified. The view of multiple needs in the same parts of the system over a long period of time also helps determine the need for the development or update of long term regional plans. The Capilano Substation 25 kV Conversion and Squamish Area Reinforcement projects are examples of integrated solutions that address multiple needs. These projects and the needs they address are described in Appendix J.

The reviews by the cross-functional teams can also result in needs being bundled in programs or deferred due to a low risk. The remaining needs would proceed individually through the next stages of planning according to their timeline. An example of program bundling is the replacement of the remaining end-of-life circuit breakers across the province not addressed by integrated projects.

Third-party requests to connect load or a generator, which are considered growth projects, are not typically considered for bundling with other capital expenditure needs, and they normally proceed individually through their respective mandated and schedule-driven process. Those processes, however, benefit from the readily available information on asset issues in the area impacted by the third-party interconnection requests.

Step 3

The third step of the process is to study the needs in detail, either individually or in bundles, and identify technically feasible alternatives for the project or program that would remediate the needs. Specialised technical planning studies may be required to identify alternatives to address needs resulting from issues such as load growth, new generation and system reliability. For programs, BC Hydro utilizes an asset class strategy for all major transmission and distribution assets covering each stage of the asset's life cycle. These asset class strategies would have considered overhaul, continuing maintenance and replacement alternatives. The studies vary in length from a few weeks to several years depending on the complexity of the needs and alternatives. Once the studies are complete, funded projects and programs are released to the delivery groups for continuation of the project and program lifecycle. All projects released to Project Delivery follow the standard project lifecycle, and commence in identification phase. The delivery processes are described in section 6.4, and the project lifecycle is discussed further in section 6.4.1.3.

Step 4

Once a year, projects and programs in the planning process are brought into a single transmission and distribution capital investment portfolio, together with the projects and programs in the delivery process, for the preparation of the 10 Year Capital Forecast. The corporate risk framework is used to categorize each investment in the initial unconstrained portfolio, and assign risk of deferral to the investments. The labour resources required to deliver each investment together with the availability of resources are established in consultation with the resource management groups. The unconstrained Transmission and Distribution portfolio is then optimized to determine the portfolio that will maximize the risk mitigation of the portfolio given the labour and financial constraints identified. The results are reviewed with the delivery groups and Transmission, Distribution and Customer Service management, and adjustments are made to address any issues. The proposed transmission and distribution 10 Year Capital Forecast then undergoes the joint review of risk with the other business groups' capital investment forecasts, and is ultimately included in the proposed BC Hydro 10 Year Capital Forecast for review.

Step 4 of the process took place between June and September 2015 for the preparation of the 10 Year Capital Forecast for fiscal 2017 to fiscal 2026. The optimization of the transmission and distribution portfolio was done with financial constraints derived from the need to align the capital forecast with BC Hydro's 2013 10 Year Rates Plan. The optimization also took into account the resource availability for six different labour groups, including Communications, Protection and Control Technologists and Transmission Cable Designers. The six groups were identified as constraining based on the resource demand of the unconstrained portfolio. An early optimization indicated that resource availability of some groups, mainly Communications, Protection and Control Technologists, needs to be managed over time to ensure that higher risk investments are not unduly delayed. The early optimization results also triggered further discussions among the planning managers on the assessed risk of some projects. In this step, a total of $1 billion in lower risk capital investments were delayed outside the fiscal 2017 to fiscal 2019 period compared to the initial unconstrained portfolio.

Review of Results

The results of the four step planning process were reviewed and adjusted in the spring of 2016 in response to the reduced load forecast and to meet the targets within the 2013 10 Year Rates Plan. The final results delayed an additional $0.1 billion in lower risk capital investments outside the fiscal 2017 to fiscal 2019 test period. The additional reduction to the fiscal 2017 to fiscal 2019 Capital Forecast is discussed further in section 6.3.4 above.

6.3.7 Technology Capital Investment Planning

Technology capital expenditures planned over fiscal 2017 to fiscal 2019 are driven by BC Hydro's operational needs, business strategies and plans. BC Hydro's key business functions such as customer services, resource and plant management, engineering and design, project management, supply chain, asset and work management, grid operations and power restoration rely on IT. Capital investment is needed over fiscal 2017 to fiscal 2019 and beyond in order to implement, sustain, and expand BC Hydro's hardware, software and telecommunications assets. This is discussed further in sections 6.2.7.1 and 6.4.4.1.

The investment priorities are to implement and sustain IT services that:

- Support the achievement of BC Hydro's operational and compliance objectives;
- Enable and support the development and implementation of BC Hydro's strategies and plans;
- Help meet BC Hydro's safety and security commitments through programs such as Cyber Security;
- Enable BC Hydro's future business needs and control IT costs through appropriate foundational investments; and
- Are sufficiently robust and resilient.

6.3.7.1 Technology Capital Investment Categories

To assist in the planning and management of the Technology capital plan, BC Hydro classifies its technology capital investments into two main categories of Business Driven and Foundational IT expenditures.

6.3.7.2 Foundational IT Expenditures

Foundational IT expenditures implement and sustain BC Hydro's major software platforms and applications, computing infrastructure, a portion of telecommunication infrastructure and solutions, and cyber security. Foundational IT enables a wide range of business needs and helps control IT costs by providing appropriate IT standardization, integration, capacity, flexibility, security and resilience.

Each foundational IT expenditure is associated with one of four technology areas:

(a) Foundation-Applications expenditures implement and sustain the enterprise-class application platforms, including Enterprise Resource Planning, Enterprise Content Management, Project and Portfolio Management, System Integration, and Smart Metering.

The Enterprise Resource Planning investments planned for fiscal 2017 to fiscal 2019 include SAP Environmental Health and Safety implementation, SAP solution improvements for Project Portfolio Management, Finance, Human Capital Management, Customer Service and Energy Analytics, and annual SAP platform upgrades.

(b) Foundation-Infrastructure expenditures implement and sustain BC Hydro's data centre (including backup and disaster recovery) systems and user computing capabilities (for both field and office workers). These systems are comprised of core technologies including application servers, memory storage systems, personal and tablet computers, file and print infrastructure, operating systems (e.g., Windows, Unix), enterprise productivity (e.g., MS Office, Email, Calendar) and communications software, and related automation tools.

Investments planned for fiscal 2017 to fiscal 2019 include Microsoft End-User Device License, Windows 10 Upgrade, Windows Server 2008/2012 Upgrade, Microsoft Enterprise License True-up, PC Refresh and Provisioning, Storage Capacity Growth, and Data Centre and Smart Metering and Infrastructure Renewal.

(c) Foundation-Telecommunications expenditures implement and sustain a portion of BC Hydro's telecommunications systems consisting of Internet, data networks and Wi-Fi; field mobile radio; telephony including call centre voice systems, messaging and video conferencing, mobile access to email and applications; smart meter field area network; and audio-visual equipment.

Investments planned for fiscal 2017 to fiscal 2019 include Mobile Radio Optimization for lower mainland field crews, Mountain Top Radio Asset Refresh, MPLS Network Commissioning, Smart Metering and Infrastructure Field Area Network Sustainment, and Network Asset Refresh.

(d) Foundation-Cyber Security expenditures implement and sustain BC Hydro's cybersecurity systems. These expenditures provide assurance to IT services through a broad range of programs that keep pace with rapidly changing threats and risks, and changing IT solutions and compliance requirements. These expenditures provide ongoing enhancements to identity and access management, logging and monitoring, vulnerability management, end point and network security.

Investments planned for fiscal 2017 to fiscal 2019 include North American Electric Reliability Council Critical Infrastructure Protection, Distributed Denial of Service Protection, Firewall Replacements, Event Monitoring for North American Electric Reliability Council compliant network, Data Centre Network Security Improvements, and Data Loss Prevention.

Foundational capital expenditures are forecast to be $101 million or 40 per cent of the annual technology capital budget over the test period.

6.3.7.3 Business-driven IT Expenditures

Business driven IT investments support the operational needs of BC Hydro's various functional business groups directly, through improved communications, automation of specific activities or processes, and decision support. This includes the implementation and maintenance of specialized business applications such as Transmission and Distribution's Strategic Asset Management system, Generation's Construction and Contract Management and Commercial Management system, Customer Service's BCHydro.com website and portal, and Properties' facilities management system. It also includes the implementation and maintenance of strategic initiatives such as Supply Chain Applications. The Supply Chain Applications project involves the design and implementation of new business processes and information technology to support the acquisition of materials and services from third-parties. BC Hydro plans to file an application with the British Columbia Utilities Commission for the Supply Chain Applications Project.

Business needs for IT solutions are identified through collaborative planning between the Technology Group and the various business units' management.

Each business-driven expenditure is associated with the area of the business that the expenditure supports:

(a) Transmission and Distribution expenditures focus on improving services to customers in the field, improving work executed in the field and improving efficiencies for planning and execution of capital work. Investments in the test period include expenditures to improve support for a connected mobile work force.

(b) Generation expenditures focus on business area-specific solutions that support resource management requirements, generation equipment maintenance and operations, capital construction, engineering design, dam safety management, energy planning, business and economic development, and the Site C Clean Energy Project.

(c) Customer expenditures focus on web (BCHydro.com and MyHydro), billing and payment, customer relationship management, and call handling solutions. These solutions are supported by the Smart Metering and Infrastructure suite of applications managing customer meters and meter data, and outage and work management systems providing operational information to customers.

(d) Operations Support expenditures focus on application platforms that support Finance, Human Resources, Supply Chain, Properties, Communications, Safety, Security and Emergency Management. These areas rely heavily on Enterprise Resource Planning (using SAP), as well as business area specific solutions for properties management, fleet management, performance management, and training.

Business-driven expenditures account for $149 million or 60 per cent of the annual technology capital budget over the test period.

6.3.7.4 Technology Capital Planning Process

The Technology Capital Planning process utilizes a portfolio management approach in developing its capital investment plan. Business-driven IT investments are made in response to prioritized business needs from Transmission and Distribution, Generation, Customer, and Operations Support areas.

The plan for the fiscal 2017 to fiscal 2019 test period was developed through a four-step planning process. The following discussion describes the major steps in the process.

Step 1 – Identification of Capital Portfolio

The Technology Group maintains a portfolio of IT capital investments using a software-based portfolio management system. Proposed investments are captured through ongoing discussions with business groups, stakeholders and IT business advisors; active investments are tracked through the various phases of execution; and completed investments are maintained in the portfolio for reporting purposes.

Each portfolio entry represents a proposed future expenditure, an active investment (in Identification, Definition or Implementation phase), or a completed investment. Each portfolio entry, often managed as a project, includes a name, description, statement of need or opportunity, investment objectives, expected benefits, forecast costs and risks, and investment score. Each portfolio entry is also associated with a business-driven IT sub portfolio (Transmission and Distribution, Generation, Customer, and Operations Support) or a foundational IT sub portfolio (Applications, Infrastructure, Telecommunications or Cyber Security). The investment score is assessed using a standardized assessment method described in the Step 2 – Formation of a Candidate Plan section below.

Step 2 – Formation of Candidate Plan

Once the new and existing Capital Portfolio entries have been fully captured and detailed, a candidate plan is developed.

The consolidated portfolio of proposed and active investments typically exceeds available resources in each year. As a result, a process of ranking and selecting a subset of the portfolio is initiated. The chief resource constraints are funding, delivery capacity, management capacity, time to implement, and tolerance for risk. Funding constraints are determined based on the financial targets identified through the top-down planning process discussed in section 6.3.3.

In order to determine the ranking, proposed investments are first grouped by three categories: i) mandatory projects, ii) committed projects, and iii) projects to be prioritized. Mandatory investments are those required to meet safety, legal, regulatory or tariff compliance, and are not considered for prioritization, reduction in scope or delay. Committed investments are those that have proceeded to the implementation stage, or are substantially committed as of the planning date, and are not considered for prioritization, reduction in scope or delay, due to cost or risk of undertaking a change in scope or schedule. The remaining projects within the proposed portfolio are considered candidates for the prioritization process to determine which projects should be included in the Technology capital investment portfolio.

The Technology Planning team undertakes an initial prioritization of the proposed capital investment portfolio, based on the Application of an internal capital portfolio management prioritization tool, which assesses and ranks projects with respect to benefits, costs and risks.

Each project is evaluated and scored against multiple benefit categories such as strategic alignment, operational risk reduction, foundational support, cost and payback. Each project is also scored in multiple confidence categories such as clarity of objectives; track record of delivery team; architecture, sponsor and user endorsement; and certainty of schedule and cost estimates. The types of projects are also considered in the ranking since there is typically greater uncertainty for growth and strategic IT investments.

The detail of the prioritization process is entered and tracked in the IT Capital Portfolio system for review and updating. Prospective projects to be included in the portfolio are further assessed by application of the BC Hydro corporate risk framework to ensure consistency with the review of other capital investments across the company.

The scored list is sorted by a normalized score representing investment score relative to estimated cost. Projects with the highest score are selected until the annual capital funding constraint is reached. Further analysis is then done to determine whether any other constraints have been reached and selection adjustments are made in order to remain within all key constraints.

Step 3 – Stakeholder Review of Proposed Plan

The candidate plan then undergoes a series of reviews to allow dialogue among Technology Business Partnership team members, Technology Planning team members, and affected BC Hydro business stakeholders. The reviews consider factors such as portfolio value, risk and balance. This often results in re-assessment of the benefits and confidence for specific investments, re-design of programs or projects, shifting of timelines, and other compromises, to align the portfolio with corporate objectives and priorities. Portfolio selection in this step is subject to discussions among the Technology Group leadership team and may involve portfolio balancing and further consultations with project sponsors. These discussions consider broader factors including investment interdependencies, portfolio feasibility and risk, variability of program and solution designs, levels of reserve funding in major projects, and any information not reflected in the standardized assessments. The result of this process is the development of a candidate plan.

Step 4 – Finalize Technology Plan

A final review of the proposed technology capital investment plan is undertaken by both the Technology leadership and BC Hydro's executive team, as part of the overall oversight of the Technology capital investment plan, including review by the Chief Information Officer, and the Executive Vice President of Transmission Distribution and Customer Service business group.

Ongoing oversight to the Technology Capital Investment plan is provided primarily by the Executive Team, the Chief Information Officer, and also the Board Customer Service Planning Operations Committee. Oversight includes decision making with respect to Technology strategy, planning, and operations. The oversight is to provide assurance that investments in IT are prudent and well planned, that IT initiatives are efficiently managed and delivered, and that expected benefits are realized. This includes all aspects of IT managed by the Technology Group including data, infrastructure, applications, telecommunications, and cyber security; and also includes oversight of business initiatives that involve major IT investments.

Potential Changes to Technology Capital Plan

The fiscal 2017 to fiscal 2019 capital investment plan included in this application reflects the information and assumptions available as of the March 31, 2016 planning date and include the reductions implemented in response to the recent reduction in forecast load growth. However annual Technology capital plans and actual expenditures are dynamic and are expected to differ from that presented in the revenue requirements application for a number of reasons, such as:

- Emerging and changing IT priorities;
- Changes to program or project scope, schedule or cost;
- Unplanned outages or increased technology risks;
- Unexpected loss of vendor support for products or services.

In recent years the above factors have resulted in actual capital expenditures being under-plan. In the fiscal 2017 to fiscal 2019 test period, BC Hydro has made allowance for this by adjusting the forecast expenditures downwards by 16 per cent in fiscal 2017 and 10 per cent in fiscal 2018.

To help manage emerging priorities, the Technology Group maintains a waitlist of proposed investments. Capital and other resources can be re-allocated to the next highest ranked projects as resources become available. Monthly capital meetings are used to gauge program expenditures relative to plan, and prioritize the re-allocation of available resources to existing or waitlisted investments. The re-allocation follows a process similar to Step 2, seeking to optimize the use of resources within the portfolio.

Technology 5-Year Strategic Plan

The Technology Group also annually prepares a Technology 5 Year Strategic Plan, which is a forward looking document that describes the goals and action plan of the Technology Group over the upcoming five-year period.

The 5 Year Strategic Plan is set in the context of BC Hydro’s mission and priorities, the current state of BC Hydro’s IT environment, and recent advances in information technology. A five-year planning period is used in order to address BC Hydro’s near term operational needs and medium term priorities, and to establish and sustain a resilient and cost-effective IT foundation.

Technology capital planning includes ongoing confirmation of alignment between the portfolio plan and the 5 Year Strategic Plan. This helps to ensure that day-to-day investment proposals and decisions align with the forward-looking strategic plan and that variances are identified. The Technology 5 Year Strategic Plan is provided in Appendix O to this application.

6.3.8 Properties Capital Investment Planning

Properties is responsible for the supply, operations and maintenance of BC Hydro's headquarters and field facilities that house field crews and a wide range of critical functions including system operations, telecommunications, emergency operations, customer contact, and security command centers. These facilities must be operational for 24-hour emergency response in all conditions. They provide critical services to BC communities and local industry. Properties managed facilities do not include Generation plant buildings or Transmission and Distribution substations, which are included in the Generation and Transmission and Distribution capital plans respectively.

6.3.8.1 Properties Portfolio Characteristics

Properties managed facilities are on average 30 years old, with almost 40 per cent of the facilities being more than 40 years old. Continued investment in these assets in the test period and beyond is required to maintain efficient and effective operation of BC Hydro's building assets, to limit costly and disruptive failures and to achieve the organization's objectives. All Properties' projects are classified as Sustaining Capital.

6.3.8.2 Properties Capital Planning Process

The investments in the Properties portfolio are driven by the need to address the issues and risks associated with the existing physical assets and infrastructure.

Properties Capital Planning focuses on assessing the health of existing assets and determining operational requirements that cannot be met by the existing asset portfolio, to establish an effective long term capital plan.

Properties capital investments fall into three general categories:

- **Building Development** - projects include the major refurbishing or rebuilding of field buildings and the construction of new buildings in areas where BC Hydro's existing facilities are inadequate;
- **Building Improvement** - projects at existing facilities to address operational deficiencies as well as end-of-life replacements of aging building components and systems; and
- **Interior Space Renovation** - projects focus on upgrading end-of-life building components and interior space on a floor by floor basis, addressing space constraints, aging assets, and safety and accessibility concerns.

Properties develops health assessments for assets at the facilities, based on current condition, remaining life expectancy, likelihood of failure, and impact of failure. The results of these assessments identify assets that are at or near end of life. Investments in these assets are considered for inclusion in the capital plan, to complete routine end-of-life replacements of aging building components and systems.

Properties also seek stakeholder feedback from key occupant groups in order to capture each group's building-related requirements across the portfolio. These occupants assess their facilities for their ability to meet their operational priorities. This feedback results in proposed investments to address specific operational demands including, for example, inadequate office and operational space, insufficient material storage space, and undersized truck bays.

Properties proposed capital investments are subject to the BC Hydro corporate risk framework used to assist in prioritizing capital investment, and the overall top-down planning guidelines discussed in section 6.3.3. Investments included in the BC Hydro 10 Year Capital Forecast are selected based on their prioritization score and other constraints.

Additional information on the Properties capital expenditures for the fiscal 2017 to fiscal 2019 test period is provided in Appendix I and Appendix J.

6.3.9 Fleet Capital Investment Planning

Fleet is responsible for the acquisition, operational costs, maintenance and disposal of BC Hydro's 3,200 vehicle, trailer and equipment assets used by field crews and staff across the province to meet BC Hydro's operational, reliability and safety targets. The availability, reliability and safety of vehicles are critical to ensure BC Hydro employees are able to efficiently and safely complete diverse types of planned and restoration work, including work during storms and outages.

6.3.9.1 Fleet Portfolio Characteristics

Fleet manages the lifecycle of diverse vehicle and equipment assets (including vehicles (cars, SUVs, pickups, crane trucks, bucket trucks, digger derricks, service body trucks, flat deck trucks), trailers, forklifts and other types of equipment) using established fleet industry principles and practices. The present average age of vehicles (excluding trailers) in the fleet is 6.3 years, with expected planned asset lifespans ranging from ten to 15 years depending upon vehicle class (excluding trailers).

6.3.9.2 Fleet Capital Planning Process

Investments in fleet assets are made to sustain reliable operations, minimize total asset lifecycle costs, ensure fitness of given assets for evolving work purposes, and limit safety and operational risks by meeting safety and other regulatory requirements.

Fleet investments are of two major types:

- Timely replacement of older vehicles to reduce financial risks, control lifecycle costs and address age-related mechanical, safety and reliability issues. These sustaining investments form the majority of the Fleet capital plan and seek to avoid financial risk of increasing maintenance costs as assets age (including higher likelihood of costly unplanned maintenance events). It is important to continually maintain the composition of the fleet from the standpoint of average age in order to limit the build-up of high cost, older vehicles.
- Upgrading and addition of required fleet assets to improve operational productivity, flexibility and safety. This represents a small portion of the capital investment in the fleet and includes value-based vehicle purchases via the upgrading or the addition of new vehicles due to changing business needs and work method changes

In its capital planning process, Fleet identifies and ranks vehicles for replacement using asset information (asset age/remaining life, mileage, maintenance costs, utilization rates, observed downtime frequency), input from vehicle maintenance staff regarding asset condition, and end-user input on asset condition, criticality and operational requirements. User groups also identify requirements for upgraded or additional fleet assets. This information is used to assemble a list of vehicles for replacement planning. The process is initiated in advance of the expected end of life criteria (i.e., for a vehicle with a ten-year life replacement planning is started at approximately the seven year mark). The general replacement criteria are established based on historical data, as well as the suggested useful life in a commercial application as determined by a vehicle supplier. In addition, the vehicle application and the environment it has been used in will have an impact on the actual life of the vehicle, and is also considered.

Through the Application of the corporate prioritization framework, top-down planning and expenditure guidelines and other constraints, the list of vehicles for replacement, upgrades and vehicle additions are prioritized. Recommended acquisition plans are vetted through senior management.

Additional information on the Fleet capital expenditure forecast for fiscal 2017 to fiscal 2019 plan is provided in Appendix I and Appendix J.

6.4 Capital Project and Program Delivery

6.4.1 Capital Delivery Organizational Groups

BC Hydro's capital investments are delivered by organizational groups that are structured and positioned to implement our capital projects and programs in an efficient and timely manner. There are three main types of capital investments that are delivered:

1. Capital projects, which are delivered by the following groups:
   - Capital Infrastructure Project Delivery Group, which includes delivery of the Site C Clean Energy Project; the Properties business unit; and the Technology business unit;
2. Capital programs and recurring work or small projects, which are delivered by the following groups:
   - The Program and Contract Management, and Customer Services and Distribution Design groups, both within Transmission, Distribution and Customer Services Business Group;
   - Generation Operations, within the Training, Development and Generation Business Group; and
3. Capital vehicle and equipment purchases, which are delivered by the Fleet business unit, within the Transmission, Distribution and Customer Services Business Group.

The processes for delivery of the planned capital investments are discussed in the following sections, starting with a discussion of the Capital Infrastructure Project

Delivery Group, which is responsible for the delivery of all large capital projects in the capital plan.

6.4.1.1 Capital Infrastructure Project Delivery Group

The Capital Infrastructure Project Delivery Group was founded in February 2015 dedicated to delivering Generation and Transmission and Distribution capital projects typically in excess of $1 million. All Technology, Properties and Fleet capital projects and programs continue to be delivered by the Technology, Properties and Fleet business units, respectively, due to the unique nature and resourcing requirements of their capital investments. Approximately 70 per cent of the $7.6 billion in capital expenditures planned in the fiscal 2017 to fiscal 2019 test period will be delivered by the Capital Infrastructure Project Delivery Business Group, with the balance delivered by the originating Business Groups.

The execution of Generation and Transmission and Distribution projects in excess of $1 million requires analysis of multiple design alternatives, and multiple methods of execution. The Capital Infrastructure Project Delivery Business Group includes Engineering, Aboriginal Relations and Environmental Risk Management, whose functions are critical elements in delivering these projects across the Province. The Capital Infrastructure Project Delivery Group organizational structure is discussed further in section 5.6.

To successfully deliver the capital plan Capital Infrastructure Project Delivery needs to be thoughtful, coordinated and disciplined and employ a consistent, unified approach. All projects managed by Capital Infrastructure Project Delivery use the Integrated Project and Portfolio Management solution, which contains:

(i) A comprehensive set of practices, and supporting procedures, processes, and guidelines;

(ii) An integrated IT tool set, including SAP, Primavera P6, SharePoint, Unifier, and Business Warehouse; and

(iii) Ongoing training and development, including an internal Community of Practice.

The Integrated Project and Portfolio Management solution was developed following these guiding principles:

- Integrate project scope, schedule and costs;
- Create work packages with clear responsibilities;
- Use resource loaded schedules;
- Forecast and track costs and resources at the same level; and
- Define a system of record for each data component.

Projects managed by Capital Infrastructure Project Delivery warrant a designated Project Manager, who is accountable for leading the delivery planning, execution, and close-out of the project.

In contrast, capital project delivery work that is managed within the Generation and Transmission and Distribution Business Groups is typically for capital investments of less than $1 million in cost, and of lower complexity and risk. The project team for projects managed within Generation and Transmission and Distribution and Customer Service will typically involve only one or few engineering discipline(s), and the role of the Project Manager may be fulfilled by someone performing other tasks as well.

The processes and practices used by Capital Infrastructure Project Delivery are also used to varying degrees by the other groups responsible for the delivery of capital investments.

Table 6-6, below summarizes the asset class, initiating organization, and the primary organization that delivers the projects.

Table 6-6 Delivery of BC Hydro Capital Expenditures by Organizational Group

Asset Portfolio	Project Initiating Business Group	Project Delivery Organization
Site C Clean Energy Project (Generation Growth)	Generation	Capital Infrastructure Project Delivery
Generation Growth and Sustain	Generation	Capital Infrastructure Project Delivery (Note 1)
Transmission Growth and Sustain	Transmission, Distribution and Customer Service	Capital Infrastructure Project Delivery (Note 1)
Distribution Growth and Sustain	Transmission, Distribution and Customer Service	Transmission and Distribution Program and Contracts Management (Note 1)
Customer driven "new connections" work under 5 megawatt (**MW**)	Transmission, Distribution and Customer Service	Customer Services and Distribution Design
Technology	Business Groups and Technology	Technology Business Unit
Properties	Business Groups and Properties	Properties Business Unit
Fleet	Business Groups and Fleet	Fleet Business Unit
Other	Other	Other (Note 2)

Note 1: Generation Operations delivers a portion of the generation sustain work (generally projects less than $1 million), Transmission and Distribution Program and Contracts Management delivers a portion of the Transmission Sustain projects, and Capital Infrastructure Project Delivery delivers a portion of the Distribution Growth projects, depending upon project complexity.

Note 2: Other includes capital projects for Security, Human Resources, Materials Management, and are generally small in size.

6.4.1.2 Governance in the Delivery of Capital Investments

BC Hydro has implemented governance structures and processes to provide oversight to the capital delivery processes across BC Hydro.

Capital Projects Committee (of the Board of Directors)

The Capital Projects Committee is one of the standing committees of the Board of Directors and is dedicated to assisting the Board of Directors in fulfilling its obligations and oversight responsibilities relating to BC Hydro's goal of delivering its capital projects on time and on budget. The Capital Projects Committee meets quarterly in conjunction with the board meeting. The Board of Directors provides strategic and policy level advice and direction to BC Hydro management on matters related to capital projects, and fulfilling its associated obligations and oversight responsibilities. Specifically, these areas of responsibility include, but are not limited to dam safety, execution of long-term capital plans and budgets, project oversight, and relationships with First Nations.

Capital Delivery Management Committee

The Capital Delivery Management Committee includes members of the executive team, senior management from the Operations groups, Finance, Supply Chain, and key capital investment delivery-focused business units. The committee meets monthly, with a mandate to provide advice and direction to groups involved in the planning and delivery of BC Hydro's capital investments, with respect to adherence to regulatory requirements, BC Hydro standards and long-term strategies, the capital planning process, and re-alignment of priorities of the capital plan if needed. Members review and monitor overall capital investment portfolio performance, and the progression and results of various initiatives; and ensure key portfolio delivery risks are identified so that steps can be taken to manage them. In addition to managing yearly objectives, the Capital Delivery Management Committee also takes a long-term view given the nature of the assets and the business.

Capital Delivery Management Committee Working Team

The Capital Delivery Management Committee Working Team provides feedback, recommendations, and insights to the Capital Delivery Management Committee to enable them to make informed decisions as part of the portfolio management process. The Capital Delivery Management Committee Working Team is composed of managers and directors responsible for managing the assets, managing resources and delivering capital projects, and also includes finance support staff.

The Working Team primarily focuses on the near-term, managing to the fiscal budget and identifying any capital portfolio realignment needed to ensure financial and resource constraint limits are not exceeded. The Working Team also offers specific recommendations on where realignment of the capital investment portfolio is needed and how best it should be executed. In addition to managing adherence to the fiscal budget, the Working Team identifies any potential areas for portfolio or project management improvement and provides solutions to the Capital Delivery Management Committee.

Project Accountability Meetings (for Capital Infrastructure Project Delivery Managed Projects)

The Project Accountability Meetings provide oversight to projects with forecast capital costs greater than $50 million, and for projects under $50 million where there is the risk of significant delays or cost increases. These meetings provide a forum for the Project Manager to update key internal stakeholders about the ongoing status of each project, and for the stakeholders to ask questions and provide input and guidance. The discussion will include items such as project schedule, cost, scope, safety, operations, aboriginal relations, stakeholder engagement and any other related matters. There are separate Project Accountability Meetings for transmission projects and for generation and dam safety projects.

Project Management Meetings (for Capital Infrastructure Project Delivery Managed Projects)

Depending on the stage of the capital project, the project's estimated cost, scope, alternatives, and implementation plans are subject to endorsement by a review at the Gate Governance board before approval by senior executives. The Project Management Meetings are bi-weekly meetings and perform as 'gates' to review and determine if a project is ready to progress to the next stage of its lifecycle. There are two types of Project Management Meetings and the differentiation is based on the capital cost of the project. The project sponsor, project initiators, and project teams attend the meeting as needed to advance individual projects. In addition to funding and stage progression approvals, these meetings are avenues for discussions with, and to get guidance from, key delivery partners on the status of projects or any issues projects might be facing or could potentially be facing in the near future.

The project management meetings are differentiated as follows:

Meeting Type	Generation Capital Projects Size	Transmission Capital Projects Size
Major Project Management Meeting	Projects ≥ $20 million	Projects ≥ $10 million
Non- Major Project Management Meeting	Projects < $20 million	Projects < $10 million

6.4.1.3 Capital Infrastructure Project Delivery Project Delivery – Processes and Practices

The following sections describe the main processes and practices used by the Capital Infrastructure Project Delivery Group in the delivery of BC Hydro's capital projects, including; the scalable Project and Portfolio Management practices; the project lifecycle; project initiation and management; resourcing; and the management of issues related to aboriginal relations, stakeholder engagement, safety, environment, and community engagement with respect to delivery of capital projects and programs. Many of the processes and practices described below are also followed by Transmission, Distribution and Customer Service Program and Contract Management, Customer Services and Distribution Design, the Technology Group, and Properties in the delivery of the components of the capital investment plan they are responsible for. Processes and practices in capital project and program delivery that are unique to these groups are discussed below. The Site C Clean Energy Project also follows processes and practices similar to those used by Capital Infrastructure Project Delivery.

Project and Portfolio Management Practices

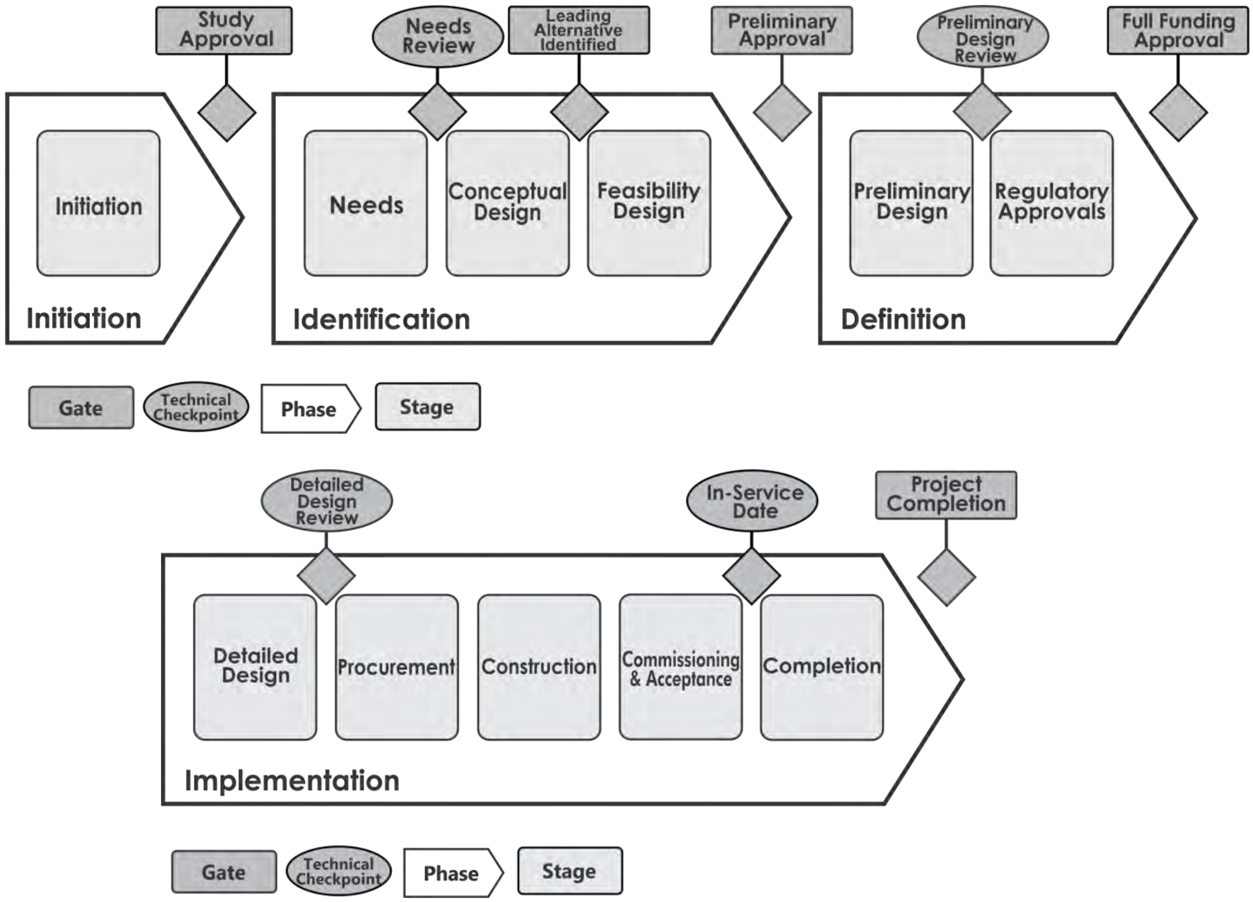
BC Hydro's Project and Portfolio Management is a combination of processes, IT systems, and defined accountabilities, providing a consistent, scalable framework for delivering projects and programs to meet project delivery, customer, statutory and regulatory requirements. The processes within the integrated Project and Portfolio Management solution are utilized by Capital Infrastructure Project Delivery and ensure a systematic and repeatable way of executing projects in the optimal manner, with the appropriate decision making, oversight, and continuous improvement. The Project and Portfolio Management processes include practices related to project management, design, procurement, contract and construction management, First Nations, regulatory, environmental, social issues and properties management. The Project and Portfolio Management processes also describe the consistent project lifecycle that is followed, from early project initiation through project implementation. The IT systems include an integration of Primavera P6 Scheduling Software, SAP Financials, Unifier Contract Management solution, and SharePoint.

As part of the processes, there are prescribed accountabilities and responsibilities within the defined roles that exist for project teams. Each project is led by a Project Manager who is accountable to a project initiator and to the Portfolio Director. The Project Manager is accountable to the Project Director for delivery of the project in accordance with the approved definition of the project. As such, the Project Manager is accountable for determining how the project will be delivered, including delivery models, procurement strategies, obtaining resources, obtaining all permits and regulatory approvals, putting contracts in place and managing the plan to achieve the agreed objectives. The Project Initiator defines the problem or opportunity that requires a project to be initiated. The initiator is accountable to the Project Sponsor for the justification for the Project. The Project Initiator is generally responsible for setting the project requirements, which are translated by the Project Manager into project scope.

The Project Lifecycle within Project and Portfolio Management

The project lifecycle is the full set of activities that BC Hydro utilizes to provide guidance, approval and oversight of capital projects. These activities are a key component of the Project and Portfolio Management practices discussed above. The lifecycle process is scalable, depending on project size and complexity, and is divided into phases, which are in turn sub-divided into stages, with key activities in each stage. Consistent with project governance, associated go/no go decision points occur in the stages, and determine if the project will proceed to the following stage. For each project that advances through to completion, all the phases must be completed. Figure 6-3 below illustrates the project lifecycle sequence from project initiation through to project completion. A high level summary of the typical project phases of the project lifecycle follows the diagram.

Figure 6-3 Project Lifecycle Sequence from Project Initiation to Completion



Description of Project Lifecycle Phases

The following provides a high level summary of the key activities within the project phases:

Initiation - identifies and defines an opportunity or problem.

Project Identification: reviews conceptual alternatives, evaluates feasibility, recommends an alternative and produces a project plan for Definition Phase funding, complete with a business case. The phase ends with a go/no go decision to proceed to the next phase. A leading alternative is identified during the conceptual design stage and a preferred alternative is confirmed at the end of feasibility design stage. The expected estimate accuracy at the end of feasibility study is +50/-15 per cent, nine times out of ten.

Project Definition: carries out a detailed investigation of the preferred alternative, prepares a preliminary design and a Project Plan for Implementation Phase funding complete with business case. This phase also includes the securing of all licences and regulatory approvals and any key defining agreements. The phase ends with a go/no go decision to proceed to the Implementation Phase. Regulatory applications are produced on the basis of the preliminary designs and the expected estimate accuracy is +15/-10 per cent, nine times out of ten.

Project Implementation: includes detailed design, material and equipment procurement, construction and testing and commissioning. The phase ends with the Project Initiator acknowledging acceptance of the project results by signing the Project Completion and Evaluation Report.

Gate approval points are positioned at the end of key stages in the project lifecycle to allow management to confirm that the proposed project solution remains in alignment with business drivers. As part of BC Hydro's Project and Portfolio Management Practices, a standardized estimating process is followed on all projects, to enhance the efficiency, accuracy and credibility of estimates. The process for determining estimates is based on industry practice, and estimates are checked and reviewed for accuracy, assumptions, risks and construction methodology depending on financial thresholds. Third party reviews, and on occasion a partially or completely independent estimate(s), are undertaken for projects that are especially large, complex, difficult to build, or not supported by sufficient in-house expertise.

For projects at the initiation or planning level, a problem or opportunity has been identified, but the required response has not yet been determined. Early in the Identification Phase, a number of different project alternatives are identified to address the problem or opportunity. Each alternative can result in a very different project scope, schedule and cost. During the Identification phase of the project, the identified alternatives are investigated in terms of a scope of work, implementation schedule and cost. The selection and approval of the preferred alternative is completed at the end of the Identification Phase. Since a cost estimate for the project can only be developed once the preferred alternative is determined, which defines the scope and implementation schedule for the project, the first engineering cost estimate and target in service date for a project are available at the start of the Definition Phase of the project lifecycle. During the Definition Phase, the preliminary design for the preferred alternative is completed and an updated cost estimate and target in service date are developed and endorsed. The implementation decision for a project is based on the preliminary design level cost estimate available at the end of the Definition phase.

For planning and portfolio management purposes only, a planning cost allowance, cost allowance range, and in service date may be developed for planned projects and those projects in the Identification Phase. These planning allowances have a very high degree of uncertainty, and should not be interpreted as a cost estimate or cost estimate range for the project. As described above, the first engineering cost estimate and cost estimate range for a project are available at the start of the Definition Phase of the project lifecycle. The planning in service date should be interpreted as the date the project is scheduled within the portfolio of future projects, and should not be interpreted as a forecast in-service date for the project.

Project Release Process

The project release processes for generation, transmission, and distribution projects managed by the Capital Infrastructure Project Delivery group have been aligned to adhere to a unified approach for delivering projects. The project initiating group, typically the asset management group, releases projects to the project delivery group who assume responsibility for the project from that point forward. The process includes verification that adequate resources are available prior to project release, and projects are typically staged for release on a quarterly basis to enable the business to adequately respond to changing conditions.

6.4.2 Resourcing Strategy in Delivery of Projects

The successful implementation of BC Hydro's capital projects and programs over the fiscal 2017 to fiscal 2019 test period requires the identification, retention, and management of an appropriate mix of both internal and external human resources. The external market not only provides needed additional capacity, but in many cases specific skills or expertise that is not resident within BC Hydro. BC Hydro's preferred strategy for meeting and managing these human resource requirements is discussed below.

Knowledgeable Owner Objective

BC Hydro's resourcing strategy is to be a Knowledgeable Owner. This means BC Hydro will retain the mix of skills and competencies needed to design and construct assets that can be safely operated and maintained. To do so effectively, BC Hydro will maintain full technical responsibility and act as the Professional of Record for a pre-determined number and mix of projects. This ensures that internal resources are becoming and acting as Knowledgeable Owners at every stage throughout the delivery process to enable a full understanding of the BC Hydro system, the asset management strategies, regular and emergency maintenance practices, and the corporation's strategic priorities.

Owner's Engineer Model

The Knowledgeable Owner's Objective also drives the Owner's Engineer model. BC Hydro uses a portfolio of internal and external engineering resources to design projects. Where external resources are used, BC Hydro will provide sufficient oversight and direction, the level of which will vary depending on the project's risk, complexity, and phase, to ensure adherence to standards and maintain consistency in the delivery of projects. This strategy is consistent with BC Hydro's Labour Mix Principles (refer to BC Hydro's Workforce Plan, Appendix F).

Overall Project Resourcing Approach

The process BC Hydro follows for meeting human resource requirements for delivering its capital investments is provided below. The process is iterative depending on BC Hydro requirements and resourcing constraints.

1. Confirm appropriate internal staffing levels;
2. Identify and source a number of long-term external service provider arrangements with firms or consortiums as needed;
3. Confirm staff augmentation levels with external resources, including contractors; and
4. Source from external service providers specific and niche assignments as needed.

6.4.3 Safety, First Nations and Environment

BC Hydro's priorities, goals and objectives with respect to Safety, First Nations and the Environment are discussed in Chapter 1, section 1.3. BC Hydro has established policies and practices in Project and Portfolio Management to ensure these priorities are addressed in the delivery of its capital investments.

6.4.3.1 Delivering Capital Investments Safely

BC Hydro's corporate wide priorities and objectives with respect to safety are discussed in Chapter 5, section 5.7.6. BC Hydro strives to deliver its capital investment portfolio in a safe way for employees, contractors and the general public. A top priority is providing an injury-free workplace for all employees and contractors as well as keeping the public safe in relation to our assets. In the past five years, BC Hydro has sought to proactively reduce safety incidents by instituting safety procedures, improving work processes, and repatriating electrical-based safety trades training. There are a number of ongoing initiatives that will positively impact how BC Hydro delivers capital investments safely over the fiscal 2017 to fiscal 2019 test period:

Contractor Safety Management

The project to develop the Contractor Safety Management system seeks to ensure there is clarity in roles and responsibilities for managing worker safety for BC Hydro and its agents and contractors. We are implementing a number of pilot projects to test practicality, clarity and effectiveness of the new contractor safety processes and requirements. Beginning in fiscal 2017 there will be a single BC Hydro approach to contractor safety management that is scalable and consistent with other related BC Hydro processes, policies, and procedures. An important element of this project is the revision of our Standard Form Contracts to ensure clarity in the roles, responsibilities, and obligations of both BC Hydro and our contractors with respect to sustaining a progressive and high performing safety culture. Going forward, key safety performance metrics will also be included in contracts to monitor overall safety performance and further ensure workers on our sites are safe.

Safety Management System

The Contractor Safety Management system is one core element of BC Hydro’s Safety Management System, which is currently being improved. The Safety Management System is a structured system of roles, responsibilities, policies, standards, rules, procedures, and programs that supports effective management of occupational health and safety risks across the company. Improvements to the Safety Management System will make it easier for employees and contractors in the field to get the information and support they need to work safely, and will provide managers at all levels with reliable information and consistent processes to effectively manage safety risks, including risks associated with project and contract work. As part of the Safety Management System, the Contractor Safety

Management system will embed and make clearer safety accountabilities and responsibilities in work procedures and contracts to support effective management of safety risks in project and contract work.

Safety by Design

Safety by Design is the application of engineering principles and standards to ensure our assets are designed to be safe. It proceeds through a systematic identification and analysis of hazards and barriers that are in place or which need to be implemented to eliminate hazards or reduce to an acceptable level the risk posed by these hazards. The result is improved safety for our employees, contractors, the public and the environment.

The application of Safety by Design is mandatory and embedded in capital delivery processes through the Project and Portfolio Management practices. A cross-functional team in the Safety Key Business Unit provides ongoing support to ensure consistent and reliable application of Safety by Design principles across BC Hydro. For additional discussion on the Safety Key Business Unit refer to section 5.7.6.

6.4.3.2 Aboriginal Consultation and Engagement in Delivery of Capital Projects and Transmission and Distribution Capital Programs

As described in section 5.6, BC Hydro's engagement with First Nations is guided by its Statement of Aboriginal Principles. In the context of capital project delivery, BC Hydro undertakes a consultation and engagement process that is consistent with its commitment to these Principles, as well as its legal obligations.

BC Hydro seeks to inform First Nations of its multi-year plans and the identification of potential projects through ongoing engagement with First Nations throughout the Province. By taking this approach, BC Hydro provides First Nations with information to facilitate a better understanding of possible impacts of projects. BC Hydro will gain a better understanding of First Nations interests and impacts, which may be incorporated into planning. Consultation and engagement continue through all phases of the project lifecycle (refer to section 6.4.1.3 for project lifecycle description) providing potentially affected First Nations with ongoing opportunities to provide input and feedback which will assist in developing impact mitigation measures. In addition, BC Hydro provides capacity funding so that First Nations may consult on projects, and may also seek First Nations' involvement in projects through contracting or employment opportunities. BC Hydro is committed to ongoing engagement with First Nations, and through these relationships, First Nations continue to have the opportunity to provide feedback once projects are in-service.

6.4.3.3 Protecting the Environment

BC Hydro seeks to minimize the impact to the environment as it delivers its capital investments. The Environmental Risk Management group (discussed further in Chapter 5, section 5.6.6), is tasked with managing key environment risks, and has identified key issues that can affect delivery of the BC Hydro's capital plan over the next decade.

Fisheries and Wildlife, Water, and Land

Due to their size and breadth, BC Hydro's capital projects and investments may impact the environment in a number of ways. Despite our efforts, there may be impacts and risks that cannot be fully mitigated, and in those cases BC Hydro will seek to identify these risks as early as possible and manage the process to minimize any system or financial impacts.

The programs listed below have been developed to manage a capital project's progression through the environmental regulatory process:

- BC Hydro works to minimize the risk, and conserve and enhance fish and wildlife impacted by dam projects by proactively working in partnership with the Province, Fisheries and Oceans Canada, other public stakeholders, and First Nations. The Fish and Wildlife Compensation Program currently provides social and environmental benefits to offset the construction of our hydroelectric facilities in the Peace, Coastal, and Columbia regions;

- The Water Use Plan monitoring and strategic fish programs were developed to meet regulatory requirements and support operational requirements for hydroelectric facilities. These programs manage the BC Hydro Operational Authorizations and Regulatory Agency relationships to promote timely approval for capital projects; and
- The Contaminated Sites Management Program leads to early and better identification and remediation of potential contamination.

Engaging Communities on Projects

BC Hydro engages with stakeholders in communities impacted by projects before final design decisions are made by maintaining regular lines of communication with our stakeholders and shareholder. BC Hydro plans to build on these activities by sharing the long-term view of ongoing and upcoming projects much earlier. Being proactive with communities and property owners builds public understanding and support, which can reduce project delays.

6.4.4 Other Organizational Groups Delivering Capital Investments

6.4.4.1 Transmission and Distribution Program and Contract Management Group

Transmission and Distribution Program and Contract Management is responsible for the delivery of the majority of recurring capital and maintenance work programs on BC Hydro's transmission and distribution systems. The group will deliver close to $974 million of BC Hydro's capital expenditures over the test period. This work includes Distribution Programs, Distribution Projects, Transmission Programs, Vegetation and Access Management Programs, and Contract Management.

The Program and Contract Management group applies Project and Portfolio Management concepts (discussed in section 6.4.1.3 above) and also "factory production management" concepts in a tailored fashion to manage the capital investment. For example, Program and Contract Management uses a repeatable framework in the execution of work assigned to the group, which focuses on creating a predictable approach to completing units of work by ensuring adequate controls are embedded in the work program delivery processes. These capital investments are typically like for like replacements based on pre-defined design standards, and thus there are limited or no alternatives to evaluate.

Additional information on the Program and Contract Management group and capital delivery processes is found in Chapter 5, section 5.5.5.

6.4.4.2 Customer Services and Distribution Design

Transmission and Distribution Customer Services and Distribution Design will deliver close to $440 million of BC Hydro's capital expenditures over the test period. Distribution Design provides all the technical design services and project management for customer driven "new connections" work under 5 MW. More complex work over 5 MW or customer projects considered higher risk are managed by the major projects group in Asset Investment are supported by Distribution Design technical services.

Distribution Design follows a process of designing to standards, with engineering support where required, and following a simplified project management structure that involves standardized work order packages, with environmental, heritage, safety and job planning processes and checklists. This enables project cycle times to align with customer requirements. Approximately 35,000 express orders are issued per year for very simple connections and customer work (no design work required) and approximately 5,000 work orders involving design services are issued per year for new customer connections.

6.4.4.3 Generation Operations Capital Investment Delivery

Generation Operations will deliver approximately $54 million of BC Hydro's capital expenditures over the test period. Generation Operations manages projects that have low complexity and that have a total cost of less than $1 million. These capital investments are typically like-for-like replacements where there are limited or no alternatives to evaluate.

6.4.4.4 Technology Capital Investment Delivery

The Technology Group will deliver close to $250 million of BC Hydro's capital expenditures over the test period.

The Technology Group is within the Transmission, Distribution and Customer Service Business Group and has adopted capital delivery practices in alignment with Project and Portfolio Management Practices in the delivery of BC Hydro's IT capital investments.

The Technology Group uses a framework called Information Technology Delivery Standard Process to aid managers, service providers and project teams in delivering successful projects. This framework aligns with the Project and Portfolio Management Practices and supports the unique character of IT projects.

The framework uses a project lifecycle model consistent with BC Hydro's Project and Portfolio Management Practices, using the standard phases but with uniquely defined stages.

The Technology Group employs two primary delivery models in order to optimize the use of internal and market-based delivery capacity:

- Managed teams, where BC Hydro employee or consultant project managers manage blended teams of employees, vendors and individual contractors; and
- Outsourced teams of external service providers in both long-term and shorter term arrangements.

6.4.4.5 Properties Capital Investment Delivery

The Properties Group will deliver close to $260 million of BC Hydro's capital expenditures over the test period. The delivery of Properties' capital projects are managed in an integrated manner, using both internal Properties resources as well as external parties. Properties' Capital Delivery processes align with the standard BC Hydro project lifecycle for managing projects, whereby projects progress through the four phases of delivery: Initiation, Identification, Definition, and Implementation. Gate approvals are formal approval points positioned at the end of key stages in the project lifecycle to allow management to confirm that the proposed project solution remains in alignment with business drivers and that the project is delivering on key project objectives including cost, schedule, and scope.

6.5 Description of Actual and Planned Capital Expenditures and Additions Fiscal 2015 to Fiscal 2019

The following sections provide information on BC Hydro's planned capital expenditures and additions for the fiscal 2015 to fiscal 2019 period. Information on major variances for fiscal 2015 to fiscal 2016 actual to plan is provided in Appendix K.

6.5.1 Generation Capital Expenditures and Additions

The Generation actual and planned capital expenditures for fiscal 2015 to fiscal 2019 are presented in Table 6-7 and Table 6-8, below. Capital expenditures related to the Site C Clean Energy Project are excluded from Table 6-7 and the discussion in this section.

Table 6-7 Generation Actual and Plan Capital Expenditures Fiscal 2015 to Fiscal 2019

($ millions)	F2015		F2016		F2017	F2018	F2019
	RRA	Actual	RRA	Actual	Plan	Plan	Plan
Hydroelectric Generation							
Growth	112.1	107.0	62.9	61.6	20.0	2.4	0.7
Redevelopment / Rehabilitation	272.4	227.7	296.4	268.3	335.2	277.0	121.9
Dam Safety	78.7	49.8	82.0	42.4	57.0	94.7	124.3
Sustaining - Other	157.0	133.1	145.5	103.8	149.8	205.2	238.6
Total Hydroelectric Generation	620.1	517.6	586.9	476.1	561.9	579.3	485.5
Non Integrated Areas							
Growth	4.0	0.9	8.3	-	-	-	-
Sustaining	4.7	4.4	4.4	12.7	7.7	7.2	6.6
Total Non Integrated Areas	8.7	5.3	12.7	12.7	7.7	7.2	6.6
Thermal Generation							
Growth	-	0.1	-	(0.4)	-	-	-
Sustaining	3.7	3.2	7.4	9.7	8.4	8.9	6.8
Total Thermal Generation	3.7	3.3	7.4	9.3	8.4	8.9	6.8
Total Gross Generation	632.6	526.2	607.0	498.1	578.0	595.5	499.0
Less: Portfolio Risk Adjustment	-	-	-	-	(28.0)	(59.0)	(74.0)
Total Generation	632.6	526.2	607.0	498.1	550.0	536.5	425.0
Less: Contribution in Aid	~~-~~ (0.7)	~~-~~ (1.1)	~~-~~ (3.9)	(1.7)	-	-	-
TOTAL	~~632.6~~ 631.9	~~526.2~~ 525.1	~~607.0~~ 603.1	496.4	550.0	536.5	425.0

The Portfolio Adjustment in Table 6-7 above is an approximation of how the capital expenditure forecast for the portfolio as a whole is likely to change over the test period, from the planned amounts. The approach considers that projects at different levels of maturity in the project lifecycle will have different levels of schedule and cost variability, and across the entire portfolio, a number projects will be subject to change over time. The level of uncertainty increases further into the future and is most pronounced in fiscal 2019. The largest impacts are due to the schedule variability associated with projects that are currently in early stages of the project lifecycle, given that their scope, schedule and cost will likely not be as well defined as more mature projects that are further in the project lifecycle and that are closer to completion. This is a new approach that has evolved as BC Hydro's understanding of project and portfolio management for Generation has matured, and is considered to be an enhancement on summing individual project estimates into a portfolio view. Without the adjustment, given the portfolio of work, it is likely that the portfolio level forecast will be overstated. Section 6.4.1.3describes the expected cost estimate accuracy of projects through-out the project lifecycle.

The Generation actual and planned capital additions for fiscal 2015 to fiscal 2019 are presented in Table 6-8, below.

Table 6-8 Generation Actual and Plan Capital Additions Fiscal 2015 to Fiscal 2019

($ millions)	F2015		F2016		F2017	F2018	F2019
	RRA	Actual	RRA	Actual	Plan	Plan	Plan
Hydroelectric Generation							
Growth	298.4	293.3	298.7	245.4	26.6	0.9	0.2
Redevelopment / Rehabilitation	30.0	19.7	40.0	58.6	304.0	184.4	955.5
Dam Safety	45.6	34.4	93.4	67.3	57.4	66.9	87.5
Sustaining - Other	223.9	122.1	155.1	153.5	101.1	124.6	268.1
Total Hydroelectric Generation	597.9	469.5	587.2	524.8	489.2	376.8	1,311.3
Non Integrated Areas							
Growth	-	-	-	-	-	-	-
Sustaining	8.9	10.4	11.9	5.6	8.3	6.9	4.2
Total Non Integrated Areas	8.9	10.4	11.9	5.6	8.3	6.9	4.2
Thermal Generation							
Growth	-	0.1	-	-	-	-	-
Sustaining	6.4	3.0	5.2	4.0	15.6	3.4	16.8
Total Thermal Generation	6.4	3.1	5.2	4.0	15.6	3.4	16.8
Total Generation	613.2	483.0	604.3	534.5	513.1	387.2	1,332.3
Less: Contribution in Aid	-	~~-~~ (3.0)	-	~~(1.7)~~ (2.3)	~~-~~ (0.3)	-	-
TOTAL	613.2	~~483.0~~ 480.0	604.3	~~532.8~~ 532.2	~~513.1~~ 512.8	387.2	1,332.3

Over the fiscal 2017 to fiscal 2019 test period planned capital expenditures total approximately $1.5 billion and include the following:

- Growth Capital expenditures total $23.1 million and include planned expenditures for Mica Units 5 and 6 and Revelstoke Unit 6;
- Redevelopment/Rehabilitation expenditures total $734.1 million, and include planned expenditures on the John Hart Generating Station replacement - $520.4 million and the Ruskin Dam Safety and Powerhouse Upgrade - $210 million;
- Dam Safety expenditures total $276 million, and include planned expenditures on the WAC Bennet Dam Rip Rap upgrade - $99.3 million, the John Hart Dam Seismic Upgrade - $24 million, and the GMS Bennett Dam Spillway Gate Upgrade - $17 million, as well as a number of smaller projects; and
- Sustaining-Other expenditures total $593.9 million, and include planned expenditures on Bridge River 2 - Units 5 and 6 Upgrade - $50 million, Cheakamus - Units 1 and 2 Generator Replacement - $42 million, G.M. Shrum G1-10 Control System Upgrade - $32 million, and Bridge River 1 – Transformer Replacement T1 and T2 - $30 million as well as a number of smaller projects.

Over the fiscal 2017 to fiscal 2019 test period planned capital additions total $2.23 billion and include the following:

- Growth Capital additions for Mica Units 5 and 6 - $26 million;
- Generation Station Redevelopment/Replacement additions include the John Hart Generating Station Replacement - $955.5 million and the Ruskin Dam Safety and Powerhouse Upgrade - $488.4 million;
- Dam Safety additions include the GM Shrum – WAC Bennett Dam Rip Rap Upgrade - $99.3 million; and
- Sustaining-Other Capital additions include the Bridge River 2 Upgrade Units 5 and 6 - $52.2 million, the Cheakamus Replace Units 1 and 2 Generators - $34.2 million, the GM Shrum Upgrade Units 1 to 10 Control Systems - $28.1 million, the Bridge River 1 Transformer Replacements T1 and

T2 - $37.6 million, and the Puntledge Recoat Interior and Exterior of Steel Penstock - $23 million.

A sample of the Generation projects with capital expenditures over the test period are described below, to illustrate the diversity of Generation projects. Additional information on Generation projects impacting the capital expenditures and capital additions presented in Table 6-8 and Table 6-9 are provided in Appendix I and Appendix J.

6.5.1.1 Hydroelectric Generation Growth Projects

Growth projects are to meet anticipated customer demand (Growth), or are improvements at existing generating stations to increase supply-side efficiency (Resource Smart).

In addition to the Site C Clean Energy Project, BC Hydro is working on two major growth hydroelectric projects during the test period, namely completing the Mica Generating Station Units 5 and 6 project and progressing the Revelstoke Unit 6 addition.

6.5.1.2 Generation Sustaining Projects – Redevelopment/Rehabilitation

Redevelopment and rehabilitation projects are to redevelop facilities or significant elements of facilities that are at end of life. Some of the older facilities are relatively mature in their overall lifecycle, and have a large number of different risks that need to be mitigated simultaneously. These can include condition issues and risks associated with the major generating equipment, and auxiliary systems, as well as buildings, water passages and large civil assets. In these cases, rather than undertaking many separate projects, it is more beneficial to take a more co-ordinated redevelopment or rehabilitation approach. The resulting benefits include improved efficiency in project delivery, reduced project costs, shorter outages and a reduction in the complexity of project management oversight.

Redevelopment projects will generally impact a significant portion of the infrastructure at a facility, and may include the construction of entirely new facilities as well as significant work on the dams and civil structures. Rehabilitation projects also involve addressing risks associated with multiple different assets simultaneously, but are generally less extensive in scope than redevelopment projects, due to less remediation of the foundational infrastructure.

Below is a representative sample of projects underway during the fiscal 2017 to fiscal 2019 test period (more complete information is available in Appendix J):

(i) **John Hart Generating Station Replacement (Redevelopment):** The existing generating station, located on Vancouver Island, has been in operation since 1947. The age and condition of the John Hart facility indicate the need for significant capital investment in the powerhouse and penstocks to ensure reliable generation from the facility in the long term and to mitigate seismic and environmental risks. Refer to Appendix J, page 2 for additional information.

(ii) **Ruskin Dam Safety and Powerhouse Upgrade (Redevelopment)**: The primary dam safety issues being addressed are the unacceptable risks associated with the condition of the seismic stability of the dam, spillway operational reliability, as well as the static and seismic deficiencies in the right abutment. Most of the major generating station equipment is in Poor or Unsatisfactory condition and requires significant capital investment to support continued safe and reliable operation.

6.5.1.3 Dam Safety Projects

Dam Safety projects are focused on mitigating risks associated with dams and other water conveyance or retention infrastructure within a hydroelectric setting. Risks are associated with safe storage and passage of water under normal operating conditions, the ability to pass floods (from the annual freshet to extreme events), and the ability to withstand a major seismic event without any harmful release of water.

Though aging and normal wear and tear present constant challenges, our aim is to manage the whole fleet of dams so that there is no significant deterioration in the risk position and that the overall level of risk is kept well within limits considered to be tolerable. Whenever it is possible to make improvements or necessary to take remedial measures, we first refer to international and Canadian best practices, seeking to achieve as large an increment to safety as possible, and at the very minimum, not to accept any reduction in the level of safety. We therefore seek to balance the cost of each possible improvement against the added safety it would achieve.

Below is a representative sample of projects underway during the fiscal 2017 to fiscal 2019 test period (more complete information is available in Appendix J):

(i) **W.A.C. Bennett Dam Rip-Rap Upgrade Since** original construction in the 1960s, wind generated waves, ice loading and freeze-thaw actions have damaged the existing rip-rap. As the rip-rap erodes, the underlying dam fill becomes exposed to erosion. The protective layers on the dam face (rip-rap and underlying filter material) must be rebuilt on the upper portion of the dam face. Refer to Appendix J, page 11 for additional information.

(ii) **John Hart Dam Seismic Upgrade** A seismic performance investigation was carried out and the withstand of the various component dams and spillway is significantly less than the Maximum Design Earthquake, and damage from a seismic event could lead to uncontrolled release of the reservoir. Therefore, seismic upgrades to the dams and spillway are required. Refer to Appendix J, page 13 for additional information.

(iii) **Peace Canyon Flood Discharge Gates Reliability Improvement** Upgrades to the electrical, mechanical and protection and control equipment are required to ensure the reliability of the Water Discharge System to pass flows without endangering the dams and/or the public. Refer to Appendix J, page 10 for additional information.

6.5.1.4 Generation Sustaining – Other Projects

Sustaining investments mitigate or resolve key risks identified with existing assets. This includes:

- Projects to replace major generating equipment at generating facilities that is in Poor or Unsatisfactory condition;
- The replacement or upgrade of facility infrastructure such as fire protection systems, Heating, Ventilating and Air Conditioning, ground grid, security, roofs, remote town site accommodation and cranes; and
- Projects to address safety, environmental or regulatory issues and risks.

Below is a representative sample of projects underway during the fiscal 2017 to fiscal 2019 test period (more complete information is available in Appendix J):

(i) **Bridge River 2 Upgrade Units 5 and 6:** The purpose of this project is to restore the reliability of the Unit 5 and 6 generators as well as the reliability of other major components (governors, exciters and circuit breakers) and their ancillary systems. The Equipment Health Rating of the generators is Unsatisfactory and both generators have been de-rated by 36 per cent. There is a high risk of further failures, resulting in an unplanned unit outage of up to 18 months. Upgrading the units will mitigate the significant reliability risk and provide an opportunity to increase unit capacity. Refer to Appendix I, page 1 of 9, line 34 and Appendix J, page 22 for additional information.

(ii) **Cheakamus Recoat Units 1 and 2 Penstocks (Interior and Exterior):** To support the longevity of a penstock, the protective coating will typically be reapplied periodically throughout the penstock's service life. The internal and external coatings of the Cheakamus penstocks have failed and active corrosion is reducing the thickness of the steel and could impact the penstock service life if recoating is not undertaken. The purpose of this project is to strip and recoat the interior and exterior of the penstocks, thereby protecting the steel from further deterioration. Refer to Appendix J, page 30 for additional information.

6.5.1.5 Thermal Generation

Non-Integrated Areas

All expenditures in fiscal 2017 to fiscal 2019 in Non-Integrated areas are to sustain existing assets. The Remote Community Electrification expenditures (growth) ended in fiscal 2016 with the completion of Good Hope Lake Diesel Generating Station electrification.

Gas-Fired Generation

Burrard Generating Station: With BC Hydro's Interior to Lower Mainland transmission line, Mica Generating Station Units 5 and 6 and a third transformer at Meridian Substation in-service, BC Hydro is able to serve load in the Lower Mainland and better respond to unplanned events without the need for Burrard's generating capability. BC Hydro has stopped generating electricity at Burrard; however Burrard will continue to provide voltage support to the transmission system by operating up to four units as synchronous condensers. This will provide savings for BC Hydro customers.

As a result, there is limited capital investment at Burrard in fiscal 2017 to fiscal 2019, while plans are developed for the investment required to convert Burrard from a generating station to a synchronous condenser station. Additional investments will be to implement sustainable synchronous condenser operations, address issues with asbestos at the facility and the building roof. Total capital investment planned at Burrard during the three-year test period is $13.6 million.

Prince Rupert Gas and Fort Nelson Gas Generating Stations: Capital investment planned at these generating stations during the three-year test period totals

$10.5 million, with a number of investments to improve safety, realize efficiency improvements and sustain the existing assets.

6.5.2 Transmission and Distribution Capital Expenditures and Additions

The planned capital expenditures and additions for fiscal 2017 to fiscal 2019 for Transmission and Distribution, classified by Growth and Sustain categories are provided in Tables 6-9 and 6-10, below.

Table 6-9 Transmission and Distribution Forecast Fiscal 2017 to Fiscal 2019 Capital Expenditures

($ millions)	F2015		F2016		F2017	F2018	F2019
	RRA	Actual	RRA	Actual	Plan	Plan	Plan
Transmission							
Growth (Schedule 13, Line 10)	810.9	822.3	488.4	382.7	417.0	222.0	192.7
Sustaining (Schedule 13, Line 11)	175.4	193.9	256.8	235.0	255.5	326.3	373.9
Distribution							
Growth (Schedule 13, Line 13)	161.3	206.7	191.4	224.7	224.7	233.4	209.5
Sustaining (Schedule 13, Line 14)	182.2	138.5	164.6	192.5	185.0	160.1	187.6
Total	1,329.8	1,361.4	1,101.2	1,034.9	1,082.3	941.8	963.8
Less: Contribution in Aid	~~(85.1)~~ (84.4)	~~(333.9)~~ (333.3)	~~(124.1)~~ (120.2)	~~(133.8)~~ (132.1)	(86.4)	(100.2)	(106.4)
TOTAL	~~1,244.7~~ 1,245.4	~~1,027.5~~ 1,028.1	~~977.1~~ 981.0	~~901.1~~ 902.8	995.9	841.6	857.3

Table 6-10 Transmission and Distribution Forecast Fiscal 2017 to Fiscal 2019 Capital Additions

($ millions)	F2015		F2016		F2017	F2018	F2019
	RRA	Actual	RRA	Actual	Plan	Plan	Plan
Transmission							
Growth	1,153.4	968.0	1,439.7	1,286.6	392.1	231.2	213.8
Sustaining	175.0	159.8	240.4	219.4	255.2	216.9	245.0
Distribution							
Growth	159.9	169.9	187.3	200.2	189.8	241.6	229.0
Sustaining	155.0	180.7	159.9	212.1	182.2	157.7	184.0
Total	1,643.3	1,478.4	2,027.3	1,918.3	1,019.3	847.4	871.8
Less: Contribution in Aid	~~(162.7)~~ (85.1)	~~(333.2)~~ (385.3)	~~(129.3)~~ (124.1)	~~(109.2)~~ (108.8)	(89.8)	(88.0)	~~(84.4)~~ (84.6)
TOTAL	~~1,480.6~~ 1,558.2	~~1,145.2~~ 1,093.1	~~1,898.0~~ 1,903.2	~~1,809.1~~ 1,809.5	929.5	759.4	~~787.4~~ 787.2

6.5.2.1 Transmission Planned Capital Expenditures and Additions Fiscal 2017 to Fiscal 2019

Transmission capital expenditures and additions include Substation Distribution Asset expenditures and additions. The Substation Distribution Asset costs are tracked separately, enabling the determination of transmission function costs for rate design and other purposes. Tables 6-11 and 6-12 below provides functional details regarding the forecast capital expenditures and additions.

Table 6-11 Transmission Capital Expenditures Fiscal 2017 to Fiscal 2019

($ million)	F2015 RRA	F2015 Actual	F2016 RRA	F2016 Actual	F2017 Plan	F2018 Plan	F2019 Plan
Transmission Growth							
Regional System Reinforcement	483.2	496.9	279.0	174.0	247.2	68.4	66.4
Bulk System Reinforcement	232.0	213.6	84.3	97.8	30.1	22.1	24.4
Station Expansion & Modifications	40.3	46.4	101.4	69.4	88.8	74.1	59.2
Feeder Position/ Section Additions	13.4	12.2	10.5	4.0	1.1	1.2	-
Generator Interconnections	23.6	22.6	4.7	24.6	30.3	26.4	15.1
Customer Requested Projects	18.4	30.7	8.4	13.0	19.5	29.7	27.7
Growth Total	810.9	822.3	488.4	382.7	417.0	222.0	192.7
Transmission Sustain - Stations							
Circuit Breakers	28.0	38.2	45.6	37.1	28.2	16.2	12.8
Other Power Equipment	30.1	41.8	29.7	52.4	48.5	83.2	143.3
Protection and Control	11.2	14.2	24.2	13.2	11.6	22.3	21.7
Stations Auxiliary Equipment	12.9	8.5	15.5	16.6	30.6	21.8	22.8
Stations Risk Mitigation	3.1	2.7	9.8	5.6	6.5	8.3	8.7
Telecommunications	7.8	3.4	10.6	3.6	7.7	13.0	12.4
Sustain Stations Total	93.2	108.7	135.4	128.5	133.2	164.7	221.6
Transmission Sustain - Lines							
Cable Sustainment	7.1	2.0	12.1	2.1	12.0	30.0	21.5
O/H Lines Life Extension	47.1	47.5	76.1	52.0	70.6	94.6	89.9
OH Lines Performance Improvement	5.2	9.3	6.2	9.0	4.1	3.8	4.3
OH Lines Risk Mitigation	9.2	10.6	5.0	26.0	19.2	15.4	20.9
ROW Sustainment	9.0	13.6	11.6	13.3	10.2	10.4	10.5
OH/UG Relocations	4.6	2.1	10.3	4.1	6.2	7.5	5.2
Sustain Lines Total	82.2	85.2	121.4	106.5	122.4	161.6	152.3
Total Gross	986.3	1,016.2	745.2	617.7	672.5	548.3	566.6
Less Contributions in Aid	(19.8)	(243.9)	(49.3)	(19.4)	(9.8)	(21.8)	(26.2)
Total Net	966.4	772.3	695.9	598.3	662.7	526.5	540.5

Table 6-12 Transmission Capital Additions
Fiscal 2017 to Fiscal 2019

($ million)	F2015 RRA	F2015 Actual	F2016 RRA	F2016 Actual	F2017 Plan	F2018 Plan	F2019 Plan
Transmission Growth							
Regional System Reinforcement	989.0	798.5	596.0	538.2	272.9	9.7	129.7
Bulk System Reinforcement	19.1	40.1	692.6	705.1	18.2	26.4	0.8
Station Expansion & Modifications	69.3	62.7	113.4	16.3	37.7	158.0	74.2
Feeder Position/ Section Additions	26.4	13.7	6.2	15.1	2.0	0.0	1.2
Generator Interconnections	44.7	40.4	8.2	1.2	55.7	13.8	-
Customer Requested Projects	5.0	18.4	23.4	35.0	5.7	23.4	7.9
Growth Total	1,153.4	973.8	1,439.7	1,310.8	392.2	231.2	213.8
Transmission Sustain - Stations							
Circuit Breakers	30.8	30.6	42.1	25.2	56.4	17.6	13.5
Other Power Equipment	29.6	30.6	29.8	50.8	41.4	36.8	58.6
Protection and Control	11.4	8.5	21.6	21.1	13.0	20.1	21.8
Stations Auxiliary Equipment	12.9	6.0	15.0	14.9	29.0	23.5	22.6
Stations Risk Mitigation	2.8	0.8	8.5	0.4	6.7	7.9	8.6
Telecommunications	6.9	2.6	10.0	1.4	7.8	11.9	12.5
Sustain Stations Total	94.5	79.2	126.9	113.7	154.4	118.0	137.6
Transmission Sustain - Lines							
Cable Sustainment	6.6	3.5	11.1	0.1	4.9	4.2	8.6
O/H Lines Life Extension	42.3	59.0	70.2	57.2	53.2	60.4	52.4
OH Lines Performance Improvement	6.0	0.8	6.0	16.8	4.4	3.9	4.2
OH Lines Risk Mittigation	10.9	1.2	5.8	18.4	22.0	16.1	19.8
ROW Sustainment	9.8	12.3	11.1	9.7	10.7	10.4	10.5
OH/UG Relocations	5.1	4.4	9.2	1.1	5.5	4.0	11.9
Sustain Lines Total	80.6	81.2	113.5	103.3	100.8	98.9	107.4
Total Gross	1,328.4	1,134.2	1,680.1	1,527.8	647.3	448.1	458.8
Less CIA Expenditures	~~(96.9)~~ (19.8)	(317.5)	~~(59.0)~~ (49.3)	~~(24.7)~~ (24.3)	(13.8)	(9.7)	~~(4.3)~~ (4.4)
Total Net	~~1,231.5~~ 1,308.6	816.8	~~1,621.1~~ 1,630.8	~~1,503.1~~ 1,503.6	633.5	438.4	454.4

6.5.2.2 Transmission Growth Expenditures and Additions

Regional System Reinforcement

The regional transmission systems generally comprise a large portion of the 230 kV system and all of the 138 kV and 60 kV systems. Regional transmission systems include transmission facilities that service localized geographic areas. Growth capital projects at this level often involve the installation of additional regional capacity in order to support area load growth and maintain area supply reliability and can include upgrades of and additions to lines or substation equipment.

Annual capital expenditures in Regional System Reinforcement remain high at $247 million in fiscal 2017 but reduce to between $66 million and $68 million in the fiscal 2018 to fiscal 2019 period.

Annual capital additions in Regional System Reinforcement in the fiscal 2017 to fiscal 2019 test period fluctuate between $10 million and $273 million. The additions increase in fiscal 2019 when the Horne Payne Substation Upgrade and Kamloops Substation projects are placed in-service. These projects are described in Appendix J.

Regional System Reinforcement projects greater than $5 million with expenditures and additions in the fiscal 2017 to fiscal 2019 test period are listed in Appendix I, page 3 of 9, lines 1 to 14.

Bulk System Reinforcement

The bulk system is composed of high voltage transmission lines and related equipment that interconnect the large remote generating stations in the Peace River and Columbia River areas with the major load centres in the Lower Mainland and on Vancouver Island. The bulk system includes the 500 kV transmission system, parts of the 230 kV system, the transmission connections to Vancouver Island, and interconnections with other utilities through external and internal interties to FortisBC, Rio Tinto Alcan, Alberta and the U.S.

After the in-service of the Interior to Lower Mainland project in fiscal 2016, annual capital expenditures on the bulk system will decrease over the fiscal 2017 to fiscal 2019 test period to between $22 million and $30 million.

Annual capital additions on the bulk system will also decrease in the fiscal 2017 to fiscal 2019 test period to between $1 million and $26 million.

Bulk system reinforcement projects greater than $5 million with expenditures in the fiscal 2017 to fiscal 2019 test period are listed in Appendix I, page 3 of 9, lines 15 to 17.

Station Expansion and Modifications

Station expansion and modification projects replace, upgrade, or add capacity to existing substations to alleviate operational constraints or limitations resulting from local load growth. These projects impact transmission and distribution facilities within the substation, and may involve installing additional transformer capacity, adding switchgear, converting to higher voltages, and reconfiguring existing facilities to accommodate increased capacity requirements.

Annual capital expenditures in the fiscal 2017 to fiscal 2019 test period peak at $89 million and then decrease to $59 million by fiscal 2019. This is primarily due to the completion of the Big Bend Substation, Arnott Capacity Upgrade and the Campbell River Substation Capacity Upgrade in fiscal 2018. The South Surrey Area Reinforcement project is also forecast to have significantly progressed by the end of fiscal 2018. All four projects are described in Appendix J, pages 56, 57, 58 and 60.

Annual capital additions in the fiscal 2017 to fiscal 2019 test period range between $38 million and $158 million. The peak of $158 million in fiscal 2018 is primarily due to the completion of the Big Bend Substation, Arnott Capacity Upgrade and Campbell River Substation Capacity Upgrade projects in fiscal 2018. The $74 million in fiscal 2019 includes capital additions for the South Surrey Area Reinforcement and Fernie Substation Upgrade projects as well as for the Westbank Substation Upgrade. The last two projects are also described in Appendix J, pages 59 and 62.

Station expansion and modifications projects greater than $5 million with expenditures in fiscal 2017 to fiscal 2019 are listed in Appendix I, page 3 of 9.

Feeder Position/Section Additions

Feeder position and sections are located within substations and supply the interface between the substation and the distribution system for BC Hydro's distribution- connected customers. These projects provide additional capacity for distribution customer load growth or for increased operational flexibility.

There are very few projects specifically to add feeder positions in the fiscal 2017 to fiscal 2019 test period. Capital expenditures and additions are $2 million or less annually under this category. However, the need to provide additional feeder positions at a number of substations will be addressed under integrated projects such as the Campbell River Substation Capacity Upgrade project and the Horne Payne Substation Upgrade project. Both projects and the multiple needs they address are described in Appendix J at pages 58 and 40.

Generator Interconnections

Generation interconnection projects involve the design and construction of facilities that are required to connect and integrate generation facilities to the existing transmission system. To connect generation facilities, tap lines or a three breaker ring bus substation and communication equipment are usually built, and protection coordination studies are done to establish the required setting changes. To integrate a generator into a regional network, BC Hydro would reinforce existing transmission lines as required to enable higher energy flows.

To determine the scope of upgrades required for a project, BC Hydro will perform a series of interconnection studies that identify impacts to the grid and the corresponding network upgrades required. Cost responsibility for network upgrades are defined in the OATT. Under the OATT, the customer is responsible to bring their system to the BC Hydro grid, which includes designing, procuring and funding their interconnection facilities. BC Hydro is responsible to design, procure, construct and fund the network upgrades within the BC Hydro system. The customer is required to provide security for the estimated cost of the network upgrades, which is returned over time to the customer per the tariff.

Currently, the majority of new IPP interconnections are coming through BC Hydro's Standing Offer Program. The program limits the funding BC Hydro will provide for network upgrades to a pre-determined threshold amount. The forecasts for interconnection costs include only the estimated network upgrade costs. They do not include the costs of those facilities that are the responsibility of the customer to construct.

Annual capital expenditures included in the fiscal 2017 to fiscal 2019 test period vary between $15 million and $30 million. This level is similar to the level of actual expenditures in fiscal 2015 and fiscal 2016. Only those projects with high probability of proceeding are included in the capital forecast.

Annual capital additions forecast in the fiscal 2017 to fiscal 2019 test period decrease from $56 million to zero as there are no projects forecast to complete in fiscal 2019. The higher level in fiscal 2017 is primarily due to the completion of the Meikle Wind IPP and Upper Lillooet River projects fiscal 2017.

Generator interconnection projects greater than $5 million with expenditures in the fiscal 2017 to fiscal 2019 test period is listed in Appendix I, page 3 of 9, lines 22 to 25.

Customer Requested Projects

Customer requested projects are initiated when an upgrade is needed on the transmission system to accommodate a new supply point (e.g., a new industrial or mining company) or an increase in an existing supply point.

BC Hydro's transmission load extension policy set out in Tariff Supplement No. 6 defines BC Hydro and customer rights and responsibilities, including what a customer is responsible to pay or provide a Revenue Guarantee for. Payments from customers toward the cost of a project are reported as Contributions in Aid, which is discussed further at the end of section 6.5.2.3.

Annual capital expenditures in the fiscal 2017 to fiscal 2019 test period range from $20 million to $30 million. This level is similar to the level of actual expenditures in fiscal 2015 and fiscal 2016. Only those projects with high probability of proceeding are included in the capital forecast.

Annual capital additions in the fiscal 2017 to fiscal 2019 test period range from $6 million to $24 million. The higher level is fiscal 2018 is due to the planned completion of one larger project.

Customer requested projects greater than $5 million with expenditures in the fiscal 2017 to fiscal 2019 test period are listed in Appendix I, page 3 of 9, lines 18 to 21. Contributions in Aid are included in Appendix I – Transmission.

6.5.2.3 Transmission Sustaining Expenditures and Additions

Circuit Breakers

Circuit breakers are used to isolate sections of the transmission and distribution system and to interrupt high currents under fault conditions. They are the primary protection device on the transmission and distribution system and must be capable of reliably interrupting both load currents and fault currents. The system currently has over 3,700 circuit breakers made up of a variety of different equipment in terms of voltage classes (from 12 kV to 500 kV).

The planned expenditures for the test period are for the replacement of individual circuit breakers as they reach end-of-life. The timing of the replacements is based on condition, failure rates and risk to the system. Refurbishment of circuit breakers is considered but usually not possible due to obsolescence. The circuit breaker expenditures also include a large project to replace the entire 230 kV gas-insulated switchgear at Horsey Substation. The project is listed in Appendix I, page 3 of 9, line 39 and described in Appendix J, page 66.

After the completion of the Horsey Gas-Insulated Switchgear Replacement project in fiscal 2017, annual capital expenditures in the fiscal 2017 to fiscal 2019 test period decline from $28 million to $13 million and annual capital additions decline from $56 million to $14 million. The decline over the test period is also due to a gradual decrease in the number of 230 kV and 500 kV circuit breakers needing replacement.

Other Power Equipment

Other power equipment expenditures are for the replacement or refurbishment of disconnect switches, surge arrestors, power transformers, instrument transformers, shunt reactors, shunt capacitors, synchronous condensers, high-voltage direct current systems, series capacitor stations, cable terminations, and load tap changers. The Other Power Equipment expenditures now also include large integrated projects to replace multiple power equipment and circuit breakers. There are five such projects at Mainwaring, Esquimalt, Barnard, Horsey and Newell substations with expenditures during the fiscal 2017 to fiscal 2019 test period. The projects are listed in Appendix I, page 4 of 9, lines 43, 44, 46, 48 and 49 and described in Appendix J, pages 69, 70, 72 and 74.

Annual capital expenditures in the fiscal 2017 to fiscal 2019 test period increase from $49 million to $143 million, which is higher than the actual expenditures in fiscal 2015 and fiscal 2016. Expenditures are increasing over the period mainly due to the five large aforementioned projects.

Protection and Control

Protection and Control expenditures are for the replacement of protective relaying and control systems at transmission stations. Protection and Control assets isolate transmission equipment from electrical faults, ensure stability and reliability of the transmission system, and provide local and remote control and monitoring of the transmission system.

Annual capital expenditures and additions in the fiscal 2017 to fiscal 2019 test period range between $12 million and $22 million. The increase in fiscal 2018 and fiscal 2019 over prior years is due to the North American Electric Reliability Council Critical Infrastructure Protection V5 Compliance at Medium Impact Transmission and Distribution Stations Project. This project is listed in Appendix I, page 4 of 9, line 47 and described in Appendix J, page 73.

Stations Auxiliary Equipment

Auxiliary equipment expenditures are for the replacement of station equipment used to support the transmission system, including station cables, bus work and insulators, steel structures, equipment foundations, grounding systems, station power supplies, batteries and chargers, air compressors and dryers, buildings and Heating, Ventilating and Air Conditioning equipment, perimeter fences, drainage systems, and gravel.

Annual capital expenditures and additions in the fiscal 2017 to fiscal 2019 test period range between $22 million and $31 million. The increase in the period over fiscal 2015 and fiscal 2016 is due to increased activity in programs to replace end of life station service equipment and wood pole structures in substations. These programs have higher expected expenditures in fiscal 2017 with a decreasing trend in fiscal 2018 and fiscal 2019 as the high priority substations are addressed.

Stations Risk Mitigation

The Stations Risk Mitigation expenditures address safety, seismic, environment, severe weather and security risks. Each risk is evaluated based on business impact (e.g., reliability, financial, environmental, safety) and probability of occurrence to determine the appropriate magnitude and duration of investment that is required to mitigate the risk.

Annual capital expenditures and additions in the fiscal 2017 to fiscal 2019 test period range between $7 million and $9 million. Both expenditures and additions are increasing over fiscal 2015 and fiscal 2016 primarily to upgrade security at various substations.

Telecommunications

BC Hydro operates a telecommunications system to support transmission system protection, control, and voice and data communications. The telecommunications expenditures are for the replacement of telecommunication infrastructure including microwave radio, power line carrier, fibre optic cable, copper pairs, leased line, and VHF/UHF radio.

The annual capital expenditures and additions in fiscal 2017 to fiscal 2019 range between $8 million and $13 million. The increased expenditures starting in fiscal 2017 are mainly required to replace the radio system on Vancouver Island that is at end of life.

Cable Sustainment

Underground and submarine cables are generally used where overhead lines are not feasible or where there is a particular requirement of the site to use cables. There are over 400 km of underground or submarine cables on the transmission system. Most of these circuits are located in Vancouver, Burnaby, Coquitlam and Victoria, and include 69 kV, 138 kV, 230 kV and 500 kV voltage levels. Cable sustainment expenditures are for the replacement of cables and ancillary equipment (e.g., pumping equipment and duct banks).

Annual capital expenditures in the fiscal 2017 to fiscal 2019 test period range from $12 million to $30 million and capital additions range between $4 million and $9 million. Relative to fiscal 2015 and fiscal 2016, capital expenditures and additions are forecast to increase as more cables and ancillary equipment approach end of life. The George Massey Tunnel Transmission Relocation project also contributes to increasing expenditures in the fiscal 2017 to fiscal 2019 test period. The project is included in Appendix I, page 4 of 9, line 42 and is described in Appendix J, page 68.

Overhead Lines Life Extension

The overhead transmission network consists of conductor systems, metal support structures, wood poles, and associated equipment which includes spacer dampers, aircraft warning markers, and disconnect switches. The overhead network has over 18,400 km of transmission lines. These circuits include approximately 23,000 metal support structures and approximately 116,000 wood poles. Overhead lines life extension expenditures cover the replacement or refurbishment of line components. The expenditures also include the complete replacement of circuit 2L99 under the TKT – Terrace to Kitimat Transmission project. This project is listed in Appendix I, page 4 of 9, line 41 and described in Appendix J, page 67.

Overhead lines life extension expenditures cover the replacement or refurbishment of line components. Annual capital expenditures in the fiscal 2017 to fiscal 2019 test period range from $71 million to $95 million. The increase in the fiscal 2017 to fiscal 2019 test period over the actual expenditures in fiscal 2015 and fiscal 2016 is primarily due to the TKT-Terrace to Kitimat Transmission project.

Annual capital additions in the fiscal 2017 to fiscal 2019 test period range from $52 million to $60 million. The level is comparable to the actual capital additions in fiscal 2015 and fiscal 2016.

Overhead Lines Performance Improvement

Investments in this category are to address transmission lines subject to localized weather conditions causing performance issues. This work is intended to bring the line back to its designed reliability level. Examples include local sections subject to unequal ice loading, high instances of lightning strikes, or salt fog. Currently, the focus of the expenditures is on reducing lightning caused outages by installing transmission arcing horns.

Annual capital expenditures and additions in the fiscal 2017 to fiscal 2019 test period remain constant at $4 million each year, which is lower than actual expenditures in fiscal 2015 and fiscal 2016 as a result of the prioritization of work, with the timing of lower priority work being adjusted.

Overhead Lines Risk Mitigation

The Overhead Lines Risk Mitigation program addresses issues and potential events which could put the system at risk of a prolonged outage or pose safety concerns. Currently, the focus of the expenditures is on reducing the risk to public safety and operating concerns associated with deficient transmission line to ground clearances. Civil protective work to protect transmission structures against flooding and slides are also addressed under this program.

Annual capital expenditures in the fiscal 2017 to fiscal 2019 test period range between $15 million and $21 million and capital additions range between $16 million and $22 million. Actual expenditures and additions in the fiscal 2015 to fiscal 2016 range between $1 million and $26 million. The varying levels year over year are driven by differences in the scope of work required to address line to ground clearance deficiencies of the specific targeted circuits.

Rights-of-Way Sustainment

BC Hydro is responsible for managing the rights-of-way and infrastructure that allow access to the power system, including interest in over 16,000 km of resource roads. This includes roads located along BC Hydro’s corridors where BC Hydro is the sole maintainer, and also includes industry-maintained roads leading to the power system facilities where BC Hydro has shared obligations for road maintenance (such as Forest Service Roads, telecom station roads, and other types of permit roads on Crown land). The Rights-of-Way Sustainment program restores roads in poor condition, and replaces road structures that are at end-of-life (such as bridges, gates, culverts, and retaining walls). The program also acquires and renews legal status of rights-of-way for overhead transmission lines throughout the province.

Annual capital expenditures and additions in the fiscal 2017 to fiscal 2019 test period remain relatively constant at $10 million. The forecasted decrease compared to the levels in fiscal 2015 and fiscal 2016 is due to lower investments to address deficient and miscellaneous rights.

Overhead/Underground Relocations

Third party requested line relocations are expenditures initiated when BC Hydro enters into an agreement with a third-party who wishes to have transmission lines relocated. The third party will pay for all costs incurred, resulting in an offsetting contribution in aid of construction for the capital expenditure, except for relocations due to highway rerouting by the Ministry of Transportation, where a small offsetting portion of the cost is received according to a protocol agreement. The small cost recognizes the benefit of rights-of-way provided to BC Hydro by the Ministry of Transportation at no cost. BC Hydro may also relocate transmission lines where legally or contractually obligated.

Annual capital expenditures in the fiscal 2017 to fiscal 2019 test period range from $5.2 million to $7.5 million. The level is higher than actual expenditures in fiscal 2015 and fiscal 2016 due to the 60L020 Segment Relocation project. The 60L020 Segment Relocation is listed in Appendix I, page 3 of 9, line 40.

Annual capital additions in the fiscal 2017 to fiscal 2019 test period range from $4 million to $12 million. The high of $12 million in fiscal 2019 is primarily due to the completion of the 60L020 Segment Relocation project in that year.

Contributions in Aid

Contributions in Aid are periodic or lump-sum payments or consideration received from customers or third parties to provide funding toward the cost of construction or acquisition of an asset where the ownership, operation and maintenance responsibilities remain with BC Hydro. Contributions In Aid is further discussed in the Customer Requested Projects and Overhead/Underground Relocations sections above.

Transmission Contributions in Aid amounts are forecast to increase from fiscal 2017 to fiscal 2019 due to expected payments associated with the Northwest Substation Upgrade Projects listed in Appendix I, page 3 of 9, line 16 and described in Appendix J page 53.

Transmission Contributions in Aid additions are forecast to decrease over the period after the planned completion of a number of third party driven load interconnections in fiscal 2017.

6.5.3 Distribution Capital Expenditures and Additions

The Distribution planned capital expenditures and additions for fiscal 2015 to fiscal 2019 are provided in Table 6-13 and Table 6-14, below.

Table 6-13 Distribution Capital Expenditures
Fiscal 2015 to Fiscal 2019

($ million)	F2015 ~~Plan~~ RRA	F2015 Actual	F2016 ~~Plan~~ RRA	F2016 Actual	F2017 Plan	F2018 Plan	F2019 Plan
Distribution Growth							
Customer Driven							
Customer Connections	103.3	136.8	111.3	157.2	132.9	140.2	141.4
Major Customer Connections	14.9	3.5	15.4	6.4	17.7	18.2	18.6
IPP	-	9.5	-	5.6	4.6	4.7	4.7
Customer Driven Total	118.3	149.7	126.7	169.2	155.2	163.1	164.6
System Expansion and Improvement	42.9	56.5	64.6	55.3	69.1	69.8	44.4
Uneconomic Extension Assistance	0.1	0.4	0.2	0.2	0.4	0.5	0.5
Growth Total	161.3	206.7	191.4	224.7	224.7	233.4	209.5
Distribution Sustain							
System Expansion and Improvement	30.7	35.5	43.2	60.7	49.4	29.7	55.1
Asset Replacement							
Poles	48.2	68.9	75.0	74.4	81.7	77.2	74.0
Overhead Equipment	2.4	2.3	3.2	11.2	11.1	11.4	15.8
Underground Equipment	17.8	16.1	26.6	27.6	30.9	29.5	30.3
Trouble	10.2	10.0	10.4	15.8	10.5	10.8	11.0
Asset Replacement Total	78.6	97.3	115.2	129.1	134.2	128.9	131.0
Beautification	1.4	0.3	1.4	1.4	1.4	1.4	1.5
Smart Metering	71.5	5.4	4.8	1.4	-	-	-
Sustain Total	182.2	138.5	164.6	192.5	185.0	160.1	187.6
Total Gross	343.4	345.1	356.0	417.2	409.8	393.4	397.1
Less Contributions in Aid	(64.6)	~~(89.1)~~ (89.4)	(70.9)	~~(112.6)~~ (112.7)	(76.6)	(78.4)	(80.3)
Total Net	278.8	~~256.0~~ 255.7	285.1	~~304.6~~ 304.5	333.2	315.0	316.8

Table 6-14 Distribution Capital Additions
Fiscal 2015 to Fiscal 2019

($ million)	F2015 RRA	F2015 Actual	F2016 RRA	F2016 Actual	F2017 Plan	F2018 Plan	F2019 Plan
Distribution Growth							
Customer Driven							
Customer Connections	104.6	107.4	109.4	143.2	132.8	139.9	141.3
Major Customer Connections	13.9	2.9	15.3	3.8	17.8	18.1	18.5
IPP	-	8.0	-	5.5	3.7	4.7	4.7
Customer Driven Total	118.5	118.3	124.6	152.5	154.4	162.7	164.5
System Expansion and Improvement	41.2	45.3	62.5	47.5	35.0	78.5	64.0
Uneconomic Extension Assistance	0.1	0.5	0.2	0.2	0.4	0.5	0.5
Growth Total	159.9	164.1	187.3	200.2	189.8	241.6	229.0
Distribution Sustain							
System Expansion and Improvement	32.4	61.2	45.3	53.2	44.3	26.5	51.9
Asset Replacement							
Poles	49.7	75.2	69.7	75.6	82.0	78.1	74.6
Overhead Equipment	2.5	8.9	3.0	5.8	10.3	11.3	14.9
Underground Equipment	18.4	19.6	24.8	20.1	33.8	29.6	30.1
Trouble	10.2	5.9	10.4	22.0	10.5	10.7	10.9
Asset Replacement Total	80.7	109.7	107.9	123.4	136.6	129.8	130.6
Beautification	1.4	1.0	1.4	0.0	1.4	1.4	1.5
Smart Metering	40.4	8.9	5.3	33.8	-	-	-
Sustain Total	155.0	180.7	159.9	210.5	182.3	157.7	184.0
Total Gross	314.9	344.8	347.2	410.7	372.1	399.3	413.0
Less Contributions in Aid	~~(65.8)~~ (65.3)	(67.8)	~~(70.3)~~ (74.8)	(84.5)	(76.0)	(78.3)	~~(80.1)~~ (80.2)
Total Net	~~249.1~~ 249.6	~~277.1~~ 277.0	~~276.9~~ 272.4	326.2	~~296.0~~ 296.1	321.0	~~332.9~~ 332.8

6.5.3.1 Distribution Growth Capital Expenditures and Additions

Customer Driven Expenditures

Customer driven expenditures are in response to commercial and residential requests for connections to the distribution system. This category includes expenditures to connect residential and small commercial load customers (approximately 35,000 requests annually), major distribution loads defined as greater than 5MVA and/or $1 million in interconnection costs, and distribution voltage IPP projects.

Annual capital expenditures and additions increase in the fiscal 2017 to fiscal 2019 test period from $154 million to $165 million based on a 0.5 per cent predicted level of growth and includes a one-time increase in fiscal 2018 for customer meter inventory to facilitate Measurement Canada meter testing requirements. Customer driven expenditures are forecast based on historical levels while additions are forecast based on the assumption that most expenditures are capitalized in the year they are incurred. The results for fiscal 2015 and fiscal 2016, which varied from the trend, are discussed in Appendix K. There is one customer driven project greater than $5 million with expenditures in the fiscal 2017 to fiscal 2019 test period, and the project is listed in Appendix I page 5 of 9, line 1.

System Expansion and Improvement - Growth

System expansion and improvement growth expenditures address existing capacity constraints and anticipated load growth. The existing infrastructure in high growth load centres (such as the Lower Mainland, Victoria, Dawson Creek, and Kamloops) of BC Hydro’s distribution system is at or near capacity, and system upgrades are required to supply the load and meet the demand of customers. BC Hydro is undertaking several projects to increase the capacity and transfer load at the highest risk locations.

Annual capital expenditures in the fiscal 2017 to fiscal 2019 test period are forecast to peak in fiscal 2018 at $70 million, a $14 million increase from the fiscal 2016 actuals, before decreasing to $44 million in fiscal 2019. System Expansion and Improvement projects are subject to year over year fluctuations as a result of the prioritization of work, with the timing of lower priority work being adjusted.

Annual capital additions in the fiscal 2017 to fiscal 2019 test period range from $35 million to $79 million. While additions in fiscal 2015 and fiscal 2016 have been steady at $45 million and $48 million, respectively, there is a year over year fluctuation in the test period largely due to a larger number of multi-year projects in fiscal 2017, with additions not occurring until fiscal 2018 once the projects are placed in-service.

System Expansion and Improvement growth projects greater than $5 million with expenditures in the fiscal 2017 to fiscal 2019 test period are listed in Appendix I page 5 of 9, lines 2 to 13.

Uneconomic Extension Assistance

The Uneconomic Extension Assistance program expenditures provide financial assistance toward the cost of uneconomic overhead electrical extensions as per the Electric Tariff.

Annual capital expenditures and additions for Uneconomic Extension assistance remain constant at under $1 million in the fiscal 2017 to fiscal 2019 test period, consistent with prior years.

6.5.3.2 Distribution Sustaining Capital Expenditures and Additions

System Expansion and Improvement - Sustain

System expansion and improvement sustaining expenditures maintain and improve distribution system performance including addressing customer reliability, safety risks and regulatory and legal requirements.

Annual capital expenditures and additions range in the fiscal 2017 to fiscal 2019 test period from $27 million to $55 million, with fiscal 2015 and fiscal 2016 results also showing significant fluctuations. Year over year fluctuations are the result of prioritization of work with the timing of lower priority work being adjusted. Most of these expenditures are for various small projects that relate to the following three areas.

- **Customer Reliability-** The objective of customer reliability expenditures is to improve reliability on targeted distribution circuits that are performing poorly. The scope of customer reliability projects may include new standby feeders, feeder ties, reclosers, as well as circuit undergrounding or reconfiguration, line relocations and protection upgrades.
- **Distribution Automation -** Automation of distribution devices provides operating personnel with remote visibility of system parameters and system status, facilitates remote operability, and in general enables greater flexibility to efficiently operate the system. Expenditures are focused on automation of reclosing and switching devices to enable faster fault isolation and outage restoration, thereby enhancing service reliability, and on automation of voltage management devices to improve power quality.
- **Downtown Vancouver Redevelopment** - The Downtown Vancouver Redevelopment initiative is a long term strategic plan to convert the downtown core from a 12 kV dual-radial system to a 25 kV open loop system over the next 30 plus years. The Cathedral Square transformer failure in 2007, the manhole fire in 2008, and the Murrin transformer failure in 2013 have demonstrated the considerable supply risk and vulnerability of the aging and congested distribution system in the downtown Vancouver area. This initiative will start to address the risk of long, high consequence outages in the high density downtown area. The initiative will replace aging assets with equipment that meets current standards and introduce automation (per above), to provide operational flexibility, reduce congested circuits as well as reduce outage restoration times. In conjunction with the Downtown Vancouver Redevelopment, BC Hydro will continue with a safety initiative in downtown Vancouver to eliminate potential hazards to the public. The replacement circuits

will be an underground automated open loop system to align with the overall redevelopment initiative.

System Expansion and Improvement sustain projects greater than $5 million with expenditures in the fiscal 2017 to fiscal 2019 test period are listed in Appendix I page 5 of 9, lines 13 to 14.

Asset Replacement - Distribution asset replacements expenditures address equipment that has reached end of life. The forecast level of capital expenditures and additions for Asset Replacements remains between $129 million and $137 million annually during the fiscal 2017 to fiscal 2019. The higher level of investment, which began in fiscal 2016, is needed to address the increasing number of assets that have been assessed to be in Poor or Very Poor condition and are at, or approaching, end of life. Individual program expenditures will vary year by year based on the relative priority of work.

Distribution asset replacements fall into the following four categories:

- ***Poles*** **-** This category covers wood and concrete poles as well as elevated platforms. Poles and platforms at end of life pose a significant risk to crews and the general public and may cause outages on the system. An increasing number of BC Hydro's approximately 900,000 distribution system wood poles are reaching end of life. Of the total population of wood poles in the system, 87,000 are currently greater than 50 years of age. Wood pole end-of-life is identified by a series of inspection programs that run throughout the fiscal year. In the test period, approximately 32,000 wood poles will be replaced.

  Concrete poles were first installed on the distribution system in the early 1980s. Due to safety issues related to a lack of adequate integral bonding, concrete poles have been deemed to be at end-of-life. In the test period approximately 5,000 concrete poles will be replaced with wood poles. The current plan is to replace all concrete poles by the end of fiscal 2022.

Elevated equipment platforms support larger overhead transformers, multiple voltage regulators and other heavy overhead type equipment. In the test period, approximately 250 equipment platforms will be replaced due to end-of-life.

- ***Underground System* -** Underground system assets include feeder cables, submarine cables, residential distribution cables and equipment, transformers and switchgear. Underground systems typically supply densely populated areas. Equipment in poor condition can pose a significant risk to system reliability and to public and worker safety. Detailed condition assessments combined with risk assessments are used to identify replacements of underground system assets. An example is the replacement of live-front transformers, which were installed in the 1960s. Inspections have identified some units that need to be replaced because perforations are developing in the unit enclosures due to corrosion. These openings in the enclosure are significant electrical hazards for the public. In addition to corrosion issues, live-front equipment creates a higher safety risk for workers and is being replaced in order to meet BC Hydro's current safety standards. All remaining live-front transformers are being replaced over the next five years with dead-front units which provide additional safety barriers for workers and the public. Transformers and switchgear with polychlorinated biphenyl levels at or above 50 ppm will begin to be proactively replaced starting in fiscal 2019 to ensure all units in the category are removed by the December 31, 2025 Federal Polychlorinated Biphenyl Regulation deadline.
- ***Overhead System* -** Overhead system assets include transformers, voltage regulators, circuit reclosers, conductor, and switches including porcelain fuse cut-out switches. BC Hydro also manages a fleet of street lights as part of the distribution overhead system. Porcelain fused cut-out switches, which are prone to failing, posing a significant falling object safety hazard to workers and the public, will continue to be replaced at a rate of approximately 8,000 units over the fiscal 2017 to fiscal 2019 test period. The replacement program started in

fiscal 2010 and all high risk areas of the province have been addressed as of the end of fiscal 2016. The program will focus on medium risk areas during the test period. Equipment on the overhead system with polychlorinated biphenyl levels at or above 50 ppm will also begin to be proactively replaced starting in fiscal 2019 to ensure all units in the category are removed by the December 31, 2025 Federal Polychlorinated Biphenyl Regulation deadline. A five year deployment of light-emitting diode street lights is planned to begin in fiscal 2018 to replace the current fleet of existing high pressure sodium units. This program is subject to a successful pilot installation in the Lower Mainland which begins in fiscal 2017.

- ***Trouble* -** Trouble capital expenditures are for equipment replacements that meet capitalization rules and resulting from routine trouble calls, which are day to day restoration of power outages; storms, which are events causing outages over a large geographic area or affecting a large number of customers, or is of extended duration; or damage to plant, which are events where a third party may be liable for the cost of the system repairs. BC Hydro and contractor crews respond to about 55,000 dispatched calls per year regarding the distribution system. The forecast expenditures are based on historical levels.

Beautification

BC Hydro assists municipalities with financial support through its beautification program. BC Hydro provides one third of the cost of converting overhead facilities to underground in urban municipal areas. The forecast expenditures will be two-third offset by contributions from the municipalities.

Annual capital expenditures and additions in the fiscal 2017 to fiscal 2019 test period remain constant at under $2 million, consistent with prior years.

Smart Metering and Infrastructure

BC Hydro's Smart Metering and Infrastructure Program involved the replacement of customer meters with smart meters and upgrading the technology and telecommunications infrastructure.

The *Clean Energy Act* required BC Hydro to "install and put into operation smart meters and related equipment" and to "establish a program to install and put in to operation a smart grid", both in accordance with and to the extent required by regulations, and exempts BC Hydro from sections 45 to 47 of the *Utilities Commission Act* with respect to the actions taken to comply with those obligations.

Smart Metering and Infrastructure capital expenditures and additions have been categorized into three areas based on asset groupings: Distribution, Technology and Other. The expenditures and additions in this section related solely to the Distribution system assets, which are comprised of Smart Meter devices and the associated hardware.

The Smart Metering and Infrastructure Program completed in fiscal 2016 and as such there are neither capital expenditures nor additions in the fiscal 2017 to fiscal 2019 test period.

Contributions in Aid

Contributions in Aid are periodic or lump-sum payments or consideration received from customers or third parties to provide funding toward the cost of construction or acquisition of an asset, where the asset ownership, operation and maintenance responsibilities remain with BC Hydro. Distribution Contributions In Aid are mostly received under the Customer Driven Program but also under the Beautification and Uneconomic Extension Assistance Programs. All three programs are discussed above.

Distribution Contributions In Aid are forecast to increase from fiscal 2017 to fiscal 2019 together with the increase in the trend associated with customer driven investments.

6.5.4 Business Support Capital Expenditures and Additions

Business Support includes capital expenditures and additions for the categories of Technology, Properties and Fleet/Other. Actual and planned capital expenditures and additions for fiscal 2015 to fiscal 2019 are provided in Table 6-15 and Table 6-16, below.

Table 6-15 Business Support Capital Expenditures Fiscal 2015 to Fiscal 2019

($ millions)	F2015		F2016		F2017	F2018	F2019
	RRA	Actual	RRA	Actual	Plan	Plan	Plan
Business Support							
Technology (Schedule 13, Line 19)	164.1	115.2	109.3	122.3	83.9	93.4	78.8
Properties (Schedule 13, Line 22)	96.3	83.9	85.1	78.8	95.7	75.0	88.3
Fleet / Other (Schedule 13, Line 25)	29.7	47.9	36.6	72.5	49.7	48.6	39.6
TOTAL	290.1	247.0	231.0	273.6	229.2	217.0	206.6

Table 6-16 Business Support Capital Additions Fiscal 2015 to Fiscal 2019

($ millions)	F2015		F2016		F2017	F2018	F2019
	RRA	Actual	RRA	Actual	Plan	Plan	Plan
Business Support							
Technology (Schedule 13, Line 45)	113.7	82.3	103.0	145.2	81.6	91.1	112.6
Properties (Schedule 13, Line 53)	113.4	83.6	92.4	160.9	68.3	118.1	25.5
Fleet / Other (Schedule 13, Line 56)	28.0	26.5	35.2	23.7	55.3	46.1	45.7
TOTAL	255.1	192.4	230.6	329.8	205.2	255.4	183.8

The Business Support planned fiscal 2017 to fiscal 2019 capital expenditures and additions are discussed in the following sections, by each category of Technology, Properties and Fleet/Other.

6.5.5 Technology Group Capital Expenditures and Additions

The Technology Group capital expenditures and capital additions for fiscal 2015 to fiscal 2019 are presented in Table 6-17 and Table 6-18 respectively, below. To align with Uniform System of Accounts reporting, the Technologies category includes expenditures and additions for Technology IT, Smart Metering and Infrastructure expenditures related to technology and Other expenditures, which are shown separately in the Table 6-17 and Table 6-18 below.

Table 6-17 Technology Group Actual and Plan Capital Expenditures Fiscal 2015 to Fiscal 2019

($ millions)	F2015		F2016		F2017	F2018	F2019
	RRA	Actual	RRA	Actual	Plan	Plan	Plan
Technology	88.4	69.8	95.4	78.4	81.4	92.4	76.2
Smart Metering and Infrastructure	70.2	44.3	11.2	44.0	-	-	-
Other	5.5	1.1	2.7	-	2.5	1.0	2.6
Total	164.1	115.2	109.3	122.3	83.9	93.4	78.8

Table 6-18 Technology Group Actual and Plan Capital Additions Fiscal 2015 to Fiscal 2019

($ millions)	F2015		F2016		F2017	F2018	F2019
	RRA	Actual	RRA	Actual	Plan	Plan	Plan
Technology	85.2	54.6	85.5	73.1	79.1	90.1	110.0
Smart Metering and Infrastructure	26.1	22.5	11.3	67.8	-	-	-
Other	2.4	5.2	6.2	4.3	2.5	1.0	2.6
Total	113.7	82.3	103.0	145.2	81.6	91.1	112.6

Technology IT capital expenditures by the Business-driven and Foundational driven functional categories are presented in Table 6-19, below.

Table 6-19 Technology IT Actual and Plan Capital Expenditures by Functional Category, Fiscal 2015 to Fiscal 2019

($ million)	F2015 RRA	F2015 Actual	F2016 RRA	F2016 Actual	F2017 Plan	F2018 Plan	F2019 Plan
Business-driven IT							
T&D	15.8	16.7	23.3	15.0	18.6	10.8	5.3
Generation	4.7	6.4	4.5	7.3	7.7	6.3	4.8
Customer	11.8	7.4	7.6	15.5	19.1	11.9	4.6
Operations Support	9.8	12.3	5.5	7.1	8.6	39.9	25.3
Business-driven IT Total	42.1	42.8	40.9	44.9	54.0	68.9	40.0
Foundational IT							
Infrastructure	12.0	7.6	9.4	13.1	16.3	14.5	15.5
Telecommunications	6.3	4.7	12.2	7.7	10.8	13.1	11.2
Applications	16.3	8.7	8.8	9.7	9.6	3.7	4.3
Cyber Security	4.5	4.3	4.3	2.0	5.5	2.3	3.6
Innovation	1.0	1.8	1.0	1.0	0.2	0.0	0.0
Foundation IT Total	40.1	27.1	35.7	33.5	42.4	33.6	34.6
Total Gross	82.2	69.8	76.7	78.4	96.4	102.5	74.6
Portfolio Adjustment	6.2	0.0	18.7	0.0	(15.0)	(10.1)	1.6
Total Net	88.4	69.8	95.4	78.4	81.4	92.4	76.2

Technology IT capital additions by Business-Driven and Foundational driven categories are presented in Table 6-20, below.

Table 6-20 Technology IT Actual and Plan Capital Additions by Category, Fiscal 2015 to Fiscal 2019

($ million)	F2015 RRA	F2015 Actual	F2016 RRA	F2016 Actual	F2017 Plan	F2018 Plan	F2019 Plan
Business-driven IT							
T&D	13.5	10.2	30.2	15.7	16.5	21.6	5.3
Generation	4.3	3.5	5.5	7.4	9.5	9.1	5.6
Customer	12.7	2.4	7.6	11.6	10.1	27.6	4.6
Operations Support	10.0	18.1	7.2	2.5	8.1	6.7	71.4
Business-driven IT Total	40.5	34.1	50.5	37.2	44.2	65.0	86.9
Foundational IT							
Infrastructure	12.0	2.0	9.4	12.6	16.6	15.7	15.5
Telecommunications	5.7	7.9	11.4	7.3	13.8	12.8	11.9
Applications	16.3	6.5	6.8	10.8	13.3	4.4	4.3
Cyber Security	8.3	4.1	4.3	3.3	8.5	2.3	3.6
Innovation	1.0	0.0	1.0	1.9	0.2	0.0	0.0
Foundation IT Total	43.3	20.5	32.9	35.9	52.4	35.2	35.3
Total Gross	83.8	54.6	83.4	73.1	96.6	100.2	122.2
Portfolio Adjustment	1.4	0.0	2.1	0.0	(17.5)	(10.1)	(12.2)
Total Net	85.2	54.6	85.5	73.1	79.1	90.1	110.0

6.5.5.1 Technology IT Capital Expenditures Fiscal 2017 to Fiscal 2019

A discussion of the Technology fiscal 2017 to fiscal 2019 planned capital expenditures by functional category of expenditure is provided below.

6.5.5.2 Business-Driven IT Capital Expenditures Fiscal 2017 to Fiscal 2019

Business-driven IT expenditures are made in response to prioritized business needs from Transmission and Distribution, Generation, Customer, and Operations Support areas. The following discusses the major functional categories of planned capital expenditures over the test period.

Transmission and Distribution

During the fiscal 2017 to fiscal 2019 period, planned capital expenditures of $34.6 million will focus on improving services to customers, improving work executed in the field and improving efficiencies for planning and execution of capital work. The largest undertaking in fiscal 2017 and fiscal 2018 will be the Graphical Work Design Tool project to improve the existing graphical design and analysis solution for the Distribution network.

Transmission and distribution assets are widely distributed throughout the province, and until recently, the inability for field workers to communicate electronically in some areas has limited the effectiveness of IT applications in supporting work activities. Work will continue in order to improve IT support for the mobile workforce.

Ongoing improvement programs will continue through the test period for a variety of business applications supporting asset management, engineering and design, outage management, and project delivery activities.

Generation

During the fiscal 2017 to fiscal 2019 period, capital expenditures of $18.9 million are to upgrade, enhance, and additions to the Generation IT assets and capabilities. For example, the Generation resource management applications are regularly improved to respond to regulatory requirements, energy market changes, environmental requirements, and weather patterns. Upgrades to Construction Contract Management and Portfolio and Project Management applications will support the delivery of BC Hydro's capital program, through improved management of contracts for complex construction projects. Although originally sponsored by Generation, the Construction Contract Management and Portfolio and Project Management solutions are considered to be enterprise applications since they support multiple functional areas of BC Hydro.

Planned improvements to the Commercial Management system will to support the management and optimization of generation outages.

A new program will also be initiated in the test period to develop a Geographical Information System – based Dam Safety program which will provide related studies, reviews, recommendations, and other Dam Safety related documents on Generation generating plants, and river systems.

Customer

During the fiscal 2017 to fiscal 2019 period, capital expenditures of $35.6 million are to address two focus areas.

The first area of focus is making it easier for customers to do business with us, and also providing energy conservation tools. This includes web, billing, payment, customer management and call handling solutions.

The second focus is the reliability, stability and resilience of the underlying IT platforms, including the web platform and the call handling environment. Capital investment in the web platform will increase capacity and failover capabilities in order to accommodate significant increases in web traffic and ensure business continuity, particularly during storm events such as was experienced in late summer 2015. Similarly, the call handling platform technologies and architecture require updates to ensure operational stability, support increasing capacity, and enable alignment of customer services across multiple service delivery channels.

Operations Support

During the fiscal 2017 to fiscal 2019 period, capital expenditures of $73.9 million are to help enable specific BC Hydro priorities.

The Supply Chain Applications Project involves the design and implementation of new business processes and information technology to support the acquisition of materials and services from third-parties. An application for this project is expected to be filed with the British Columbia Utilities Commission. A new SAP-based solution will replace the existing Ventyx PassPort supply chain solution, providing operational improvements and enabling future operating advantages. This is the largest single Operations Support investment planned for the test period representing over

25 per cent of total Operations Support capital additions in the test period. Additional project information is provided in Appendix I, page 7 of 9, line 2 Appendix J, page 75.

Other planned expenditures are as follows. The Fleet and Garage Management System project will implement a third-party software solution to improve operational efficiencies within Fleet Services, and enable industry best practices outlined in the Supply Chain business model. The Field Access to Safety project will improve the development, sustainment and accessibility of safety and environmental rules, standards, programs and work procedures for BCH employees completing hazardous work. The Hazard Barrier Register project will integrate BC Hydro operational data and introduce new processes and measures to systematically reduce organizational risk.

6.5.5.3 Foundational IT Capital Expenditures Fiscal 2017 to Fiscal 2019

Foundational IT expenditures are made in response to prioritized technology needs in Infrastructure, Telecommunications, Enterprise Applications, and Cyber Security areas. The following discusses the major Foundational IT capital expenditures by functional category over the test period.

Infrastructure

During the fiscal 2017 to fiscal 2019 period, capital expenditures of $46.3 million are to maintain and upgrade capacity for data center compute, storage and networks to support continued growth and enhancements for applications and also to upgrade BC Hydro’s personal computing assets and maintain print capabilities.

The Data Centre Refresh project will replace or upgrade the aging and end of life IT infrastructure in the primary data centre. The Windows Server upgrade project is well into implementation and will upgrade all servers to current versions. Data storage needs continue to grow rapidly driven by increasing IT use, new storage-intensive technologies, and changing records retention policies. Ongoing data centre expenditures include the sustainment of Windows and Unix servers.

The annual personal computer refresh program will continue, to enable the Windows update to version 10, allowing users access to current versions of Microsoft Office software.

Telecommunications

During the fiscal 2017 to fiscal 2019 period, capital expenditures of $35.1 million are required to maintain and upgrade capacity for radio, telephony, smart meter network, branch office networks and audio-visual systems to support worker safety and reliable access to core applications and systems.

The Mountain Top Radio Asset Refresh program will replace aging shelters, radios and batteries at many of the remote radio repeater sites around the province. The Mobile Radio Optimization project will improve radio coverage and use within the Lower Mainland. The Smart Metering and Infrastructure Field Area Network Sustainment project will sustain and expand the Smart Metering and Infrastructure network in response to aging assets and customer growth. The MPLS Network Commissioning project will complete the implementation of the substation data network.

Enterprise Applications

During the fiscal 2017 to fiscal 2019 period, capital expenditures of $17.7 million are to provide technical upgrades and other improvements to maintain the currency and viability of BC Hydro’s enterprise applications platforms and solutions.

Annual SAP upgrades maintain BC Hydro’s primary enterprise application platform. Similarly, Oracle Primavera, IBM FileNet and Microsoft SharePoint upgrades support BC Hydro’s goals aligned to effective capital project delivery. The SAP Environment

Health and Safety Upgrade project is an upgrade to the current SAP Incident Management system and foundational to future safety program initiatives.

Ongoing program expenditures in the test period will sustain enterprise application platforms, solutions and reporting; document, record and drawing management; mobile app development; data integration; energy analytics; and IT service management capabilities.

Cyber Security

During the fiscal 2017 to fiscal 2019 period, capital expenditures of $11.4 million are to enhance existing cybersecurity platforms and provide new solutions. Enhancements are to include identity and access management, logging and monitoring, vulnerability management, end point security, and network security. New solutions are to provide data loss prevention, distributed denial of service prevention, advanced malware protection, and next generation firewall capabilities, as well as controls and systems to ensure compliance with North American Electric Reliability Council standards.

6.5.5.4 Technology Capital Additions Fiscal 2017 to Fiscal 2019

A discussion of the Technology planned capital additions by is provided below, separated into “Foundational IT Capital Additions” and “Business Driven IT Capital Additions”. Please refer to sections 6.3.7.2 and 6.3.7.3 for descriptions of these two main categories.

Business-Driven IT Capital Additions - Transmission and Distribution

During the fiscal 2017 to fiscal 2019 period, major components of capital additions are to include:

- The migration of human resources and First Nations consultation applications to a current and supported enterprise platform;

- The implementation of a mobile scheduling, dispatch and order completion system for power line technicians;
- The implementation and upgrade of mobile field computing such as truck-based wireless internet; and
- Ongoing application improvements for each of the key business units.

Business-Driven IT Capital Additions - Generation

During the fiscal 2017 to fiscal 2019 period, major components of capital additions are to include:

- Commercial Management system improvements to support the management and optimization of generation outages;
- Construction and Contract Management upgrades to better support the management of contracts for complex construction projects; and
- A Dam Safety system implementation to provide related studies, reviews, recommendations, and other Dam Safety related documents on Generation generating plants, and river systems.

Business-Driven IT Capital Additions - Customer

During the fiscal 2017 to fiscal 2019 period, major components of capital additions are to include:

- A Customer Pay Now solution to enable customers to execute a payment using BC Hydro’s MyHydro web portal and/or e-bill notifications and receive acknowledgement of the payment in near real-time in all customer facing channels;
- An Enterprise Billing Infrastructure solution to provide a new and upgraded BC Hydro bill, new electronic billing capabilities, and renewed foundational IT application components;

- Web platform improvements and website resiliency improvements;
- New energy conservation tools;
- Improved call handling solutions; and
- A new billing system for transmission customers.

Business-Driven IT Capital Additions - Operations Support

During the fiscal 2017 to fiscal 2019 period, capital additions include the Supply Chain Applications implementation; a Fleet and Garage Management solution; the Field Access to Safety solution; and a Hazard Barrier Register solution.

Foundational IT Capital Additions - Infrastructure

During the fiscal 2017 to fiscal 2019 period, capital additions include new personal computers (laptops) for office and field workers, a company-wide rollout of Windows 10 and current Microsoft Office software; upgraded data centre capacity supporting continued growth and application enhancements; upgrades of Windows Server 2003 to current versions; and ongoing sustainment of Windows and Unix servers.

Foundational IT Capital Additions - Telecommunications

During the fiscal 2017 to fiscal 2019 period, major components of capital additions are to include a Mountain Top Radio Asset Refresh project to replace aging, shelters, radios and batteries at many of the remote radio repeater sites around the province; a continuing Mobile Radio Optimization project to improve radio coverage and use within the Lower Mainland; a new Smart Metering and Infrastructure Field Area Network Sustainment program to sustain and expand the Smart Metering and Infrastructure network in response to aging assets and customer growth; and a continuing MPLS Network Commissioning project to complete the implementation of the substation data network.

Foundational IT Capital Additions - Enterprise Applications

During the fiscal 2017 to fiscal 2019 period, major components of capital additions are to include:

- Annual SAP upgrades to maintain BC Hydro's primary enterprise application platform;
- Oracle Primavera, IBM FileNet and Microsoft SharePoint upgrades to support BC Hydro's goals aligned to effective capital project delivery; and
- A SAP Environment Health and Safety Upgrade project to upgrade the current SAP Incident Management system and serve as a foundation to future safety initiatives.

There will also be ongoing program expenditures to sustain enterprise application platforms, solutions and reporting; document, record and drawing management; mobile app development; data integration; energy analytics; and IT service management capabilities.

Foundational IT Capital Additions - Cyber Security

During the fiscal 2017 to fiscal 2019 period, major components of capital additions are to include IT support for the Transmission and Distribution North American Electric Reliability Council Critical Infrastructure Protection v5 project; and a new identity and access management solution.

Smaller capital additions are to include logging and monitoring solutions, distributed denial of service prevention, intrusion detection system replacement, next generation firewall capabilities, network security improvements, and data loss prevention capabilities.

6.5.6 Properties

The actual and plan capital expenditures for the Properties category for fiscal 2015 to fiscal 2019 are provided in Table 6-21, below.

Table 6-21 Properties Capital Expenditures Fiscal 2015 to Fiscal 2019

($ millions)	F2015		F2016		F2017	F2018	F2019
	RRA	Actual	RRA	Actual	Plan	Plan	Plan
Properties							
Interior Space Renovations	26.7	16.5	17.4	16.3	11.6	11.9	-
Building Development	52.3	41.7	52.0	36.9	54.8	44.4	69.5
Building Improvements and Other	17.3	19.6	15.7	24.2	26.3	18.8	18.8
Other	-	6.1	-	1.3	3.0	-	-
Total	96.3	83.9	85.1	78.7	95.7	75.0	88.3

Properties actual and plan capital additions for fiscal 2015 to fiscal 2019 are provided in Table 6-22, below. To align with Uniform System of Accounts reporting, the Properties category includes capital additions for Other Equipment in fiscal 2016. These additions are explained in Appendix K.

Table 6-22 Properties Plan and Actual Capital Additions –Fiscal 2015 to Fiscal 2019

($ millions)	F2015		F2016		F2017	F2018	F2019
	RRA	Actual	RRA	Actual	Plan	Plan	Plan
Properties							
Interior Space Renovations	12.7	20.1	26.7	10.9	21.6	11.9	-
Building Development	88.6	50.8	48.4	39.4	4.6	87.5	6.7
Building Improvements and Other	12.1	12.7	17.3	25.7	38.2	18.8	18.8
Other	-	0.0	-	7.5	3.9	-	-
Other Equipment							
Generation	-	-	-	5.3	-	-	-
Transmission	-	-	-	21.9	-	-	-
Smart Metering and Infrastructure	-	-	-	50.2	-	-	-
Total	113.4	83.6	92.4	160.9	68.3	118.1	25.5

6.5.6.1 Properties Expenditures and Additions Fiscal 2017 to Fiscal 2019

The fiscal 2017 to fiscal 2019 plan includes expenditures for Building Development work at a number of locations, including Vernon, Victoria, and Chilliwack, primarily in fiscal 2017 and fiscal 2018. The plan also includes redevelopment of key facilities at BC Hydro's Surrey Campus. While the Construction Services/Lower Mainland Transmission project and Materials Classification Facility have independent business drivers, a swap of locations between the current Materials Classification Facility site and the current Lower Mainland Transmission site is being considered as a prudent use of land. These two projects will be planned and sequenced in a coordinated manner. The key drivers for the redevelopment of these facilities includes the following:

- The evolving business requirements of BC Hydro;
- The operation and maintenance of assets in a manner that maximizes their useful economic life and reliability; and
- Operational and worker life safety risks, including seismic risks.

These facilities must remain operational for 24 hour response in the worst of conditions in order to provide critical service to BC communities.

Interior Space Renovations expenditures and capital additions includes upgrading end-of-life building components and interior space on a floor by floor basis, addressing space constraints, aging assets, and safety and accessibility concerns. Building Improvements and Other capital expenditures and capital additions include all building improvement projects at facilities across BC Hydro's service area. These projects are typically less than $5 million in cost, and are undertaken to address issues related to safety, operational efficiency, and aging assets.

Additional information on Properties is found in Appendix I, page 9 of 9, Lines 1 to 17 and Appendix J, pages 76, 78, 80, 82 and 84.

6.5.7 Fleet Capital Expenditures and Additions

Fleet - Vehicle and Equipment actual and plan capital expenditures for fiscal 2015 to fiscal 2019 are provided in Table 6-23, below.

Table 6-23 Fleet - Vehicle and Equipment Capital Expenditures Fiscal 2015 to Fiscal 2019

($ million)	F2015		F2016		F2017	F2018	2019
	RRA	Actual	RRA	Actual	Plan	Plan	Plan
Fleet	15.0	19.7	24.2	30.7	33.9	30.9	29.6

Fleet - Vehicle and Equipment actual and plan capital additions for fiscal 2015 to fiscal 2019 are provided in Table 6-24, below.

Table 6-24 Fleet - Vehicle and Equipment Actual and Plan Capital Additions Fiscal 2015 to Fiscal 2019

($ million)	F2015		F2016		F2017	F2018	2019
	RRA	Actual	RRA	Actual	Plan	Plan	Plan
Fleet	13.8	16.1	22.4	21.2	40.3	32.4	30.2

Fleet includes vehicle and equipment capital expenditures and capital additions for fiscal 2017 to fiscal 2019, and consist mainly of annual replacements of fleet vehicles and value-based additions and upgrades to the fleet. On average, approximately 10 per cent of all vehicles in the fleet are replaced annually, which accounts for approximately 80 per cent of the total capital expenditures and capital additions per year. The remaining 20 per cent of the capital expenditures and additions are for value-based upgrades and additions to the fleet, aimed at adding vehicular capacity for field work, addressing changes in work methods, increasing safety, and meeting changing business needs, and/or increasing crew efficiency.

6.5.8 Business Support - Other Capital Expenditures and Additions

Business Support – Other Capital actual and plan expenditures for fiscal 2015 to fiscal 2019 are provided in Table 6-25, below.

Table 6-25 Business Support – Other Actual and Plan Capital Expenditures Fiscal 2015 to Fiscal 2019

($ million)	F2015		F2016		F2017	F2018	2019
	RRA	Actual	RRA	Actual	Plan	Plan	Plan
Business Support - Other	14.7	28.2	12.4	41.8	15.8	17.7	10.0

Business Support – Other actual and plan capital additions fiscal 2015 to fiscal 2019 are provided in Table 6-26, below.

Table 6-26 Business Support – Other Actual and Plan Capital Additions Fiscal 2015 to Fiscal 2019

($ million)	F2015		F2016		F2017	F2018	2019
	RRA	Actual	RRA	Actual	Plan	Plan	Plan
Business Support - Other	14.2	10.4	12.8	2.5	15.0	13.7	15.5

Business Support -Other includes capital expenditures and additions related to Materials Management upgrades, Field Operations tools and equipment, Control Centre systems upgrades, and workforce training equipment. The individual plans for these different areas are generally less than $5 million per year.

6.5.9 Site C Clean Energy Project

The Site C Clean Energy Project actual and plan capital expenditures for fiscal 2015 to fiscal 2019 are provided in Table 6-27 below.

Table 6-27 Site C Clean Energy Project Actual and Plan Capital Expenditures Fiscal 2015 to Fiscal 2019

($ million)	F2015		F2016		F2017	F2018	2019
	RRA	Actual	RRA	Actual	Plan	Plan	Plan
Site C Clean Energy	–	25.2	–	489.4	742.5	716.5	829.2

Project Background

The Site C Clean Energy Project will be a third dam and hydroelectric generating station on the Peace River in northeast B.C. Site C Clean Energy Project has an estimated capital cost of $8.335 billion, as well as a separate project reserve of $440 million held by the Provincial Treasury Board. Construction of the Site C Clean Energy Project started in summer 2015, with completion expected in 2024. There are no planned capital additions for the project in the fiscal 2017 to fiscal 2019 test period, as the assets are forecast to enter service after fiscal 2019.

Fiscal 2017 to Fiscal 2019

Revenue Requirements Application

Chapter 7

Deferral and Other Regulatory Accounts

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7.1 Introduction

This chapter addresses BC Hydro's deferral and other regulatory accounts. Regulatory accounts are common in the utility industry. BC Hydro manages these accounts in accordance with sound regulatory principles, the 2013 10 Year Rates Plan and Directions No. 6 and 7, issued on March 6, 2014. These considerations are reflected in British Columbia Utilities Commission Order No. G-48-14, which approved the ongoing use of most of the regulatory accounts. BC Hydro is requesting approval of: (i) changes to the scope and names of some of its existing regulatory accounts; (ii) amortization periods for recovery of the balances in those regulatory accounts that do not currently have approved recovery mechanisms under Order No. G-48-14 or other British Columbia Utilities Commission orders; and, (iii) the application of interest to certain regulatory account balances, where appropriate. A summary of the requested changes with respect to the regulatory accounts is provided in Table 7-9.

This chapter is structured as follows:

- Section 7.2 provides the actual fiscal 2016 closing balances of the regulatory accounts, the forecast account balances for the fiscal 2017 to fiscal 2019 test period, and the forecast balances to fiscal 2024, based on the application of the account changes and recovery mechanisms requested in this application. The total balance in the regulatory accounts is expected to increase slightly throughout the test period and decline over fiscal 2020 to fiscal 2024;
- Section 7.3 explains BC Hydro's use of regulatory accounts and considerations when setting appropriate amortization periods for the recovery of the balance in regulatory accounts;
- Section 7.4 outlines criteria for evaluating the establishment of new regulatory accounts that recognize the distinction between controllable and non-controllable costs, while also providing a threshold for the size of expenditures subject to deferral treatment;

- Section 7.5 describes BC Hydro's regulatory accounts and their purpose. The discussion includes the three cost of energy deferral accounts (the Heritage Deferral Account, Non-Heritage Deferral Account and Trade Income Deferral Account);
- Section 7.6 explains the application of interest to several regulatory accounts at BC Hydro's weighted average cost of debt in recognition that BC Hydro incurs carrying costs; and
- Section 7.7 provides a summary table of requested changes to the regulatory accounts with this application.

Additional information on the regulatory accounts is also provided in Schedules 2.1 and 2.2 of Appendix A.

7.2 Regulatory Account Balances: Fiscal 2015 and Fiscal 2016 Actual, Fiscal 2017 to Fiscal 2024 Forecast

BC Hydro's actual and forecast deferral and regulatory account balances for the fiscal 2015 to fiscal 2019 period are provided in Table 7-1 below.

Table 7-1 Summary of Deferral and Regulatory Account Balances, Fiscal 2015 to Fiscal 2016 Actual and Fiscal 2017 to Fiscal 2019 Forecast

$-Million	F2015 Actual	F2016 Actual	F2017 Forecast	F2018 Forecast	F2019 Forecast
Opening Balance	4,699.5	5,434.4	5,908.3	5,684.7	5,894.2
Additions	799.1	796.6	269.8	258.2	174.4
Interest	67.2	72.5	76.1	68.4	60.2
Recoveries/Other	(131.4)	(395.2)	(569.5)	(117.1)	(122.7)
Net change	734.9	473.9	(223.6)	209.5	111.9
Closing Balance	5,434.4	5,908.3	5,684.7	5,894.2	6,006.1

Table 7-2 provides the fiscal 2015 to fiscal 2016 actual and fiscal 2017 to fiscal 2024 forecast balances of BC Hydro's regulatory accounts. The account balances shown for fiscal 2017 and onward are based on current information and assumptions.

Actual results will be different than those presented, for reasons discussed later in this chapter.

At the beginning of fiscal 2017, BC Hydro had balances in 25 regulatory accounts, with a combined total net balance of $5.9 billion. At the end of fiscal 2019 the total net balance in the accounts is forecast to be $6.0 billion. The total net account balance is forecast to be reduced to $3.6 billion by the end of fiscal 2024, based on the recovery mechanisms and application of interest that BC Hydro is requesting with this application. The three Cost of Energy deferral accounts and a number of the regulatory accounts are designed to capture variances between forecast and actual costs or revenue on an ongoing basis, which ensures customers pay the actual costs; therefore, there will continue to be either debit or credit balances in these accounts, depending on actual costs and revenues.

BC Hydro forecasts that the total balance in the regulatory accounts at the end of the test period will be reduced by approximately 40 per cent at the end of the 2013 10 Year Rates Plan period (i.e., from $6.0 billion to $3.6 billion at the end of fiscal 2024) based on existing regulatory mechanisms and those proposed with this application.

Table 7-2 Regulatory Account Balances - Fiscal 2015 to Fiscal 2016 Actual, Forecast Fiscal 2017 to Fiscal 2024 ($ million)

	($ million)	F2015 Actual	F2016 Actual	F2017 Forecast	F2018 Forecast	F2019 Forecast	F2020 Forecast	F2021 Forecast	F2022 Forecast	F2023 Forecast	F2024 Forecast
	Cost of Energy Variance Accounts										
1	Heritage Deferral Account	$165	($24)	($20)	($16)	($11)	($7)	($4)	($2)	($1)	($1)
2	Non-Heritage Deferral Account	524	917	771	613	440	253	136	75	55	33
3	Trade Income Deferral Account	245	250	210	167	120	69	37	21	15	9
	Total	933	1,143	961	764	549	316	170	94	69	42
	Other Cash Variance Accounts										
4	Storm Restoration Costs	8	30	20	10	0	0	0	0	0	0
5	Amortization of Capital Additions	(4)	(10)	(6)	(3)	0	0	0	0	0	0
6	Total Finance Charges	(173)	(306)	(204)	(102)	0	0	0	0	0	0
7	Rock Bay Remediation	20	(27)	(18)	(9)	(0)	(0)	(0)	(0)	(0)	(0)
8	Arrow Water Systems	4	0	0	0	0	0	0	0	0	0
9	Asbestos Remediation	10	5	3	2	0	0	0	0	0	0
10	Home Option Purchase Plan	11	0	0	0	0	0	0	0	0	0
11	Real Property Sales	8	18	25	16	2	(0)	(0)	(0)	(0)	(0)
12	Minimum Reconnection Charges	N/A	1	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
13	Mining Customer Payment Plan	N/A	N/A	0	0	0	0	0	0	0	0
	Total	(115)	(290)	(180)	(87)	2	(0)	(0)	(0)	(0)	(0)
	Non-Cash Variance Accounts										
14	Foreign Exchange Gains/Losses	(71)	(69)	(63)	(32)	3	1	2	3	3	3
15	Non-Current Pension Costs	564	691	306	274	243	211	179	147	114	82
16	Debt Management	N/A	N/A	0	0	0	0	0	0	0	0
	Total	493	622	242	242	246	212	181	150	117	85
	Benefit Matching Accounts										
17	DSM	841	907	932	996	991	968	942	915	886	854
18	First Nations Costs	151	133	131	120	101	82	62	43	24	5
19	Site C	419	436	453	472	491	511	531	551	572	593
20	Future Removal and Site Restoration	(33)	(9)	0	0	0	0	0	0	0	0
21	Pre-1996 Contributions In Aid of Construction	87	92	91	88	83	78	73	68	63	58
22	SMI	283	283	261	239	217	196	174	152	130	109
23	Capital Project Investigation	30	25	20	15	10	6	1	(0)	(0)	(0)
	Total	1,779	1,867	1,889	1,930	1,894	1,840	1,783	1,730	1,674	1,618
	Non-Cash Provisions										
24	First Nations Provisions	413	409	399	396	401	406	411	415	420	425
25	Arrow Water Systems Provision	4	5	3	3	3	2	2	2	2	2
26	Environmental Provisions	352	381	338	302	267	231	203	186	169	155
	Total	770	794	740	700	670	639	615	604	591	582
	Rate Smoothing Accounts										
27	Rate Smoothing	166	287	497	783	1,083	1,491	1,589	1,286	733	0
	Total	166	287	497	783	1,083	1,491	1,589	1,286	733	0
	IFRS Transition Accounts										
28	IFRS Pension	650	612	574	535	497	459	421	382	344	306
29	IFRS Property, Plant and Equipment	758	873	962	1,025	1,064	1,079	1,071	1,039	1,007	976
	Total	1,409	1,485	1,535	1,561	1,562	1,538	1,491	1,421	1,352	1,282
Total		**$ 5,434**	**$ 5,908**	**$ 5,685**	**$ 5,894**	**$ 6,006**	**$ 6,035**	**$ 5,830**	**$ 5,284**	**$ 4,536**	**$ 3,609**

The balances shown in Table 7-1 and Table 7-2, are forecasts and actual balances will be different than presented for a number of reasons.

First, the forecast indicates that the balance in the three Cost of Energy Deferral Accounts will be substantially reduced by the end of fiscal 2024. These accounts capture the variances between forecast and actual energy costs and forecast and actual revenues from energy sales, and forecast and actual trade income in each year, which can be positive or negative. Variables beyond BC Hydro's control, such as weather, make forecasting energy costs and revenue and trade income challenging. As discussed later in this chapter, the difficulty in accurately forecasting these items is one of the common reasons why deferral accounts are used.

Second, the balance in the Non-Current Pension Cost Regulatory Account (BC Hydro is requesting the name of this account be changed to the Pension Costs Regulatory Account in this application, as discussed in section 7.5.12) is based on a forecast of unrecognized actuarial gains and losses. The annual actuarial gains and losses are subject to large positive and negative fluctuations, as actuarial gains and losses are sensitive to changes in market discount rates, rates of return on pension plan assets and significant changes in key actuarial assumptions. Therefore, the actual actuarial gains or losses at the end of each year are difficult to forecast accurately.

Third, the forecast Demand-Side Management Regulatory Account balances are based on the activities and expenditures in the current Demand-Side Management Plan, which is discussed further in Chapter 10. Forecast balances beyond the test period for the Demand-Side Management Regulatory Account may differ depending on modifications to demand-side management expenditures.

Fourth, BC Hydro has several regulatory accounts that capture variances between forecast and actual costs, which arise due to the nature of the costs and external variables. These include, for example, regulatory accounts to capture variances in actual versus plan finance charges and storm restoration costs. BC Hydro expects the balances in these accounts will be different than forecast in this application due to non-controllable factors such as interest rates and weather. The table below sets out the forecast amounts, from which the variances to be recorded in these accounts will be determined.

Table 7-3 Fiscal 2017 to Fiscal 2019 Forecast Balances of Deferral and Regulatory Accounts

		Schedule Reference	F2017 Plan ($ million)	F2018 Plan ($ million)	F2019 Plan ($ million)
	Heritage Deferral Account				
1	Heritage Payment Obligation	4.0 L77	305.3	285.4	317.1
	Non-Heritage Deferral Account				
2	Non-Heritage COE Subject to Deferral	4.0 L92	1,271.9	1,409.3	1,482.9
3	Total Rate Revenue	1.0 L23	4,469.9	4,626.1	4,836.8
	Trade Income Deferral Account				
4	Trade Income	1.0 L17	115.2	115.2	115.1
	Other Regulatory Accounts				
5	Non-Current PEB - Pension	8.0 L24	(6.6)	0.2	(1.8)
6	Storm Restoration Costs (Note 1)	N/A	6.7	6.7	6.7
7	Total Finance Charges	8.0 L35-23-24	512.5	521.9	567.3
8	Amortization of Capital Additions	13.0 L93	29.4	85.2	151.8
9	Net Gain on Real Property Sales	5.0 L91	10.0	10.0	10.0
10	Future Removal and Site Restoration	5.0 L87-90	30.9	35.7	30.6
11	Current PEB – Operating Cost	N/A	52.2	53.0	53.8

Note 1: Included in the operating costs total shown on line 8, schedule 5.4.

7.3 Types of Regulatory Accounts and Amortization Periods

Regulatory accounts are common in the utility industry. The general purpose of a regulatory account is to defer, for future recovery or refund, costs or revenues that would otherwise be recognized in the current accounting period for ratemaking purposes under the accounting standards applicable to the utility. Regulatory accounts can also be used to protect ratepayers from volatility in costs and revenues and windfall gains or losses. Regulatory accounts can either be regulatory assets (amounts potentially to be recovered from ratepayers) or regulatory liabilities (amounts potentially to be refunded to ratepayers).

There are, in general terms, five situations in which it is appropriate to use regulatory accounts:

1. To defer to a future period differences between forecast and actual costs or revenues;
2. To better match costs with benefits for customers;
3. To establish a non-cash provision regulatory account, in order to create a regulatory asset to match an accounting liability that is required under the accounting standards, prior to the actual expenditure of funds;
4. To smooth out the rate impact of a large non-recurring cost or to smooth out rate increases; or
5. To defer the impact of a required change in the accounting treatment of costs to ensure proper recovery of those costs in rates.

These types of regulatory accounts are discussed further below, including discussion on the considerations in determining appropriate recovery mechanisms or amortization periods for the recovery of balances in each type of regulatory accounts.

7.3.1 Variance Accounts

In some cases, regulatory accounts may be used to transfer to customers risks and benefits that are non-controllable. Such risks and benefits include the variances between forecast and actual costs due to changes in variables such as water inflow levels, interest rates, and market prices of energy, which are difficult to forecast. These include cash and non-cash variance accounts.

BC Hydro believes that it should assume financial responsibility for controllable risks and create regulatory accounts for non-controllable risks. In the

Fiscal 2005 - Fiscal 2006 Revenue Requirements Application, BC Hydro proposed the following criteria to assess whether a risk is controllable or non-controllable:[50]

1. BC Hydro's ability to directly or indirectly influence the cost category;
2. The volatility of the cost category;
3. The predictability of the cost category;
4. The materiality of the cost category to the revenue requirement; and
5. The frequency of major exceptions within the cost category.

In its Decision on the Fiscal 2005 - Fiscal 2006 Revenue Requirements Application, the Commission accepted BC Hydro's proposed criteria but concluded that risk/reward considerations were also a relevant criterion. The Commission noted that even if some costs are non-controllable, the risk of variances from forecasts may be appropriately borne by the shareholder because of risk/reward considerations.[51]

BC Hydro believes the British Columbia Utilities Commission's determination is appropriate, and is not proposing any changes in this application to the criteria used to assess whether a risk is controllable or non-controllable.

Variances in costs due to impacts of non-controllable risks are generally recovered over a short time period such as over the next test period. This recovery period supports intergenerational equity, in that the benefits associated with the deferred cost are generally more immediate.

BC Hydro's three energy deferral accounts, the Heritage Deferral Account, Non-Heritage Deferral Account and Trade Income Deferral Account, discussed in section 7.5, are examples of variance accounts that defer, for recovery or refund in a future period, differences between forecast and actual costs or revenues. All three of those accounts are contemplated in section 7 of Direction No. 7.

[50] BC Hydro Fiscal 2005/Fiscal 2006 Revenue Requirement Application Argument, page 70.
[51] Fiscal 2005/Fiscal 2006 Revenue Requirement Application Decision, pages 29 to 30.

Other cash variance accounts capture the difference between forecast and actual costs for non-energy related costs that BC Hydro considers to be non-controllable. Examples of such accounts are the Storm Restoration and the Total Finance Charges regulatory accounts. BC Hydro is therefore proposing in this application that balances in the Storm Restoration and the Total Finance Charges regulatory accounts that accrue over a test period be recovered over the following test period. In other words, any balance that exists at the start of a test period should be recovered over that test period. BC Hydro believes this is appropriate as these accounts represent costs that provide immediate, rather than long-term benefits.

Non-Cash Variance Accounts capture the differences between forecast and actual non-controllable costs, which are non-cash in nature, for recovery from or refund to ratepayers in a future period. There are three regulatory accounts in this category:

1. The Foreign Exchange Gains/Losses;
2. The Non-Current Pension Cost regulatory account (proposed to be renamed the Pension Cost Regulatory Account with this application); and
3. The Debt Management Regulatory Account.

The recovery period for these accounts should match the underlying attribute. For example, the Commission has approved the Foreign Exchange Gains/Losses account to be amortized on a straight-line pool basis over the weighted average life of the related debt. Consistent with this treatment, BC Hydro is proposing with this application that the Non-Current Pension Cost account be amortized over the average remaining service life of employees.

7.3.2 Benefit Matching Accounts

Regulatory accounts are often used to reflect timing differences between when a utility spends money to provide a service or acquire an asset, and when that expenditure is recovered from ratepayers. The benefit of a particular service or asset may accrue to ratepayers over a long period of time. Regulatory accounts can be used to match the benefit with the cost, thereby supporting intergenerational equity for current and future ratepayers. As a result, the amortization period for this type of account will vary depending on the period of time over which the benefit of the particular service or asset accrues to ratepayers. Through the use of this type of regulatory account, BC Hydro's current customers are not required to pay for the full cost of an asset or service that will provide benefits to customers in the future.

An example of this type of account is the regulatory treatment of costs associated with demand-side management measures. BC Hydro is spending money in current years to reduce the amount of electricity that customers would otherwise use in current and future periods, resulting in lower energy costs and delayed or reduced infrastructure costs. The benefits of such reduced costs from the demand-side management measures will impact current and future customers, and the cost of the demand-side management measures is therefore properly matched to the benefits realized by those future customers by deferring and amortizing those costs over 15 years, which is the average term of demand-side management benefits. The regulatory treatment of demand-side management measures is contemplated in section 7(d) of Direction No. 7.

The Site C Regulatory Account is another example of a regulatory account established to provide a better matching of costs and benefits for different generations of customers. If the Site C Clean Energy Project investigation costs were expensed as incurred, it could cause an unfair rate impact on current ratepayers considering the long development period before the Site C Clean Energy Project will be placed into service and provide benefits.

7.3.3 Non-Cash Provisions

Non-cash provisions are regulatory accounts set up in response to loss provision liabilities required under BC Hydro's Prescribed Standards (which are defined in section 8.12). As such, these provisions are not recovered in rates until such time as actual cash expenditures are made against the provision. At that time the provision is normally drawn down by the amount of the expenditure and a corresponding amount is entered in the matching regulatory account, which is then amortized into rates, based on the approved amortization method. The provision regulatory accounts remain in place until the loss provision liability is no longer required under the Prescribed Standards. The provision regulatory accounts are regulatory assets which preserve BC Hydro's right to collect in rates, subject to Commission approval, any actual amounts paid in respect of these provisions. BC Hydro currently has three non-cash provision regulatory accounts: the First Nations Provisions, the Environmental Provisions and the Arrow Water Systems Provision Regulatory Accounts.

7.3.4 Rate Smoothing Accounts

Concerns about rate impacts can also lead to the establishment of a regulatory account for the purpose of smoothing the required rate increases over a period of time, or to smooth the rate impact of a large one-time expenditure. The recovery period for this type of account would be determined by the amount and nature of the expenditure, as well as other rate increase pressures that may exist at the time. The Rate Smoothing Regulatory Account is prescribed in Direction No. 7, sections 7(h) and 9(2).

7.3.5 IFRS Transition Accounts

A change in the accounting standards applicable to BC Hydro may give rise to non-controllable financial impacts, requiring regulatory account treatment in order to keep BC Hydro financially whole, while protecting customers from sudden large rate increases. For example, in fiscal 2013 BC Hydro transitioned to the Prescribed Standards directed by the Province's Treasury Board (as discussed in section 8.12 above these include IFRS). This change impacted the method of accounting for capital overheads. It also required BC Hydro to, among other things, recognize on its balance sheet all unamortized experience gains and losses on the pension and other post-employment benefit plans not previously recognized in its financial statements. To maintain BC Hydro's ability to recover the impacts of these changes from customers over a reasonable time period, BC Hydro proposed the establishment of the IFRS Transition Regulatory Accounts.

These accounts have been established under the criteria of rate smoothing and benefit matching of asset costs with their useful lives. If BC Hydro were to have recognized the impact of the transition to IFRS in its rates at the time of the transition, the rate impact for customers would have been significant in the year of transition. The IFRS Transition Regulatory Accounts also act to recover the transition costs of pension and capital assets over the same period of time as if the IFRS rules had not come into being as part of the Prescribed Standards, and therefore have recovery periods of 20 years for the IFRS Pension regulatory account and 40 years for the IFRS Property, Plant & Equipment Regulatory Account.

7.3.6 Summary of Recovery Mechanisms

Table 7-4 below provides a summary of the rationale for determining the appropriate recovery mechanisms for BC Hydro's regulatory accounts, based on the foregoing discussion regarding the nature of the accounts, and BC Hydro's objectives in recovering the account balances.

Table 7-4 Summary of Rationale for Regulatory Account Recovery Mechanisms

Type of Regulatory Account	Rationale for Recovery Mechanism
Variance Accounts:	
Cost of Energy Variance Accounts	The Deferral Account Rate Rider mechanism, discussed in section 7.5.1, minimizes intergenerational inequity by being responsive to the changing net balance in the cost of energy variance accounts, while maintaining rate stability for customers to the extent practicable.
Other Cash Variance Accounts	To minimize intergenerational inequity, cash variance accounts should be recovered in the subsequent test period.
Non-Cash Variance Accounts	Non-cash variances should be recovered over the remaining period of the associated asset or liability (e.g., remaining service life of employees or remaining term of debt issuances).
Benefit Matching Accounts	To achieve intergenerational equity, the recovery period should match the future benefit period of the expenditure.
Non-Cash Provisions	Since non-cash provisions are not recovered in rates, no recovery mechanism is required. The provision is drawn down when actual expenditures are charged to the regulatory account.
Rate Smoothing Accounts	In the case of the Rate Smoothing Regulatory Account, BC Hydro will recover the balance during the later years of 2013 10 Year Rates Plan.
IFRS Transition Accounts	To smooth the impact of changes in accounting standards, the balances in these accounts should be recovered on the same basis as they would have been recovered under the previous accounting rules.

As discussed, BC Hydro believes there should be an alignment of cost and benefit recognition in determining the appropriate recovery period for the regulatory accounts to address intergenerational equity concerns. This is reflected in the contrasting shorter and longer recovery periods for different regulatory accounts based on the nature of the costs in the accounts. However, these objectives may, from time to time, need to be balanced with the objective of keeping rates low, which may give rise to rate mitigation or smoothing mechanisms.

British Columbia Utilities Commission Order No. G-48-14 approved the recovery mechanisms for BC Hydro’s Cost of Energy Deferral Accounts and the Demand-Side Management Regulatory Account, on an ongoing basis. However, for many of

BC Hydro's regulatory accounts the order approved the amortization of specific amounts from the accounts for the fiscal 2015 to fiscal 2016 test period only, and as such these accounts do not have approved recovery mechanisms in place for fiscal 2017 and onward. With this application BC Hydro is requesting approval of recovery mechanisms for these accounts, to be applied on an ongoing basis for efficiency and predictability of rate impact. The regulatory account recovery mechanisms for which BC Hydro is seeking approval are discussed further in section 7.5, where a qualitative discussion of each regulatory account is provided. They are summarized in Table 7-9.

7.4 Threshold for Establishing New Regulatory Accounts

BC Hydro believes that the criteria discussed in section 7.3 for situations where a regulatory account may be warranted continue to be applicable. With respect to the deferral of differences between forecast and actual costs, BC Hydro remains of the view that it should assume financial responsibility for controllable risks and create regulatory accounts for non-controllable risks. However, to limit the number of regulatory accounts, an objective measure should be used as a threshold for creating a new regulatory account. BC Hydro believes that un-forecast and non-controllable expenditures with a net income impact of greater than $10 million in a fiscal year would be considered material; therefore, in these cases, a new regulatory account would be warranted to defer the impact for future recovery.

7.5 Description of BC Hydro's Regulatory Accounts and Existing or Proposed Recovery Periods for the Accounts

A qualitative discussion of BC Hydro's deferral and regulatory accounts is provided below, including a description of the account, the history of the account and also the existing or proposed recovery mechanism or period of the account balance.

BC Hydro is only proposing changes to a limited number of accounts.

7.5.1 Cost of Energy Deferral Accounts

BC Hydro has three Cost of Energy deferral accounts that capture the differences between actual and forecast revenues and energy costs. These are the Heritage Deferral Account, the Non-Heritage Deferral Account and the Trade Income Deferral Account. The Heritage Deferral Account and Trade Income Deferral Account were created pursuant to Heritage Special Direction No. HC2. In Order No. G-96-04, the British Columbia Utilities Commission approved the Non-Heritage Deferral Account to capture variances between the forecast and actual energy costs that are not associated with heritage assets.

The Heritage Deferral account captures variances between actual and forecast energy costs associated with BC Hydro's Heritage Resources that are incurred to supply Heritage Electricity. Heritage Resources include: (i) BC Hydro's electric and thermal facilities, including related civil works and plant, as listed in the *Clean Energy Act*, Schedule 1, and (ii) potential investments that increase capacity, energy or ancillary service capability of those facilities, pursuant to Direction No. 7. Heritage Energy is defined as 49,000 GWh per year less the energy generated for delivery under the Skagit Valley Treaty, and may be modified by British Columbia Utilities Commission Order.

The annual energy costs associated with the Heritage Resources, as determined by Direction No. 7 is termed the Heritage Payment Obligation. These costs include:

- Water rentals;

- Energy purchases, including purchases of gas and electricity;
- Operating costs of Heritage Resources;
- Costs associated with ownership of the Heritage Resources, such as depreciation, interest and finance costs; and
- Costs or payments related to generation related transmission access required by the Heritage Resources, net of any revenues received for the provision of other services by BC Hydro.

Annual variances between the actual and forecast Heritage Payment Obligation amount are deferred to the Heritage Deferral Account.

The purpose of the three cost of energy variance accounts (which are also referred to collectively as the “Cost of Energy Deferral Accounts”) is to defer the difference between forecast and actual costs of energy, load, and trade income, for recovery in future periods. Differences can be positive or negative. For example, variances may occur due to variations in reservoir water levels (due to more or less precipitation and snow melt in any given year), resulting in the requirement for BC Hydro to change its mix of energy resources to meet load demand. While rates are set assuming average water inflow levels, the lower cost hydro generation levels can fluctuate by +/- 5,000 GWh between low and high water years, resulting in the need to sell surplus power or purchase energy from the market. As water inflow levels are non-controllable, it is appropriate that the risk/reward should be borne by BC Hydro’s customers and applied to rates.

Other examples are the deferral of variances between actual and forecast revenue and energy costs arising from variances between BC Hydro’s actual and forecast domestic load and also variances in cost of supply from Independent Power Producers, which can be impacted by factors such as weather. These variances are deferred to the Non-Heritage Deferral Account.

BC Hydro also includes in its revenue requirements forecast income from the non-domestic trading activities of Powerex. Variances between actual and plan income are deferred to the Trade Income Deferral Account.

In accordance with British Columbia Utilities Commission Order No.G-48-14, and section 7(a), (b) and (c) of Direction No. 7, BC Hydro is to continue to defer on an ongoing basis:

- The variances between the actual and forecast heritage payment obligation to the Heritage Deferral Account;
- The variances between actual and forecast trade income to the Trade Income Deferral Account; and
- The variances between actual and forecast cost of energy arising from differences between actual and forecast domestic customer load, and Burrard costs as defined in Direction No. 7, to the Non-Heritage Deferral Account.

Additionally, with this application, BC Hydro requests the following:

- Effective starting in fiscal 2017, annual negotiations costs related to First Nations be excluded from the calculation of the heritage payment obligation for the purposes of deferring variances to the Heritage Deferral Account. BC Hydro believes it should bear the risks associated with the variances in annual negotiations costs.

BC Hydro recovers the balances in the Cost of Energy deferral accounts using the Deferral Account Rate Rider. Section 10(a) of Direction No. 7 provides that the British Columbia Utilities Commission must continue to set the Deferral Account Rate Rider for fiscal 2015 and future fiscal years at 5 per cent.

With respect to how the forecast revenues from the Deferral Account Rate Rider are accounted for, Direction No. 7 establishes a mechanism whereby the portion of the forecast revenues from the Deferral Account Rate Rider that is applied to the deferred balance in the Cost of Energy Deferral Accounts varies depending on the size of the balance in the account. The methodology is set out in section 10(3) of Direction No. 7.

Table 7-5 below sets out the Deferral Account Rate Rider, and the percentage of Deferral Account Rate Rider revenue forecast to be applied to the Cost of Energy Deferral Accounts over the fiscal 2017 to fiscal 2019 test period, and shows that all Deferral Account Rate Rider revenue is forecast to be applied to the deferred balances in the Cost Of Energy Deferral Accounts. The amounts shown in Table 7-5 are based on the forecast of balances shown on Table 7-2.

Table 7-5 Forecast Deferral Account Rate Rider Revenues Applied to Deferral Accounts

	F2015 (%)	F2016 (%)	F2017 (%)	F2018 (%)	F2019 (%)
DARR	5.0	5.0	5.0	5.0	5.0
Proportion of Forecast DARR Revenue applied to Deferral Accounts	100	100	100	100	100
Proportion of Forecast DARR Revenue applied to Revenues	0	0	0	0	0

7.5.2 Storm Restoration Costs Regulatory Account

By Order No. G-16-09 to the Fiscal 2009 - Fiscal 2010 Revenue Requirements Application, the British Columbia Utilities Commission approved the ongoing deferral of the difference between actual storm related restoration costs and the average of the actual storm restoration costs for the five most recent normal weather years. For the purposes of this calculation, fiscal 2011 through fiscal 2015 comprise the five most recent normal weather years, and resulted in an average annual storm restoration cost of $6.7 million. Fiscal 2016 was excluded from the analysis because costs were 350 per cent of the annual average, due to a major storm event in August 2015. BC Hydro has included $6.7 million per year in its fiscal 2017 to fiscal 2019 operating plans for storm restoration costs.

With this application, BC Hydro requests the following:

- The closing fiscal 2016 balance in the account be recovered over the fiscal 2017 to fiscal 2019 test period; and
- On an ongoing basis, the forecast account balance at the end of a test period is to be recovered over the next test period.

7.5.3 Amortization of Capital Additions Regulatory Account

By Order No. G-16-09, the British Columbia Utilities Commission directed BC Hydro to defer in a regulatory account any differences between forecast and actual amortization of capital additions. As paraphrased at page 191 of the Decision, the British Columbia Utilities Commission determined that *"the most effective solution to ensuring that amortization charges collected in revenue requirements for the test period appropriately reflect the capital assets that are actually utilized for the benefit of ratepayers during the same test period is to establish a new regulatory account."* The regulatory account was continued in the Fiscal 2011 Revenue Requirement Application Negotiated Settlement Agreement, the Fiscal 2012 - Fiscal 2014 Amended Revenue Requirements Application and the Fiscal 2015 - Fiscal 2016 Revenue Requirements Rate Application.

With this application, BC Hydro requests the following:

- The Amortization of Capital Additions Regulatory Account continue on an ongoing basis, due to the ongoing variability in any given year between actual and planned capital additions, and the resulting impact of that variance on amortization;
- The closing fiscal 2016 balance in the account be recovered over the fiscal 2017 to fiscal 2019 test period; and
- On an ongoing basis, the forecast account balance at the end of a test period is to be recovered over the next test period.

7.5.4 Total Finance Charges Regulatory Account

By Order No. G-16-09 to the Fiscal 2009 - Fiscal 2010 Revenue Requirements Application, the British Columbia Utilities Commission directed BC Hydro to defer in a regulatory account any differences between forecast and actual finance charges for fiscal 2009 and fiscal 2010. This regulatory account was continued by British Columbia Utilities Commission decisions on the Fiscal 2011 Revenue Requirement Application Negotiated Settlement Agreement, the Fiscal 2012 - Fiscal 2014 Amended Revenue Requirements Application and the Fiscal 2015 - Fiscal 2016 Revenue Requirements Rate Application.

With this application BC Hydro requests the following:

- The Total Finance Charges Regulatory Account be continued on an ongoing basis due to the continuing uncertainty and potential volatility of interest rates and any variances in the actual amount of debt borrowed compared to plan;
- The closing fiscal 2016 balance in the account be recovered over the fiscal 2017 to fiscal 2019 test period; and
- On an ongoing basis, the forecast account balance at the end of a test period is to be recovered over the next test period.

7.5.5 Rock Bay Remediation Regulatory Account

By Order No. G-75-11, the British Columbia Utilities Commission approved the establishment of the Rock Bay Remediation Regulatory Account for the deferral of actual expenditures in fiscal 2011 related to the remediation of BC Hydro's Rock Bay property. By Order Nos. G-55-12 and G-57-13 the account was extended to defer actual remediation costs incurred in fiscal 2012 and fiscal 2013 respectively.

Order No. G-48-14 extended this period to include remediation costs incurred in fiscal 2014 and later fiscal years as prescribed by Direction No. 7, and directed BC Hydro to amortize specific amounts from the regulatory account in fiscal 2015 and fiscal 2016 as prescribed by Direction No. 6.

The actual remediation costs deferred to the regulatory account for fiscal 2015 and fiscal 2016 were lower than the specific amounts BC Hydro was directed to amortize in Order No. G-48-14, and resulted in a closing credit balance at the end of fiscal 2016.

With this application BC Hydro requests the following:

- The closing fiscal 2016 balance in the account be recovered over the fiscal 2017 to fiscal 2019 test period;
- Effective starting in fiscal 2017, and on an ongoing basis, actual Rock Bay remediation costs will be deferred to this account each year, and forecast Rock Bay remediation costs will be amortized from the account in each year;
- Interest will continue to be applied to balances in the account, consistent with the application of interest to other variance accounts, based on BC Hydro's current weighted average cost of debt;
- Effective starting in fiscal 2017, and on an ongoing basis, the forecast interest charged to the Rock Bay Remediation Regulatory Account each year be recovered in each year; and
- On an ongoing basis, the forecast account balance at the end of a test period is to be recovered over the next test period.

7.5.6 Arrow Water Systems Regulatory Account

In the mid-1960s, BC Hydro relocated residents affected by the creation of the Hugh Keenleyside Dam and Arrow Lakes Reservoir to the newly constructed towns of Edgewood, Fauquier and Burton, and also to Robson, all now part of the Regional District of Central Kootenay. BC Hydro built the drinking water systems in Burton, Fauquier, and Edgewood when the towns were constructed, and upgraded and assumed control of the Robson drinking water system to compensate for impacts related to construction of the Keenleyside Dam. Currently, the water systems (collectively known as the Arrow Water Systems) serve 338 customers and generate annual revenue of less than $100,000.

On January 4, 2011, BC Hydro divested the assets of the Arrow Water Systems to the Regional District of Central Kootenay at a nominal price. Costs related to the divestiture, including the write-down of assets, were not included in the Fiscal 2011 Revenue Requirement Application Negotiated Settlement Agreement. BC Hydro applied to the British Columbia Utilities Commission in fiscal 2011 for approval to establish a regulatory account to capture the costs associated with the divestiture of the Arrow Water Systems.

British Columbia Utilities Commission Order No. G-90-11 established the Arrow Water Systems Regulatory Account and the Arrow Water Systems Provision Regulatory Account. The latter account is discussed further in section 7.5.22. Order No. G-48-14 set the amortization from the account at $4.7 and $4.5 million in fiscal 2015 and fiscal 2016, respectively, which reflected divestiture costs incurred to date.

In accordance with the terms of the agreement with the Regional District of Central Kootenay on the divestiture of the Arrow Water Systems assets, BC Hydro pays the Regional District of Central Kootenay on an annual basis the water fees on behalf of the regions residents, whose water accounts were in good standing with BC Hydro at the time of the transfer, and will continue to do so until those residents who qualified are no longer on title for their properties. This cost is estimated at $0.3 million per year. This amount, as well as any other expenditures associated with divestiture are transferred from the Arrow Water Provision Regulatory Account to the Arrow Water Systems Regulatory Account and a corresponding amount is amortized annually from the regulatory account.

With this application BC Hydro requests approval to continue to recover on an ongoing basis the annual costs charged to the regulatory account and to draw down the Arrow Water Provision account by an equal amount, as discussed further in the section 7.5.22.

7.5.7 Asbestos Remediation Regulatory Account

Starting in fiscal 2013 and in following years, BC Hydro began to incur expenditures related to asbestos remediation at its facilities. By Order No. G-7-13 the British Columbia Utilities Commission approved the establishment of the Asbestos Remediation Regulatory account for unplanned asbestos remediation costs in fiscal 2013 and fiscal 2014. Order No. G-48-14 directed BC Hydro to amortize specific amounts from the regulatory account in fiscal 2015 and fiscal 2016 and authorized BC Hydro to defer to the account unplanned costs associated with asbestos remediation at its facilities, on an ongoing basis.

BC Hydro also incurs costs annually in regard to compliance with Polychlorinated Biphenyl Regulations. As discussed in section 7.5.24, until the end of fiscal 2016 BC Hydro expensed the annual forecast amount of these costs and reduced the Environmental Provisions Regulatory account by an equal amount. BC Hydro believes it is appropriate to defer to a regulatory account, on an ongoing basis, the variance between actual costs and forecast amounts in order to recover these amounts in future rates. Rather than request the creation of a new regulatory account to capture these variances, BC Hydro believes it is appropriate and efficient to charge these variances to the Asbestos Remediation Regulatory Account, and to change the terms of the account and the name of the account to reflect this practice.

With this application BC Hydro requests the following:

- The name of the regulatory account be changed from the Asbestos Remediation Regulatory Account to the Remediation Regulatory Account;
- The closing fiscal 2016 balance in the account be recovered over the fiscal 2017 to fiscal 2019 test period;

- Effective starting in fiscal 2017, and on an ongoing basis, actual asbestos remediation costs at BC Hydro facilities will be deferred to this account each year, and forecast asbestos remediation costs will be amortized from this account each year;
- Effective starting in fiscal 2017, and on an ongoing basis, actual expenditures related to compliance with polychlorinated biphenyl regulations will be deferred to this account each year, and forecast expenditures related to compliance with polychlorinated biphenyl regulations will be amortized from this account each year;
- Interest will continue to be applied to balances in the account, consistent with the application of interest to other variance accounts, based on BC Hydro's current weighted average cost of debt;
- Effective starting in fiscal 2017, and on an ongoing basis, the forecast interest charged to the Remediation Regulatory Account each year be recovered in each year; and
- On an ongoing basis, the forecast account balance at the end of a test period is to be recovered over the next test period.

7.5.8 Real Property Sales Regulatory Account

By Order No. G-48-14 the Real Property Sales Regulatory Account was established to defer the variances between BC Hydro's actual and forecast real property gain/loss from real estate sales, with interest to be accrued in a fiscal year at the rate of BC Hydro's weighted average cost of debt in that fiscal year.

The 2013 10 Year Rates Plan included a target of $50 million of net gains from real property sales over the first five years (i.e., fiscal 2015 through fiscal 2019) of the plan. In the Fiscal 2015 - Fiscal 2016 Revenue Requirements Rate Application, as part of the 2013 10 Year Rates Plan, BC Hydro included in each of fiscal 2015 and fiscal 2016 $10 million forecast net gains from real estate sales. Similarly in this application, BC Hydro has included $10 million in forecast net gains in each of the test years.

The timing of completion of real estate transactions is difficult to accurately forecast and the account serves to smooth the recognition of gains/losses from real estate sales that could otherwise impact rates in a particular year. BC Hydro expects to achieve the targeted $50 million of net gains by the end of fiscal 2019, meaning that this account is expected to self-clear based on the forecast gains and losses experienced over the fiscal 2017 to fiscal 2019 test period, and will have a zero balance by the end of fiscal 2019, subject to potential interest charges.

BC Hydro is not requesting any changes to this account with this application.

7.5.9 Minimum Reconnection Charges Deferral Account

By Order No G-175-15 the British Columbia Utilities Commission approved, on an interim basis pending final order(s) on BC Hydro's 2015 Rate Design Application, a reduction in BC Hydro's minimum reconnection charge and also approved the creation of the Minimum Reconnection Charges Deferral Account to defer the revenue impact of the decrease in BC Hydro's minimum reconnection charge for fiscal 2016, and to recover the balance of the account in rates in fiscal 2017.

With this application BC Hydro is requesting that this account be closed, upon the recovery of the balance in the account in fiscal 2017 rates.

7.5.10 Mining Customer Payment Plan Regulatory Account

In accordance with section 3(2) of Order in Council No. 123, issued on February 29, 2016, Order No. G-34-16 authorized BC Hydro to establish the Mining Customer Payment Plan Regulatory Account to defer to future fiscal years amounts equal to the sum of the following:

(i) The account balances of mining customers, if those account balances are impaired;

(ii) Any other amounts that are payable to BC Hydro by mining customers before the closing date and that are impaired; and

(iii) Any taxes paid by BC Hydro on behalf of mining customers on the account balances referred to in subparagraph (i) and amounts referred to in subparagraph (ii).

The order also directed BC Hydro to reduce the Mining Customer Payment Plan Regulatory Account by an amount collected from an applicable mining customer, and to include in the Mining Customer Payment Plan Regulatory Account interest determined in a fiscal year at the rate of BC Hydro's weighted average cost of debt in that fiscal year.

The order arose from the Province’s decision to allow companies operating metal and coal mines in B.C. to temporarily defer a portion of their BC Hydro electricity payments during the current slowdown in the sector due to low commodity prices.

BC Hydro is not requesting any changes to this account with this application.

7.5.11 Foreign Exchange Gains/Losses Regulatory Account

By Order No. G-47-02 the British Columbia Utilities Commission approved the deferral and amortization of foreign exchange gains and losses on the translation of foreign denominated long-term monetary items, using the straight-line pool method, for the fiscal year beginning April 1, 2002 and future periods.

BC Hydro is not requesting any changes to this account with this application.

7.5.12 Non-Current Pension Costs Regulatory Account

By Order No. G-16-09 to the Fiscal 2009 - Fiscal 2010 Revenue Requirements Application, the British Columbia Utilities Commission approved the establishment of a regulatory account to defer the difference between forecast and actual non-current pension costs in fiscal 2010. The Fiscal 2011 Revenue Requirement Application Negotiated Settlement Agreement extended this regulatory account for fiscal 2011 and directed that the closing fiscal 2011 balance of the account be amortized over a five-year period beginning in fiscal 2012. British Columbia Utilities Commission Order No. G-77-12A extended the account for fiscal 2012 to fiscal 2014, and expanded the scope of the account to include the difference between forecast and actual non-current other post-employment benefit costs, beginning in fiscal 2012. British Columbia Utilities Commission Order No. G-48-14, as prescribed by section 7(g) of Direction No. 7, directed BC Hydro to continue to defer, on an ongoing basis the variances between its actual and forecast non-current pension costs to the Non-Current Pension Costs Regulatory Account, and to amortize specific amounts from the account in fiscal 2015 and fiscal 2016.

In August, 2015 BC Hydro filed an application with the British Columbia Utilities Commission for approval to defer the operating cost variance between the Fiscal 2015 - Fiscal 2016 Revenue Requirements Rate Application Plan and actual fiscal 2016 post-employment benefits current pension costs, arising from a change in the actuarial discount rate. BC Hydro submitted that the Fiscal 2015 - Fiscal 2016 Revenue Requirements Rate Application Plan was based on an actuarial discount rate of 4.62 per cent while the actual fiscal 2016 discount rate calculated in accordance with IFRS is 3.51 per cent, which resulted in an operating cost variance of $17.2 million for fiscal 2016. By Order No. G-148-15 the British Columbia Utilities Commission approved the deferral of the fiscal 2016 variance to the Non-Current Pension Costs Regulatory Account for future recovery, with the disposition of the variance to be addressed by BC Hydro in its next revenue requirement application.

With this application, BC Hydro requests the following changes with respect to the Non-Current Pension Costs Regulatory Account:

- The name of the Non-Current Pension Costs Regulatory Account be changed, effective fiscal 2017, and on an ongoing basis, to the Pension Costs Regulatory Account;

- In addition to the current definition of variances that may be charged to the account, the annual variance between the forecast costs and actual costs related to the operating cost portion of the post-employment benefits current pension costs also be deferred to the Pension Costs Regulatory Account, on an ongoing basis. These variances arise primarily due to changes between the planned and actual actuarial assumptions, which are expected to continue;
- The methodology used to forecast current service costs on BC Hydro's post-retirement benefit plans be changed, effective fiscal 2017 and on an ongoing basis. The forecast current service costs in previous revenue requirements applications were determined using the current discount rate in effect at the time the forecast was prepared. However, over the period from fiscal 2011 to fiscal 2016 the annual discount rate has ranged from a high of 6.12 per cent to a low of 3.51 per cent, giving rise to large variations between actual and planned results, and making it difficult to accurately forecast pension expense. To minimize the volatility of the discount rate used for revenue requirements applications, starting in fiscal 2017 and on an ongoing basis, BC Hydro is proposing to use an average of actual past discount rates used in the calculation of actual current service costs in the preceding five fiscal years for forecasting purposes. For the test period, the average is based on the actual discount rate used in the calculation of actual current service costs in fiscal 2012 to fiscal 2016. The fiscal 2012 to fiscal 2016 five-year average is calculated at 4.38 per cent. BC Hydro believes this change may help to minimize intergenerational inequity caused by volatility in actual costs compared to plan. The changes requested are intended to improve the accuracy and completeness of BC Hydro's planned pension costs included in the Fiscal 2017 – Fiscal 2019 Revenue Requirements Application. By deferring the variances between actual and planned costs, and through the recovery mechanism proposed in the following subsection, ratepayers will only pay actual pension costs incurred by BC Hydro;

- The portion of the forecast account balance at the start of a test period related to the variances transferred to the account during the previous test period be amortized over a period of time based on the expected average remaining service life of the active plan members at the start of the test period;
- The actuarial gain which is forecast to be transferred to the Pension Costs Regulatory Account in fiscal 2017, as a result of using the forecast discount rate of 4.38 per cent, be amortized, beginning in fiscal 2018, over a 12-year period, which is the currently expected average remaining service life of the active plan members at the beginning of fiscal 2018;
- The portion of the actual or forecast account balance at the start of the test period related to variances between its actual and forecast non-current pension costs for the fiscal 2015 to fiscal 2016 test period, be amortized over the 12-year period ending in fiscal 2028, which is the currently expected average remaining service life of the active plan members at the beginning of the fiscal 2017 to fiscal 2019 test period; and
- The portion of the actual or forecast account balance at the start of the test period related to variances between its actual and forecast non-current pension costs for the fiscal 2011 to fiscal 2014 test period, continue to be amortized over the remaining years of the 13-year period ending in fiscal 2027, which was the period of time based on the expected average remaining service life of the active plan members at the beginning of the fiscal 2015 to fiscal 2016 test period.

7.5.13 Debt Management Regulatory Account

In the fall of 2015, BC Hydro applied for approval of a Debt Management Regulatory Account, to capture mark-to-market gains and losses of financial contracts that hedge future long-term debt. The Application was approved by Order No. G-42-16.

The Debt Management Regulatory Account was requested as BC Hydro plans to lock-in historically low interest rates by entering into future debt hedges to mitigate interest rate risk on future long-term debt that BC Hydro expects to issue. Interest will not be applied to the balances in the Debt Management Regulatory Account. In accordance with the Order, the gains or losses from Future Debt Hedges recorded in the Debt Management Regulatory Account will be amortized over the remaining term of the associated long-term debt issuances, commencing at the beginning of the test period subsequent to the test period in which the long-term debt to which the Future Debt Hedge is associated is issued.

BC Hydro is not requesting any changes to this account with this application.

7.5.14 Demand-Side Management Regulatory Account

The costs in the Demand-Side Management Regulatory Account reflect expenditures made on demand-side management activities, including expenditures related to achieving energy savings. Direction No. 7, section 7(d) and British Columbia Utilities Commission Order No. G-48-14 authorized BC Hydro to continue to defer to the Demand-Side Management Regulatory Account, costs associated with the development, implementation and administration of demand-side measures, and to amortize the balance of the account into rates over 15 years, on an ongoing basis.

BC Hydro is not requesting any changes to this account with this application.

7.5.15 First Nations Costs Regulatory Account

By Order No. G-53-02, the British Columbia Utilities Commission approved the deferral of costs related to negotiations and settlements with First Nations, and also approved the amortization of actual negotiation costs and approved settlement costs, over a ten-year period. Settlement payments transferred to the First Nations Costs Regulatory Account from the First Nations Provisions Regulatory Account are not amortized or recovered, pending British Columbia Utilities Commission approval to do so. The nature of these settlements is discussed further in section 7.5.21. By Order No. G-11-08, BC Hydro must submit an application to the British Columbia Utilities Commission for a determination of the manner in which settlement payments may be recovered in rates.

BC Hydro is proposing to recover (i) forecast lump sum settlement payments over a ten-year period starting in the year of payment; (ii) forecast annual settlement payments in the year of payment; and (iii) actual negotiation costs in the year of expenditures. Differences arising from variances between forecast and actual lump sum settlement payments and forecast and actual annual settlement payments in a test period are proposed to be recovered over the following test period.

British Columbia Utilities Commission Order No. G-48-14 directed the amortization of specific amounts from the account for fiscal 2015 and fiscal 2016, and also directed the accrual of interest on the account going forward. Actual transfers to the account in fiscal 2015 and fiscal 2016 were different from the amounts on which the specific amortization in British Columbia Utilities Commission Order No. G-48-14 was based, resulting in BC Hydro recording higher amortization than what would have resulted if amortization had been calculated on actual transfers. BC Hydro proposes to refund this difference in amortization to the ratepayers.

With this application BC Hydro requests that:

(i) The actual fiscal 2016 closing balance in the First Nations Costs Regulatory Account that is related to the difference between the specific amortization amounts directed by British Columbia Utilities Commission Order No. G-48-14, and the calculation of amortization based on actual transfers into the First Nations Costs Regulatory Account in fiscal 2014, fiscal 2015 and fiscal 2016, be amortized (this is a credit amount, the amortization of which has the effect of the amount being returned to ratepayers) in fiscal 2017;

(ii) The actual fiscal 2016 closing balance in the First Nations Costs Regulatory Account that is related to settlement payments and negotiations costs incurred prior to fiscal 2015 be amortized over eight years beginning in fiscal 2017. In the Regulatory Accounts Report filed as Appendix H to the Fiscal 2015 - Fiscal 2016 Revenue Requirements Rate Application, BC Hydro proposed that a ten-year amortization period for the account would be appropriate, and by Order No. G-48-14 amounts were amortized from the account for fiscal 2015 and fiscal 2016, leaving eight years remaining of the proposed ten-year amortization period. A ten-year amortization period is consistent with the amortization period for actual negotiation costs and approved settlement costs directed by British Columbia Utilities Commission Order No. G-53-02;

(iii) The actual fiscal 2016 closing balance in the First Nations Costs Regulatory Account that is related to the lump sum settlement payment made in fiscal 2016 is to be amortized over nine years, beginning in fiscal 2017. BC Hydro has recorded one-year of amortization from the account for fiscal 2016, leaving nine years remaining of the proposed ten-year amortization period described above;

(iv) Effective starting in fiscal 2017, and on an ongoing basis, actual lump sum settlement payments will be deferred to this account each year, and the forecast lump sum settlement payments are to be amortized over ten years, starting in the year of payment. Any difference between amortization of forecast lump sum settlement payments and the calculation of amortization based on actual settlement payments will give rise to a variance;

(v) Effective starting in fiscal 2017, and on an ongoing basis, actual negotiations costs will be deferred to this account each year, and actual negotiations costs will be recovered from this account each year. As a result, variances between forecast and actual negotiations costs will not be deferred to the First Nations Costs Regulatory Account, and, as described in section 7.5.1, will also not be deferred to the Heritage Deferral Account. BC Hydro believes it should bear the risks associated with the variances between forecast and actual annual negotiations costs;

(vi) Effective starting in fiscal 2017, and on an ongoing basis, actual annual settlement payments will be deferred to this account each year, and forecast annual settlement payments will be amortized from this account each year;

(vii) Interest will continue to be applied to balances in the account, consistent with the application of interest to other variance accounts, based on BC Hydro's current weighted average cost of debt;

(viii) Effective starting in fiscal 2017, and on an ongoing basis, the forecast interest charged to the First Nations Costs Regulatory Account be amortized from this account in each year;

(ix) On an ongoing basis, the forecast account balance in the First Nations Costs Regulatory Account at the end of a test period related to the difference between amortization of forecast annual and lump sum settlement payments and the calculation of amortization based on actual annual and lump sum settlement payments during that test period is to be recovered over the following test period; and

(x) On an ongoing basis, the forecast account balance in the First Nations Costs Regulatory Account at the end of a test period related to the difference between forecast interest recovered and actual interest charged to the First Nations Cost Regulatory Account during that test period is to be recovered over the following test period.

7.5.16 Site C Regulatory Account

By Order No. G-143-06, the British Columbia Utilities Commission approved the creation of a regulatory account in respect of Site C Clean Energy Project expenditures and approved deferral to the account project costs incurred in fiscal 2007 and fiscal 2008. The Fiscal 2009 - Fiscal 2010 Revenue Requirements Application Decision and Fiscal 2011 Revenue Requirement Application Negotiated Settlement Agreement extended the deferral of project costs to the Site C Regulatory Account to the end of fiscal 2011. By Order No. G-77-12A regarding the

Fiscal 2012- Fiscal 2014 Amended Revenue Requirement Application, the British Columbia Utilities Commission authorized the deferral to the Site C Regulatory Account of all operating costs incurred related to the Site C Clean Energy Project in fiscal 2012 to fiscal 2014. By Order No. G-48-14, the British Columbia Utilities Commission authorized the deferral to the account of all operating costs incurred in fiscal 2015 and fiscal 2016. Following the final investment decision by the Province to proceed with the Site C Clean Energy Project, BC Hydro commenced capitalization of costs related to the project starting in January 2015. Notwithstanding that BC Hydro has commenced capitalization of costs, certain costs related to the project may not be eligible for capitalization under the Prescribed Standards. For example, some legal costs are eligible for capitalization under the Prescribed Standards, but some are not.

With this application, BC Hydro requests the ability to defer to the account any costs related to the Site C Clean Energy Project that are not able to be capitalized under the Prescribed Standards.

BC Hydro is not requesting approval of a recovery mechanism for the account with this application. BC Hydro will request a recovery mechanism for the regulatory account in a future application.

7.5.17 Future Removal and Site Restoration Regulatory Account

Prior to fiscal 2005, BC Hydro accrued a provision (named the Future Removal and Site Restoration provision) for future dismantling costs over the lives of certain assets. Dismantling cost accruals were reflected as increases in the provision on the balance sheet and as amortization expense in the income statement. The amortization expenses were recovered in rates. In fiscal 2005, the accounting rules changed with the introduction of asset retirement obligations, and future dismantling costs were no longer required to be accrued in amortization expense.

Order No. G-96-04 on BC Hydro’s Fiscal 2005 - Fiscal 2006 Revenue Requirements Application directed BC Hydro to establish the Future Removal and Site Restoration

Regulatory Account, with a balance equal to the fiscal 2004 ending balance in the Future Removal and Site Restoration accounting provision, to ensure that the balance remained as a liability to be utilized for dismantling costs incurred in fiscal 2005 and future years, in respect of assets where no Asset Retirement Obligation has been recorded. In other words, the fiscal 2004 balance of the Future Removal and Site Restoration provision was transferred to the regulatory account to be kept available to offset future removal and site restoration activities as originally intended rather than being transferred to retained earnings to the benefit of the Province, as would have been the case in the absence of the order.

This account is being drawn down as actual expenditures are made. The Future Removal and Site Restoration Regulatory Account had an $8.7 million balance at the start of fiscal 2017 and is expected to be fully drawn down during fiscal 2017.

With the drawdown of this account to a zero balance, BC Hydro will begin to forecast annual dismantling costs for inclusion in rates. However actual dismantling costs are expected to differ from forecast amounts due to timing differences – dismantling work often occurs based on capital project schedules, which can change and cause material shifts in the timing of dismantling expenditures. Additionally, the full scope and cost of dismantling activities is not known until the dismantling activities are completed. For this reason, BC Hydro believes that it is appropriate to defer, starting in fiscal 2017 when the current balance in the account is fully drawn down, and on an ongoing basis the variances between planned and actual dismantling costs to the regulatory account. BC Hydro also proposes that the account name be changed to reflect variances between planned and actual dismantling costs.

With this application BC Hydro requests the following:

- The Future Removal and Site Restoration Regulatory Account be renamed the Dismantling Cost Regulatory Account;

- The terms of the account be changed so that the account defers, on an annual basis, any variances between planned and actual dismantling costs, to be effective starting in fiscal 2017. Deferral of the variances between planned and actual dismantling costs aligns with the criteria for deferral of costs discussed in section 7.3. Actual dismantling costs are subject to a number of non-controllable events such as project schedule changes and cost variances, and therefore could differ materially from plan in a given year;
- Interest will be applied to balances in the account, consistent with the application of interest to other variance accounts, based on BC Hydro's current weighted average cost of debt; and
- On an ongoing basis, the forecast account balance at the end of a test period is to be recovered over the next test period.

7.5.18 Pre-1996 Contributions in Aid of Construction Regulatory Account

In fiscal 2006 BC Hydro engaged Gannett Fleming to complete a depreciation study, which was filed as part of the Fiscal 2007 - Fiscal 2008 Revenue Requirements Application. Gannett Fleming recommended that the amortization period for assets referred to as "Profile ID 99403 Distribution Pre-1996 Contributions in Aid" be increased from the then-approved period of 25 years to 45 years. Section 7(iv) of the Fiscal 2007 - Fiscal 2008 Revenue Requirements Application Negotiated Settlement Agreement provided that the amortization period for these assets would be retained at 25 years. In its financial records BC Hydro changed the amortization period for these assets from 25 to 45 years to match the depreciation study, and implemented the Fiscal 2007 - Fiscal 2008 Revenue Requirements Application Negotiated Settlement Agreement commitment by creating a regulatory account to capture the difference in the revenue requirement impacts of a 45-year amortization period and a 25-year amortization period. This regulatory account is being amortized over 45 years and will be fully amortized at the end of fiscal 2040.

BC Hydro is not requesting any changes to this account with this application.

7.5.19 SMI Regulatory Account

By British Columbia Utilities Commission Order Nos. G-64-09 and G-67-10, the British Columbia Utilities Commission approved the establishment of the SMI (Smart Metering and Infrastructure Program) Regulatory Account to defer the operating costs incurred by BC Hydro with respect to the Smart Metering and Infrastructure Program in fiscal 2009 and fiscal 2010, respectively. British Columbia Utilities Commission Order No. G-115-11 authorized BC Hydro to include its actual fiscal 2011 Smart Metering and Infrastructure Program operating costs up to $5.8 million in the SMI Regulatory Account. British Columbia Utilities Commission Order No. G-77-12A to BC Hydro's Fiscal 2012 - Fiscal 2014 Amended Revenue Requirements Application approved the deferral to the account of the following: the amount of actual net operating costs, amortization on capital assets, finance charges, and return on equity in relation to the Smart Metering and Infrastructure Program from fiscal 2012 to fiscal 2014. BC Hydro has submitted quarterly reports pursuant to British Columbia Utilities Commission Order No. G-67-10 on the amount of actual expenditures in relation to the Smart Metering and Infrastructure Program and a comparison of the actual expenditures with the planned expenditures. By Order No. G-166-13, and in accordance with section 3(2) of Direction No. 4, BC Hydro was directed to defer to the account:

- Program costs;
- Investigation costs and infrastructure costs that are not recovered from eligible customers at premises where a legacy meter or radio-off meter is installed; and
- Costs related to smart meters, which are incurred during the period January 1, 2013 to March 31, 2014.

By Order No. G-48-14 on BC Hydro's Fiscal 2015 - Fiscal 2016 Revenue Requirements Rate Application, the British Columbia Utilities Commission approved the amortization from the SMI Regulatory Account of specific amounts in each of fiscal 2015 and fiscal 2016 and also approved deferral to the account of, the net operating costs incurred in fiscal 2015 to fiscal 2016 arising from the Smart Metering and Infrastructure program. As the Smart Metering and Infrastructure Program is complete and operationalized, BC Hydro is not forecasting any additions to the account for the fiscal 2017 to fiscal 2019 test period.

With this application BC Hydro requests the following:

- The actual fiscal 2016 closing account balance is to be recovered over a period of 13 years, starting in fiscal 2017, which is the remaining period of the original 15-year amortization period proposed in the Regulatory Accounts Report filed in the Fiscal 2015 - Fiscal 2016 Revenue Requirements Rate Application. The 15-year amortization period is based on the average life of Smart Metering and Infrastructure assets.

7.5.20 Capital Project Investigation Costs Regulatory Account

By Order No. G-16-09 related to BC Hydro's Fiscal 2009 - Fiscal 2010 Revenue Requirements Application, the British Columbia Utilities Commission approved the establishment of a regulatory account for capital project investigation costs for fiscal 2009 and fiscal 2010. The Fiscal 2011 Revenue Requirement Application Negotiated Settlement Agreement provided that additions to the Capital Project Investigation Costs Regulatory Account would be discontinued at the end of fiscal 2011, and that the closing fiscal 2011 balance would be amortized beginning in fiscal 2012. The Fiscal 2011 Revenue Requirement Application Negotiated Settlement Agreement also provided that BC Hydro may apply for regulatory accounting treatment for investigation costs for large projects. The amortization of the fiscal 2011 closing balance in the account over 10 years commencing in fiscal 2012 was approved by Order No. G-77-12A.

BC Hydro is not requesting any changes to this account with this application.

7.5.21 First Nations Provisions Regulatory Account

By Order No. G-56-06, the British Columbia Utilities Commission approved the establishment of a regulatory asset corresponding to the amount of a loss provision that BC Hydro recorded on its financial statements as required under the prescribed accounting standards in respect of two First Nations claims. By Order No. G-11-08, the British Columbia Utilities Commission amended the First Nations Provisions regulatory asset to allow the balance of the regulatory account to reflect loss provisions as required under the accounting standards, related to any First Nations claim, and to allow the periodic adjustment of the balance of the regulatory account to reflect adjustments to the loss provisions required under the accounting standards.

BC Hydro's settlements with First Nations may include both lump sum payments and annual payments. When settlement payments are made, corresponding amounts are transferred from the First Nations Provisions Regulatory Account to the First Nations Costs Regulatory Account, and recovered in rates through amortization of that regulatory account.

BC Hydro is not requesting any changes to this account with this application.

7.5.22 Arrow Water Systems Provision Regulatory Account

By Order No. G-90-11 the British Columbia Utilities Commission approved the establishment of the Arrow Water Systems Provision Regulatory Account. BC Hydro was required under the accounting standards to record a loss provision liability in regards to the divestiture of the Arrow Water system, and the recording of the loss provision liability and the corresponding Arrow Water Systems Provision regulatory asset preserved BC Hydro's ability to seek recovery of actual costs in rates. As payments are made the provision account is drawn down and amounts transferred to the Arrow Water Systems Regulatory Account and amortized into rates, subject to approval by the British Columbia Utilities Commission. The Arrow Water Systems Provision Regulatory Account will continue to carry a balance of approximately

$3 million over the fiscal 2017 to fiscal 2019 test period, and is projected to be fully drawn down to zero by fiscal 2031, which is the time period when BC Hydro's obligation to pay water fees for qualifying residents is expected to expire.

BC Hydro is not requesting any changes to this account with this application.

7.5.23 Environmental Provisions Regulatory Account

By Order No. G-88-10 the British Columbia Utilities Commission approved the establishment of the Environmental Provisions Regulatory Account in the amount of the loss provision liability recognized by BC Hydro in its financial statements, in respect of compliance with the Polychlorinated Biphenyl Regulations and remediation of environmental contamination at Rock Bay, and to periodically adjust the amounts in the regulatory account to match the changes required under prescribed accounting standards in the loss provision liability. By Order No. G-7-13, the terms of the Environmental Provisions Regulatory Account was expanded to include the loss provision liability related to asbestos remediation at BC Hydro's facilities.

As BC Hydro makes actual expenditures related to compliance with the Polychlorinated Biphenyl Regulations, the remediation of Rock Bay and the remediation of asbestos at its facilities, the balance in the Environmental Provisions Regulatory Account is reduced accordingly.

In the case of actual costs associated with remediation activities at Rock Bay, as the actual costs are incurred they are deferred to the Rock Bay Remediation Regulatory Account, described in section 7.5.5, and the provision is reduced by an equal amount. In the case of actual costs associated with asbestos remediation, as the actual costs are incurred they are deferred to the Asbestos Remediation Regulatory Account, described in section 7.5.7, and the provision is reduced by an equal amount. The actual balances in the Rock Bay Remediation Regulatory account and the Asbestos Remediation Regulatory Account are recovered through the mechanisms discussed in sections 7.5.5 and 7.5.7, respectively.

In the case of costs associated with compliance with polychlorinated biphenyl regulations, until the end of fiscal 2016 the costs were expensed as incurred, and the Environmental Provisions Regulatory Account reduced by an equal amount.

With this application BC Hydro requests the following, as further discussed in section 7.5.7:

- Starting in fiscal 2017 and on an ongoing basis, that, as the actual costs associated with compliance with polychlorinated biphenyl regulations are deferred to the Asbestos Remediation Regulatory Account (BC Hydro is requesting that this account be renamed the Remediation Regulatory Account), the Environmental Provisions Regulatory Account be reduced by an equal amount, similar to the treatment of the other environmental remediation regulatory accounts.

7.5.24 Rate Smoothing Regulatory Account

Order No. G-48-14 established the Rate Smoothing Regulatory Account in fiscal 2015 to defer for recovery in rates in future fiscal years, those portions of the allowed revenue requirement in a particular fiscal year that were not, or are not to be recovered in rates in that particular fiscal year. As part of the 2013 10 Year Rates Plan, this account was to be created to keep rate increases as gradual and predictable as possible, by spreading costs that occur in the earlier years of the 2013 10 Year Rates Plan over the later years of the Plan. Additionally, this account is to be paid down to zero by the end of fiscal 2024.

Additions to the account were made in fiscal 2015 of $166.2 million and in fiscal 2016 of $121.2 million, in accordance with Direction 6, to achieve the approved rate increases of 9.0 per cent in fiscal 2015 and 6.0 per cent in fiscal 2016, respectively.

In order to achieve the capped rate increases of 4.0 per cent, 3.5 per cent and 3.0 per cent in fiscal 2017, fiscal 2018 and fiscal 2019, respectively, as set out in section 9 of Direction No. 7, with this application BC Hydro is requesting approval of the additions to the account for fiscal 2017 to fiscal 2019 as indicated in Table 7-6, below.

Table 7-6 Fiscal 2015 to Fiscal 2019 Rate Smoothing Regulatory Account – Actual and Forecast Additions

Deferral	($ million)
Fiscal 2015 Actual	166.2
Fiscal 2016 Actual	121.2
Fiscal 2017 Plan	210.0
Fiscal 2018 Plan	285.9
Fiscal 2019 Plan	299.4

BC Hydro is on track to reduce the balance of this account to zero by fiscal 2024, as required by the 2013 10 Year Rates Plan. However, BC Hydro is not requesting approval of a recovery mechanism for the account with this application.

7.5.25 IFRS Property, Plant and Equipment Regulatory Account

The IFRS Property, Plant and Equipment Regulatory Account enables the deferral of overhead costs that can no longer be capitalized under IFRS, as they are not directly attributable to the construction of an asset.

British Columbia Utilities Commission Order No. G-77-12A to the Fiscal 2012 - Fiscal 2014 Amended Revenue Requirements Application implemented BC Hydro's proposal that overhead costs that can no longer be capitalized should not be immediately absorbed in rates as it would result in a significant rate impact, but rather should be deferred and transitioned into operating expenditures over ten years. The order also directed that the balance of the regulatory account is to be amortized over 40 years.

In order to transition the overhead costs that can no longer be capitalized under IFRS into rates over a ten-year period, BC Hydro proposed in the Fiscal 2012 - Fiscal 2014 Amended Revenue Requirements Application to charge

100 per cent of ineligible overhead costs to the IFRS Property, Plant & Equipment Regulatory Account in fiscal 2012 and starting in fiscal 2013 reduce the percentage of the ineligible overhead costs that would be charged to the regulatory account by 10 per cent each year. BC Hydro also proposed to amortize the additions to the regulatory account over forty years, based on the composite life of BC Hydro's assets in order to match the overhead costs with the benefits of the underlying assets.

By British Columbia Utilities Commission Order No. G-48-14 on the Fiscal 2015 - Fiscal 2016 Revenue Requirements Rate Application, specific amounts were amortized from the regulatory account for each of fiscal 2015 and fiscal 2016, respectively, which was based on the 40-year amortization period directed by British Columbia Utilities Commission Order No. G-77-12A.

BC Hydro is not requesting any changes to the regulatory account, nor the recovery mechanism for the account with this application.

The actual and forecast annual additions to the IFRS Property, Plant & Equipment Regulatory Account are set out in Table 7-7, below. As indicated in the table, additions to the account are forecast to be zero by fiscal 2022.

Table 7-7 IFRS Property, Plant & Equipment Regulatory Account

($ million)	Additions to Regulatory Account ($ million)
Fiscal 2012 Actual	221.8
Fiscal 2013 Actual	229.6
Fiscal 2014 Actual	179.5
Fiscal 2015 Actual	156.8
Fiscal 2016 Actual	134.4
Fiscal 2017 Plan	112.0
Fiscal 2018 Plan	89.6
Fiscal 2019 Plan	67.2
Fiscal 2020 Plan	44.8
Fiscal 2021 Plan	22.4
Fiscal 2022 Plan	0.0

7.5.26 IFRS Pension Regulatory Account

On transition to IFRS in fiscal 2013 BC Hydro was required to recognize all unamortized experience gains and losses on the pension and other post-employment benefit plans not previously recognized in its financial statements. To maintain BC Hydro's ability to recover this amount from customers, BC Hydro requested in its Fiscal 2012 - Fiscal 2014 Amended Revenue Requirements Application the establishment of a regulatory account (the IFRS Pension Regulatory Account) with an opening liability balance in fiscal 2013 equal to the actual unamortized experience gains and losses on the pension and other post-employment benefit plans that BC Hydro must recognize in its financial statements at the time of conversion to IFRS. British Columbia Utilities Commission Order No. G-77-12A implemented this request and also set the amortization period, proposed by BC Hydro to be over 20 years, starting in fiscal 2013. By British Columbia Utilities Commission Order No. G-48-14 specific amounts were amortized for fiscal 2015 and fiscal 2016, which were based on a 20-year amortization period in accordance with British Columbia Utilities Commission Order No. G-77-12A.

BC Hydro is not requesting any changes to this account with this application.

7.6 Application of Interest to Regulatory Accounts

This section explains that it is generally appropriate for regulatory account balances to attract interest at BC Hydro's weighted average cost of debt in recognition that BC Hydro incurs carrying costs.

7.6.1 Rationale for Application of Interest Charge to Regulatory Account Balances

The principle of matching costs with benefits that BC Hydro applies in determining whether a regulatory account is warranted is also considered in the determination of whether interest should be applied to a regulatory account balance. This is due to the fact that the carrying costs of maintaining the account balances may have a real financial cost in any particular period that needs to be recovered in rates. For cash variance regulatory accounts that arise from a direct cash outlay by BC Hydro, the related interest costs are generally included as part of the regulatory accounts. BC Hydro incurs financing charges to carry amounts that were paid in cash but not recovered in rates in the same test period. For some accounts, the interest cost may be immediately expensed from the regulatory account to rates, rather than being deferred and amortized for recovery in future rates.

Variance regulatory accounts such as energy deferral accounts also attract interest because BC Hydro does not forecast variances in the accounts and therefore must fund the variances. In the case of lower than forecast revenues, BC Hydro incurs debt which results in finance charges.

Interest applied to regulatory accounts does not have the effect of increasing or decreasing BC Hydro's allowed net income, as the interest added to regulatory accounts is intended to offset the unbudgeted incremental interest costs that BC Hydro has incurred.

Based on the forgoing criteria, BC Hydro applies interest to all regulatory accounts, with the exception of the following accounts:

a) Non-cash regulatory accounts (such as provisions);

b) Rate-smoothing regulatory accounts (since the annual transfers to a rate-smoothing regulatory account already reflect the impact of the account on finance charges);

c) The Total Finance Charges Regulatory Account (since interest costs are part of total finance charges); and

d) Regulatory accounts that capture timing differences (such as pre-1996 Contributions).

In addition, interest is not charged to the Demand-Side Management Regulatory Account, similar to the treatment for capital projects, as demand-side management expenditures generally go into service in the year of expenditure and BC Hydro does not defer interest on capital projects after they enter service. Table 7-8, below indicates which deferral and regulatory accounts have interest applied to balances.

Table 7-8 Application of Interest to Deferral and Regulatory Accounts

Deferral and Regulatory Account	Interest Applied to Balance
Cost of Energy Variance Accounts	
Heritage Deferral Account	Yes
Non Heritage Deferral Account	Yes
Trade Income Deferral Account	Yes
Other Cash Variance Accounts	
Storm Restoration Costs Regulatory Account	Yes
Amortization of Capital Additions Regulatory Account	Yes
Total Finance Charges Regulatory Account	No
Rock Bay Remediation Regulatory Account	Yes
Arrow Water Systems Regulatory Account	Yes
Asbestos Remediation Regulatory Account	Yes
Real Property Sales Regulatory Account	Yes
Minimum Reconnection Charges Deferral Account	Yes
Mining Customer Payment Plan Regulatory Account	Yes

Deferral and Regulatory Account	Interest Applied to Balance
Non Cash Variance Accounts	
Foreign Exchange Gains/Losses Regulatory Account	No
Non-Current Pension Costs Regulatory Account	No
Debt Management Regulatory Account	No
Benefit Matching Accounts	
Demand-Side Management Regulatory Account	No
First Nations Costs Regulatory Account	Yes
Site C Regulatory Account	Yes
Future Removal and Site Restoration Regulatory Account[52]	Yes
Pre-1996 Contributions in Aid of Construction Regulatory Account	No
SMI Regulatory Account	Yes
Capital Project Investigation Costs Regulatory Account	No
Non Cash Provisions	
First Nations Provisions Regulatory Account	No
Arrow Water Systems Provisions Regulatory Account	No
Environmental Provisions Regulatory Account	No
Rate Smoothing Accounts	
Rate Smoothing Regulatory Account	No
IFRS Transition Accounts	
IFRS Property, Plant and Equipment Regulatory Account	No
IFRS Pension Regulatory Account	No

7.6.2 Interest Rate Applied to Deferral and Other Regulatory Accounts

As approved in the Decision on BC Hydro's Fiscal 2012 to Fiscal 2014 Amended Revenue Requirements Application and section 1(xxv) of Order No. G-77-12A, the interest rate applicable to BC Hydro's deferral and other 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 for the fiscal 2017 to fiscal 2019 test period is 4.04 per cent, 4.06 per cent and 4.13 per cent respectively.

[52] As discussed in section 7.5.17, BC Hydro is requesting this account be re-named the Dismantling Cost Regulatory Account and the terms of the account be changed so that account defers variances between planned and actual dismantling costs, starting in fiscal 2017, and that interest be applied to the account.

7.7 Summary of Requested Changes to Regulatory Accounts in F17-F19 RRA

The following Table 7-9 provides a summary of the requests that BC Hydro is making with this application, regarding its deferral and regulatory accounts, with respect to:

1. Account scope;
2. Recovery mechanism; and
3. The application of interest.

Note that for certain accounts, the account scope, recovery mechanism (if established) and application of interest to the account has been approved on an ongoing basis by previous British Columbia Utilities Commission orders, and no change is requested.

Table 7-9 Summary of Regulatory Account Orders Requested by BC Hydro in Fiscal 2017–F2019 Revenue Requirements Application

	Account	Requested Changes to Account Scope	Requested Changes to Recovery Mechanism	Requested Changes to Interest
Cost of Energy Variance Accounts				
1	Heritage Deferral Account	• Effective starting in fiscal 2017, annual negotiations costs related to First Nations be excluded from the calculation of the heritage payment obligation for the purposes of deferring variances to the Heritage Deferral Account. BC Hydro believes it should bear the risks associated with the variances in annual negotiations costs.	• No Change	• No Change
2	Non Heritage Deferral Account	• No Change	• No Change	• No Change
3	Trade Income Deferral Account	• No Change	• No Change	• No Change
Other Cash Variance Accounts				
4	Storm Restoration Costs Regulatory Account	• No Change	• The closing fiscal 2016 balance in the account be recovered over the fiscal 2017 to fiscal 2019 test period; and • On an ongoing basis, the forecast account balance at the end of a test period is to be recovered over the next test period.	• No change

	Account	Requested Changes to Account Scope	Requested Changes to Recovery Mechanism	Requested Changes to Interest
5	Amortization of Capital Additions Regulatory Account	• The Amortization of Capital Additions Regulatory Account continue on an ongoing basis, due to the ongoing variability in any given year between actual and planned capital additions, and the resulting impact of that variance on amortization.	• The closing fiscal 2016 balance in the account be recovered over the fiscal 2017 to fiscal 2019 test period; and • On an ongoing basis, the forecast account balance at the end of a test period is to be recovered over the next test period.	• No change
6	Total Finance Charges Regulatory Account	• The Total Finance Charges Regulatory Account be continued on an ongoing basis due to the continuing uncertainty and potential volatility of interest rates and any variances in the actual amount of debt borrowed compared to plan.	• The closing fiscal 2016 balance in the account be recovered over the fiscal 2017 to fiscal 2019 test period; and • On an ongoing basis, the forecast account balance at the end of a test period is to be recovered over the next test period.	• No change
7	Rock Bay Remediation Regulatory Account	• Effective starting in fiscal 2017, and on an ongoing basis, actual Rock Bay remediation costs will be deferred to this account each year, and forecast Rock Bay remediation costs will be amortized from this account in each year.	• The closing fiscal 2016 balance in the account be recovered over the fiscal 2017 to fiscal 2019 test period; • Effective starting in fiscal 2017, and on an ongoing basis, the forecast interest charged to the Rock Bay Remediation Regulatory Account each year be amortized from this account in each year; and • On an ongoing basis, the forecast account balance at the end of a test period is to be recovered over the next test period.	• Interest to be applied to balances in the account, consistent with the application of interest to other variance accounts, based on BC Hydro's current weighted average cost of debt.

	Account	Requested Changes to Account Scope	Requested Changes to Recovery Mechanism	Requested Changes to Interest
8	Arrow Water Systems Regulatory Account		• With this application BC Hydro requests approval to continue to recover on an ongoing basis the annual costs charged to the regulatory account and to draw down the Arrow Water Provision account by an equal amount.	• No change
9	Asbestos Remediation Regulatory Account	• The name of the regulatory account be changed from the Asbestos Remediation Regulatory Account to the Remediation Regulatory Account; • Effective starting in fiscal 2017, and on an ongoing basis, actual asbestos remediation costs at BC Hydro facilities will be deferred to this account each year; and • Effective starting in fiscal 2017, and on an ongoing basis, actual expenditures related to compliance with polychlorinated biphenyl regulations will be deferred to this account each year.	• The closing fiscal 2016 balance in the account be recovered over the fiscal 2017 to fiscal 2019 test period; • Effective starting in fiscal 2017, and on an ongoing basis, forecast asbestos remediation costs will be amortized from this account each year; • Effective starting in fiscal 2017, and on an ongoing basis, forecast expenditures related to compliance with polychlorinated biphenyl regulations will be amortized from this account each year; • Effective starting in fiscal 2017, and on an ongoing basis, the forecast interest charged to the Remediation Regulatory Account each year be amortized in each year; and • On an ongoing basis, the forecast account balance at the end of a test period is to be recovered over the next test period.	• Interest to be applied to balances in the account, consistent with the application of interest to other variance accounts, based on BC Hydro’s current weighted average cost of debt.
10	Real Property Sales Regulatory Account	• No Change	• No Change	• No Change

	Account	Requested Changes to Account Scope	Requested Changes to Recovery Mechanism	Requested Changes to Interest
11	Minimum Reconnection Charges Deferral Account	• With this application BC Hydro is requesting that this account be closed upon recovery of the balance in the account in fiscal 2017 rates.	• No Change	• No Change
12	Mining Customer Payment Plan Regulatory Account	• No Change	• No Change	• No Change
Non Cash Variance Accounts				
13	Foreign Exchange Gains/Losses Regulatory Account	• No Change	• No Change	• No Change
14	Non-Current Pension Costs Regulatory Account	• The name of the Non-Current Pension Costs Regulatory Account be changed, effective fiscal 2017, and on an ongoing basis, to the Pension Costs Regulatory Account; • In addition to the current definition of variances that may be charged to the account, the annual variance between the forecast costs and actual costs related to the operating cost portion of the post-employment benefits current pension costs also be deferred to the Pension Costs Regulatory Account, on an ongoing basis. These variances arise primarily due to changes between the planned and actual actuarial assumptions, which are expected to continue; and • The methodology used to forecast current	• That the portion of the forecast account balance at the start of a test period related to the variances transferred to the account during the previous test period be amortized over a period of time based on the expected average remaining service life of the active plan members at the start of the test period; • The actuarial gain which is forecast to be transferred to the Pension Costs Regulatory Account in fiscal 2017, as a result of using the forecast discount rate of 4.38 per cent, be amortized, beginning in fiscal 2018, over a 12-year period, which is the currently expected average remaining service life of the active plan members at the beginning of fiscal 2018;	• No change

	Account	Requested Changes to Account Scope	Requested Changes to Recovery Mechanism	Requested Changes to Interest
		service costs on BC Hydro's post-retirement benefit plans be changed, effective fiscal 2017 and on an ongoing basis. The forecast current service costs in previous revenue requirements applications were determined using the current discount rate in effect at the time the forecast was prepared. However, over the period from fiscal 2011 to fiscal 2016 the annual discount rate has ranged from a high of 6.12 per cent to a low of 3.51 per cent, giving rise to large variations between actual and planned results, and making it difficult to accurately forecast pension expense. To minimize the volatility of the discount rate used for revenue requirements applications, starting in fiscal 2017 and on an ongoing basis, BC Hydro is proposing to use an average of actual past discount rates used in the calculation of actual current service costs in the preceding five fiscal years for Revenue Requirements Application forecasting purposes. For the test period, the average is based on the actual discount rate used in the calculation of actual current service costs in fiscal 2012 to fiscal 2016. The fiscal 2012 to fiscal 2016 five-year average is calculated at 4.38 per cent. BC Hydro believes this change may help to minimize intergenerational inequity caused by volatility in actual costs compared to plan. The changes requested are intended to improve the accuracy and completeness of BC Hydro's planned pension costs included in the Fiscal 2017 – Fiscal 2019 Revenue	• The portion of the actual or forecast account balance at the start of the test period related to variances between its actual and forecast non-current pension costs for the fiscal 2015 to fiscal 2016 test period, be amortized over the 12-year period ending in fiscal 2028, which is the currently expected average remaining service life of the active plan members at the beginning of the fiscal 2017 to fiscal 2019 test period; and • The portion of the actual or forecast account balance at the start of the test period related to variances between its actual and forecast non-current pension costs for the fiscal 2011 to fiscal 2014 test period, continue to be amortized over the remaining years of the 13-year period ending in fiscal 2027, which was the period of time based on the expected average remaining service life of the active plan members at the beginning of the fiscal 2015 to fiscal 2016 test period.	

	Account	Requested Changes to Account Scope	Requested Changes to Recovery Mechanism	Requested Changes to Interest
		Requirements Application. By deferring the variances between actual and planned costs, and through the recovery mechanism proposed in the following subsection, ratepayers will only pay actual pension costs incurred by BC Hydro.		
15	Debt Management Regulatory Account	• No Change	• No Change	• No Change
Benefit Matching Accounts				
16	Demand-Side Management Regulatory Account	• No Change	• No Change	• No Change
17	First Nations Costs Regulatory Account	• Effective starting in fiscal 2017, and on an ongoing basis, actual lump sum settlement payments will be deferred to this account each year, and the forecast lump sum settlement payments are to be amortized over ten years, starting in the year of payment. Any difference between amortization of forecast lump sum settlement payments and the calculation of amortization based on actual settlement payments will give rise to a variance; • Effective starting in fiscal 2017, and on an ongoing basis, actual negotiations costs will be deferred to this account each year, and actual negotiations costs will be recovered from this account each year. As a result, variances between forecast and actual negotiations costs will not be deferred to the	• The actual fiscal 2016 closing balance in the First Nations Costs Regulatory Account that is related to the difference between the specific amortization amounts directed by British Columbia Utilities Commission Order No. G-48-14, and the calculation of amortization based on actual transfers into the First Nations Costs Regulatory Account in fiscal 2014, fiscal 2015 and fiscal 2016, be amortized (this is a credit amount, the amortization of which has the effect of the amount being returned to ratepayers) in fiscal 2017; The actual fiscal 2016 closing balance in the First Nations Costs Regulatory Account that is related to settlement payments and negotiations costs incurred prior to fiscal 2015 be amortized over eight years beginning in	• Interest to be applied to balances in the account, consistent with the application of interest to other variance accounts, based on BC Hydro's current weighted average cost of debt.

	Account	Requested Changes to Account Scope	Requested Changes to Recovery Mechanism	Requested Changes to Interest
		First Nations Costs Regulatory Account, and, as described in section 7.5.1, will also not be deferred to the Heritage Deferral Account. BC Hydro believes it should bear the risks associated with the variances between forecast and actual annual negotiations costs; and • Effective starting in fiscal 2017, and on an ongoing basis, actual annual settlement payments will be deferred to this account each year, and forecast annual settlement payments will be amortized from this account each year.	fiscal 2017. In the Regulatory Accounts Report filed as Appendix H to the Fiscal 2015 - Fiscal 2016 Revenue Requirements Rate Application, BC Hydro proposed that a 10-year amortization period for the account would be appropriate, and by Order No. G-48-14 amounts were amortized from the account for fiscal 2015 and fiscal 2016, leaving eight years remaining of the proposed 10-year amortization period. A 10-year amortization period is consistent with the amortization period for actual negotiations costs and approved settlement costs directed by British Columbia Utilities Commission Order No. G-53-02; • The actual fiscal 2016 closing balance in the First Nations Costs Regulatory Account that is related to the lump sum settlement payment made in fiscal 2016 is to be amortized over nine years, beginning in fiscal 2017. BC Hydro has recorded one-year of amortization from the account for fiscal 2016, leaving nine years remaining of the proposed 10-year amortization period described above; • Effective starting in fiscal 2017, and on an ongoing basis, the forecast interest charged to the First Nations Costs Regulatory Account be amortized from this account in each year; • On an ongoing basis, the forecast	

	Account	Requested Changes to Account Scope	Requested Changes to Recovery Mechanism	Requested Changes to Interest
			account balance in the First Nations Costs Regulatory Account at the end of a test period related to the difference between amortization of forecast annual and lump sum settlement payments and the calculation of amortization based on actual annual and lump sum settlement payments during that test period is to be recovered over the following test period; and • On an ongoing basis, the forecast account balance in the First Nations Costs Regulatory Account at the end of a test period related to the difference between forecast interest recovered and actual interest charged to the First Nations Cost Regulatory Account during that test period is to be recovered over the following test period.	
18	Site C Regulatory Account	• With this application, BC Hydro requests the ability to defer to the account any costs related to the Site C Clean Energy Project that are not able to be capitalized under the Prescribed Standards.	• No Change	• No Change
19	Future Removal and Site Restoration Regulatory Account	• The Future Removal and Site Restoration Regulatory Account be renamed the Dismantling Cost Regulatory Account. • The terms of the account be changed so that the account defers, on an annual basis, any variances between planned and actual dismantling costs, to be effective starting in fiscal 2017.	• On an ongoing basis, the forecast account balance at the end of a test period is to be recovered over the next test period.	• Interest will be applied to balances in the account, consistent with the application of interest to other variance accounts, based on BC Hydro's current weighted average cost of debt.

	Account	Requested Changes to Account Scope	Requested Changes to Recovery Mechanism	Requested Changes to Interest
20	Pre-1996 Contributions in Aid of Construction Regulatory Account	• No Change	• No Change	• No Change
21	SMI Regulatory Account	• No Change	• The actual fiscal 2016 closing account balance is to be recovered over a period of 13 years, starting in fiscal 2017, which is the remaining period of the original 15-year amortization period proposed in the Regulatory Accounts Report filed in the Fiscal 2015 - Fiscal 2016 Revenue Requirements Rate Application. The 15-year amortization period is based on the average life of Smart Metering and Infrastructure assets.	• No change
22	Capital Project Investigation Costs Regulatory Account	• No Change	• No Change	• No Change
Non Cash Provisions				
23	First Nations Provisions Regulatory Account	• No Change	• No Change	• No Change
24	Arrow Water Systems Provisions Regulatory Account	• No Change	• No Change	• No Change

	Account	Requested Changes to Account Scope	Requested Changes to Recovery Mechanism	Requested Changes to Interest
25	Environmental Provisions Regulatory Account	• Starting in fiscal 2017 and on an ongoing basis, that as the actual costs associated with compliance with polychlorinated biphenyl regulations are deferred to the Asbestos Remediation Regulatory Account (BC Hydro is requesting that this account be renamed the Remediation Regulatory Account), and the Environmental Provisions Regulatory Account be reduced by an equal amount, similar to the treatment of the other environmental remediation regulatory accounts.		
Rate Smoothing Accounts				
26	Rate Smoothing Regulatory Account	• With this application BC Hydro is requesting approval of the additions to the account for fiscal 2017 to fiscal 2019 as indicated in Table 7-6.	• No Change	• No Change
IFRS Transition Accounts				
27	IFRS Property, Plant and Equipment Regulatory Account	• No Change	• No Change	• No Change
28	IFRS Pension Regulatory Account	• No Change	• No Change	• No Change

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Fiscal 2017 to Fiscal 2019
Revenue Requirement Application

Chapter 8

Other Revenue Requirements Items

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8.1 Other Revenue Requirements Items

This chapter addresses the other revenue requirement items, including amortization expense, capital structure, return on equity, finance charges, taxes, non-tariff and inter-segment revenue, subsidiary net income, the allocation of BC Hydro's business support costs, and provisions and other. This chapter also discusses accounting changes required due to the Prescribed Standards followed by BC Hydro (these are defined in section 8.12 and include the International Financial Reporting Standards (**IFRS**)). Please note, in the tables in this Chapter, references to F2015 RRA or F2016 RRA signifies the Plan amount from the Fiscal 2015 – Fiscal 2016 Revenue Requirements Rate Application.

Amortization Expense

Depreciation and amortization (collectively referred to as amortization) is the allocation of the original cost of assets over their estimated service lives. BC Hydro's forecast amortization expense is shown in Appendix A, Schedule 7.0, and includes:

- the amortization of property, plant and equipment in service;
- amortization related to Electricity Purchase Agreements that are classified as capital leases;
- dismantling costs related to assets which do not have an associated provision required under the Prescribed Standards as defined in section 8.12 (before regulatory transfers and recoveries); and
- amortization of the following regulatory accounts: Demand-Side Management, Future Removal and Site Restoration, Pre-1996 Contributions, and the Capital Additions Regulatory Account.

Property, plant and equipment in service are amortized on an individual component-by-component basis over the expected useful lives of the assets using the straight-line method. The depreciation rates used in this Application are the same as those previously approved by the British Columbia Utilities Commission, with the exception of certain property, plant and equipment at the Burrard synchronous condense facility. In this Application, BC Hydro is seeking approval for the depreciation rates of certain property, plant and equipment at this facility, as the rates prescribed by Direction No. 7 only included depreciation rates for fiscal 2015 and fiscal 2016. Table 8-1 provides the detailed depreciation rates for each year of the test period for which BC Hydro is seeking British Columbia Utilities Commission approval. The depreciation rates shown in Table 8-1 for a given fiscal year would be applied against the net book value of the asset at the beginning of that fiscal year.

Table 8-1 Burrard Synchronous Condense Facility Depreciation Rates

Class of Property, Plant and Equipment		F2017 Depreciation Rate (%/year)	F2018 Depreciation Rate (%/year)	F2019 Depreciation Rate (%/year)
C12002	Road, Paved/Gravel	25.0	33.3	50.0
C12203	Bridge, Concrete	25.0	33.3	50.0
C12401	Drainage System Yard	11.1	12.5	14.3
C21901	Roofs	11.1	12.5	14.3
C22001	Plant Concrete Steel	11.1	12.5	14.3
C22002	Comm Concrete Steel	11.1	12.5	14.3
C22005	Building, Comp Pool	11.1	12.5	14.3
C22006	Equipment Shelter	30.8	44.4	80.0
C22009	Building-HVAC Sys&Cp	11.9	12.6	14.3
C22101	Off Trailer/Mob Home	11.1	12.5	14.3
C23801	Cranes	11.1	12.5	14.3
C25101	Structure Supp Steel	11.1	12.5	14.3
C25301	Foundations	11.1	12.5	14.3
C25401	Ducts & Trenches	11.1	12.5	14.3
C25601	Barriers & Enclos	33.3	50.0	100.0
C30102	Insulation, Boiler	11.1	12.5	14.3
C30501	Piping, High Press	15.6	18.5	22.6
C30606	Instrument, Boiler	33.3	50.0	100.0
C30607	DNU - Asbe Abatement	11.1	12.5	14.3
C30802	Water Sys Ammonia	11.1	12.5	14.3
C31001	Water Intk/DisStruct	11.1	12.5	14.3

Class of Property, Plant and Equipment		F2017 Depreciation Rate (%/year)	F2018 Depreciation Rate (%/year)	F2019 Depreciation Rate (%/year)
C31002	Protection, Cathodic	11.1	12.5	14.3
C31003	Gates, Inlet/Outlet	11.1	12.5	14.3
C34004	Turbine, Comp Pool	11.1	12.5	14.3
C34005	Coils, Stator	11.4	12.9	14.8
C34006	Rotor, Generator	11.1	12.5	14.3
C34007	Generator, Comp Pool	17.4	18.5	21.9
C34008	Supervisory Sys Turb	40.4	67.8	100.0
C34009	Cooling Sys Hydrogen	16.5	19.	24.4
C42004	Major Maint.-Rewedge	11.2	12.6	14.4
C42102	Exciter, Static	11.1	12.5	14.3
C48003	Generator, Composite	11.1	12.5	14.3
C48004	Generator, Diesel	35.0	53.9	61.8
C49001	Pump	19.2	23.7	31.1
C49002	Motor	11.1	12.5	14.3
C51001	Condensor,SyncRotary	11.1	12.5	14.3
C52105	Transformer, Stn Ser	11.1	12.5	14.3
C52504	Trans,Volt,Encaps.	11.1	12.5	14.3
C54101	Breaker,Air/Magnetic	11.1	12.5	14.3
C54201	Use Ind Disconnect	33.3	50.0	100.0
C55401	Buswork & StnConduct	11.1	12.5	14.3
C55501	Grounding Systems	11.1	12.5	14.3
C56001	Insulators	11.1	12.5	14.3
C59001	Power Supp Uninterr	34.3	52.2	74.3
C59101	Regulator FeederCirc	11.1	12.5	14.3
C59201	Charger System, Batt	18.1	13.0	14.3
C61001	Fencing	11.1	12.5	14.3
C62001	Fire Protection Sys	25.1	33.5	50.4
C62501	Firefighting Equip	100.0	-	-
C65001	Panels/Cubicles, P&C	11.2	12.6	14.4
C67003	Contain Fac, Concret	11.1	12.5	14.3
C67005	Oil Spill Containmen	11.1	12.5	14.3
C68202	Term Unit,Rem(Slave)	33.4	50.0	100.0
C68204	Distributed Ctrl Sys	12.0	13.6	14.6
C68301	Radio,MW,Analog	11.1	12.5	14.3
C68904	Telephone Sys Cell	20.7	26.1	35.3
C70104	Instrumentation-Digi	11.1	12.5	14.3

Class of Property, Plant and Equipment		F2017 Depreciation Rate (%/year)	F2018 Depreciation Rate (%/year)	F2019 Depreciation Rate (%/year)
C75104	Compressor, Air	11.1	12.5	14.3
C75201	Tanks,Steel,Air/Fuel	11.1	12.5	14.3
C75301	Water Supply System	16.7	20.1	25.1
C80101	Computer,HW,Micro	46.2	85.7	100.0
C82504	Loader/Backhoe	11.1	12.5	14.3
C82550	Tools/Work EquipMisc	13.9	16.2	18.1
C82551	DNU - Tools/Work Equ	37.1	59.0	26.0
C82601	Test/Calibration	94.2	100.0	-
C82603	Manufacturing/Test	11.1	12.5	14.3
C85001	Office Furniture	62.8	63.2	100.0
C85002	DNU - Office Equipme	33.3	50.0	100.0
C88002	Lab Equipment, Misc	37.5	60.0	100.0

Amortization expense also includes amortization related to Electricity Purchase Agreements that are classified as capital leases. This is discussed in section 8.11 below.

Dismantling costs related to assets which do not have an associated provision required under the Prescribed Standards (which are defined in section 8.12) are included within amortization expense (before regulatory transfers and recoveries). They are then transferred to the Future Removal and Site Restoration Regulatory Account, thereby reducing the balance in this account, as shown on Appendix A, Schedules 2.2 and 7.0. As this account is forecast to be reduced to a zero balance in fiscal 2017, subsequent dismantling costs for the test period will be included in operating expenditures (specifically, within Provisions and Other). Please refer to section 7.5.6 for more information about the Future Removal and Site Restoration Regulatory Account.

Amortization expense is summarized in the table below. Increases in amortization expense over the test period are primarily due to forecast capital additions, as described in Chapter 6.

Table 8-2 Amortization Expense

	($ million)	F2015 RRA	F2016 RRA	F2017 Plan	F2018 Plan	F2019 Plan
		1	2	3	4	5
1	Amortization of Capital Assets	651.3	701.0	759.8	796.3	832.8
2	Dismantling Costs	24.6	31.2	8.6	0.0	0.0
3	IPP Capital Leases	22.8	25.8	17.0	29.4	22.8
4	Total Gross Amortization	698.7	758.0	785.4	825.7	855.6
5	DSM Amortization	73.3	83.3	89.1	96.7	105.5
6	FRSR Amortization	(24.6)	(31.2)	(8.6)	0.0	0.0
7	Pre-1996 CIAC Amortization	(6.3)	(4.7)	0.7	3.2	4.9
8	Capital Additions Regulatory Account	(9.8)	(9.4)	(3.6)	(3.4)	(3.3)
9	Regulatory Account Recoveries	32.5	38.0	77.6	96.5	107.2
10	Total Current Amortization (Schedule 7.0, line 59)	731.2	796.0	863.0	922.2	962.8

8.2 Capital Structure

BC Hydro’s capital structure is prescribed by Direction No. 7.

Pursuant to the definition of “deemed equity” in section 1 of Direction No. 7, BC Hydro’s equity for ratemaking purposes is deemed to be 30 per cent of “rate base”, which is also defined in section 1 of Direction No. 7.

The components of the “rate base” for any fiscal year, as defined in section 1 of Direction No. 7, can be summarized as follows:

1. $250 million working capital allowance;
2. Plus the sum of the average balances of:
    (a) property, plant and equipment in service net of accumulated amortization;
    (b) intangible assets net of accumulated amortization; and
    (c) the Demand-Side Management Regulatory Account.
3. Minus: the average balances of contributions in aid of construction; Columbia River Treaty contributions; and leased assets.

“Rate base”, as defined in section 1 of Direction No. 7, excludes expenditures incurred by BC Hydro on or after April 1, 2011 that the British Columbia Utilities

Commission determines should not be recovered in rates. There are no such exclusions as at March 31, 2016.

Forecast rate base over the test period is shown in the table below.

Table 8-3 Rate Base

	($ million)	F2015 RRA	F2016 RRA	F2017 Plan	F2018 Plan	F2019 Plan
		1	2	3	4	5
1	Net Assets in Service	17,455.9	19,581.6	20,221.6	20,875.1	22,390.5
2	Net Contributions	(1,237.7)	(1,311.3)	(1,613.2)	(1,661.9)	(1,716.1)
3	Net Demand-Side Management	897.8	945.6	931.8	995.7	990.9
4	Pre-1996 Contributions	(87.4)	(92.1)	(91.4)	(88.2)	(83.3)
5	Powerex and Powertech Assets	24.4	26.6	42.4	43.2	43.6
6	Columbia River Treaty Contributions	0.0	0.0	0.0	0.0	0.0
7	Allowance for Working Capital	250.0	250.0	250.0	250.0	250.0
8	Total Rate Base (Schedule 9, line 41)	17,303.0	19,400.4	19,741.2	20,413.9	21,875.6

8.3 Return on Equity

BC Hydro’s return on equity is prescribed by section 4 of Direction No. 7. For fiscal 2017, BC Hydro’s annual rate of return on deemed equity is 11.84 per cent. BC Hydro's net income for fiscal 2017 is equal to the product of deemed equity and 11.84 per cent. For fiscal years after fiscal 2017, also pursuant to Direction No. 7, the prescribed annual rate of return on deemed equity is that which would be necessary to yield a distributable surplus in the applicable fiscal year equal to the product of (i) the distributable surplus in the immediately preceding fiscal year, and (ii) 100 per cent plus the percentage change in the British Columbia consumer price index in the applicable fiscal year.

Distributable surplus, as defined in section 1 of Direction No. 7, has the same meaning as in Heritage Special Directive No. HC1 to the British Columbia Hydro and Power Authority, which is equal to “for a fiscal year, the consolidated net income earned by the authority and its subsidiaries from all sources, as included in the authority’s audited consolidated financial statements for that year”.

The change with respect to distributable surplus for fiscal years after 2017 will have the effect of reducing BC Hydro’s net income relative to what it would have been before this change. This is due to the fact that BC Hydro's net income would have been higher under the previous formula as its rate base is increasing significantly as a result of BC Hydro's capital program, as described in Chapter 6.

Table 8-4 shows the forecast British Columbia consumer price index (as a per cent change, by year) for fiscal 2018 and fiscal 2019, as provided by the Government.[53]

Table 8-4 B.C. Consumer Price Index

	F2018	F2019
Forecast B.C. Consumer Price Index (%)	2.0	2.0

The calculation of the BC Hydro's return on equity for the test period is set out in Appendix A, Schedule 9 and is summarized in the table below. The effective return on equity percentage in F2018 is reduced to 11.59 per cent ($698.4 million/$6,023.3 million) and in F2019 is further reduced to 11.23 per cent ($712.4 million/$6,343.4 million).

Table 8-5 Return on Equity

	($ million)	F2015 RRA	F2016 RRA	F2017 Plan	F2018 Plan	F2019 Plan
1	Rate Base	17,303.0	19,400.4	19,741.2	20,413.9	21,875.6
2	Deemed Equity Percentage	30%	30%	30%	30%	30%
3	Year-End Deemed Equity	5,190.9	5,820.1	5,922.4	6,124.2	6,562.7
4	Mid-Year Deemed Equity	4,911.7	5,505.5	5,783.0	6,023.3	6,343.4
5	Return on Equity Percentage	11.84%	11.84%	11.84%		
6	BC Consumer Price Index				2.0%	2.0%
7	Gross Return on Equity (Schedule 9.0, line 54)	581.5	651.9	684.7	698.4	712.4
8	Regulatory Account Transfers	(11.3)	0.0	0.0	0.0	0.0
9	Current Return on Equity (Schedule 9.0, line 58)	592.8	651.9	684.7	698.4	712.4

8.4 Finance Charges

Finance charges represent the cost of the debt portfolio, and are largely comprised of interest charges on BC Hydro's debt. Total finance charges are calculated net of sinking fund income, finance charges capitalized to unfinished construction (interest

[53] The forecast can be found on page 84, Table 3.6.2 at the link below. Please note that the data is presented in calendar years so '2017' in the table is used for BC Hydro's fiscal 2018, and so on. http://bcbudget.gov.bc.ca/2016/bfp/2016_Budget_and_Fiscal_Plan.pdf.

during construction) and interest allocated to regulatory accounts. Commencing in fiscal 2012, the forecast interest during construction and the interest allocated to regulatory accounts in a given year have both been based on BC Hydro's forecast weighted average cost of debt in that year.[54]

BC Hydro's long-term debt comprises bonds and revolving borrowings obtained under agreement with the Province. BC Hydro's debt is either held or guaranteed by the Province.

BC Hydro uses derivative financial instruments, principally interest rate and foreign currency swaps, to manage interest rate and foreign exchange risks related to existing debt.

On March 30, 2016, British Columbia Utilities Commission Order No. G-42-16 approved the Debt Management Regulatory Account to capture mark-to-market gains and losses related to the hedging of future debt. Hedging future debt will enable BC Hydro to effectively lock in long-term interest rates at historically low levels. BC Hydro has begun implementing its new debt management hedging strategy and anticipates its completion in fiscal 2017. Further information regarding the Debt Management Regulatory Account can be found in Chapter 7.

To forecast finance charges, BC Hydro employs a number of market variables and economic forecasts of short and long-term interest rates and Canada/U.S. exchange rates. For debt that has been hedged, or is intended to be hedged in the near future, BC Hydro uses actual or forecast contract rates. For unhedged future debt over the test period, BC Hydro uses economic forecasts that are developed and provided by the Treasury Board of the Province of British Columbia.

The following table identifies the interest rate for unhedged debt and foreign exchange rate forecasts used for fiscal 2017 to fiscal 2019.

[54] As required under IFRS International Accounting Standard 23 Borrowing Costs.

Table 8-6 Interest Rate and Exchange Rate Forecasts

	F2017 Plan	F2018 Plan	F2019 Plan
Canadian Short-term Interest Rate (%)	0.72	1.40	2.03
U.S. Short-term Interest Rate (%)	1.27	2.29	3.05
Canadian Long-term Interest Rate (%)	2.96	3.67	4.60
U.S. Long-term Interest Rate (%)	3.21	3.77	4.65
USD$/CAD$ Exchange Rate	0.738	0.778	0.802

Source: Treasury Board Forecast, January 2016.

Foreign currency-denominated revenues and expenses are translated into Canadian dollars at the rate of exchange in effect at the transaction date. Foreign currency denominated monetary assets and liabilities are translated into Canadian dollars at the rate of exchange prevailing at the balance sheet date.

As shown on Appendix A, Schedule 2.2, gains and losses arising from the translation of unhedged foreign denominated long-term monetary items are included in the Foreign Exchange Losses/(Gains) Regulatory Account and are amortized on a straight-line basis in accordance with British Columbia Utilities Commission Order No. G-47-02. Deferred foreign currency translation adjustments related to long-term debt are amortized over the weighted average remaining term to maturity of the foreign currency denominated debt portfolio. Deferred foreign currency translation adjustments related to sinking funds are amortized over the weighted average remaining term to maturity of the sinking fund portfolio.

Forecast finance charges are shown on Appendix A, Schedule 8.0 and are summarized in the table below. Over the test period, finance charges before regulatory accounts are expected to increase primarily as a result of forecast increases in debt levels, due to capital expenditures.

Table 8-7 Finance Charges

	($ million)	F2015 RRA	F2016 RRA	F2017 Plan	F2018 Plan	F2019 Plan
		1	2	3	4	5
1	Total Current Finance Charges (Schedule 8.0, line 47)	606.8	726.6	506.9	523.2	566.6

8.5 Taxes

Taxes include school taxes and grants-in-lieu of general taxes, and taxes related to Electricity Purchase Agreements that are classified as capital leases.

The *Hydro and Power Authority Act* exempts BC Hydro from all property taxes other than those levied in respect of schools. School taxes are based on the assessed value of taxable assets prepared by B.C. Assessment and school tax rates are established by the Province. School taxes are paid on all assessable property with the exception of certain facilities related to the generation of power on the Peace, Pend d'Oreille, and Columbia rivers.

The *Hydro and Power Authority Act* authorizes BC Hydro to pay grants-in-lieu of general municipal, regional district and local improvement taxes. Order in Council No. 1218/65 and Order in Council No. 510/07 set out the formula used to calculate the grant payments. Annual grants paid include the following items:

- General grants equivalent to general, regional district and local improvement taxes on the assessed value of all land of BC Hydro and on the assessed value of improvements such as office buildings, garages, warehouses, line stores and substation buildings. Assessed values of generating plants, substation equipment, transmission lines and distribution lines are excluded from this calculation;
- Revenue grants equal to 1 per cent of gross revenue from sales of electricity within the province, excluding revenue from power sold to other distribution systems for resale; and
- Special grants-in-lieu of general taxes on dams, reservoirs and powerhouses. These grants are based on installed capacity, or imputed nameplate generating capacity in the case of storage dams.

Forecast school taxes and grants-in-lieu are shown on Appendix A, Schedule 6.0 and are summarized in the table below. Over the test period, taxes are forecast to increase primarily as a result of increased property values (for land, buildings and electric system assets) and increased forecast revenue from electricity sales (which leads to higher grants-in-lieu).

Table 8-8 Taxes

	($ million)	F2015 RRA	F2016 RRA	F2017 Plan	F2018 Plan	F2019 Plan
		1	2	3	4	5
1	Grants in Lieu	84.4	88.5	93.6	97.5	102.6
2	School Taxes	124.7	129.9	127.1	130.2	133.6
3	IPP Capital Leases	4.8	5.8	2.6	4.2	2.5
4	Total Current Taxes (Schedule 6.0, line 31)	213.8	224.1	223.3	231.8	238.7

8.6 Non-Tariff Revenues

Non-Tariff revenues include revenues from amortization of contributions in aid of construction, meter and transformer rentals, building rentals, interconnections, external transmission revenues under the Open Access Transmission Tariff, and other revenues. Appendix A, Schedule 15.0 presents the components of Non-Tariff revenues. Forecast Non-Tariff revenues over the test period are summarized in the table below.

Table 8-9 Non-Tariff Revenues

	($ million)	F2015 RRA	F2016 RRA	F2017 Plan	F2018 Plan	F2019 Plan
		1	2	3	4	5
1	Total Current Non-Tariff Revenues (Schedule 15.0, line 36)	116.5	123.3	134.5	136.7	139.0

8.7 Inter-Segment Revenues

Inter-Segment revenues include:

- The allocation of business support costs to Powerex;
- Point-to-point transmission costs allocated to Powerex; and
- An allocation of BC Hydro’s cost of point-to-point transmission, largely related to BC Hydro’s Skagit Valley Treaty obligations.

Forecast Inter-Segment revenues are summarized on Appendix A, Schedule 3.0, line 51 and are shown in the table below.

Table 8-10 Inter-Segment Revenues

	($ million)	F2015 RRA	F2016 RRA	F2017 Plan	F2018 Plan	F2019 Plan
		1	2	3	4	5
1	Powerex - Corporate Allocation	(3.0)	(3.0)	(2.8)	(2.8)	(2.9)
2	Powerex PTP Charges	(23.4)	(29.2)	(11.8)	(10.1)	(16.6)
3	BC Hydro PTP Charges	(26.2)	(21.3)	(47.8)	(51.4)	(45.9)
4	Total Current Inter-Segment Revenues (Schedule 3.0, line 51)	(52.6)	(53.5)	(62.5)	(64.3)	(65.3)

8.8 Subsidiary Net Income

The net income of BC Hydro's subsidiaries is included for the purposes of setting BC Hydro's rates pursuant to section 6 of Direction No. 7. BC Hydro has two subsidiaries in this regard: Powerex and Powertech.

For rate setting purposes the net income of Powerex is deemed to be Trade Income as defined in section 1 of Direction No. 7. In the test period, Trade Income is forecast at $115 million per year (net of BC Hydro's allocation of business support costs as described in section 8.9), and is reflective of Powerex's average net income over the last five years (i.e., fiscal years 2012 through 2016). Using a five-year average as the basis of forecasting Powerex net income is consistent with prior revenue requirement applications and is reasonable given the year-to-year volatility in market conditions.

Forecast subsidiary net income for the test period is provided on Appendix A, Schedule 1.0, line 19 and is shown in the table below.

Table 8-11 Subsidiary Net Income

	($ million)	F2015 RRA	F2016 RRA	F2017 Plan	F2018 Plan	F2019 Plan
		1	2	3	4	5
1	Powerex Net Income	(110.0)	(110.0)	(115.2)	(115.2)	(115.1)
2	Powertech Net Income	(4.2)	(5.1)	(4.5)	(4.8)	(5.1)
3	Total Current Subsidiary Net Income (Schedule 1.0, line 19)	(114.2)	(115.1)	(119.7)	(119.9)	(120.2)

8.9 Allocation of Business Support Costs

For the purpose of determining the Transmission Revenue Requirement (as described in Chapter 9), BC Hydro's business support costs are allocated to transmission, distribution, generation and customer care functions as shown on Appendix A, Schedule 3.1.

Business support costs are expenditures that are required to support BC Hydro's core operational functions of transmission, distribution, generation and customer care. These costs reside in several business groups across the company and include the following:

- Operations Support Business Group current operating costs (excluding capital lease operating costs and Energy Planning and Economic Development key business unit costs) as well as amortization, taxes, and non-tariff revenue related to this business group; and
- The operating costs of the following key business units: Properties, Technology, and Training and Development.

As shown on that schedule, the following business support costs are first assigned to the function:

- Insurance costs are allocated based on the assets covered by the policies and the risks associated with the operations of the respective functions;
- Non-current pension costs are allocated based on labour costs before benefits; and
- Fleet vehicle costs are allocated based on usage.

The remaining business support costs are then allocated to the functions based on the average of their proportionate shares of expenditures (operating costs and capital) and headcount. As shown on Appendix A, Schedule 3.1, BC Hydro has allocated $2.8 million, $2.8 million and $2.9 million of business support costs to

Powerex for fiscal 2017, fiscal 2018 and fiscal 2019, respectively, in accordance with Directive 9 of the Fiscal 2009 – Fiscal 2010 Revenue Requirements Application. This allocation represents the share of non-current pension costs and insurance costs attributable to Powerex.

The forecast allocation of business support costs for the test period is summarized in the table below.

Table 8-12 Allocation of Business Support Costs

	($ million)	F2015 RRA	F2016 RRA	F2017 Plan	F2018 Plan	F2019 Plan
		1	2	3	4	5
1	Business Support Costs	(310.7)	(372.9)	(377.0)	(313.6)	(331.5)
2	Allocation to functional groups:					
3	Generation	85.4	101.9	92.1	74.0	79.3
4	Transmission	96.1	115.0	119.0	97.2	103.0
5	Distribution	108.2	128.5	139.9	120.7	126.4
6	Customer Care	18.0	24.6	23.1	18.9	20.0
7	Total (Schedule 3.1, line 75)	307.7	369.9	374.1	310.7	328.7
8	Powerex	3.0	3.0	2.8	2.8	2.9
9	Allocation of Business Support Costs	310.7	372.9	377.0	313.6	331.5
10	Total	0.0	0.0	0.0	0.0	0.0

8.10 Provisions and Other

"Provisions and Other" refers to gains and losses on tangible and intangible assets, non-cash provision expenses and other costs that are not within the scope of other Nature View[55] expense items on BC Hydro's financial statements. Provisions and Other also include dismantling costs, as well as gains and losses on mass asset retirements. In addition, for revenue requirement modelling purposes, transfers to the Rate Smoothing Regulatory Account are included in Provisions and Other (as shown in Appendix A, Schedule 5, line 114). For external reporting purposes, transfers to the Rate Smoothing Account are included in Domestic Revenues.

[55] Under the Nature View presentation, costs are classified by their nature (i.e., labour, materials, services, energy purchases, water rentals, amortization, etc), rather than by their function.

8.11 Accounting Policy Issues

8.11.1 Accounting Treatment of Certain Electricity Purchase Agreements

BC Hydro is required by accounting standards to review all Electricity Purchase Agreements to determine whether the Electricity Purchase Agreement arrangements have an embedded lease. Electricity Purchase Agreements that are determined to contain a lease must then be assessed to determine whether the lease is an operating or a capital lease.[56]

One of BC Hydro's Electricity Purchase Agreements was forecast as a capital lease in the Fiscal 2015 – Fiscal 2016 Revenue Requirements Rates Application. However, the accounting treatment for the Electricity Purchase Agreement was reassessed when the facility reached commercial operation in fiscal 2015 and it was determined that the Electricity Purchase Agreement should be treated as an operating lease. The fiscal 2015 and fiscal 2016 variances in costs due to the change in the accounting for the Electricity Purchase Agreement were deferred to the Non-Heritage Deferral Account.

The table below shows the impact of this change in fiscal 2015 and fiscal 2016, including the deferral of $22.8 million and $31.0 million respectively into the Non-Heritage Deferral Account that was not required under existing regulatory orders, but was done to provide the benefit of the change to ratepayers.

[56] In January 2016, the International Accounting Standards Board issued a new Leases standard (IFRS 16) effective for BC Hydro's fiscal 2020. The new standard will impact the accounting for Electricity Purchase Agreements.

Table 8-13 Income Statement Impact from Change in Accounting Treatment

	F2015 Actual ($ million)	F2015 RRA ($ million)	Difference ($ million)	F2016 Actual ($ million)	F2016 RRA ($ million)	Difference ($ million)
Income Statement						
Domestic Energy Costs	27.4	(1.0)	(28.4)	87.2	(8.0)	(95.2)
Operating Costs	0.0	11.1	11.1	0.0	15.1	15.1
Taxes	0.0	2.6	2.6	0.0	3.6	3.6
Depreciation and Amortization	0.0	9.1	9.1	0.0	12.1	12.1
Finance Charges	0.0	54.6	54.6	0.0	72.8	72.8
Subtotal	27.4	76.4	49.0	87.2	95.5	8.3
Items within the Scope of Existing Regulatory Orders						
Finance Charges (Total Finance Charges Regulatory Account)	54.6	0.0	(54.6)	72.8	0.0	(72.8)
Cost of Energy (NHDA)	(28.4)	0.0	28.4	(95.2)	0.0	95.2
Subtotal	26.2	0.0	(26.2)	(22.4)	0.0	22.4
Items Outside the Scope of Existing Regulatory Orders						
Depreciation and Amortization (applied to NHDA)	9.1	0.0	(9.1)	12.1	0.0	(12.1)
Operating Costs (applied to NHDA)	11.1	0.0	(11.1)	15.5	0.0	(15.5)
Taxes (applied to NHDA)	2.6	0.0	(2.6)	3.4	0.0	(3.4)
Total Deferred to NHDA	**22.8**	**0.0**	**(22.8)**	**31.0**	**0.0**	**(31.0)**
Income Statement Impact	76.4	76.4	0.0	95.7	95.5	(0.2)

The fiscal 2017 to fiscal 2019 forecast includes four Electricity Purchase Agreements accounted for as capital leases. Two of the Electricity Purchase Agreements were in operation prior to fiscal 2017 and two of the Electricity Purchase Agreements are expected to achieve commercial operation during fiscal 2017. The capital lease treatment of these Electricity Purchase Agreements results in the Cost of Energy supplied by the Electricity Purchase Agreements being recognized as operating costs, taxes, amortization, finance charges and Cost of Energy.

As indicated in section 4.4.2.3 of the Application, the IPP Cost of Energy in Appendix A, Schedule 4.0, line 37 does not include all of the costs for the four Electricity Purchase Agreements that qualify as capital leases for the period fiscal 2017 to fiscal 2019. Table 8-14 below indicates the classification of costs associated with these four Electricity Purchase Agreements and also has references to the financial schedules in Appendix A where the costs of these capital lease Electricity Purchase Agreements are included.

Table 8-14 Treatment of Four Qualifying Electricity Purchase Agreements

	Reference	F2017 Plan	F2018 Plan	F2019 Plan
Cost of Energy		15.4	16.5	2.4
Operating Costs	5.1 L15	28.2	63.6	54.3
Taxes	6.0 L12	2.6	4.2	2.5
Amortization	7.0 L23	17.0	29.4	22.8
Finance Charges	8.0 L20	25.1	44.7	42.4
Total		**88.3**	**158.4**	**124.4**

8.12 Prescribed Standards

Pursuant to Government Organization Accounting Standards Regulation 257/2010, effective April 1, 2012, BC Hydro prepares its financial statements in accordance with the principles of IFRS, combined with regulatory accounting in accordance with Financial Accounting Standards Board Accounting Standards Codification 980 Regulated Operations (collectively, the “Prescribed Standards”).

BC Hydro has prepared the Application in accordance with Prescribed Standards in effect as at April 1, 2016. The International Accounting Standards Board has issued the following significant changes to standards relevant to the test period:

- International Financial Reporting Standards 9 Financial Instruments – effective in fiscal 2019 for BC Hydro; and
- International Financial Reporting Standards 15 Revenue from Contracts with Customers – effective in fiscal 2019 for BC Hydro.

In January 2016, the International Accounting Standards Board issued a new Leases standard (International Financial Reporting Standards 16 Leases) effective in fiscal 2020 for BC Hydro.

It remains appropriate to proceed at this time under the Prescribed Standards that BC Hydro has used. BC Hydro is unable to accurately assess the impacts of these new standards until closer to the respective implementation dates as clarifications and interpretive guidance may be developed by the International Accounting Standards Board, accounting firms and industry groups to assist in the implementation of the new standards. BC Hydro may, at a subsequent date, seek regulatory deferral treatment of the impacts associated with the implementation of these new standards.

8.13 Uniform System of Accounts

In the Fiscal 2009 – Fiscal 2010 Revenue Requirements Application Decision, the British Columbia Utilities Commission directed BC Hydro to prepare revenue requirement applications filed after January 1, 2011 in accordance with the Uniform System of Accounts. Consolidated schedules of operating costs and property, plant and equipment balances in a form that complies with the Uniform System of Accounts are included in Appendix M.

BC Hydro
Power smart

Fiscal 2017 to Fiscal 2019
Revenue Requirements Application

Chapter 9

Transmission Revenue Requirements

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9.1 Introduction

This chapter describes the determination of BC Hydro's proposed Open Access Transmission Tariff **(OATT)** rates as set out in Appendix T and summarized in ~~Table 9-3~~ Table 9-8 below. As the main users of the transmission system, BC Hydro and Powerex account for approximately 98.5 per cent of the revenue collected through the OATT. External transmission customers account for the remaining approximately 1.5 per cent of revenue.

The rates charged for Network Integration Transmission Service, Point-To-Point Transmission Service and Ancillary Services under the OATT are designed to collect BC Hydro's Transmission Revenue Requirement. The Transmission Revenue Requirement is the sum of BC Hydro's net transmission function costs as calculated using a cost of service methodology that is consistent with the method used in BC Hydro's previous revenue requirement applications as well as the method previously used by the British Columbia Transmission Corporation. The calculation of the Transmission Revenue Requirement remains consistent with the British Columbia Utilities Commission's 1998 Decision accompanying Order No. G-43-98 related to BC Hydro's Application for Approval of Wholesale Transmission Services. BC Hydro believes that the proposed OATT rates are just and reasonable and should be approved as sought.

The proposed fiscal 2017 OATT rates are higher than the interim fiscal 2017 OATT rates approved by the British Columbia Utilities Commission through Order No. G-40-16, as shown in Table 9-8 below. BC Hydro proposes to recover any difference between the final OATT rates approved by the British Columbia Utilities Commission and the interim rates through a one-time charge to Transmission Customers. This charge would be based on actual volumes of Transmission Services multiplied by the difference between the applicable final OATT rate and the applicable interim rate.

This chapter is organized as follows:

- Section 9.2 describes how the Transmission Revenue Requirement is determined through the direct assignment or allocation of transmission-related costs to the transmission function based on cost causation principles and consistent with past practice.
- Section 9.3 sets out the proposed OATT rates and describes how the rates were derived consistent with past practice.
- Section 9.4 explains the forecast of point-to-point revenue.
- Section 9.5 discusses the proposed OATT rates for the test period.

Please note, in the tables in this Chapter, references to F2015 RRA or F2016 RRA signifies the Plan amount from the Fiscal 2015 - Fiscal 2016 Revenue Requirements Rate Application.

9.2 Transmission Revenue Requirements

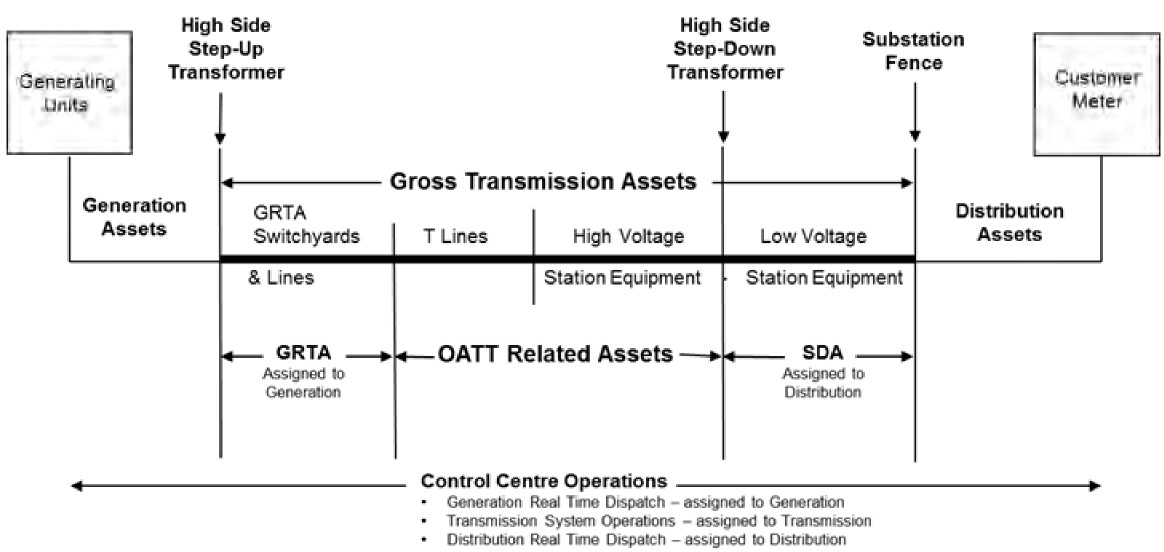
9.2.1 Transmission Revenue Requirement Overview

BC Hydro's Transmission Revenue Requirement is BC Hydro's net transmission-related costs as determined through an allocation or direct assignment of BC Hydro's costs as discussed below. The cost of service methodology used to derive the Transmission Revenue Requirement is based on cost causation and is consistent with past practice. The methodology remains consistent with that previously used by BC Hydro and the British Columbia Transmission Corporation and the British Columbia Utilities Commission's 1998 Decision accompanying Order No. G-43-98 related to BC Hydro's Application for Approval of Wholesale Transmission Services.

The Transmission Revenue Requirement includes the costs associated with BC Hydro's OATT Related Assets, i.e., the transmission lines and high-voltage station equipment that are used to provide transmission service pursuant to the

OATT. As shown by the asset boundaries in Figure 9-1, BC Hydro's Gross Transmission Assets include assets from the high voltage side of the step-up transformers located at the generation stations to the substation fence at distribution voltage. As also shown in Figure 9-1, both Generation Related Transmission Assets and Substation Distribution Assets must be excluded from the Gross Transmission Assets to arrive at the OATT Related Assets.

Figure 9-1 Asset Boundary for Transmission Revenue Requirement and OATT Rates



Using fiscal 2017 as an example, Figure 9-2 illustrates the allocation and direct assignment of costs, as shown in the financial schedules in Appendix A, to establish the gross transmission costs (related to the Gross Transmission Assets in Figure 9-1) and the Transmission Revenue Requirement (related to the OATT Related Assets in Figure 9-1), and the recovery of the Transmission Revenue Requirement through the proposed OATT rates.

Figure 9-2 Fiscal 2017 Transmission Revenue Requirement Components ($ million) with References to Appendix A Financial Schedules

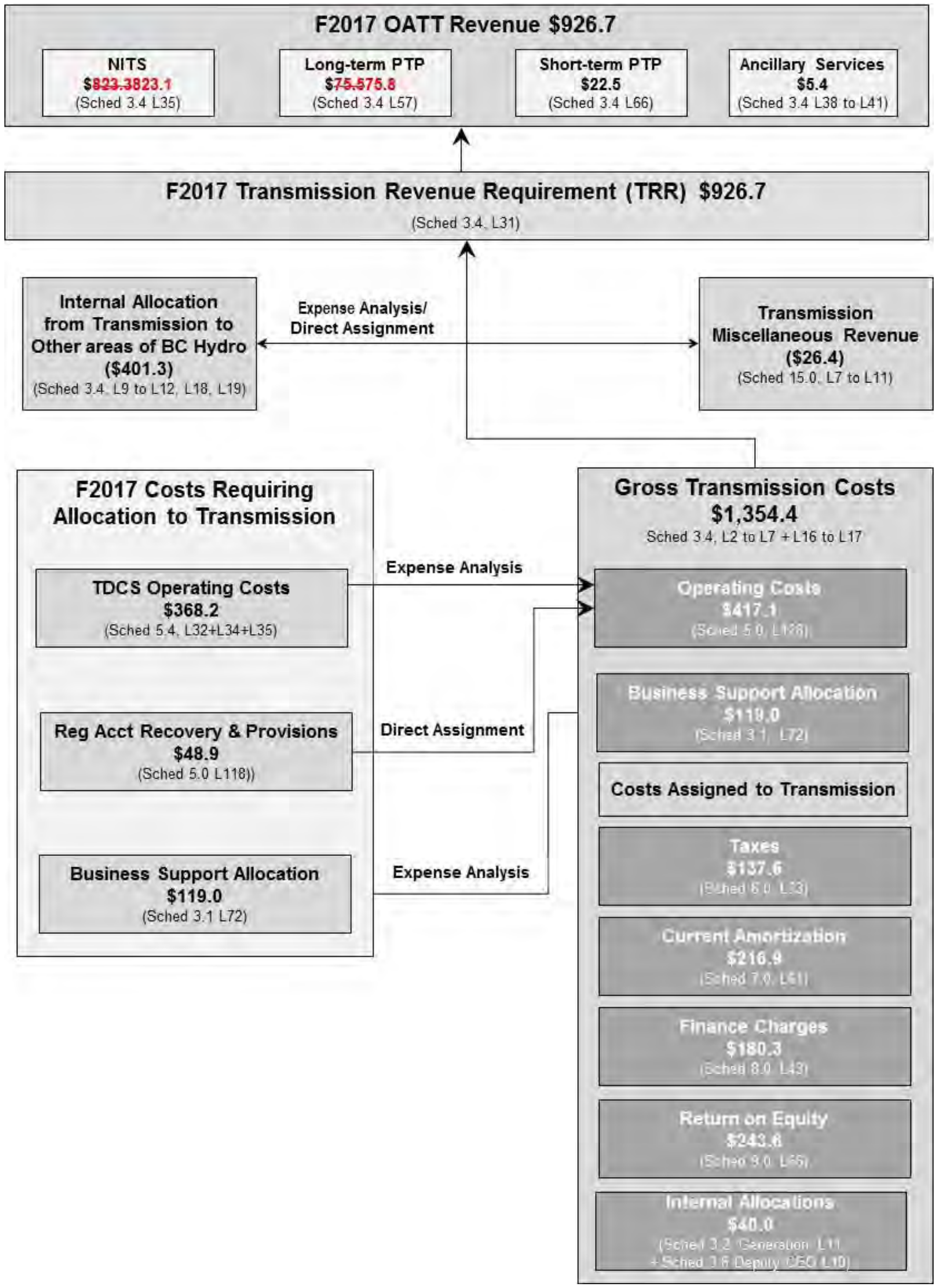


Table 9-1 sets out the cost components that make up the Transmission Revenue Requirement from fiscal 2015 through fiscal 2019. The allocation or direct assignment of the components of the Transmission Revenue Requirements is discussed in the subsections that follow.

Table 9-1 Transmission Revenue Requirement

		F2015 RRA ($ million)	F2015 Actual ($ million)	F2016 RRA ($ million)	F2016 Actual ($ million)	F2017 Plan ($ million)	F2018 Plan ($ million)	F2019 Plan ($ million)
		1	2	3	4	5	6	7
1	Operating Cost	367.4	383.3	366.8	371.1	417.1	407.8	396.3
2	Taxes	126.1	123.7	132.0	128.5	137.6	141.7	147.2
3	Amortization	158.9	184.6	187.1	184.9	216.9	230.3	240.9
4	Finance Charges	167.0	182.1	233.0	241.7	180.3	~~187.9~~ 187.8	~~199.0~~ 198.9
5	Return on Equity	163.1	177.7	209.0	218.0	243.6	250.8	250.1
6	Business Support Cost	96.1	95.2	115.0	126.4	119.0	97.2	103.0
7	**Internal Allocations to Transmission:**							
8	Generation Ancillary Services	1.8	1.3	1.8	1.9	2.5	2.5	2.5
9	Capital Infrastructure Project Delivery	61.6	58.2	61.7	46.4	37.5	36.5	36.5
10	Adjustment to offset re-org impact	(24.2)	-	(24.0)	-	-	-	-
11	**Gross Transmission Costs**	1,117.9	1,206.1	1,282.5	1,319.0	1,354.4	~~1,354.7~~ 1,354.6	~~1,375.5~~ 1,375.4
12	**Less Internal Allocations from Transmission**							
13	Generation Related Transmission Assets	(43.3)	(43.3)	(43.3)	(43.3)	(43.3)	(43.3)	(43.3)
14	Substation Distribution Assets	(123.2)	(115.3)	(148.3)	(121.2)	(125.0)	(128.5)	(126.1)
15	Generation Real Time Dispatch	(1.7)	(1.7)	(1.8)	(1.8)	(1.6)	(1.5)	(1.6)
16	Distribution Real Time Dispatch	(16.7)	(16.7)	(17.1)	(17.1)	(16.7)	(16.2)	(16.6)
17	Aboriginal Relations and Negotiations	(19.4)	(19.6)	(19.3)	-	-	-	-
18	Technology and Customer Service	(184.2)	(185.6)	(185.9)	(185.1)	(214.7)	(212.2)	(211.6)
19	**Less Miscellaneous Revenues**							
20	Secondary Revenues	(7.4)	(8.8)	(7.5)	(6.2)	(5.1)	(5.1)	(5.0)
21	Amortization of Contributions	(8.1)	(9.5)	(10.9)	(13.7)	(13.6)	(14.2)	(14.4)
22	Fortis General Wheeling Agreement	(5.0)	(5.0)	(4.8)	(4.8)	(4.7)	(4.9)	(5.0)
23	Interconnections	(4.0)	(10.6)	(4.2)	(4.3)	(3.0)	(1.9)	(1.9)
24	**Subtotal**	(413.2)	(416.2)	(443.1)	(397.5)	(427.7)	(427.9)	(425.4)
25	**Transmission Revenue Requirement**	704.7	789.9	839.4	921.5	926.7	~~926.8~~ 926.7	~~950.1~~ 950.0

9.2.2 Operating Costs and Internal Allocations to Transmission

Consistent with past practice, operating costs are directly assigned or allocated to the transmission function based on cost causation as discussed below.

The business groups carrying out transmission functions are the Transmission, Distribution and Customer Service Business Group and the Capital Infrastructure Project Delivery Business Group. The operating costs of each of these groups are discussed in Chapter 5.

The Transmission, Distribution and Customer Service Business Group includes operating costs for transmission and distribution functions, as well as customer service and technology. Technology operating costs are allocated as part of the business support allocation shown in Appendix A, Schedule 3.1 and customer service operating costs are included in the customer care allocations shown in Appendix A Schedule 3.3. Once technology and customer service costs are assigned as discussed in section 9.2.6.6 below, the remaining operating costs of the business group must be allocated between the transmission and distribution functions.

The Capital Infrastructure Project Delivery Business Group includes project delivery and engineering functions for transmission, distribution and generation as well as environmental risk management and Aboriginal Relations functions. As a result, it necessary to allocate an appropriate share of the operating costs of the Capital Infrastructure Project Delivery Business Group to the transmission function.

The portion of these operating costs and internal allocations relating to the transmission function was calculated by determining the relevant functional activity of each Key Business Unit within the business groups. The functional activities performed by the business groups being analysed are shown in Table 9-2.

Table 9-2 Key Business Unit Functional Activities

1.	**Distribution:**
	Substation Distribution Assets
	Distribution Real-time Dispatch
	Distribution Other
2.	**Generation:**
	(i) Generation Real-time Dispatch
	Generation Related Transmission Assets
	Generation Other
3.	**Transmission:**
	(i) Scheduling, System Control and Dispatch Service (OATT Rate Schedule 3)
	Transmission Other

Where possible, costs were directly assigned to one of the functional activities shown in Table 9-2. Where direct assignment was not possible, costs were allocated to the functional activities using one or more of the following parameters to develop allocation factors:

(i) Planned maintenance and/or capital expenditures:

Historical expenditures;

Headcount analysis based on Full-Time Equivalents (**FTEs**);

Manager interviews; and

Specific activity analysis.

Table 9-3 summarizes the basis of allocation used for each Key Business Unit in the Transmission, Distribution and Customer Service and Capital Infrastructure Project Delivery Business Groups.

Table 9-3 Allocation of Operating Costs

Key Business Unit	Basis of Allocation to Functional Activities
Transmission, Distribution and Customer Service Business Group	
Field and Grid Operations	Direct assignment; maintenance and capital programs; activity analysis; manager interviews
Asset Investment Management and Distribution Engineering	Direct assignment, maintenance and capital programs; manager interviews
Distribution Design	Direct assignment to distribution other
Program and Contract Management	Direct assignment, maintenance and capital programs; manager interviews
Capital Infrastructure Project Delivery Business Group	
Project Delivery	Direct assignment; capital programs managed by Project Delivery, manager interviews
Site C	Direct assignment to generation other
Generation and Transmission Engineering	Direct assignment; capital programs and manager interviews
Dam Safety	Direct assignment to generation other
Environmental Risk Management	Direct assignment and manager interviews
Aboriginal Relations	Direct Assignment to transmission other and generation other

As a result of the above analysis, gross transmission is assigned 48 per cent of the Transmission, Distribution and Customer Service Business Group operating costs after the direct assignment of technology and customer service as discussed in section 9.2.6.6 below, and 22 per cent of the Capital Infrastructure Project Delivery Business Group operating costs before the direct assignment of capital overhead and capital project investigation expenses.

Also assigned to transmission are generation operating costs relating to the generation ancillary services that BC Hydro provides to OATT customers.

A portion of the total costs allocated to gross transmission from the Transmission, Distribution and Customer Service and Capital Infrastructure Project Delivery Business Groups are subsequently allocated to generation and distribution as discussed in section 9.2.6 below.

The operating costs and internal allocations assigned to transmission are shown on lines 2, 16 and 17 of Appendix A, Schedule 3.4.

9.2.3 Taxes

Taxes are directly assigned to the gross transmission function as shown on line 3 of Appendix A, Schedule 3.4. Taxes that are directly assigned to the gross transmission function also include taxes relating to Generation Related Transmission Assets and to Substation Distribution Assets. To derive the taxes specific to the OATT Related Assets, taxes are further allocated through direct assignment and asset analysis. These taxes are included in the internal allocations to Generation Related Transmission Assets and to Substation Distribution Assets in lines 9 and 10 of Appendix A, Schedule 3.4.

9.2.4 Amortization, Finance Charges and Return on Equity

Amortization, finance charges and return on equity assigned to gross transmission are shown on lines 4, 5 and 6 respectively of Appendix A, Schedule 3.4.

The amortization assigned to gross transmission includes amortization related to Substation Distribution Assets, Generation Related Transmission Assets, OATT Related Assets and 10 per cent of demand-side management amortization. As directed by Order No. G-43-98m,[57] demand-side management amortization is directly assigned to transmission. The remaining gross transmission amortization

[57] The British Columbia Utilities Commission determined that it is appropriate to allocate 10 per cent of the annual capitalized DSM costs to the transmission revenue requirement on page 28 section 2.3.4 of its decision attached to Order No. G-43-98, dated April 23, 1998. Order No. G-43-98 and accompanying decision are available at: http://www.ordersdecisions.bcuc.com/bcuc/decisions/en/item/111697/index.do.

has been allocated to the functional activities using allocation factors derived from asset analysis.

The finance charges and return on equity that have been assigned to gross transmission are allocated to the functional activities shown in Table 9-2 on the basis of the average rate base for each fiscal year. Accordingly, the allocated amount for the gross transmission function has been assigned to the functional activities of Substation Distribution Assets, Generation Related Transmission Assets and Transmission Other using rate base as an allocator.

9.2.5 Business Support Cost Allocation

BC Hydro allocates its business support costs to its operating functions. The business support costs assigned to gross transmission are shown on line 7 of Appendix A, Schedule 3.4.

To derive the further allocation of the gross transmission business support costs to the transmission and distribution functional activities shown in Table 9-2, allocation factors are derived from FTEs, maintenance and capital expenditures, and fleet and material management business unit usage.

9.2.6 Internal Allocations from Transmission

Internal allocations from gross transmission are shown on lines 9 to 13, 18 and 19 of Appendix A, Schedule 3.4, and are described below.

9.2.6.1 Generation Related Transmission Asset Allocation

By Letter No. L-92-07 the British Columbia Utilities Commission accepted that a fixed charge of $43.3 million was appropriate for Generation Related Transmission Asset costs, and that re-evaluations of Generation Related Transmission Asset costs were not required.

The $43.3 million internal allocation of Generation Related Transmission Asset costs from the transmission function to the generation function is shown on line 9 of Appendix A, Schedule 3.4.

9.2.6.2 Substation Distribution Asset Allocation

All substation assets, including distribution specific substation assets, are recorded as transmission property. Substations with both transmission and distribution functions include assets common to both functions such as buildings, fences and heating, ventilation and air conditioning equipment.

The Substation Distribution Asset allocation is necessary to transfer the distribution-related portion of the substation costs, including an allocation of common assets, to the distribution function. To determine an appropriate share of gross transmission costs to Substation Distribution Assets, allocation factors are determined using asset analysis, maintenance, capital expenditures, manager interviews and direct assignment. The costs allocated to the Substation Distribution Asset functional activity include operating costs, capital related expenses, taxes and business support costs as discussed in the above sections.

The internal allocation of Substation Distribution Asset costs from gross transmission to distribution is shown on line 10 of Appendix A, Schedule 3.4 and the internal allocation of Substation Distribution Asset costs from the Capital Infrastructure Project Delivery Business Group is shown on line 11 of Appendix A, Schedule 3.6.

9.2.6.3 Generation Real Time Dispatch

Generation real time dispatch activities performed by Transmission, Distribution and Customer Service include generation control, water conveyance, alarm monitoring, notification and reporting services, data services and Supervisory Control and Data Acquisition system services and includes a portion of operating costs and business support costs. These control centre activities support the operation of both the generation and transmission systems. To derive the allocation of the total cost for this activity manager interviews were conducted.

The internal allocation of generation real time dispatch costs from the transmission function to generation is shown on line 11 of Appendix A, Schedule 3.4.

9.2.6.4 Distribution Real Time Dispatch

Distribution real time dispatch supports the operation of the distribution system, and includes activities performed by the control centre within Transmission, Distribution and Customer Service. This activity supports the operation of the distribution system from inside the substation fence downstream of the high side of the step down transformer, outside the substation fence, and restoration of the distribution system due to outages. The cost for distribution real time dispatch includes costs for the restoration centre and an allocation of business support costs assigned to gross transmission and Transmission, Distribution and Customer Service business support costs. To derive the allocation of the total cost for this activity manager interviews were conducted.

The internal allocation of distribution real time dispatch costs from the transmission function to distribution is shown on line 12 of Appendix A, Schedule 3.4.

9.2.6.5 Aboriginal Relations and Negotiations

With this application Aboriginal Relations and Negotiations business group costs, which are described in Chapter 5, section 5.6.5, are included as part of the Capital Infrastructure Project Delivery Business Group and are directly assigned to the transmission and generation functions.

The direct assignment of Aboriginal Relations costs to the transmission function is shown on line 39 of Appendix A, Schedule 3.6. The direct assignment of Regulatory First Nations Recoveries costs to the transmission function is show on line 64 of Appendix A, Schedule 3.6.

9.2.6.6 *Technology and Customer Service*

Technology and customer service are part of the Transmission, Distribution and Customer Service Business Group, and these costs are included in the gross transmission operating costs shown on line 2 of Appendix A, Schedule 3.4.

Technology supports all of the BC Hydro functions. As such, the operating costs for technology have been assigned from gross transmission operating costs to business support, line 15 of Appendix A, Schedule 3.1, where these costs are then allocated to BC Hydro's functions.

Customer service supports BC Hydro's customer care function, and as such the operating costs customer service have been assigned from gross transmission operating costs to customer care on line 16 of Appendix A, Schedule 3.3.

9.2.7 Miscellaneous Revenue

The miscellaneous revenue functionalized to transmission are shown on line 8 of Appendix A, Schedule 3.4.

Miscellaneous revenue continues to be directly assigned to the transmission function as shown on lines 6 to 12 of Appendix A, Schedule 15.0, and are described below.

9.2.7.1 *External OATT Revenue*

External OATT revenue consists of revenue from external parties (i.e., parties other than BC Hydro and Powerex) for: Point-To-Point Transmission Service; Scheduling, System Control and Dispatch Service; and other Ancillary Services.

The forecast of total external OATT revenue is based on fiscal 2016 actual volumes adjusted for known changes to long term contracts and is summarized on lines 73 to 76 of Appendix A, Schedule 3.4, and is also reflected on line 6 of Appendix A, Schedule 15.0.

9.2.7.2 FortisBC General Wheeling Agreement

Wheeling is the transportation of electricity from one utility's service area to another's. Wheeling revenue is collected from FortisBC in accordance with the General Wheeling Agreement. The charges for the wheeling of electricity from the Point of Supply to the Creston, Okanagan and Princeton Points of Interconnection are set out in BC Hydro’s Rate Schedule 3817. In accordance with the General Wheeling Agreement the forecast of wheeling revenue for the fiscal 2017 to fiscal 2019 period reflects annual rate increases equal to the forecast increases in the Consumer Price Index and expected increases in volumes based on the nomination provided by FortisBC.

The forecast of wheeling revenue from FortisBC is shown on line 7 of Appendix A, Schedule 15.0.

9.2.7.3 Secondary Revenue

Secondary revenue is revenue received from external parties for the non-electric use of transmission assets, such as facility and digital communications site rentals.

The forecast of secondary revenue is shown on line 8 of Appendix A, Schedule 15.0.

9.2.7.4 Interconnection Revenue

Interconnection revenue consists of payments for engineering studies done by BC Hydro for generator and load interconnection customers connecting to the transmission system. Under the OATT, BC Hydro conducts engineering studies for these customers requesting service, and the customers pay for the engineering studies.

The forecast of transmission interconnection revenue is shown on line 9 of Appendix A, Schedule 15.0.

9.2.7.5 Amortization of Contributions

Amortization of Contributions revenue relates to contributions from external parties toward the construction of capital assets.

The forecast of Amortization of Contributions revenue is shown on line 10 of Appendix A, Schedule 15.0. Details of the components of Amortization of Contributions are shown on Appendix A, Schedule 11, lines 29 plus 30 minus line 25.

9.3 OATT Rates

9.3.1 Introduction

The Transmission Revenue Requirement is collected through BC Hydro's OATT rate schedules for the following services:

1. Network Integration Transmission Service;
2. Point-To-Point Transmission Service; and
3. Ancillary Services.

Of the total Transmission Revenue Requirement collected under the OATT, approximately 1.5 per cent is collected from customers external to BC Hydro and Powerex.

The following subsections discuss the derivation of the OATT rates as set out in Appendix A, Schedule 3.4. The calculation of the OATT rates is consistent with the design of the OATT rates previously approved by British Columbia Utilities Commission and the past practice of BC Hydro and the British Columbia Transmission Corporation.

9.3.2 Network Integration Transmission Service

The Network Integration Transmission Service charge equals the Transmission Revenue Requirement less the revenues from Point-To-Point Transmission Service and ancillary services, as illustrated in the following equation:

$$\text{Monthly NITS}^{58}\text{ Charge} = \frac{\text{TRR}^{59} - (\text{PTP}^{60}\text{ Revenue} + \text{Ancillary Services Revenue})}{\text{12 months}}$$

The derivation of the monthly Network Integration Transmission Service charge is shown in Table 9-4.

Table 9-4 Calculation of Monthly NITS Charge

		Reference	F2015 Approved ($ million)	F2016 Approved ($ million)	F2017 Plan ($ million)	F2018 Plan ($ million)	F2019 Plan ($ million)
			1	2	3	4	5
1	**TRR**	Schedule 3.4 L31	**704.7**	**839.4**	**926.7**	~~926.8~~ 926.7	~~950.1~~ 950.0
2	**Less PTP and Ancillary Services Revenue:**						
3	PTP Revenue	Schedule 3.4 L72	(74.6)	(89.8)	~~(98.0)~~ (98.3)	~~(100.1)~~ (98.5)	~~(102.8)~~ (101.3)
4	Ancillary Service	Schedule 3.4 L38+L39+L40+L41	(4.8)	(4.8)	(5.4)	(5.3)	(5.3)
5	**Total PTP and Ancillary Services Revenue**	L3+L4	**(79.4)**	**(94.6)**	~~(103.4)~~ (103.6)	~~(105.3)~~ (103.7)	~~(108.1)~~ (106.6)
6	**NITS Revenue Requirement**	Schedule 3.4 L35	**625.2**	**744.8**	~~823.3~~ 823.1	~~821.5~~ 823.0	~~842.0~~ 843.4
7	**Monthly NITS Charge**	Schedule 3.4 L36	**52.1**	**62.1**	**68.6**	~~68.5~~ 68.6	~~70.2~~ 70.3

9.3.3 Point-To-Point Transmission Service

The Point-To-Point Transmission Service rate is based on the following:

$$\text{PTP}^{60}\text{ Rate} = \frac{(\text{TRR}^{59} - \text{Ancillary Services Revenue})}{(\text{Maximum Capacity Supply})}$$

The billing determinant for the long-term Point-To-Point Transmission Service rate is BC Hydro's Maximum Capacity Supply, as ~~included in BC Hydro's 2013 Integrated Resource Plan~~shown in Chapter 3 on Table 3-9 row (d).

[58] Network Integration Transmission Service.
[59] Transmission Revenue Requirement.
[60] Point-To-Point Transmission Service.

The derivation of the Point-To-Point Transmission Service rate is shown in Table 9-5.

Table 9-5 Calculation of the Point-To-Point Transmission Service Rate

		Reference	F2015 Approved ($ million)	F2016 Approved ($ million)	F2017 Plan ($ million)	F2018 Plan ($ million)	F2019 Plan ($ million)
			1	2	3	4	5
1	TRR	Schedule 3.4 L31	704.7	839.4	926.7	~~926.8~~ 926.7	~~950.1~~ 950.0
2	Less Ancillary Services	Schedule 3.4 L38+L39+L40+L41	(4.8)	(4.8)	(5.4)	(5.3)	(5.3)
3	**Net TRR**	Schedule 3.4 L42	**699.9**	**834.6**	**921.3**	**921.5**	~~**944.8**~~ **944.7**
4	Maximum Capacity Supply (MW)	Schedule 3.4 L.43	13,034	12,846	~~13,034~~ 12,978	~~12,846~~ 13,124	~~12,872~~ 13,115
5	Annual Billing Determinants (MW month)	L4 x 12 months	156,408	154,152	~~156,408~~ 155,736	~~154,152~~ 157,488	~~154,464~~ 157,380
6	**PTP Rate ($/MW Month)**	L3 X 1,000,000/L5 = Schedule 3.4 L45	**4,474.87**	**5,413.99**	~~**5,890.60**~~ **5,916.10**	~~**5,978.14**~~ **5,851.07**	~~**6,116.40**~~ **6,002.66**

9.3.4 Ancillary Services

9.3.4.1 Scheduling, System Control and Dispatch

Scheduling, System Control and Dispatch services include:

- Pre-scheduling, Settlements and Billing - transactional processing through market operation and business systems to ensure accurate transmission schedules are confirmed for customers followed by timely invoicing, accounting and performance reporting;
- Revenue Reporting and Forecasting - providing monthly and annual revenue reports for OATT services and provision of the historical information and forecasts for future years as required for determination of revenue requirements and rate setting; and
- Real-Time Scheduling - managing the transmission reservations and energy schedules in real-time. Interchange Operators coordinate with Bonneville Power Authority and the Alberta Electric System Operator at least every hour to match

schedules and reach a net interchange schedule which is incorporated into the Automatic Generation Control system to maintain energy balance.

The Scheduling, System Control and Dispatch rate is a volume-driven rate, calculated as the total cost for Scheduling, System Control and Dispatch divided by the total forecasted volumes for Network Integration Transmission Service, long-term Point-To-Point and short-term Point-To-Point services.

The derivation of the Scheduling, System Control and Dispatch rate is shown in Table 9-6.

Table 9-6 Calculation of Scheduling, System Control and Dispatch Rate

		Schedule Reference	F2015 Approved	F2016 Approved	F2017 Plan	F2018 Plan	F2019 Plan
			1	2	3	4	5
1	**PTP Volumes (MWh)**						
2	Long-Term PTP	Schedule 3.4 L54	10,240,440	10,240,440	9,355,680	9,355,680	9,355,680
3	Short Term PTP	Schedule 3.4 L63	6,528,034	7,635,498	10,052,378	10,480,466	10,908,554
4	**Total PTP Volumes**		**16,768,474**	**17,875,938**	**19,408,058**	**19,836,146**	**20,264,234**
5	NITS and Secondary Transmission		12,587,232	12,587,232	8,325,721	8,325,721	8,325,721
6	**Total Volumes**	**Schedule 3.4 L50**	**29,355,706**	**30,463,170**	**27,733,779**	**28,161,867**	**28,589,955**
7	**Scheduling, Control and Dispatch Cost ($ million)**	Schedule 3.4 L49	3.0	3.0	2.9	2.8	2.8
8	**Scheduling Fee[61] ($/MWh)**	**(L8/L7) =Schedule 3.4 L51**	**0.102**	**0.099**	**0.105**	**0.099**	**0.099**

9.3.4.2 Other Ancillary Services

BC Hydro provides ancillary generation services for OATT customers. Other ancillary services include energy imbalance service, loss compensation service, spinning and supplemental operating reserve services, and reactive power service. The revenue from these other external ancillary services is shown on line 39 of Appendix A, Schedule 3.4.

[61] Scheduling, System Control and Dispatch rate.

9.4 Point-To-Point Revenue Forecast

The long-term Point-To-Point revenue is derived from the forecast long-term Point-To-Point volumes and the proposed long-term Point-To-Point rates. The forecasts of long-term Point-To-Point volumes are based on committed long-term transmission contracts.

The short-term Point-To-Point revenue forecast reflects the discounting of short-term Point-To-Point rates on export and wheel-through transactions. The applicable rates are $3.00/MWh during Heavy Load Hours and $1.00/MWh during Light Load Hours, Sundays and North American Electricity Reliability Council holidays. The forecast of external short-term Point-To-Point volumes are based on fiscal 2016 actual volumes. The internal short term Point-To-Point volumes are based on the energy studies model.

Table 9-7 summarizes the forecast Point-To-Point revenue and volumes.

Table 9-7 Summary of Forecast Point-To-Point Revenue and Volumes

		Schedule Reference	F2015 Approved	F2016 Approved	F2017 Plan	F2018 Plan	F2019 Plan
			1	2	3	4	5
1	**PTP Revenue ($ million)**						
2	Long Term PTP	Schedule 3.4 L57	62.8	76.0	~~75.5~~ 75.8	~~76.6~~ 75.0	~~78.4~~ 76.9
3	Short-Term PTP	Schedule 3.4 L66	11.8	13.8	22.5	23.4	24.4
4	**Total PTP Revenue**	**Schedule 3.4 L72**	**74.6**	**89.8**	**~~98.0~~ 98.3**	**~~100.1~~ 98.5**	**~~102.8~~ 101.3**
5	**PTP Volumes (MWh)**						
6	Long-Term PTP	Schedule 3.4 L54	10,240,440	10,240,440	9,355,680	9,355,680	9,355,680
7	Short Term PTP	Schedule 3.4 L63	6,528,034	7,635,498	10,052,378	10,480,466	10,908,554
8	**Total PTP Volumes**		**16,768,474**	**17,875,938**	**19,408,058**	**19,836,146**	**20,264,234**
9	**PTP Average Price ($/MWh)**						
10	Long Term PTP	Schedule 3.4 L60	6.13	7.42	~~8.07~~ 8.10	~~8.19~~ 8.02	~~8.38~~ 8.22
11	Short Term PTP	Schedule 3.4 L69	1.81	1.81	2.24	2.24	2.24

9.5 Proposed OATT Rates

Table 9-8 summarizes the proposed OATT rates as derived from the above analyses. BC Hydro believes that the OATT rates are just and reasonable and should be approved as filed.

Table 9-8 Interim and Proposed OATT Rates
Fiscal 2017 to Fiscal 2019

	Rate Schedule	Rate Class	Reference	F2017 Interim[62]	F2017 Plan	F2018 Plan	F2019 Plan
				1	2	3	4
1	Attachment H	**NITS Revenue Requirement ($)**	Schedule 3.4 L35	805,500,000	~~823,300,000~~ 823,100,000	~~821,500,000~~ 823,000,000	~~842,000,000~~ 843,400,000
2	RS 00	**NITS Monthly Rate ($)**	Schedule 3.4 L36	67,125,000	~~68,608,333~~ 68,591,667	~~68,458,333~~ 68,583,333	~~70,166,667~~ 70,283,333
3	RS 01	**Long Term Firm Point-to-Point**					
4		Yearly - $/MW of Reserved Capacity per year	Schedule 3.4 L44	69,455	~~70,687~~ 70,993	~~71,738~~ 70,213	~~73,397~~ 72,032
5		**Short Term Firm and Non-Firm Maximum Price for Delivery**					
6		Monthly - $/MW of Reserved Capacity per month	Schedule 3.4 L45	5,787.91	~~5,890.60~~ 5,916.10	~~5,978.14~~ 5,851.07	~~6,116.40~~ 6,002.66
7		Weekly - $/MW of Reserved Capacity per week	Schedule 3.4 L46	1,335.67	~~1,359.37~~ 1,365.25	~~1,379.57~~ 1,350.25	~~1,411.48~~ 1,385.23
8		Daily - $/MW of Reserved Capacity per day	Schedule 3.4 L47	190.29	~~193.66~~ 194.50	~~196.54~~ 192.36	~~201.09~~ 197.35
9		Hourly - $/MW of Reserved Capacity per hour	Schedule 3.4 L48	7.93	~~8.07~~ 8.10	~~8.19~~ 8.02	~~8.38~~ 8.22
10	RS 03	**Scheduling, System Control and Dispatch Service ($)**					
11		per MW of Reserved Capacity per hour	Schedule 3.4 L51	0.099	0.105	0.099	0.099

[62] Fiscal 2017 Interim Rates as approved by the British Columbia Utilities Commission through Order No. G-40-16. Interim rates are not shown in Appendix A, Schedule 3.4.

BC Hydro
Power smart

Fiscal 2017 to Fiscal 2019
Revenue Requirements Application

Chapter 10

Demand-Side Management Expenditures

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10.1 Introduction

In this chapter BC Hydro sets out the information and analysis in support of our request pursuant to section 44.2 of the *Utilities Commission Act* for acceptance of our proposed fiscal 2017 to fiscal 2019 demand-side measures expenditure schedule.[63] The proposed expenditure schedule is presented in Table 10-1 below and includes the expenditures on demand-side measures that we anticipate making over the fiscal 2017 to fiscal 2019 test period as part of its Demand-Side Management Plan.

Table 10-1 Fiscal 2017 to Fiscal 2019 Demand-Side Measures Expenditure Schedule

	Demand-Side Measures Expenditures ($ million)
F2017	113.7
F2018	104.8
F2019	100.7
Thermo-Mechanical Pulp (F2017-F2019)[64]	55.8
Three-Year Total	375.0

For over 25 years, BC Hydro's demand-side management programs have supported energy conservation and encouraged the adoption of more energy efficient products and equipment. Over the same period, a lot has changed. Customer acceptance of certain energy efficient products has increased, new technologies have improved access to energy data and changing customer expectations and system needs have presented new opportunities in areas such as capacity-focused demand-side management and low-carbon electrification.

In June 2015, we initiated a process to modernize and improve the cost-effectiveness of our demand-side management programs to leverage new technologies and respond to changing customer expectations and system needs. As a result of this

[63] Demand-side management expenditures for the period beginning fiscal 2020 (the longer-term demand-side measures outlook) will be the subject of a future filing informed by the 2018 Integrated Resource Plan.

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

process, BC Hydro reduced the average cost of its demand-side management programs to $22/MWh while remaining on track to meet the *Clean Energy Act* target to offset at least 66 per cent of incremental demand from 2008 to 2020 through conservation and maintaining the capability to acquire further demand-side management electricity savings in the future should those savings be required.

BC Hydro's Demand-Side Management Plan continues investments in areas such as capacity-focused conservation, including a load curtailment pilot program for large industrial customers. BC Hydro is also increasing its focus on measures that provide new tools, information and technologies to customers to help them make use of available energy data, including from smart meters, to make smart choices about their energy consumption. By having access to information more specific to them, customers can make informed choices and save money.

BC Hydro has eliminated or modified programs that are not as cost-effective or are less aligned with customer expectations and system needs, while retaining or expanding programs that align well with new priorities. BC Hydro is maintaining a broad range of measures to provide access to conservation opportunities and information for all customer groups while also creating economic and environmental benefits such as reducing greenhouse gas emissions and other non-energy benefits.

Given the reduction in the rate of growth of demand for electricity in the short term, BC Hydro has extended our moderation strategy for three more years.

BC Hydro believes that the proposed demand-side measures expenditure schedule is in the public interest and should be accepted as filed.

This chapter is organized as follows:

- Section 10.2 reviews the outcome of the fiscal 2014 to fiscal 2016 demand-side management initiatives and explains how BC Hydro has advanced its knowledge of capacity resources and investigated codes and standards opportunities;

- Section 10.3 describes the framework for BC Hydro's demand-side management expenditures. It explains how the Demand-Side Management Plan meets multiple customer, Government and BC Hydro objectives, including how it is aligned with British Columbia's Energy Objectives and the *Demand-Side Measures Regulation*;
- Section 10.4 provides more details on the expenditures, energy and capacity savings and other benefits of the Demand-Side Management Plan;
- Section 10.5 explains how BC Hydro developed the Demand-Side Management Plan, including responding to changing customer expectations and system needs and maintaining a broad range of initiatives. It describes the three demand-side management tools, the capacity-focussed pilots and the two supporting initiatives that make up the Demand-Side Management Plan;
- Section 10.6 explains how BC Hydro has identified and mitigated risks to the successful implementation of the Demand-Side Management Plan; and
- Section 10.7 demonstrates that BC Hydro manages the performance of the Demand-Side Management Plan in a comprehensive manner, including tracking a number of performance metrics and regular management oversight and reporting.

10.2 Review of Fiscal 2014 to Fiscal 2016 Demand-Side Management Initiatives

Over the past three years, we have implemented demand-side management initiatives while advancing our knowledge of capacity resources and investigating codes and standards opportunities. These initiatives included the launch of a new Thermo-Mechanical Pulp program to provide BC Hydro's thermo-mechanical pulp customers with capital funding to complete significant upgrades to their facilities. Energy savings in all three customer sectors have been achieved through a combination of codes and standards, rate structures, and programs.

BC Hydro's 2013 Integrated Resource Plan recommended actions for demand-side management included recommendations to moderate spending on demand-side management over the fiscal 2014 to fiscal 2016 period and to prepare to increase spending to achieve the long-term target of 7,800 GWh per year in energy savings, and 1,400 megawatts in capacity savings, by fiscal 2021. Table 10-2 below shows the moderation of demand-side management expenditures for fiscal 2014 to fiscal 2016 as recommended by the 2013 Integrated Resource Plan.

Table 10-2 2013 Integrated Resource Plan Recommendations

	Associated Demand-Side Measures Expenditures ($ million)			
	F2014	F2015	F2016	Three-Year Total
Action 1 – Conservation and Efficiency Measures	175	145	125	445
Action 2 – Pursue Capacity Conservation				5.75
Action 3 – Additional Codes and Standards Opportunities		1.5	1.5	3
Total	175	146.5	126.5	453.75

In the Fiscal 2015 - Fiscal 2016 Revenue Requirements Rate Application, BC Hydro submitted its demand-side measures expenditure schedule for fiscal 2014, fiscal 2015 and fiscal 2016 reflecting expenditures of $236.3 million for fiscal 2014, $150.5 million for fiscal 2015 and $131.1 million for fiscal 2016. In Order No. G-48-14, Directives 1 and 33, the British Columbia Utilities Commission accepted the demand-side measures expenditures pursuant to section 44.2 of the *Utilities Commission Act* as prescribed by Direction No. 6 to the British Columbia Utilities Commission.

Subsequent to Order No. G-48-14, an additional $19.6 million was added to the initial fiscal 2016 Plan budget of $131.1 million for the Thermo-Mechanical Pulp program, as authorized by the Direction to the British Columbia Utilities Commission respecting the Authority's TMP Program.[65]

The following subsections discuss the actual results of BC Hydro's expenditures on demand-side management for fiscal 2014, fiscal 2015 and fiscal 2016 in relation to the three recommended actions in the 2013 Integrated Resource Plan.

10.2.1 2013 Integrated Resource Plan Recommended Action 1: Moderate Current Spending

Table 10-3 and Table 10-4 provide the savings results and the associated expenditures on demand-side management compared to plan values. The costs for 2013 Integrated Resource Plan Recommended Actions 2 and 3 are also included in these expenditure values. Details for the results are provided in the Annual Demand-Side Management Activities Reports contained in Appendix Y.

Table 10-3 Demand-Side Management Incremental Electricity Savings (GWh/year)

	Plan Values	Actual
F2014	737	686
F2015	578	444
F2016	927	872

Table 10-4 Demand-Side Management Expenditures ($ million)[66]

	Plan Values	Actual
F2014	236.3 (Note 1)	120.3
F2015	150.5	124.8
F2016	150.6[67]	145.2

Note 1: Refer to second paragraph below on formation of the $236.3 million plan value.

[65] Order in Council No. 404 (BC Reg. 139/2015). Online at: http://www.bcuc.com/Documents/SpecialDirections/2015/07 14 2015_OIC404 BCHydro TMP Program.pdf.

[66] Expenditures on the 2013 Integrated Resource Plan Recommended Actions 2 and 3 are included in these totals.

[67] The $150.6 plan value for fiscal 2016 reflects the $131.1 million accepted in Order No. G-48-14 plus $19.6 million for the Thermo-Mechanical Pulp program as noted above.

Fiscal 2014 was a year in transition for BC Hydro's demand-side measures initiatives due to Government approval of the 2013 Integrated Resource Plan. It provided revised direction for the demand-side measures savings activities through a moderation of planned expenditures beginning in fiscal 2014 given the sufficiency of existing resources to meet the demand for electricity in the short term.

In fiscal 2014, the variance between plan and actual is primarily due to the fiscal 2014 plan value in BC Hydro's Fiscal 2015 - Fiscal 2016 Revenue Requirements Rate Application not reflecting the transition to a moderation strategy as recommended by the 2013 Integrated Resource Plan. In order to implement the recommended moderation strategy, BC Hydro reduced its fiscal 2014 plan from $236.3 million to $151.3 million (with corresponding energy savings of 778 GWh per year) to align with the year-end forecast in the Fiscal 2015 – Fiscal 2016 Revenue Requirements Rate Application. Expenditures were $120.3 million, 22 per cent below the revised plan amount of $151.3 million. Electricity savings were 686 GWh per year, 12 per cent below the revised plan of 778 GWh per year. The variances were primarily due to project delays in the Industrial Power Smart Partner – Transmission program and adjustments made to the offer to manage participation and incentive levels in the Commercial Power Smart Partner program.

In fiscal 2015, expenditures were 17 per cent below plan primarily due to an Industrial Load Displacement large customer project being delayed until fiscal 2016. Electricity savings were 23 per cent below plan due to the incorporation of evaluation results for Residential, Commercial and Industrial Distribution Rate Structures where customer response to the rate structures was lower than expected.

In fiscal 2016, expenditures were four per cent below plan, and savings were 12 per cent below plan due to a number of projects being delayed by customers until fiscal 2017.

A detailed initiative by initiative variance analysis is provided in the fiscal 2014 to fiscal 2016 year-end reports provided in Appendix Y.

10.2.2 2013 Integrated Resource Plan Recommended Action 2: Pursue Capacity Conservation

In line with 2013 Integrated Resource Plan Recommended Action 2 to gain experience in capacity-focused demand-side management initiatives, BC Hydro advanced its investigation of capacity focused demand-side management over the past two years. These activities can be categorized into two areas: load curtailment and demand response.

10.2.2.1 Load Curtailment

For transmission customers, BC Hydro is currently conducting a multi-year load curtailment pilot. This effort also responds to the October 2013 task force recommendation of the Industrial Electricity Policy Review[68] to "develop options that take advantage of industrial power consumption flexibility". The initial phase from January to March 2015 was a bilateral agreement which allowed BC Hydro to explore load curtailment design options and help in formulating the next stage of the pilot. Subsequently, through a Request for Proposals process, eligible customers proposed amounts of load they were capable of curtailing with a maximum total requirement of 100 megawatts for up to 36 days per year in aggregate. BC Hydro selected all interested proponents and prorated the expected number of curtailment days or days they need to be available to fit within budget (a total of 126 megawatts was contracted for 28 days).

Participants were given day-ahead notice to curtail their load for up to 16 hours per day, up to six consecutive days per week from November 2015 through April 2016. Curtailments began in November with participants utilizing the flexibility and storage within their industrial process to provide dependable demand relief to the BC Hydro system. Another Request for Proposals will be released in fiscal 2017 for year two of

[68] Copy available at https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/regulatory-matters/october-2013-industrial-electricity-policy-review-report.pdf

the pilot, based on the results of year one. The learnings, both from a participant and BC Hydro perspective, will inform future potential program design.

10.2.2.2 Demand Response

BC Hydro is conducting a demonstration pilot in Sidney and North Saanich using wireless load control relays on residential water heaters in participating residential customers' homes. The pilot also includes field testing of an alternative three-element water heater which may also help create demand reductions. In-field testing began in 2015 and will carry into early 2017. After the conclusion of the testing period, a participant survey will be conducted and meter data will be analyzed to determine the impact of these two measures on both demand and participants.

BC Hydro is also in the early stages of researching additional demand-side management demand response program options including programmable communicating thermostats and other connected home technologies. Thermostat solutions need to be suitable for homes with baseboard heating and provide cost-effective management of multiple heating zones. Opportunities have also been identified to control or design new flexible electrical load to manage capacity (e.g., electric vehicle charging).

For commercial and distribution industrial customers, BC Hydro is conducting a manual-call demand response program with several different business types. Participants elect their own actions for implementation during events and enact those plans when called by the utility. Measures can include refrigeration, lighting, heating, ventilation and air conditioning systems and other sources, depending on each business type. This project is in year two of operation. The data acquired will be analyzed to understand the impacts on load, participant operations and occupant comfort.

Additionally, BC Hydro is in the very early stages of researching paths towards auto-demand response with commercial and industrial customers, integration to building management systems, the future of connected buildings and the impact and opportunities with electric vehicle fleets.

10.2.3 2013 Integrated Resource Plan Recommended Action 3: Explore More Codes and Standards

Over the fiscal 2014 to fiscal 2016 period, BC Hydro undertook a number of activities to explore additional cost-effective savings opportunities through codes and standards, as well as the activities required to put more codes and standards into place. These activities, in addition to the base level of activities in support of codes and standards, generally fall into the following categories:

- Developing long-term roadmaps with short-term action plans for reaching near-net zero new buildings and low-energy existing buildings;
- Identifying barriers and potential cost-effective opportunities, including pilot projects;
- Building capacity and acceptance in the market-place for additional codes and standards; and
- Leading the initial stages of work to develop the next wave of improvements to codes and standards.

Specific activities that have been completed or are in progress include:

- Completion of long-term roadmaps and action plans for Near Net Zero small residential buildings, home labeling and building benchmarking, and enhanced building code compliance;
- BC Hydro is working on policy options for the development and adoption of a “Retrofit Code”, which, like the B.C. Building Energy Code for new construction, would apply to existing buildings and require energy efficiency upgrades based on certain triggers;

- BC Hydro has worked at a variety of levels within the National Energy Code development process to advance future editions of the National Energy Code for Buildings. This includes leading efforts to ensure the next iteration of the National Energy Code for Buildings in 2017 delivers at least a 15 per cent incremental improvement over the 2011 version;
- BC Hydro began implementing activities to enhance compliance with the current B.C. Building Code and Vancouver Building Bylaw. Improving compliance with existing building code levels is imperative before moving to the next level of codes. BC Hydro has led a compliance working group, with representation from the Province and a number of local governments, to identify the steps and initiatives required to enhance compliance. Work is currently focusing on creating a common, province-wide code compliance checklist for building designers and building inspectors, as well as working directly with local government officials and inspectors to increase inspections for compliance with energy provisions of the code;
- BC Hydro supported the development of potential updates to the B.C. Energy Efficiency Regulation. This work has been initiated by the Ministry of Energy and Mines to identify new product regulations or additional performance requirements for existing regulations over the next ten years; and
- BC Hydro led work at the Canadian Standards Association to develop new performance standards for a variety of product categories, including variable-capacity heat pumps, industrial refrigeration, slurry pumps, gas compressors and data centres. Performance standards are a necessary pre-condition for eventual adoption into energy efficiency regulations.

10.3 Framework for Fiscal 2017 to Fiscal 2019 Demand-Side Management Expenditures

This section describes BC Hydro's technical capacity to carry out the Demand-Side Management Plan, the relevant legal framework and how the proposed expenditures advance current company-wide priorities. This section then sets out how BC Hydro determined its forecast fiscal 2017 to fiscal 2019 demand-side management expenditures and the overall level of expenditure. It explains how the proposed expenditures continue an approach of moderation outlined in Recommended Action 1 of the 2013 Integrated Resource Plan, are consistent with the Minister's Letter of Support, and meet British Columbia's energy objectives, and the requirements of the *Demand-Side Measures Regulation*.

10.3.1 Technical Capacity

BC Hydro has offered demand-side management programs to its customers since 1989. The BC Hydro Conservation and Energy Management team is composed of full time BC Hydro employees who have extensive experience in demand-side management delivery from design through implementation and evaluation.

In addition to internal technical capacity, BC Hydro actively seeks out and partners with other agencies, trade allies and utilities to deliver its demand-side management initiatives. Examples of this partnering include:

- The BC Hydro Alliance of Energy Professionals (comprised of approximately 800 members including contractors, consulting engineers, distributors and registered experts);
- A network of over 350 retail locations and manufacturers of energy-efficient products; and
- Coordination with FortisBC on joint demand-side management offers and implementation (further described in section 10.7.4).

10.3.2 Legal and Policy Framework

BC Hydro files its fiscal 2017 to fiscal 2019 demand-side measures expenditure schedule pursuant to subsection 44.2(1)(a) of the *Utilities Commission Act*. Pursuant to subsection 44.2(3), after reviewing the expenditure schedule, the British Columbia Utilities Commission must accept the schedule if the British Columbia Utilities Commission considers that making the expenditures referred to in the schedule would be in the public interest, or reject the schedule. Alternatively, the British Columbia Utilities Commission may accept or reject a part of the expenditure schedule.

Pursuant to section 44.2(5.1) of the *Utilities Commission Act*, in considering whether to accept a demand-side measures expenditure schedule filed by BC Hydro, the British Columbia Utilities Commission must consider:

- The interests of persons in British Columbia who receive or may receive service from BC Hydro;
- British Columbia's energy objectives, as set out in section 2 of the *Clean Energy Act*;
- An applicable Integrated Resource Plan approved under section 4 of the *Clean Energy Act*; and
- The extent to which the demand-side measures are cost-effective within the meaning prescribed by the *Demand-Side Measures Regulation*.[69]

Chapter 10 as a whole describes how the fiscal 2017 to fiscal 2019 demand-side measures expenditures are in the interests of persons in B.C. who receive or may receive service from BC Hydro. The sections of this chapter listed below describe how the fiscal 2017 to fiscal 2019 demand-side measures expenditures align with the other criteria set out in section 44.2(5.1) of the *Utilities Commission Act*:

[69] B.C. Reg. 326/2008 (Ministerial Order M271), B.C. Reg. 228/2011 (Ministerial Order M335) and B.C. Reg. 141/2014 (Ministerial Order M233).

- Section 10.3.4 describes BC Hydro’s 2013 Integrated Resource Plan recommended actions for demand-side management, and the actions BC Hydro is taking on the demand-side management portfolio for the fiscal 2017 to fiscal 2019 period to align with BC Hydro’s priorities and changing customer expectations and system needs;
- Section 10.3.6 describes B.C.’s Energy Objectives, and how the fiscal 2017 to fiscal 2019 demand-side measures expenditures will contribute to and align with these objectives; and
- Section 10.4.4 describes how the fiscal 2017- fiscal 2019 demand-side measures expenditures satisfy the cost-effectiveness tests prescribed by section 4 of the *Demand-Side Measures Regulation*.

10.3.3 Company-Wide Priorities

Our vision is “to be the most trusted, innovative utility company in North America by being smart about power in all we do”. Three of the company-wide priorities form part of the framework for planning demand-side management for the fiscal 2017 to fiscal 2019 period:

- Explore the full potential of energy conservation;
- Make it easy for customers to do business with us; and
- Continue to improve the way we operate.

The company-wide priority of “exploring the full potential of energy conservation” speaks to an expanded demand-side management scope that aligns with the action items of the 2013 Integrated Resource Plan. Our current approach gives effect to this priority in several ways. For example, the exploration of capacity initiatives as described in section 10.2.2 introduces a focus beyond GWh or energy savings. In the past, capacity savings have been viewed as an associated benefit of conservation programs rather than a key objective on its own. The 2013 Integrated Resource Plan signaled a shift in this resource focus given changing system needs.

This expanded demand-side management scope is also informed by an increase in the information and communication tools and technology available to both utilities and customers on customer energy consumption. Some examples of this include: smart metering infrastructure, smart thermostats, building management and process control systems, and the general growth in telecommunications networks, sensor and machine-to-machine communications technology. Customers increasingly expect to be able to use these tools to communicate with their utility. They also expect that BC Hydro will provide additional products and services to leverage these technologies, making it easier for customers to do business with us. In addition, these new technologies have the capability to allow loads to respond dynamically to both utility system needs and customer energy management expectations.

Utilities across North America are seeing similar changes in customer expectations. For instance, as Consolidated Edison stated in their Integrated Long-Range Plan:[70]

> "**2. Customers are changing the way they interact with us**
>
> Customer expectations are changing. A significant portion of this change is driven by changing priorities and an increased ability to individualize services to one's own needs. About three-quarters of the current U.S. population was born after the invention of the computer, and about one-fifth of the population was born after the emergence of mobile computing (smart phones and lightweight laptops). Roughly half of all Americans use computers extensively in their day-to-day activities such as banking, shopping, communicating, and researching and about one-fifth of the population use mobile computing extensively. The banking, telecommunications and retail industries have established an extensive online presence, including product offerings, customer services, and access to information.
>
> Over the next 20 years, as the composition of the population changes and people's experience with technology increases, we anticipate that our customers will expect us to interact with them electronically on a real-time basis. Further, we expect that the

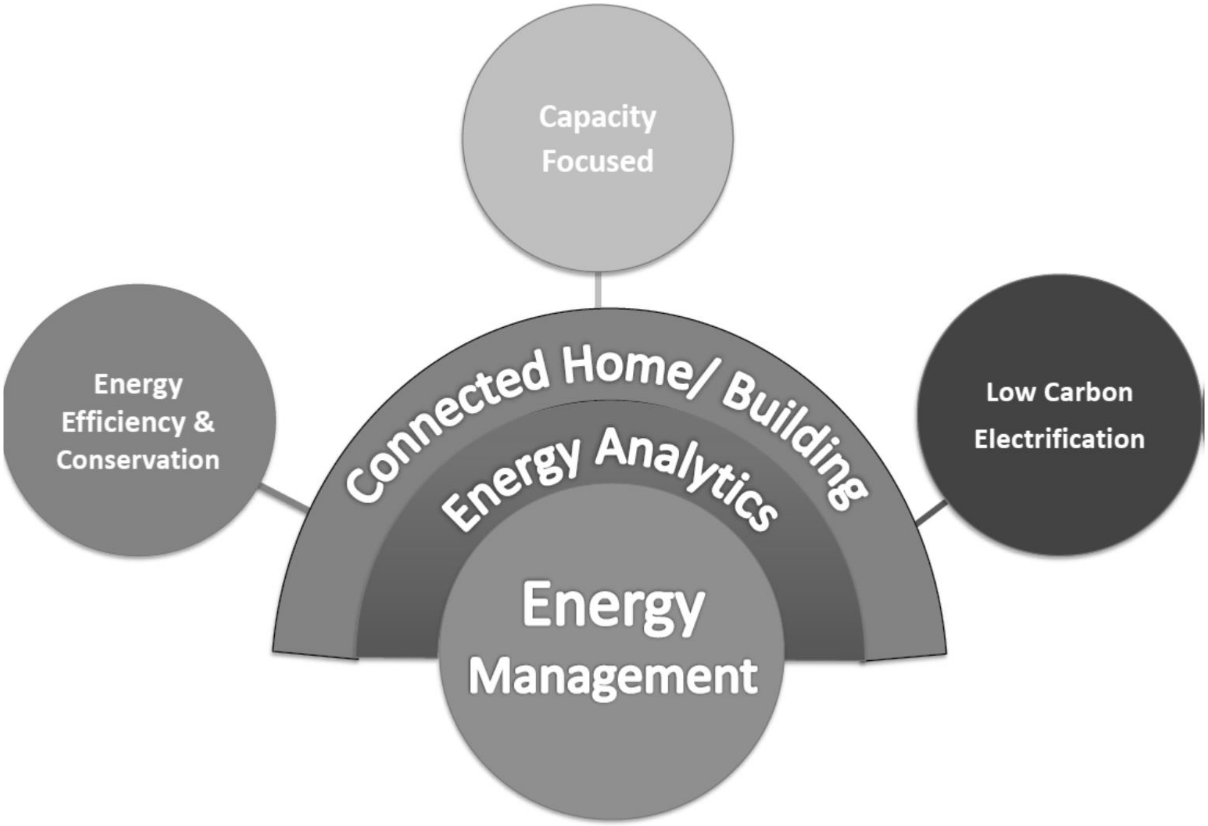
[70] Consolidated Edison Company of New York Integrated Long-Range Plan, April 2012, page 23, http://www.coned.com/publicissues/PDF/Integrated%20Long-range%20Plan.pdf

> way customers make decisions will change. The immediate access to information through smart phones and the ability to connect with distant places and people through the Internet have given rise to electronic social networks such as Facebook, LinkedIn and Twitter. These networks are facilitating information flow and playing a key role in decision-making for individuals and businesses alike.
>
> Each year the portion of the population that has experienced customized services and real-time access to information increases, all enabled by advances in technology that would have seemed far-fetched even just 20 years ago. In predicting how these changes in technology will affect the energy industry, we believe that our customers will want more customized value-added services. More specifically, as emerging energy technologies mature over time and reach the market, customers may adopt real-time energy management solutions and self-generation technologies. These systems and technologies can be integrated with grid electricity to create sophisticated, individualized real-time energy-management services for our customers to use. Customers will also expect to use technological devices to access the most current information on service work that may affect the area, as well as outage information and the estimated time for service restoration."

These changing customer expectations are prompting the introduction of new aspects of energy conservation (or more expansively termed as energy management), as outlined in Figure 10-1.

BC Hydro is also expanding how energy management initiatives are undertaken, with a wide variety of potential offers and the Application of energy insights from customer and our system data.

Figure 10-1 Energy Management Elements



BC Hydro has made changes to our Demand-Side Management Plan to align with this expanded energy management scope and company-wide priorities, as well as the 2013 10 Year Rates Plan and our changing customer and system needs. The Demand-Side Management Plan continues to provide a foundation of energy management support and initiatives for customers, while at the same time beginning a shift to put more emphasis on leveraging new technology capabilities in the marketplace. BC Hydro is also expanding how energy management initiatives are undertaken, with a variety of potential offers and the application of energy insights from customer and BC Hydro system data. This approach allows BC Hydro to use the flexibility of energy management to pursue not only energy savings, but also other forms of demand-side management including capacity and low carbon electrification that deliver benefits (e.g., MW reductions, greenhouse gas emission reductions) to meet the needs of BC Hydro and its customers. This is described in section 10.5. The change in demand-side management initiatives will respond to changing customer and system needs and new opportunities, while achieving cost savings and keeping rates low.

This shift in focus has prompted BC Hydro to eliminate or modify programs that are not as cost-effective or are less aligned with customer expectations and system needs, while retaining or expanding programs that align well with new priorities. BC Hydro is maintaining a broad range of measures to provide access to conservation opportunities and information for all customers.

10.3.4 2013 Integrated Resource Plan and Objectives for Demand-Side Management in Fiscal 2017 to Fiscal 2019

BC Hydro develops a Demand-Side Management Plan and outlook through the Integrated Resource Plan process, which is required by subsection 3(6)(b) of the *Clean Energy Act* to be submitted to Government every five years after submission of the first Integrated Resource Plan. The 2013 Integrated Resource Plan was approved by the Lieutenant Governor in Council on November 25, 2013 pursuant to Order in Council No. 514.[71] The 2013 Integrated Resource Plan is the applicable approved Integrated Resource Plan for the purposes of section 44.2(5.1) of the *Utilities Commission Act*.

BC Hydro's 2018 Integrated Resource Plan will recommend a demand-side management target and related actions for the period beginning fiscal 2020.

As set out in Chapter 4 of the 2013 Integrated Resource Plan, in 2013 BC Hydro forecast that it would have sufficient resources to meet growing electricity demand over the short to mid-term planning period, and that it would need to acquire new resources towards the middle and end of the planning horizon. As part of the short-term energy supply management strategy, different alternative means were

[71] Copy available at http://www.bclaws.ca/civix/document/id/arch_oic/arc_oic/0514_2013.

considered for reaching the long-term demand-side management target of 7,800 GWh per year of energy savings and associated capacity savings by fiscal 2021. The 2013 Integrated Resource Plan Recommended Action 1 provided direction to moderate demand-side management initiatives in the short term (and specified demand-side measures expenditure levels for fiscal 2014 to fiscal 2016), and to be prepared to ramp up activities to meet the long-term demand-side management target by fiscal 2021.

10.3.4.1 Framework for Fiscal 2017 to Fiscal 2019 Expenditures

In considering demand-side management for the fiscal 2017 to fiscal 2019 period, BC Hydro considered opportunities to be innovative and take advantage of new technologies, and respond to changing customer expectations and system needs, while reducing costs. Given the reduced demand for electricity in the short term and the flexibility of demand-side management, BC Hydro determined that modification to the 2013 Integrated Resource Plan forecast expenditures for the fiscal 2017 to fiscal 2019 period. BC Hydro developed a framework, discussed below, to guide the determination of the Demand-Side Management Plan for fiscal 2017 to fiscal 2019.

The framework incorporated cost-effectiveness tests, and consideration of other attributes, which are then used to assess alternatives. BC Hydro's analysis under the assessment framework yielded a Demand-Side Management Plan that extends a moderation strategy for three more years, providing expenditures and energy savings reductions relative to the path forecast in the 2013 Integrated Resource Plan. The Demand-Side Management Plan will meet the B.C. Energy Objective "to take demand-side measures and to conserve energy, including the objective of BC Hydro reducing its expected increase in demand for electricity by the year 2020 by at least 66 per cent."

BC Hydro's assessment framework included consideration of the cost-effectiveness of demand-side management initiatives using two tests:

- **The Total Resource Cost Test**: In accordance with the *Demand-Side Measures Regulation*, BC Hydro uses the Total Resource Cost Test as a determinant of whether an individual demand-side management initiative and the demand-side management portfolio as a whole are cost-effective. The Total Resource Cost Test helps BC Hydro to assess how the cost of demand-side management compares to the cost of other supply-side resource options; and
- **The Utility Cost Test**: For the purposes of determining the fiscal 2017 to fiscal 2019 demand-side management expenditures, BC Hydro also relied on the Utility Cost Test. This test is used to understand the impact of a demand-side management investment on BC Hydro's revenue requirement.

For the Total Resource Cost and Utility Cost Tests, the long-run marginal cost of electricity from the 2013 Integrated Resource Plan was used as the basis to compare the demand-side management investment against other resource options.

In addition to using the long-run marginal cost as the avoided cost stream to determine cost-effectiveness, BC Hydro added an extra Utility Cost Test screening filter using the B.C.-border sell price forecast as the avoided energy cost stream (which is approximately $36 per MWh) in order to prioritize demand-side management investments. This ensures that even surplus energy resulting from demand-side management would have a positive impact on BC Hydro's revenue requirements, because the utility cost of demand-side management would be less than the wholesale market price.

Any demand-side management initiative that did not pass the Total Resource Cost Test (at long-run marginal cost) and did not pass the Utility Cost Test at the value of $36 per MWh was investigated for modifications to pass these tests, with the exception of the demand-side measures initiatives specified in section 3 of the *Demand-Side Measures Regulation*.

Our assessment framework also included the attributes listed below. These attributes were considered in reviewing each initiative to determine whether it should be included, adjusted or cancelled in the Demand-Side Management Plan (these attributes were not applied in any particular order):

- Meeting the B.C. Energy Objective of BC Hydro reducing its expected increase in demand for electricity by the year 2020 by at least 66 per cent;
- Maintaining flexibility (to ramp up) through sustaining energy conservation presence and relationships with customers and suppliers (e.g., the BC Hydro Alliance of Energy Professionals);
- Supporting priority BC Hydro and government initiatives and strategic objectives (e.g., explore the full potential of energy conservation, and customer strategy);
- Meeting the targets of the 2013 10 Year Rates Plan;
- Providing broad access and coverage to conservation programs and information across each customer sector;
- Limiting missed opportunities for demand-side management customer projects; and
- Addressing energy and capacity load resource balance system needs (e.g., capacity initiatives).

The cost-effectiveness tests and the other components of the framework ensure that the proposed fiscal 2017 to fiscal 2019 demand-side measures expenditures are beneficial to customers in that the expenditures will not increase BC Hydro's revenue requirement, are cost-effective compared to supply-side resource options, and provide access and coverage to conservation programs and information for each customer sector so that customers have the opportunity to reduce their electricity bills. Demand-side management also provides additional non-energy benefits as described in section 10.4.3.5.

10.3.4.2 Alternatives Considered

The following table and discussion compares BC Hydro's proposed Demand-Side Management Plan that extends the moderation strategy of the 2013 Integrated Resource Plan Recommended Action 1, against the following two alternatives for illustrative purposes:

- 2013 Integrated Resource Plan Alternative: This is a higher level of demand-side management based on the 2013 Integrated Resource Plan demand-side management outlook, updated to reflect new developments such as lower than planned savings from conservation rates and new energy savings from codes and standards. There are cost and rate consequences with regard to this alternative; and
- No Programs Alternative: This is a lower level of demand-side management which would have cancelled all demand-side management programs in fiscal 2017, allowing for wind down of program expenditures, but continuing Codes and Standards and Rate Structures. This alternative would still reduce new incremental demand by at least 66 per cent by 2020, which is the minimum amount of demand-side management that can be targeted per B.C. Energy Objective 2(b). There are significant consequences with this alternative, as discussed further below.

10.3.4.3 Analysis

As among the alternatives outlined above, the Demand-Side Management Plan set out in this application is the preferred option for balancing the multiple attributes of importance to BC Hydro and its customers.

The performance of the Demand-Side Management Plan versus the two alternative scenarios on the attributes set out above is provided below in Table 10-5.

Table 10-5 Performance of Alternative Demand-Side Management Plans

	Attribute	Unit	2013 Integrated Resource Plan	Demand-Side Management Plan	No Programs
1	Program Total Resource Cost Test (@ BC Hydro long-run marginal cost) (>1=cost-effective)	Benefit-cost ratio	2.0	2.1	2.2
2	Program Utility Cost Test (@ BC Hydro long-run marginal cost) (>1=cost-effective)	Benefit-cost ratio	2.9	3.2	3.0
3	Program Utility Cost Test (@Market Prices) (>1=reduced revenue requirement)	Benefit-cost ratio	1.2	1.4	1.1
4	% Load Growth at F2021 (mid Load Forecast, without LNG) – *Clean Energy Act* energy objective of at least 66%.	%	116	106	102
5	Flexibility to ramp programs up to IRP incremental GWh levels	Years	n/a	3-5 years	7-10 years
6	Support for other BC Hydro or Government initiatives	HML	High	Medium-High	Low
7	Directional rate impact (F2020 to F2024) – relative to the proposed Demand-Side Management Plan	%	Increase Rates	n/a	Decrease Rates
8	Impact to Demand-Side Management Program 3-year spend (F2017 to F2019) – relative to the proposed Demand-Side Management Plan	$ million	+120	n/a	-180
9	Impact on customers broad access to demand-side management programs	HML	Low	Medium	High
10	Missed demand-side management project opportunities	HML	Low	Medium	High

All alternatives are cost-effective compared to both market prices and long-run marginal costs (as shown in Table 10-5, Rows 1 to 3). Both the proposed Demand-Side Management Plan and the No Programs alternative provide rate decrease impacts (Table 10-5, Row 7) relative to the 2013 Integrated Resource Plan alternative.

All three alternatives meet the B.C. energy objective of BC Hydro reducing its expected increase in demand for electricity by the year 2020 by at least 66 per cent based on the mid load forecast without load from liquefied natural gas projects (Table 10-5, Row 4). However, this metric can be highly variable given changes in the load forecast (for example, due to a recession) or assumptions regarding industrial growth (for example, load from liquefied natural gas projects). As such, the results in Table 10-5, Row 4 represent a snapshot in time. Depending on the assumptions used in calculating this metric, the results can vary significantly. Table 10-6 explores this variability with some further examples.

Table 10-6 Variability of Per Cent Load Growth Metric

	Attribute	Unit	2013 Integrated Resource Plan	Demand-Side Management Plan	No Programs
4	% Load Growth at F2021 (mid Load Forecast, without LNG)	%	116	106	102
4a	% Load Growth at F2021 (high Load Forecast with LNG)	%	64	59	56
4b	% Load Growth at F2022 (mid Load Forecast with LNG)	%	85	76	72

Table 10-6, Row 4a portrays the per cent growth results with the high load forecast and with load from LNG projects. On this perspective, none of the alternatives meet the B.C. energy objective; however, the 2013 Integrated Resource Plan alternative almost achieves 66 per cent and the Demand-Side Management Plan has some flexibility to ramp up and respond to this outcome, while the No Programs alternative would take several years longer to respond as indicated by Table 10-5, Row 5.

As 2020 is only a few years away, BC Hydro has also begun looking at the longer term impact of demand-side management, in order to provide the capability to meet future targets. While the Government has not established a demand-side management target or metric past fiscal 2021, it expects BC Hydro to consider using the 2018 Integrated Resource Plan for that discussion.[72] For illustration, if the target were to be extended just one year beyond calendar 2020 and LNG load was included in the calculation, the performance towards meeting the target drops considerably (as shown in Table 10-6, Row 4b).

Given the load forecast variability and uncertainty in the target beyond 2020, the flexibility of the Demand-Side Management Plan becomes an important attribute (Table 10-5, Row 5), and the lower level of flexibility for the No Programs alternative risks not being able to ramp up in time to meet any emerging load/resource deficit. Programs also complement rates and are critical for setting the stage for changes to codes and standards. As a result, the cancellation of all programs increases the risk that some of the anticipated savings from rates and codes and standards will not materialize and that future codes and standards development will be slowed.

Regarding other BC Hydro and Government initiatives (Table 10-5, Row 6, e.g., the Customer Strategy, or helping customers with bill reduction opportunities), the 2013 Integrated Resource Plan alternative provides the best support, followed closely by the Demand-Side Management Plan. The No Programs alternative performs relatively poorly on this attribute.

10.3.4.4 Conclusions

BC Hydro considered cost-effectiveness tests, other attributes and alternatives in arriving at its final Demand-Side Management Plan for the three years covered by this

[72] Refer to the Minister’s Letter of Support, Appendix BB.

application. After consideration of the attribute trade-offs, the Demand-Side Management Plan set out in this application is the preferred alternative for balancing the multiple objectives of importance to BC Hydro's customers.

The 2013 Integrated Resource Plan alternative was not selected because it fails to take advantage of the opportunity to realign the Demand-Side Management Plan around changing customer and system needs and utilize the flexibility to ramp up savings levels in response to emerging needs in the future. In addition, as shown in Table 10-5 Performance of Alternative Demand-Side Management Plans the 2013 Integrated Resource Plan alternative increases rates relative to the Demand-Side Management Plan and the No Programs alternative (Table 10-5, Row 7).

The No Programs alternative has significant impacts to customers and BC Hydro's strategic objectives because it does not provide customers with the opportunity to leverage technology and obtain the energy consumption insight necessary to optimize their energy consumption, reduce their bills and deliver benefits to BC Hydro and its customers. For this and other downsides of this alternative noted above, such as reduced flexibility to ramp up saving levels, the No Programs alternative was not selected.

The longer-term demand-side management outlook and expenditure levels for fiscal 2020 and beyond will be the subject of the 2018 Integrated Resource Plan and future application(s).

10.3.5 Minister's Letter of Support

By letter dated December 16, 2015 (**Minister's Letter**) and attached as Appendix BB, the Minister of Energy and Mines has confirmed that Government supports BC Hydro demand-side management plans and expenditure levels for the fiscal 2017 to fiscal 2019 period. In particular, the Minister's Letter confirms and expresses Government's support for the following objectives for fiscal 2017 to fiscal 2019 demand-side management expenditures as a prudent and responsible evolution of the demand-side management plan approved by Government as part of the 2013 Integrated Resource Plan:

- "Exceed the *Clean Energy Act* energy objective to meet at least 66 percent of incremental demand from 2008 to 2020 through conservation.
- Provide access to conservation opportunities and information for all customer groups.
- Reflect a prudent approach including discontinuing or reducing programs that are not as cost-effective and have served their purpose, reducing marketing dollars and adjusting certain offers.
- Support areas best suited to meet evolving customer and resource needs such as building codes and standards, capacity-focused DSM and customer energy management solutions.
- Leverage investments in smart meters and a smart grid by providing customers with information they need to make smart energy choices."

The Minister confirmed Government's support for demand-side management expenditures averaging $125 million per year for the fiscal 2017 to fiscal 2019 test period, and also confirmed that Government understands that as a result of these changes, BC Hydro will achieve a lower level of electricity savings than was established in the 2013 Integrated Resource Plan.

10.3.6 Alignment with B.C.'s Energy Objectives

The Demand-Side Management Plan contributes to and aligns with certain British Columbia's energy objectives as stated in section 2 of the *Clean Energy Act*. Specifically, the Demand-Side Management Plan contributes to the following B.C. Energy Objectives:

- ***To achieve electricity self-sufficiency***: The Demand-Side Management Plan's forecast energy and capacity savings will contribute to BC Hydro maintaining electricity self-sufficiency in 2016 and each year thereafter;
- ***To take demand-side measures and to conserve energy, including the objective of BC Hydro reducing its expected increase in demand for electricity by the year 2020 by at least 66 per cent***: demand-side management is forecast to reduce BC Hydro's increase in electricity demand in fiscal 2021 by approximately 106 per cent (for further details, refer to Table 10-6);
- ***To use and foster the development in British Columbia of innovative technologies that support energy conservation and efficiency and the use of clean or renewable resources***: Both the demand-side management programs and the Codes and Standards initiative will use and foster development of innovative technologies supporting energy conservation;
- ***To ensure BC Hydro's rates remain among the most competitive rates charged by public utilities in North America***: The reduction in the Demand-Side Management Plan relative to 2013 Integrated Resource Plan outlook would reduce rates, as shown in Table 10-5 Performance of Alternative Demand-Side Management Plans;
- ***To reduce B.C. greenhouse gas emissions***: The Demand-Side Management Plan is forecast to result in natural gas savings that will reduce B.C. greenhouse gas emissions. Refer to section 10.4.3.3;
- ***To encourage the switching from one kind of energy source or use to another that decreases greenhouse gas emissions in B.C.***: The Demand-Side Management Plan includes the Codes and Standards initiative which supports local governments and developers to consider and develop community wide energy plans that encourage energy efficiency and decrease greenhouse gas emissions. For details refer to Appendix V, section 1;

- ***To encourage communities to reduce greenhouse gas emissions and use energy efficiently***: The B.C. Building Codes and City of Vancouver Bylaws initiatives provide support for communities to incorporate electricity efficiency into community energy planning and implement energy efficiency policies and projects. Support will also be provided to First Nations communities for energy efficient housing and community buildings and on the development and implementation of energy efficient housing policies and community energy plans. For details refer to Appendix V, section 1; and
- ***To encourage economic development and the creation and retention of jobs***: BC Hydro's current demand-side management efforts create significant economic activity and jobs within the province.

10.3.7 Alignment with *Demand-Side Measures Regulation*

As outlined in section 10.3.3, in considering whether to accept the fiscal 2017 to fiscal 2019 demand-side measures expenditure schedule, the British Columbia Utilities Commission must consider the extent to which the demand-side measures are cost-effective within the meaning prescribed by the *Demand-Side Measures Regulation*. The proposed demand-side measures are cost-effective within the meaning of the *Demand-Side Measures Regulation*. In particular:

- ***Comparison of costs and benefits***: subsection 4(1) of the *Demand-Side Measures Regulation* allows the British Columbia Utilities Commission to compare the costs and benefits of demand-side measures individually, as a group or as a portfolio as a whole. The cost benefit comparisons at all three levels are reported in Appendix W;
- ***Total Resource Cost Test***: subsection 4(1.1) of the *Demand-Side Measures Regulation* requires the British Columbia Utilities Commission to determine cost-effectiveness by applying the Total Resource Cost Test in a prescribed manner, namely by using the amount the British Columbia Utilities Commission is satisfied represents BC Hydro's long-run marginal cost of acquiring electricity

generated from clean or renewable resources in B.C. to quantify avoided electric energy costs and to quantify avoided natural gas costs, and by increasing the total avoided cost benefits by 15 per cent. Alternatively, a utility could demonstrate the non-energy benefits attributable to demand-side measures consistent with the *Demand-Side Measures Regulation*. The Total Resource Cost Test results reported in Appendix W have been calculated using BC Hydro's long-run marginal cost and the total avoided cost benefits have been increased by 15 per cent (the 15 per cent increase is labelled non-electricity benefits in Appendix W, Table 10). Results show that the demand-side measures are cost-effective;

- ***Attribution of codes and standards savings to demand-side measures***: subsection 4(1.4) of the *Demand-Side Measures Regulation* allows the British Columbia Utilities Commission to attribute a portion of the avoided energy and capacity costs that will result from a code or standard to a demand-side measure that will increase the use of a "regulated item". BC Hydro has not included the attribution of savings under this regulation in calculating the demand-side management cost tests in Appendix W;
- ***Limit on cost-ineffective demand-side measures:*** subsections 4(1.5) and 4(1.6) of the *Demand-Side Measures Regulation* require the British Columbia Utilities Commission to determine that a demand-side measure, other than a "specified demand-side measure" or a "public awareness program", is not cost-effective if a) it is not cost-effective without applying subsection 4(1.1) and b) total expenditures on it and other such demand-side measures exceed 10 per cent of the demand-side measures expenditure portfolio in the case of an electric utility. All of the demand-side measures in the Demand-Side Management Plan are cost-effective without applying subsection 4(1.1); therefore subsections 4(1.5) and 4(1.6) do not apply;

- ***Utility Cost Test***: subsection 4(1.8) of the *Demand-Side Measures Regulation* allows the British Columbia Utilities Commission to determine that a demand-side measure, other than the specified types of measures, is not cost-effective if the demand-side measure would not be considered cost-effective under the Utility Cost Test. As shown in Appendix W, with the exception of the Low Income program, all of the demand-side measures in the Demand-Side Management Plan are cost-effective under the Utility Cost test;
- ***Demand-side measure for low income households***: subsection 4(2) of the *Demand-Side Measures Regulation* requires the British Columbia Utilities Commission to use, in addition to any other analysis it considers appropriate, the Total Resource Cost Test in determining whether demand-side measures intended specifically to assist residents of low-income households to reduce their energy consumption are cost-effective, and to increase the benefits of such demand-side measures by 40 per cent. Appendix W includes the Total Resource Cost Test result for BC Hydro's Low Income program, including the addition of 40 per cent to the benefits, showing that BC Hydro's Low Income program is cost-effective;
- ***Specified demand-side measures***: subsection (4)(4) of the *Demand-Side Measures Regulation* requires the British Columbia Utilities Commission to determine the cost-effectiveness of specified demand-side measures proposed in an expenditure portfolio[73] by determining whether the portfolio is cost-effective as a whole. BC Hydro's evidence demonstrating that the portfolio (i.e., all of the proposed demand-side measures) is cost-effective as a whole is in section 10.4.4 and Appendix W;
- ***Public awareness program***: subsection 4(5) of the *Demand-Side Measures Regulation* requires the British Columbia Utilities Commission to determine the

[73] An expenditure portfolio is defined in the Demand-Side Measures Regulation to mean "the class of demand-side measures that is composed of all of the demand-side measures proposed by a public utility in an expenditure schedule submitted under section 44.2 of the Act".

cost-effectiveness of a public awareness program by determining whether the portfolio including the public awareness program is cost-effective as a whole. BC Hydro's evidence demonstrating that the portfolio is cost-effective as a whole is provided in section 10.4.4 and Appendix W; and

- ***Ratepayer Impact Measure Test***: subsection 4(6) of the *Demand-Side Measures Regulation* indicates that the British Columbia Utilities Commission cannot determine that a demand-side measure is not cost-effective on the basis of the results of a Ratepayer Impact Measure Test. BC Hydro does not rely on the ratepayer impact measure test to assess the cost-effectiveness of its demand-side management.

Section 3 and subsection 4(1.2) and 4(1.3) of the *Demand-Side Measures Regulation* are not applicable to the demand-side measures in the Demand-Side Management Plan.

10.4 Fiscal 2017 to Fiscal 2019 Demand-Side Management Expenditures, Savings and Benefits

This section provides a more detailed view of the expenditures, energy and capacity savings and other benefits of the Demand-Side Management Plan.

10.4.1 Demand-Side Management Expenditures

As described in section 10.3.4, BC Hydro plans to extend a moderation of demand-side management expenditures for three more years (relative to the outlook in the 2013 Integrated Resource Plan), while maintaining the capability to ramp up demand-side management initiatives in later years as required as a system resource or to support changing customer expectations. As discussed further in section 10.5, the Demand-Side Management Plan maintains a broad range of measures to provide access to conservation opportunities and information for all customer groups, while reducing the overall level of demand-side management expenditures. Expenditure reductions have been achieved by discontinuing or reducing programs that are not as cost-effective or have served their purpose, reducing marketing dollars or adjusting certain offers.

At the same time, Conservation and Energy Management looks for cost reductions and service enhancements in its overall operations. The following list of initiatives from the past three years exemplifies these efforts:

- Implementation of an enterprise management resource system to manage custom project processing for energy studies, energy managers and incentives. This system, launched in August 2012, reached sustainment mode in fiscal 2014 resulting in reduced timelines, paper processing and resources required for custom program delivery. Implementation costs were $2.4 million with initial project savings of $820,000 annually. As further integration and process changes occurred, an additional $700,000 in annual savings have been achieved;
- Implementation in fiscal 2014 of a batch payment system to automate and streamline the payment of incentives for self-serve projects. Approximate costs of $75,000, with $70,000 in annual savings;
- Development of online application and payment process for rebate programs to replace customer manual data entry requirements. Costs were approximately $75,000 and it is now easier for customers to participate in rebate programs; and
- Implementation of a process review for custom projects designed to improve timelines and reduce operational touch points. Implementation costs were approximately $150,000, with annual savings of $420,000.

Table 10-7 presents a more detailed breakdown of the fiscal 2017 to fiscal 2019 demand-side management expenditures.

Table 10-7 Fiscal 2017 to Fiscal 2019 Demand-Side Management Expenditure Summary ($ million)

	F2017 Plan	F2018 Plan	F2019 Plan	F2017-F2019 Total
Codes and Standards[74]	**4.7**	**4.8**	**4.9**	**14.5**
Rate Structures	**1.2**	**1.0**	**1.2**	**3.5**
Programs				
Residential	13.1	11.8	13.0	37.9
Commercial	43.9	29.9	25.7	99.4
Industrial	26.7	28.8	27.4	82.9
Thermo-Mechanical Pulp[75]	0.0	55.8	0.0	55.8
Total Programs	**83.7**	**126.3**	**66.0**	**276.0**
Capacity Focused Demand-Side Management[76]	**10.0**	**14.2**	**14.4**	**38.6**
Supporting Initiatives	**14.0**	**14.2**	**14.2**	**42.4**
Total	**113.7**	**160.6**	**100.7**	**375.0**

Appendix W provides more details on these expenditures and the long-term demand-side management outlook out to fiscal 2024.

10.4.2 Energy and Capacity Savings

A breakdown of forecasted energy and capacity savings from the Demand-Side Management Plan is provided in Table 10-8.

74 Incorporates ongoing efforts to explore additional opportunities to leverage more codes and standards to achieve conservation savings and gain knowledge and confidence about potential savings. Kick started in fiscal 2014 to fiscal 2016 as 2013 Integrated Resource Plan Recommended Action 3.

75 The Thermo-Mechanical Pulp program is discussed in Appendix V, section 13. The Thermo-Mechanical Pulp Program is shown separately from other demand-side management programs because the costs of this program are covered by the Direction to the British Columbia Utilities Commission Respecting the Authority's TMP Program (B.C. Reg. 139/2015). This Direction is reviewed in Chapter 2 and a copy is provided in Appendix CC.

76 Load curtailment and capacity focused demand-side management pilots and programs, continuing the work initiated as 2013 Integrated Resource Plan Recommended Action 2 in fiscal 2014 to fiscal 2016.

Table 10-8 Cumulative Energy and Capacity Savings since Fiscal 2016

	F2017 Plan	F2018 Plan	F2019 Plan
Codes and Standards	838	1,096	1,410
Rate Structures	166	192	200
Programs			
Residential	83	108	137
Commercial	214	265	310
Industrial	301	373	455
Thermo-Mechanical Pulp	66	293	293
Total Programs	664	1,040	1,194
Total Energy (GWh)	**1,668**	**2,327**	**2,804**
Codes and Standards	182	234	283
Rate Structures	17	27	29
Programs			
Residential	19	28	35
Commercial	21	34	41
Industrial	29	41	51
Thermo-Mechanical Pulp	8	10	35
Total Programs	77	113	161
Total Capacity (MW)	**276**	**373**	**473**

10.4.3 Other Benefits

10.4.3.1 Reduction to the Revenue Requirements

The programs in the Demand-Side Management Plan are forecast to have a net levelized Utility Cost of $22 per MWh (fiscal 2016 value) and a net levelized Total Resource Cost of $41 per MWh (fiscal 2016 value). Levelized costs for individual demand-side management initiatives and tools are provided in Table 10 of Appendix W.

The Utility Cost and Total Resource Cost Tests compare favourably to the long-run marginal cost of electricity at $100 per MWh and BC Hydro’s reference price as described in Chapter 3. The Utility Cost of the demand-side management programs are also compared to the B.C. border sell price forecast, which is approximately $36 per MWh.

Using these price forecasts, the Demand-Side Management Expenditures for programs (at a net levelized Utility Cost of $22 per MWh) will reduce BC Hydro's revenue requirements.

10.4.3.2 Economic Development Benefits

The implementation of the Demand-Side Management Plan will generate significant economic activity and jobs within the province. These jobs include direct employment through the purchase of labour and materials, spin-off jobs from business activity in the supply chain and the spending of wages, and jobs created by the spending of demand-side management related energy bill savings. Demand-side management actions undertaken by customers also make them more competitive through the better use of electricity, creating expanded economic development.

10.4.3.3 Environmental Benefits

Demand-side management avoids the environmental impacts associated with the construction of new electricity infrastructure facilities. Additionally, the Demand-Side Management Plan is forecast to reduce the province's greenhouse gas emissions through customers reducing their natural gas usage in concert with electricity usage. For example, BC Hydro estimates that the Demand-Side Management Plan will reduce B.C. greenhouse gas emissions by approximately 16,000 tonnes in fiscal 2019. The emission savings come from initiatives where BC Hydro is not in partnership with FortisBC Energy Inc. and/or where FortisBC Energy Inc. is not already claiming these emissions.

10.4.3.4 Capacity Benefits

Energy conservation and energy efficiency savings also produce associated capacity savings; that is, capacity savings as a side-effect or additional benefit of the energy savings initiatives. The capacity savings of BC Hydro initiatives are shown in Appendix W, and Table 10-8 of this chapter.

BC Hydro has begun pilot programs to evaluate opportunities for capacity savings from direct load control and load curtailment at customer facilities. Over the past two years, pilot activities have been undertaken to better understand the potential and limitations for these savings. The potential launch and expansion of capacity-focused initiatives will increase the value of demand-side management to the BC Hydro transmission and distribution system in areas that become more capacity constrained.

10.4.3.5 Additional Customer Benefits

The projects undertaken by business customers make them more competitive in their industries through the better use of electricity. The implementation of demand-side management initiatives can also provide customers with additional benefits such as reduced waste generation or product losses, reduced maintenance costs in commercial and industrial facilities, and extended equipment life. These are referred to as customer non-energy benefits and where they can be quantified are included in the Total Resource Cost cost-benefit analysis for demand-side management initiatives.

Rather than attempt to allocate a portion of incremental costs to the non-energy component of the customer project, BC Hydro estimates the non-energy benefits and deducts them from the costs. This corrects for an overstatement of the unit cost of energy savings that would occur without factoring in the non-energy benefits related to the demand-side management initiative. This allows for a proper matching of costs and benefits from demand-side management initiatives.

There are also benefits that are more qualitative in nature, such as improved comfort in homes, an enhanced environmental responsibility, or improved customer control of energy management. Qualitative benefits are not included in the benefit cost analysis.

10.4.4 Cost-Effectiveness Analysis

The fiscal 2017 to fiscal 2019 activities are expected to produce electricity savings at a lower cost than new supply. Table 10-9 presents benefit-cost ratios for the Demand-Side Management Plan from fiscal 2016 to fiscal 2024 for the two standard demand-side management cost tests: the Utility Cost Test and the Total Resource Cost Test.[77] Appendix W contains more detailed cost test results and the levelized resource costs of individual initiatives. For both tests, values of one or greater than one indicate cost-effectiveness.

Table 10-9 Benefit-Cost Ratios[78]

	Utility Cost Test	Total Resource Cost Test
Codes and Standards	149.1	6.4
Rate Structures	19.8	6.4
Programs	3.2	2.1
All three Demand-Side Management Tools	10.3	4.0

10.5 Demand-Side Management Plan Details

This section explains how BC Hydro developed the Demand-Side Management Plan and then describes the three demand-side management tools (Codes and Standards, Rate Structures and Programs), the capacity-focussed pilots and the two supporting initiatives that make up the Demand-Side Management Plan.

BC Hydro has developed its demand-side management initiatives with guidance from the framework outlined in section 10.3. This resulted in the evolution of the Demand-Side Management Plan in a number of ways, and involved choices around what to retain, what to modify and what to cancel.

[77] Descriptions and formulas for these demand-side management cost tests are provided in Appendix ~~W~~GG.

[78] The factors included in the three benefit-cost ratios are set out in Appendix W. Economic development and environmental benefits are not factored into the benefit cost ratios. A $100 long-run marginal cost was used to calculate the values in Table 10-9.

Firstly, BC Hydro has started to pursue a number of strategies to investigate and respond to changing customer expectations and system needs with its demand-side management programs, which include:

- Increasing the focus on its strategic energy management offers for commercial and industrial customers. Strategic energy management can be defined simply as taking a holistic approach to managing energy use in order to improve energy performance, by achieving persistent energy and cost savings over the long term. It focuses on business practice change from senior management through to operations staff, affecting organizational culture to reduce energy waste and improve energy intensity. Strategic energy management emphasizes equipping and enabling management and staff to impact energy consumption through behavioral and operational change. While strategic energy management does not emphasize a technical or project centric approach, strategic energy management principles and objectives may support capital project implementation;
- Refining existing programs so that they can better leverage new information and technology. As an example of this strategy, the residential Behaviour program is utilizing information on residential customer consumption to provide customers with insights on their electricity consumption in order for them to become more informed and proactively make adjustments. A similar approach is also available to commercial customers through the Continuous Optimization offer within Leaders in Energy Management, Commercial;
- Consistent with the 2013 Integrated Resource Plan Recommended Action 2, continuing to pursue capacity-focused demand-side management to determine how capacity savings can be acquired and relied upon over the long term. BC Hydro has initiated pilot programs for both industrial load curtailment and commercial and residential demand response. More information on this can be found in section 10.2.2; and

- Exploring new sources of conservation potential and ways to achieve this potential. BC Hydro, with partners FortisBC Energy Inc. and FortisBC Inc., is in the midst of a province-wide Conservation Potential Review, which will provide insight into the technical and economic potential for demand-side management over the next 20 years. Other projects are exploring the prospect of ‘connected’ homes and buildings in the future and the ability of BC Hydro to work with customers through connected devices to manage their energy use.

Secondly, BC Hydro continues with a similar suite of demand-side management initiatives as outlined in the Fiscal 2012 – Fiscal 2014 Revenue Requirement Application, with the following exceptions for the fiscal 2017 to fiscal 2019 period:

- The Refrigerator Buy-Back program was cancelled, due to diminishing savings with second refrigerators becoming more energy efficient;
- BC Hydro no longer offers direct incentives to builders through the New Home program and will shift its focus in this area to Codes and Standards initiatives. BC Hydro believes that through this shift in focus, it can undertake activities in support of improvements to the energy efficiency of new construction and the B.C. Building Code, at a lower cost to ratepayers while still achieving energy savings;
- The industrial Load Displacement program is being cancelled. These projects generally do not represent a lost opportunity, can be captured again at some point in the future, and provide Demand-Side Management Plan expenditure reductions; and
- The Medium General Service and Large General Service conservation rates are being amended per the 2015 Rate Design application.

In developing the individual initiatives, BC Hydro considers and addresses the barriers that prevent customers from taking advantage of cost-effective opportunities to save energy:

- Awareness – customers are not aware of the more efficient technology;
- Availability – the more efficient technology or process is not available on the market;
- Accessibility – the more efficient technology of process is not easily accessible to all customers;
- Affordability – the higher first cost of a more efficient technology or process prevents customers from adopting it, even though it is cost-effective over time; and
- Acceptance – customers do not like the more efficient technology or process.

These barriers, and our response to them, are addressed in the various demand-side management initiative descriptions provided in Appendix V.

The resulting Demand-Side Management Plan includes three demand-side management tools (Codes and Standards, Rate Structures, and Programs), capacity-focused pilots, and two supporting initiatives, described in the following sections. Table 10-10 outlines the scope of the three demand-side management tools. These three tools, the capacity focused pilots and supporting initiatives are described in the subsections below.

Table 10-10 Demand-Side Management Tools and Initiatives

Tools	Initiatives	
Codes and Standards	Product and Equipment Standards	
	• Lighting • Residential appliances	• Residential electronics • Commercial/Industrial Equipment
	Building Codes	
	• B.C. Building Code (Residential and Commercial)	• City of Vancouver Building By-law (Residential and Commercial)
	Codes and Standards Strategy	
	• Technology Innovation • Sustainable Communities • Codes and Standards Investigation	• First Nations Strategies • Residential New Construction
Rate Structures	• Residential Inclining Block	• Transmission Service
Programs	Residential	
	• Behaviour • Low Income • Retail	• Home Energy Rebate Offer • Sector Enabling Activities
	Commercial	
	• Leaders in Energy Management, Commercial • New Construction	• Sector Enabling Activities
	Industrial	
	• Leaders in Energy Management, Transmission • Thermo-Mechanical Pulp	• Leaders in Energy Management, Distribution • Sector Enabling Activities

10.5.1 Codes and Standards

The term codes and standards refers to a range of government policy instruments that can influence energy efficiency, including product/equipment regulations, building codes, tax measures and municipal zoning and building permitting processes.

BC Hydro's codes and standards initiatives are coordinated with programs to help drive the efficient technologies and practices. The Demand-Side Management Plan supports and relies on government implementation of a suite of changes to codes and standards. The building codes and product and equipment standards included in the

Demand-Side Management Plan have either been enacted, announced or are planned by government.

As shown in Table 10-9, the codes and standards tool is a very cost-effective approach to achieving electricity savings compared to the investment required by BC Hydro. Appendix V describes the codes and standards approach of the Demand-Side Management Plan in more detail.

10.5.2 Rate Structures

Rate structures are changes to the design of electricity rates to provide more economically efficient price signals to customers which encourage conservation. BC Hydro currently has conservation rates in place for almost all domestic load; however, BC Hydro has applied in the 2015 Rate Design Application to eliminate the conservation price signal for general service customers. Appendix V provides more detail on the rate structures included in the Demand-Side Management Plan.

10.5.3 Programs

The Demand-Side Management Plan includes a suite of demand-side management programs that deliver a mix of information, access to efficient technology and services, technical assessment and support, and financial assistance to all customer classes, to address barriers to cost-effective energy efficiency and conservation. The demand-side management programs are designed to capture additional demand-side management potential that remains beyond that obtained from codes and standards and rate structures. In addition, programs are designed to complement rates structures and are critical in setting the stage for changes to codes and standards. Sector enabling activities, such as trade ally support and training, support the residential, commercial and industrial sector programs in achieving their savings. More detail on the programs and sector enabling activities included in the Demand-Side Management Plan is provided in Appendix V.

10.5.4 Capacity Focused Demand-Side Management

The Demand-Side Management Plan includes load curtailment and demand response pilot initiatives aimed at determining the dependability of targeted capacity savings for inclusion in BC Hydro's future integrated resource planning.

More details on the load curtailment pilots to be undertaken in the industrial sector, and demand response activities in all customer sectors can be found in Appendix V.

10.5.5 Supporting Initiatives

The Demand-Side Management Plan includes two supporting initiatives, shown in Table 10-11, that provide a critical and necessary foundation of awareness, engagement and other conditions to support the success of the Demand-Side Management Plan's tools and initiatives. Appendix V provides more detail on the supporting initiatives included in the Demand-Side Management Plan.

Table 10-11 Supporting Initiatives

Supporting Initiatives	Description
Public Awareness	Activities are designed to address two specific barriers to demand-side management participation: awareness of ways to increase energy efficiency, including through BC Hydro's demand-side management programs, and acceptance of those programs in order to increase participation and seek out energy savings opportunities.
Indirect and Portfolio Enabling	General management and infrastructure to support implementation of the Demand-Side Management Plan

10.6 Demand-Side Management Delivery Risks and Mitigation

BC Hydro's approach to demand-side management performance management is informed by the identification and assessment of demand-side management related risks and the development of mitigation measures at various stages in the demand-side management process from the design of demand-side management initiatives through to their implementation and evaluation. Risks are assessed and mitigated at the initiative level as well as at the portfolio level. This describes the material risks that have been identified and key demand-side risk mitigation tactics undertaken for the three demand-side management tools and the Demand-Side Management Plan as a whole.

10.6.1 Codes and Standards Risks and Mitigation

The principal risks as they relate to codes and standards are:

- ***Approval Risk***: Planned codes and standards are not approved by Government, or not approved at the planned time;
- ***Coverage Risk***: Codes and standards do not cover as many technologies or building types as expected or prescribe less efficient standards than expected; and
- ***Compliance Risk***: The level of compliance with a code or standard is less than expected.

A key aspect of codes and standards risk mitigation is that BC Hydro does not have direct control over the implementation of codes and standards and thus relies on the action of governments to deliver these savings. Thus there is uncertainty regarding the timing, coverage and efficiency level of codes and standards outlined in the Demand-Side Management Plan. These risks are mitigated in part by BC Hydro using its influence to support the implementation of codes and standards through its demand-side management programs and codes and standards supporting initiative. Specifically, BC Hydro:

- Provides technical and financial support to the development and identification of comprehensive and effective energy efficiency standards, regulations, codes and other government policy instruments;
- Builds stakeholder support with other Canadian and U.S. utilities (e.g., in the Pacific Northwest) for changes to codes and standards;

- Supports trade allies in their compliance with codes and standards via training and workshops for industry;
- Supports governments in their enforcement of codes and standards by providing market intelligence on energy-efficient equipment stocking and building construction practices; and
- Supports changes to codes and standards through demand-side management programs by increasing the market share of energy efficient products and building practices.

In addition, BC Hydro monitors government approval of codes and standards and uses the best available information, including results from completed evaluations, to estimate codes and standards savings. As new information becomes available, BC Hydro incorporates this information into its estimates of codes and standards savings. If it becomes apparent that codes and standards savings might be less than planned, BC Hydro can respond in a number of ways, for example:

- Approach the most appropriate government (i.e., federal, provincial or local government) to explore opportunities to expedite the enactment of regulations; and
- Consider expanded demand-side management programs to capture some of the savings expected from a code or standard.

10.6.2 Rate Structure Risks and Mitigation

The principal risk as it relates to rate structures is:

- Customer Response Risk: The customer response to the rate structure is lower than expected.

As discussed in BC Hydro's 2015 Rate Design Application, this risk materialized with the Large General Service and Medium General Service rate structures, where evaluations found that energy savings from these rates were considerably less than planned.

BC Hydro mitigates this risk in several ways during design and implementation. First, BC Hydro has a rate design process that includes customer consultations, and culminates in a transparent public review of BC Hydro's rate design application by the British Columbia Utilities Commission. Second, the customer response to rate structures is forecasted using the best available information. As new information becomes available, BC Hydro incorporates this information into its estimates of rate structure savings. Third, in implementing rate structures, BC Hydro provides information to customers to educate them on the rate structure and how they can respond to it and achieve bill savings. Finally, BC Hydro's demand-side management programs are designed to complement and support the rate structure and customer response to conservation price signals.

If rate structure savings are lower than planned, BC Hydro can take the following actions:

- Redesign rate structures;
- Increase customer communication and support effort related to rate structures; and
- Expand other demand-side management initiatives to achieve additional savings if needed and cost-effective.

10.6.3 Program Risks and Mitigation

The principal risks as they relate to programs are:

- Participation Risk: demand-side management programs do not achieve the expected level of participation;
- Savings Risk: The savings per participant in demand-side management programs is lower than expected; and

- Cost Risk: Program costs are higher than expected.

To minimize the risk of lower participation than planned, demand-side management programs are designed to address barriers to energy efficiency and elicit customer participation using information from BC Hydro customers, trade allies and other jurisdictions. BC Hydro also recognizes that changing customer expectations over time will mean that programs may need to adapt to achieve desired participation levels. BC Hydro also undertakes market and technical research into current and future demand-side management opportunities to develop the most effective initiative designs. In addition, conservation rate structures complement programs.

Programs also face a risk of delivering lower savings per participant than planned. This risk is mitigated by using a variety of sources on unit savings to forecast overall program savings, including market research, technical reviews of projects, measurement and verification results and program evaluations. In addition, if measurement and verification results indicate that less energy savings were received than the amount stated in the demand-side management incentive agreement, the incentive amount can be adjusted per the incentive agreement so that BC Hydro is not overpaying for reduced energy savings. In these agreements, BC Hydro has a mechanism to ensure that it is paying for verified savings. This linkage between measurement and verification results and incentive payments is not common among demand-side management programs in other jurisdictions.

If demand-side management program electricity savings or budget are not tracking to plan, BC Hydro can respond by:

- Modifying program advertising;
- Modifying the program application process or eligibility criteria;
- Modifying program incentives;
- Modifying the program approach; and

- Revising the list of qualifying products.

The flexibility of programs also provides a greater ability to adjust programs in response to savings shortfalls in other demand-side management tools.

10.6.4 Portfolio Risks and Mitigation

At the portfolio or plan level, relying upon the diversity of demand-side management is a key risk mitigation strategy. If demand-side management savings fall below plan or costs rise above plan, BC Hydro can shift costs or resources between initiatives or sectors. For example, through the diversity of the demand-side management plan, if one program is more successful than planned, resources may be shifted from another program to take advantage of that success. In doing so, these adjustments allow for the improvement of the Demand-Side Management Plan as it is implemented and the mitigation of both cost and deliverability risk.

10.7 Demand-Side Management Performance Management

BC Hydro manages the performance of the Demand-Side Management Plan in a comprehensive manner that includes tracking a number of performance metrics and regular management oversight and reporting.

10.7.1 Electricity Savings Confirmation

Reliably estimating demand-side management electricity savings, upon which financial decisions are made and progress towards targets are reported, is a key aspect of managing demand-side management performance. Depending on the demand-side management initiative, there can be up to four distinct areas of activity that ultimately contribute to the confirmation of demand-side management savings estimates. These are: technical review, site inspection, measurement and verification, and evaluation. Results are used in project and contract management to ensure that BC Hydro receives the expected project benefits for its incentive payments.

BC Hydro is selective in the use of these processes, and focuses its efforts where warranted to improve the accuracy of savings estimates and reduce exposure to the risks described in section 10.6.

- ***Technical Review*** – The purpose of the technical review is to ensure that energy savings are adequately described and supported by appropriate engineering calculations. For residential initiatives and prescriptive measures in the commercial and industrial customer sectors, the technical review is typically used to assess energy savings as part of the program design. For the commercial and industrial sectors, the technical review is done before and shortly after an energy conservation measure is implemented, and ensures that the following elements are in place for a specific energy conservation measure: a description of the energy conservation measure; a defined and quantified baseline condition; a system boundary; explicit engineering calculations of the electricity savings achieved; and documented and referenced assumptions that align with common industry standards and practices.
- ***Site Inspection*** –The inspection is conducted to confirm that the project is complete, was implemented as agreed with BC Hydro and to confirm or adjust the variables and assumptions used to estimate the energy savings during the technical review. Site inspection is performed on a sample of projects.
- ***Measurement and Verification*** - is the quantification of individual project energy savings through analysis of actual project operating and performance data. On-site measurement and data collection, utility billing data and computer modelling may be used to analyze and confirm the energy and demand savings from individual projects. BC Hydro conducts measurement and verification on a sample of customer projects. At the initiative level, measurement and verification analysis is used to measure and confirm program assumptions such as hours of equipment usage or product specifications. In carrying out its measurement and verification work, BC Hydro is guided by an internationally accepted protocol for

measurement and verification of energy saving projects. Further details on BC Hydro's measurement and verification approach and methods are provided in Appendix Z.

- ***Evaluation*** – BC Hydro evaluates demand-side management initiatives through studies and activities aimed at determining its effects. Evaluations use measurement and verification results and may also trigger additional measurement and verification activities to confirm technical assumptions on projects. In carrying out its evaluation activities, BC Hydro is guided by the California Evaluation Framework and Protocols and the U.S. Department of Energy Uniform Methods Project Protocols, which are generally regarded as the leading protocols for demand-side management evaluation in North America. Evaluation reports are reviewed by external demand-side management evaluation advisors and reviewed and approved by a cross-BC Hydro committee. This ensures the evaluation reports align with industry best practice. BC Hydro also files an annual report to the British Columbia Utilities Commission with Executive Summaries of the previous year's evaluation reports. The past two years of this report (covering fiscal 2014 and fiscal 2015) along with further details on BC Hydro's evaluation principles, approach and plan are shown in Appendix Z.

BC Hydro periodically updates reported demand-side management savings to reflect new information stemming from the steps outlined above, which provides a comprehensive process for estimating demand-side management savings.

10.7.2 Performance Metric Tracking

Key performance indicators are monitored by program management monthly. If the initiative is not performing as expected or if there is new information that could impact the initiative, program management will work to identify and analyze the issue and understand its potential impact on initiative performance. Once the issue is identified and understood, solutions are explored and if a specific change has a good prospect of mitigating the issue, adjustments would be made to the initiative.

The primary performance metrics for the Demand-Side Management Plan are energy savings and costs. Variances from plan are identified and discussed by management. Systemic variances from plan trigger consideration of corrective measures.

BC Hydro also tracks how effective demand-side management initiatives are at meeting customer expectations. To further gauge ongoing performance, BC Hydro is in contact with manufacturers, retailers, and other trade allies and partners to solicit feedback and gain insight into new opportunities.

Table 10-12 through Table 10-16 summarize the key demand-side management performance indicators. Both leading and lagging indicators are tracked on a continuous basis. Leading indicators are prospective (i.e. forward-looking) while lagging indicators are retrospective (i.e., "after-the-fact").

Table 10-12 Key Performance Indicators for Codes and Standards

Demand-Side Management Tool	Key Performance Indicators	
	Leading	**Lagging**
Codes and Standards	• Government plans and announcements • Public consultations • Government approval • Effective date • Program activity	• Energy savings • Costs • Compliance

Table 10-13 Key Performance Indicators for Rate Structures

Demand-Side Management Tool	Key Performance Indicators	
	Leading	**Lagging**
Rate Structures	• Effective date	• Energy savings • Costs

Table 10-14 Key Performance Indicators for Residential Initiatives

Demand-Side Management Initiative	Key Performance Indicators	
Residential	**Leading**	**Lagging**
Behaviour	• Team Power Smart members • Number of customers with MyHydro Profile and BC Hydro Account linked to it	• Challenge participants • Energy savings • Costs • Number of times Energy Visualization Portlet application of account accessed energy savings • Customer surveys
Retail Program	• Participation of and feedback from key retailers • Tracking of qualifying models • Collection of retail stocking and price point information	• Participants • Energy savings • Costs • Customer surveys • Retailer/manufacturer surveys
Low Income	• Distribution of Energy Savings Kits • Contractor crews engaged	• Participants • Energy savings • Costs • Customer surveys
Home Energy Rebate Offer	• Identified customer interest • Feedback from contractors	• Participants • Energy savings • Costs • Customer surveys • Contractor surveys

Table 10-15 Key Performance Indicators for Commercial Initiatives

Demand-Side Management Initiative	Key Performance Indicators	
Commercial	**Leading**	**Lagging**
Leaders in Energy Management, Commercial	• Energy manager agreements • Energy study agreements • Energy savings identified in completed energy studies • Identified potential customer projects • Incentive agreements	• Participants • Energy savings • Costs • Trade ally surveys • Customer surveys
New Construction	• Energy study agreements • Identified potential customer projects • Incentive agreements • Energy savings identified in completed energy studies	• Participants • Energy savings • Costs • Trade ally surveys • Customer surveys

Table 10-16 Key Performance Indicators for Industrial Initiatives

Demand-Side Management Initiative	Key Performance Indicators	
Industrial	**Leading**	**Lagging**
Leaders in Energy Management, Transmission Leaders in Energy Management, Distribution	• Energy manager agreements • Energy studies completed • Energy savings identified in completed energy studies • Identified potential customer projects • Incentive agreements	• Energy savings • Costs • Customer surveys • Participants
Thermo-Mechanical Pulp	• Status of incentive applications and agreements	• Energy savings • Costs

10.7.3 Management Review and Oversight

Oversight of the Demand-Side Management Plan occurs at both the initiative and plan levels, and is undertaken within the context of BC Hydro's governance processes and policies.

Conservation and Energy Management's governance structures are designed to ensure that the specific programs used to execute the Demand-Side Management

Plan are effective at achieving target energy savings while also effectively managing costs and mitigating operational risks. Demand-side management programs require a business case and follow the Expenditure Authorization Request process, which is the same approval process used by capital programs within BC Hydro. Non-program costs (for example sector enabling, codes and standards or portfolio-level activities) are managed through the annual budgeting process.

Demand-side management performance reporting is prepared on a monthly basis and shows expenditures versus budget, energy savings and key highlights. Performance reporting is reviewed monthly by the management team and by BC Hydro's executive team. The Board of Directors receives quarterly performance reports on demand-side management.

Beyond the internal management reviews, an annual demand-side management performance report is filed with the British Columbia Utilities Commission. The report provides information on expenditures and energy savings for the fiscal year, variances from plan, overall Demand-Side Management Plan performance and mitigation measures. The past three years of this report (covering fiscal 2014 to fiscal 2016) are provided in Appendix Y.

10.7.4 Process Improvement

In managing the Demand-Side Management Plan, BC Hydro looks for productivity and process improvements. Section 10.4 provides examples of these initiatives, outlining the costs and savings obtained. These initiatives have been central to the improved processing of customer applications over the past five years.

In addition to process and operations improvements, BC Hydro is partnering with other utilities and agencies to pool resources and present a single offer to customers. For example, since 2009 BC Hydro, FortisBC Energy Inc. and FortisBC Inc. have worked together to develop enhanced utility integration. In addition to an anticipated increase in the level of energy conservation and greenhouse gas emission reductions, greater efficiencies and reduced costs in the development and delivery of customer demand-side management programs and initiatives are being achieved.

Over the first three years, it was estimated that over $1.9 million in shared incremental cost savings were achieved, customer reach was improved, and the demand-side management programs have become more streamlined. More recently, shared operational costs savings of $4.5 million were estimated for fiscal 2014 and a further $5.4 million in fiscal 2015. Table 10-17 provides a description of these coordination activities. The Conservation Potential Review project mentioned in the table will also provide savings compared to having separate studies undertaken by each utility.

Table 10-17 BC Hydro – FortisBC Coordination Activities

Program Coordination	Accomplishments have come from joining forces and sharing skills and resources (e.g., marketing, communications, and consultation). The focus has been on the residential and commercial sectors. More limited coordination on the industrial side has occurred, starting with sharing market research, process and program guideline and includes a few discreet projects. Through this ongoing relationship, BC Hydro, FortisBC Energy Inc. and FortisBC Inc. continue to explore and identify further areas to partner.
Conservation Potential Review	BC Hydro is working with FortisBC Energy Inc. and FortisBC Inc. with involvement by Pacific Northern Gas to conduct a joint Conservation Potential Review. The Conservation Potential Review project has recently started, but it is expected that there will be results available in fiscal 2017.

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List of Appendices

Fiscal 2017 to Fiscal 2019
Revenue Requirements Application

Appendix A

Financial Schedules

Revenue Requirements Model

Revenue Requirements Summary
($ million)

Line		Reference	F2015 RRA	F2015 Actual	F2015 Diff	F2016 RRA	F2016 Actual	F2016 Diff	F2017 Plan	F2018 Plan	F2019 Plan
	Column		1	2	3 = 2 - 1	4	5	6 = 5- 4	7	8	9
1	**Cost of Energy**	3.0 L1	1,384.5	1,512.5	128.0	1,391.7	1,475.6	83.9	1,549.3	1,657.8	1,762.9
2	**Operating Costs**	3.0 L17	1,170.8	1,303.0	132.2	1,146.6	1,251.5	104.9	1,185.0	1,250.9	1,183.4
3	**Taxes**	3.0 L23	213.8	206.1	(7.7)	224.1	213.1	(11.0)	223.3	231.8	238.7
4	**Amortization**	3.0 L28	698.7	691.7	(7.0)	758.0	739.5	(18.5)	785.4	825.7	855.6
5	**Finance Charges**	3.0 L33	725.0	664.1	(60.9)	838.3	746.6	(91.7)	711.4	745.9	785.0
6	**Return on Equity**	3.0 L38	581.5	580.8	(0.7)	651.9	655.0	3.2	684.7	698.4	712.4
7	**Non-Tariff Revenue**	3.0 L42	(121.3)	(135.2)	(13.9)	(126.6)	(138.6)	(12.0)	(134.5)	(136.7)	(139.0)
8	**Inter-Segment Revenue**	3.0 L51	(52.6)	(50.6)	2.0	(53.5)	(55.7)	(2.2)	(62.5)	(64.3)	(65.3)
	Deferral Accounts										
9	Deferral Account Additions	2.1 L33	0.0	(309.8)	(309.8)	0.0	(382.3)	(382.3)	0.0	0.0	0.0
10	Interest on Deferral Accounts	2.1 L34	(30.2)	(30.6)	(0.4)	(23.8)	(36.8)	(13.0)	(41.7)	(34.3)	(26.6)
11	Deferral Account Recoveries	2.1 L35	208.4	198.1	(10.4)	223.0	209.5	(13.4)	223.5	231.3	241.8
12	Total		178.2	(142.3)	(320.5)	199.2	(209.6)	(408.7)	181.8	197.0	215.3
	Other Regulatory Accounts										
13	Regulatory Account Additions	2.2 L217	(359.0)	(489.3)	(130.3)	(310.3)	(414.3)	(104.0)	(269.8)	(258.2)	(174.4)
14	Interest on Regulatory Accounts	2.2 L218	(37.1)	(36.6)	0.5	(38.0)	(35.7)	2.2	(34.4)	(34.1)	(33.6)
15	Regulatory Account Recoveries	2.2 L219	124.5	197.8	73.2	132.9	254.1	121.2	10.3	(114.2)	(119.1)
16	Total		(271.6)	(328.1)	(56.5)	(215.4)	(195.9)	19.4	(293.9)	(406.5)	(327.0)
	Subsidiary Net Income										
17	Powerex Net Income		(110.0)	(120.1)	(10.1)	(110.0)	**(58.7)**	51.3	**(115.2)**	**(115.2)**	**(115.1)**
18	Powertech Net Income		(4.2)	(4.4)	(0.2)	(5.1)	**(4.2)**	0.9	**(4.5)**	**(4.8)**	**(5.1)**
19	Total		(114.2)	(124.5)	(10.3)	(115.1)	(62.9)	52.2	(119.7)	(119.9)	(120.2)
20	**Less Other Utilities Revenue**	14.0 L18	(16.2)	(18.6)	(2.4)	(16.5)	(18.2)	(1.7)	(12.6)	(12.0)	(12.1)
21	**Less Liquefied Natural Gas Revenue**	14.0 L19	0.0	0.0	0.0	0.0	0.0	0.0	(4.4)	(10.7)	(10.9)
22	**Less Deferral Rider**	14.0 L23	(208.4)	(198.1)	10.3	(223.0)	(209.5)	13.4	(223.5)	(231.3)	(241.8)
23	**Total Rate Revenue Requirement**		4,168.3	3,961.0	(207.3)	4,459.7	4,190.9	(268.8)	4,469.9	4,626.1	4,836.8
	Rate Revenue at Current Rates										
24	Total Domestic Revenue	14.0 L24	4,392.9	4,177.6	(215.3)	4,699.2	4,418.7	(280.5)	4,538.4	4,551.8	4,627.4
25	Less Other Utilities	Line 20	(16.2)	(18.6)	(2.4)	(16.5)	(18.2)	(1.7)	(12.6)	(12.0)	(12.1)
26	Less Liquefied Natural Gas Revenue	Line 21	0.0	0.0	0.0	0.0	0.0	0.0	(4.4)	(10.7)	(10.9)
27	Less Deferral Rider	Line 22	(208.4)	(198.1)	10.3	(223.0)	(209.5)	13.4	(223.5)	(231.3)	(241.8)
28	Revenue Subject to Rate Increase		4,168.3	3,961.0	(207.3)	4,459.7	4,190.9	(268.8)	4,298.0	4,297.8	4,362.5
29	**Revenue Shortfall**	L23 - L28	0.0	0.0		0.0	0.0		171.9	328.3	474.2
30	**Rate Increases**		9.00%	9.00%		6.00%	6.00%		4.00%	3.50%	3.00%
31	**Deferral Account Rate Rider**		5.00%	5.00%		5.00%	5.00%		5.00%	5.00%	5.00%
32	**Net Bill Impact**		9.00%	9.00%		6.00%	6.00%		4.00%	3.50%	3.00%
33	**Total Rate Revenue Requirement**	Line 23							4,469.9	4,626.1	4,836.8
34	**Rate Smoothing Regulatory Account transfers**	2.2 L172							210.0	285.9	299.4
35	**Revenue Requirement before transfers to Rate Smoothing Regulatory Account**								4,679.9	4,912.1	5,136.1

Deferral Accounts
($ million)

Line	Column	Reference	F2015 RRA	F2015 Actual	F2015 Diff	F2016 RRA	F2016 Actual	F2016 Diff	F2017 Plan	F2018 Plan	F2019 Plan
			1	2	3 = 2 - 1	4	5	6 = 5- 4	7	8	9
	Heritage Deferral Account										
1	Beginning of Year		65.4	104.8	39.4	51.2	164.7	113.5	(23.9)	(20.1)	(16.0)
2	Adjustment to Opening Balance		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	Additions	Line 41	0.0	81.7	81.7	0.0	(151.9)	(151.9)	0.0	0.0	0.0
4	Interest		2.4	4.5	2.1	1.9	0.3	(1.6)	(0.9)	(0.7)	(0.6)
5	Recovery		(16.6)	(26.2)	(9.6)	(17.7)	(37.0)	(19.2)	4.7	4.8	5.1
6	Transfer of GM Shrum 3	2.2 L67	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7	End of Year		51.2	164.7	113.5	35.4	(23.9)	(59.3)	(20.1)	(16.0)	(11.5)
	Non-Heritage Deferral Account										
8	Beginning of Year		386.3	361.6	(24.7)	302.6	524.1	221.5	916.8	771.0	612.9
9	Adjustment to Opening Balance		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10	Additions	Line 42	0.0	238.2	238.2	0.0	482.9	482.9	0.0	0.0	0.0
11	Interest		14.2	14.8	0.6	11.2	27.5	16.3	33.4	27.5	21.3
12	Recovery		(98.0)	(90.6)	7.4	(104.8)	(117.7)	(12.8)	(179.3)	(185.5)	(194.0)
13	Transfer of Storm Restoration	2.2 L47	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
14	Transfer from BCTCDA		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
15	End of Year		302.6	524.1	221.5	209.0	916.8	707.9	771.0	612.9	440.3
	Trade Income Deferral Account										
16	Beginning of Year		370.2	324.7	(45.5)	289.9	244.6	(45.3)	250.0	210.2	167.2
17	Adjustment to Opening Balance		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
18	Additions	Line 43	0.0	(10.1)	(10.1)	0.0	51.3	51.3	0.0	0.0	0.0
19	Interest		13.6	11.3	(2.3)	10.7	9.1	(1.7)	9.1	7.5	5.8
20	Recovery		(93.9)	(81.3)	12.6	(100.4)	(54.9)	45.5	(48.9)	(50.6)	(52.9)
21	End of Year		289.9	244.6	(45.3)	200.2	250.0	49.8	210.2	167.2	120.1
	BCTC Deferral Account										
22	Beginning of Year		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
23	Additions		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
24	Interest		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
25	Recovery		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
26	Transfer to NHDA		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
27	End of Year		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	End of Year Balances										
28	Heritage	Line 7	51.2	164.7	113.5	35.4	(23.9)	(59.3)	(20.1)	(16.0)	(11.5)
29	Non-Heritage	Line 15	302.6	524.1	221.5	209.0	916.8	707.9	771.0	612.9	440.3
30	Trade Income	Line 21	289.9	244.6	(45.3)	200.2	250.0	49.8	210.2	167.2	120.1
31	BCTC	Line 27	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
32	Total		643.7	933.4	289.7	444.5	1,142.9	698.4	961.1	764.1	548.9
	Summary										
33	Deferral Account Additions		0.0	309.8	309.8	0.0	382.3	382.3	0.0	0.0	0.0
34	Interest on Deferral Accounts		30.2	30.6	0.4	23.8	36.8	13.0	41.7	34.3	26.6
35	Deferral Account Recoveries		(208.4)	(198.1)	10.4	(223.0)	(209.5)	13.4	(223.5)	(231.3)	(241.8)
36	Transfer of GM Shrum 3	Line 6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
37	Transfer of Storm Restoration	Line 13	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
38	Adjustment to Opening Balance	L2+L9+L17	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
39	Deferral Account Net Transfers		(178.2)	142.3	320.5	(199.2)	209.6	408.7	(181.8)	(197.0)	(215.3)
40	**Interest Rate**	8.0 L59	4.21%	4.13%	(0.08%)	4.47%	4.08%	(0.39%)	4.04%	4.06%	4.13%

Deferral Accounts
($ million)

Line	Column	Reference	F2015 RRA	F2015 Actual	F2015 Diff	F2016 RRA	F2016 Actual	F2016 Diff	F2017 Plan	F2018 Plan	F2019 Plan
			1	2	3 = 2 - 1	4	5	6 = 5- 4	7	8	9
	Summary of Items Subject to Deferral										
41	Heritage Payment Obligation	4.0 L77	353.2	434.9	81.7	399.2	247.3	(151.9)	305.3	285.4	317.1
42	Cost of Non-Heritage Energy	4.0 L92	1,074.3	1,312.5	238.2	1,032.2	1,515.1	482.9	1,271.9	1,409.3	1,482.9
43	Trade Income	1.0 L17	110.0	120.1	10.1	110.0	58.7	(51.3)	115.2	115.2	115.1

Other Regulatory Accounts
($ million)

Line	Column	Reference	F2015 RRA	F2015 Actual	F2015 Diff	F2016 RRA	F2016 Actual	F2016 Diff	F2017 Plan	F2018 Plan	F2019 Plan
			1	2	3 = 2 - 1	4	5	6 = 5- 4	7	8	9
	Demand-Side Management										
1	Beginning of Year		820.6	787.8	(32.8)	897.8	841.4	(56.3)	907.2	931.8	995.7
2	Adjustment to Opening Balance		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	Additions	5.0 L51	150.5	124.8	(25.7)	131.1	145.2	14.1	113.7	160.6	100.7
4	F11 RRA NSA Adjustment	5.0 L10	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5	Amortization on Existing		(73.3)	(71.1)	2.2	(73.3)	(79.4)	(6.1)	(89.1)	(96.7)	(105.5)
6	Amortization on Additions		0.0	0.0	0.0	(10.0)	0.0	10.0	0.0	0.0	0.0
7	End of Year		897.8	841.4	(56.3)	945.6	907.2	(38.4)	931.8	995.7	990.9
	First Nations Costs										
8	Beginning of Year		174.9	173.0	(1.9)	174.2	151.2	(22.9)	132.8	131.1	120.4
9	Adjustment to Opening Balance		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10	Additions	5.0 L52	3.5	1.6	(1.9)	3.0	1.5	(1.5)	5.6	3.7	2.8
11	Transfer from Provision	Line 18	32.0	13.1	(18.9)	13.7	16.9	3.2	21.3	20.8	12.4
12	Interest		7.2	7.0	(0.2)	7.2	6.4	(0.8)	5.2	5.0	4.5
13	Recovery	5.0 L29	(43.5)	(43.5)	(0.0)	(43.2)	(43.2)	0.0	(33.8)	(40.2)	(39.0)
14	End of Year		174.2	151.2	(22.9)	154.8	132.8	(22.0)	131.1	120.4	101.0
	First Nations Settlement Provisions										
15	Beginning of Year		415.9	416.2	0.3	401.4	413.2	11.8	408.6	399.2	395.7
16	Additions - Operating	5.0 L93	0.0	1.4	1.4	0.0	(5.0)	(5.0)	(5.3)	0.0	0.0
17	Additions - Accretion	8.0 L7	17.5	8.6	(8.9)	17.7	17.3	(0.4)	17.2	17.2	17.4
18	Transfer to Negotiation Costs		(32.0)	(13.1)	18.9	(13.7)	(16.9)	(3.2)	(21.3)	(20.8)	(12.4)
19	End of Year		401.4	413.2	11.8	405.5	408.6	3.1	399.2	395.7	400.7
	F07/F08 RRA Depreciation Study										
20	Beginning of Year		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
21	Additions	7.0 L27	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
22	Recovery	7.0 L43	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
23	End of Year		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Site C Clean Energy Project										
24	Beginning of Year		361.6	338.0	(23.7)	376.9	418.7	41.8	435.6	453.2	471.6
25	Additions	5.0 L53	0.0	65.4	65.4	0.0	0.0	0.0	0.0	0.0	0.0
26	Interest		15.2	15.3	0.1	16.8	16.9	0.1	17.6	18.4	19.5
27	Recovery	5.0 L30	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
28	End of Year		376.9	418.7	41.8	393.7	435.6	41.9	453.2	471.6	491.1
	Future Removal and Site Restoration										
29	Beginning of Year		(65.7)	(55.2)	10.5	(41.1)	(32.8)	8.3	(8.6)	0.0	0.0
30	Adjustment to Opening Balance		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
31	Additions	N/A	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
32	Recovery	7.0 L50	24.6	22.4	(2.2)	31.2	24.2	(7.0)	8.6	0.0	0.0
33	End of Year		(41.1)	(32.8)	8.3	(9.9)	(8.6)	1.3	0.0	0.0	0.0
	Foreign Exchange Gains/Losses										
34	Beginning of Year		(96.1)	(88.8)	7.3	(94.4)	(70.8)	23.6	(68.6)	(63.3)	(32.0)
35	Adjustment to Opening Balance		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
36	Additions	8.0 L2	1.0	17.7	16.7	(0.1)	3.2	3.3	5.8	(6.8)	(3.5)
37	Recovery	8.0 L30	0.7	0.3	(0.4)	0.7	(0.9)	(1.6)	(0.6)	38.1	38.6
38	End of Year		(94.4)	(70.8)	23.6	(93.8)	(68.6)	25.3	(63.3)	(32.0)	3.1

Other Regulatory Accounts
($ million)

Line		Reference	F2015 RRA	F2015 Actual	F2015 Diff	F2016 RRA	F2016 Actual	F2016 Diff	F2017 Plan	F2018 Plan	F2019 Plan
	Column		1	2	3 = 2 - 1	4	5	6 = 5- 4	7	8	9
	Pre-1996 Customer Contributions										
39	Beginning of Year		81.1	81.1	0.0	87.4	87.4	(0.0)	92.1	91.4	88.2
40	Additions	N/A	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
41	Recovery	7.0 L51	6.3	6.3	(0.0)	4.7	4.7	0.0	(0.7)	(3.2)	(4.9)
42	End of Year		87.4	87.4	(0.0)	92.1	92.1	(0.0)	91.4	88.2	83.3
	Storm Restoration Costs										
43	Beginning of Year		(2.6)	(2.5)	0.1	(1.3)	7.9	9.2	29.5	19.7	9.8
44	Additions	5.0 L54	0.0	9.0	9.0	0.0	19.6	19.6	0.0	0.0	0.0
45	Interest		(0.1)	(0.0)	0.0	(0.0)	**0.6**	0.7	1.0	0.6	0.2
46	Recovery	5.0 L31	1.4	1.4	(0.0)	1.4	1.4	0.0	(10.8)	(10.4)	(10.0)
47	Transfer to NHDA		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
48	End of Year		(1.3)	7.9	9.2	0.0	29.5	29.5	19.7	9.8	0.0
	Procurement Enhancement										
49	Beginning of Year		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
50	Additions - Operating	5.0 L55	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
51	Additions - Amortization	7.0 L32	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
52	Interest		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
53	F11 RRA NSA Adjustment	5.0 L32	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
54	Recovery	5.0 L33	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
55	End of Year		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Capital Project Investigation										
56	Beginning of Year		34.7	34.7	(0.0)	29.9	29.8	(0.0)	25.0	20.1	15.3
57	Adjustment to Opening Balance		0.0	0.0	0.0	0.0	**(0.1)**	(0.1)	0.0	0.0	0.0
58	Additions	5.0 L56	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
59	Interest		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
60	Recovery	5.0 L34	(4.8)	(4.8)	0.0	(4.8)	(4.8)	0.0	(4.8)	(4.8)	(4.8)
61	End of Year		29.9	29.8	(0.0)	25.0	25.0	(0.1)	20.1	15.3	10.5
	GM Shrum 3										
62	Beginning of Year		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
63	Additions - Deferred Operating	5.0 L57	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
64	Additions - COE	4.0 L75	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
65	Interest		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
66	Insurance Proceeds	4.0 L50	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
67	Transfer to HDA		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
68	End of Year		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	F2010 ROE Adjustment										
69	Beginning of Year		11.3	11.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0
70	Additions	9.0 L55	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
71	Interest	N/A	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
72	Recovery	9.0 L56	(11.3)	(11.3)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
73	End of Year		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Other Regulatory Accounts
($ million)

Line		Reference	F2015 RRA	F2015 Actual	F2015 Diff	F2016 RRA	F2016 Actual	F2016 Diff	F2017 Plan	F2018 Plan	F2019 Plan
	Column		1	2	3 = 2 - 1	4	5	6 = 5- 4	7	8	9
	Net Employment Costs										
74	Beginning of Year		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
75	Additions	N/A	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
76	Interest		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
77	Recovery	5.0 L35	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
78	End of Year		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Total Taxes										
79	Beginning of Year		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
80	Additions	N/A	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
81	Interest		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
82	Recovery	6.0 L30	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
83	End of Year		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Amortization of Capital Additions										
84	Beginning of Year		(18.5)	(3.7)	14.9	(9.3)	(3.9)	5.5	(9.7)	(6.4)	(3.2)
85	Additions - Bad Debt	5.0 L63	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
86	Interest		(0.6)	(0.5)	0.1	(0.2)	(0.6)	(0.4)	(0.3)	(0.2)	(0.1)
87	Recovery	7.0 L57	9.8	0.3	(9.5)	9.4	(5.2)	(14.7)	3.6	3.4	3.3
88	End of Year		(9.3)	(3.9)	5.5	(0.1)	(9.7)	(9.6)	(6.4)	(3.2)	0.0
	Total Finance Charges										
89	Beginning of Year		(51.1)	(78.7)	(27.6)	(25.6)	(173.1)	(147.4)	(305.5)	(203.7)	(101.8)
90	Adjustment to Opening Balance		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
91	Additions	N/A	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
92	Recovery	8.0 L32+L33-L3	25.5	(94.3)	(119.9)	25.5	(132.5)	(158.0)	101.8	101.8	101.8
93	End of Year		(25.6)	(173.1)	(147.4)	(0.1)	(305.5)	(305.4)	(203.7)	(101.8)	0.0
	Smart Metering & Infrastructure										
94	Beginning of Year		282.0	276.5	(5.5)	286.7	283.4	(3.3)	282.6	260.9	239.1
95	Adjustment to Opening Balance		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
96	Additions - Deferred Operating	5.0 L58	28.4	22.7	(5.8)	21.5	24.5	3.0	0.0	0.0	0.0
97	Additions - Fibre Write-Off	5.0 L97	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
98	Additions - DSMD Write-Off	5.0 L98	0.0	9.1	9.1	0.0	0.0	0.0	0.0	0.0	0.0
99	Additions - Amortization	7.0 L28	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
100	Legacy Meter Contributions		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
101	Additions - Finance Charges	8.0 L4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
102	Additions - ROE	9.0 L53	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
103	Additions - Non tariff revenues	15.0 L34	(4.8)	(5.4)	(0.6)	(3.4)	(5.3)	(2.0)	0.0	0.0	0.0
104	Interest		11.7	11.1	(0.7)	12.5	11.4	(1.2)	10.8	9.9	9.2
105	Recovery	5.0 L36	(30.5)	(30.5)	0.0	(31.3)	(31.3)	(0.0)	(32.5)	(31.7)	(31.0)
106	End of Year		286.7	283.4	(3.3)	286.0	282.6	(3.4)	260.9	239.1	217.4
	Home Purchase Option Plan										
107	Beginning of Year		22.2	22.1	(0.1)	11.1	11.0	(0.0)	0.0	0.0	0.0
108	Additions - Deferred Operating	5.0 L59	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
109	Additions - Interest	8.0 L5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
110	Interest		0.7	0.7	0.0	0.2	0.3	0.1	0.0	0.0	0.0
111	Recovery	5.0 L37	(11.8)	(11.8)	0.0	(11.3)	(11.3)	0.0	(0.0)	0.0	0.0
112	End of Year		11.1	11.0	(0.0)	0.0	0.0	0.0	0.0	0.0	0.0

Appendix A

Other Regulatory Accounts
($ million)

Line		Reference	F2015 RRA	F2015 Actual	F2015 Diff	F2016 RRA	F2016 Actual	F2016 Diff	F2017 Plan	F2018 Plan	F2019 Plan
	Column		1	2	3 = 2 - 1	4	5	6 = 5- 4	7	8	9
	Non-Current Pension Cost										
113	Beginning of Year		219.0	279.6	60.6	186.3	563.6	377.2	690.5	305.6	274.3
114	Adjustment to Opening Balance		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
115	OCI Deferral	9.0 L8	0.0	264.5	264.5	0.0	68.5	68.5	(335.7)	0.0	0.0
116	Additions		0.0	0.0	0.0	0.0	17.2	17.2	10.1	0.0	0.0
117	Recovery - Operating	5.0 L39	(32.6)	(32.6)	0.0	(15.5)	(15.5)	(0.0)	(59.3)	(31.3)	(31.3)
118	Recovery - Finance Charges	8.0 L31	0.0	52.1	52.1	0.0	56.8	56.8	0.0	0.0	0.0
119	End of Year		186.3	563.6	377.2	170.8	690.5	519.7	305.6	274.3	243.0
	Waneta										
120	Beginning of Year		15.0	15.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
121	Additions		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
122	Recovery		(15.0)	(15.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
123	End of Year		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Environmental Provisions										
124	Beginning of Year		294.9	316.6	21.7	239.1	352.3	113.2	380.9	337.8	301.5
125	Adjustment to Opening Balance		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
126	Additions - Deferred Operating	5.0 L94	0.0	63.8	63.8	0.0	47.1	47.1	0.0	0.0	0.0
127	Additions - Amortization	7.0 L29	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
128	Additions - Accretion	8.0 L8	6.0	5.7	(0.3)	6.0	3.8	(2.2)	3.9	3.8	3.7
129	Transfer to Rock Bay		(46.4)	(20.3)	26.1	0.0	**(2.8)**	(2.8)	**(6.2)**	**(6.4)**	**(9.3)**
130	Transfer to Asbestos		(1.8)	(4.3)	(2.5)	(0.9)	**(5.6)**	(4.6)	**(22.6)**	**(14.8)**	**(13.6)**
131	Recovery	5.0 L102:L105	(13.6)	(9.2)	4.5	(13.3)	(13.9)	(0.6)	(18.3)	(18.9)	(15.3)
132	End of Year		239.1	352.3	113.2	230.9	380.9	150.1	337.8	301.5	267.0
	Rock Bay Remediation										
133	Beginning of Year		52.4	49.4	(3.0)	49.4	20.4	(29.0)	(27.2)	(18.1)	(9.1)
134	Transfer from Environmental	Line 129	46.4	20.3	(26.1)	0.0	2.8	2.8	6.2	6.4	9.3
135	Additions		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
136	Interest		2.1	2.2	0.1	1.1	**0.1**	(1.0)	(0.9)	(0.5)	(0.2)
137	Recovery	5.0 L110	(51.5)	(51.5)	0.0	(50.5)	(50.5)	0.0	3.8	3.2	(0.0)
138	End of Year		49.4	20.4	(29.0)	0.0	(27.2)	(27.2)	(18.1)	(9.1)	0.0
	IFRS PP&E										
139	Beginning of Year		617.3	617.5	0.2	758.2	758.4	0.2	873.0	961.8	1,025.4
140	Adjustment to Opening Balance		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
141	Additions - Deferred Operating	5.0 L60	156.8	156.8	0.0	134.4	134.4	0.0	112.0	89.6	67.2
142	Additions - IDC	8.0 L6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
143	Recovery	5.0 L40	(15.9)	(15.9)	(0.0)	(19.8)	(19.8)	(0.0)	(23.2)	(26.0)	(28.2)
144	End of Year		758.2	758.4	0.2	872.7	873.0	0.2	961.8	1,025.4	1,064.4
	IFRS Pension										
145	Beginning of Year		688.3	688.3	0.0	650.1	650.1	0.0	611.9	573.6	535.4
146	Adjustment to Opening Balance		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
147	Additions	N/A	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
148	Recovery	5.0 L41	(38.2)	(38.2)	0.0	(38.2)	(38.2)	(0.0)	(38.2)	(38.2)	(38.2)
149	End of Year		650.1	650.1	0.0	611.8	611.9	0.0	573.6	535.4	497.1

Other Regulatory Accounts
($ million)

Line		Reference	F2015 RRA	F2015 Actual	F2015 Diff	F2016 RRA	F2016 Actual	F2016 Diff	F2017 Plan	F2018 Plan	F2019 Plan
	Column		1	2	3 = 2 - 1	4	5	6 = 5- 4	7	8	9
	F12-F14 Rate Smoothing										
150	Beginning of Year		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
151	Additions	N/A	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
152	Recovery	5.0 L113	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
153	End of Year		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Arrow Water Divestiture Costs										
154	Beginning of Year		8.9	8.9	(0.0)	4.4	4.4	0.0	0.0	0.0	0.0
155	Additions	5.0 L95	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
155.1	Transfer from Provision	Line 161.1	0.3	0.2	(0.1)	0.3	0.3	(0.0)	1.8	0.3	0.3
156	Interest		0.3	0.3	0.0	0.1	0.1	(0.0)	0.0	0.0	0.0
157	Recovery	5.0 L111:L112	(5.0)	(4.9)	0.1	(4.8)	(4.8)	0.0	(1.8)	(0.3)	(0.3)
158	End of Year		4.4	4.4	0.0	0.0	0.0	(0.0)	0.0	0.0	0.0
	Arrow Water Provision										
159	Beginning of Year		3.2	4.2	1.0	3.0	4.1	1.1	4.6	3.0	2.8
160	Additions	5.0 L96	0.0	0.0	0.0	0.0	0.7	0.7	0.0	0.0	0.0
161	Additions - Accretion	8.0 L9	0.1	0.1	0.0	0.1	0.1	0.0	0.2	0.2	0.2
161.1	Transfer to Arrow Water Costs	5.0 L112	(0.3)	(0.2)	0.1	(0.3)	(0.3)	0.0	(1.8)	(0.3)	(0.3)
162	Recovery		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
163	End of Year		3.0	4.1	1.1	2.8	4.6	1.8	3.0	2.8	2.7
	Asbestos Remediation										
164	Beginning of Year		19.3	17.3	(2.0)	9.6	10.0	0.5	5.1	3.4	1.7
165	Transfer from Environmental	Line 130	1.8	4.3	2.5	0.9	5.6	4.6	22.6	14.8	13.6
166	Additions		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
167	Interest		0.6	0.6	(0.0)	0.2	0.2	0.0	0.2	0.1	0.0
168	Recovery	5.0 L106:L109	(12.1)	(12.1)	(0.0)	(10.8)	(10.8)	(0.0)	(24.4)	(16.6)	(15.3)
169	End of Year		9.6	10.0	0.5	(0.0)	5.1	5.1	3.4	1.7	0.0
	Rate Smoothing										
170	Beginning of Year		0.0	0.0	0.0	166.2	166.2	0.0	287.4	497.4	783.3
171	Additions	N/A	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
172	Recovery	5.0 L114	166.2	166.2	0.0	121.2	121.2	0.0	210.0	285.9	299.4
173	End of Year		166.2	166.2	0.0	287.4	287.4	0.0	497.4	783.3	1,082.7
	Real Property Sales										
174	Beginning of Year		0.0	0.0	0.0	0.0	7.9	7.9	17.7	25.1	15.9
175	Additions	5.0 L99	0.0	7.9	7.9	0.0	9.5	9.5	6.5	(10.0)	(14.0)
176	Interest		0.0	0.0	0.0	0.0	0.3	0.3	0.8	0.8	0.4
177	Recovery		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
178	End of Year		0.0	7.9	7.9	0.0	17.7	17.7	25.1	15.9	2.3
	Minimum Reconnection Charge										
179	Beginning of Year					0.0	0.0	0.0	0.5	(0.0)	(0.0)
180	Additions	15.0 L35				0.0	0.5	0.5	0.0	0.0	0.0
181	Interest					0.0	0.0	0.0	0.0	(0.0)	(0.0)
182	Recovery					0.0	0.0	0.0	(0.5)	0.0	0.0
183	End of Year					0.0	0.5	0.5	(0.0)	(0.0)	(0.0)

Other Regulatory Accounts
($ million)

Line		Reference	F2015 RRA	F2015 Actual	F2015 Diff	F2016 RRA	F2016 Actual	F2016 Diff	F2017 Plan	F2018 Plan	F2019 Plan
	Column		1	2	3 = 2 - 1	4	5	6 = 5- 4	7	8	9
	End of Year Balances										
184	Demand-Side Management	Line 7	897.8	841.4	(56.3)	945.6	907.2	(38.4)	931.8	995.7	990.9
185	First Nations Costs	Line 14	174.2	151.2	(22.9)	154.8	132.8	(22.0)	131.1	120.4	101.0
186	First Nations Settlement Provisions	Line 19	401.4	413.2	11.8	405.5	408.6	3.1	399.2	395.7	400.7
187	F07/F08 RRA Depreciation Study	Line 23	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
188	Site C Clean Energy Project	Line 28	376.9	418.7	41.8	393.7	435.6	41.9	453.2	471.6	491.1
189	Future Removal and Site Restoration	Line 33	(41.1)	(32.8)	8.3	(9.9)	(8.6)	1.3	0.0	0.0	0.0
190	Foreign Exchange Gains/Losses	Line 38	(94.4)	(70.8)	23.6	(93.8)	(68.6)	25.3	(63.3)	(32.0)	3.1
191	Pre-1996 Customer Contributions	Line 42	87.4	87.4	(0.0)	92.1	92.1	(0.0)	91.4	88.2	83.3
192	Storm Restoration Costs	Line 48	(1.3)	7.9	9.2	0.0	29.5	29.5	19.7	9.8	0.0
193	Procurement Enhancement	Line 55	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
194	Capital Project Investigation	Line 61	29.9	29.8	(0.0)	25.0	25.0	(0.1)	20.1	15.3	10.5
195	GM Shrum 3	Line 68	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
196	F2010 ROE Adjustment	Line 73	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
197	Net Employment Costs	Line 78	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
198	Total Taxes	Line 83	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
199	Amortization of Capital Additions	Line 88	(9.3)	(3.9)	5.5	(0.1)	(9.7)	(9.6)	(6.4)	(3.2)	0.0
200	Total Finance Charges	Line 93	(25.6)	(173.1)	(147.4)	(0.1)	(305.5)	(305.4)	(203.7)	(101.8)	0.0
201	Smart Metering & Infrastructure	Line 106	286.7	283.4	(3.3)	286.0	282.6	(3.4)	260.9	239.1	217.4
202	Home Purchase Option Plan	Line 112	11.1	11.0	(0.0)	0.0	0.0	0.0	0.0	0.0	0.0
203	Non-Current Pension Cost	Line 119	186.3	563.6	377.2	170.8	690.5	519.7	305.6	274.3	243.0
204	Waneta	Line 123	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
205	Environmental Provisions	Line 132	239.1	352.3	113.2	230.9	380.9	150.1	337.8	301.5	267.0
206	Rock Bay Remediation	Line 138	49.4	20.4	(29.0)	0.0	(27.2)	(27.2)	(18.1)	(9.1)	0.0
207	IFRS PP&E	Line 144	758.2	758.4	0.2	872.7	873.0	0.2	961.8	1,025.4	1,064.4
208	IFRS Pension	Line 149	650.1	650.1	0.0	611.8	611.9	0.0	573.6	535.4	497.1
209	F12-F14 Rate Smoothing	Line 153	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
210	Arrow Water Divestiture Costs	Line 158	4.4	4.4	0.0	0.0	0.0	(0.0)	0.0	0.0	0.0
211	Arrow Water Provision	Line 163	3.0	4.1	1.1	2.8	4.6	1.8	3.0	2.8	2.7
212	Asbestos Remediation	Line 169	9.6	10.0	0.5	(0.0)	5.1	5.1	3.4	1.7	0.0
213	Rate Smoothing	Line 173	166.2	166.2	0.0	287.4	287.4	0.0	497.4	783.3	1,082.7
214	Real Property Sales	Line 178	0.0	7.9	7.9	0.0	17.7	17.7	25.1	15.9	2.3
215	Minimum Reconnection Charge	Line 183				0.0	0.5	0.5	(0.0)	(0.0)	(0.0)
216	Total		4,159.9	4,501.0	341.1	4,375.3	4,765.4	390.1	4,723.6	5,130.1	5,457.2
	Summary										
217	Regulatory Account Additions		359.0	489.3	130.3	310.3	414.3	104.0	269.8	258.2	174.4
218	Interest on Regulatory Accounts		37.1	36.6	(0.5)	38.0	35.7	(2.2)	34.4	34.1	33.6
219	Regulatory Account Recoveries		(124.5)	(197.8)	(73.2)	(132.9)	(254.1)	(121.2)	(10.3)	114.2	119.1
220	Transfer of Storm Restoration	Line 47	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
221	Transfer of GM Shrum 3	Line 67	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
222	Adjustments to Opening Balances		0.0	0.0	0.0	0.0	(0.1)	(0.1)	0.0	0.0	0.0
223	OCI Deferral (Pension)		0.0	264.5	264.5	0.0	68.5	68.5	(335.7)	0.0	0.0
224	Regulatory Account Net Transfers		271.6	592.6	321.0	215.4	264.4	49.0	(41.8)	406.5	327.0
225	**Interest Rate**	8.0 L59	4.21%	4.13%	(0.08%)	4.47%	4.08%	(0.39%)	4.04%	4.06%	4.13%

Reconciliation of Current and Gross Views
($ million)

Line		Reference	F2015 RRA	F2015 Actual	F2015 Diff	F2016 RRA	F2016 Actual	F2016 Diff	F2017 Plan	F2018 Plan	F2019 Plan
	Column		1	2	3 = 2 - 1	4	5	6 = 5- 4	7	8	9
	Cost of Energy										
1	Total Gross	4.0 L45	1,384.5	1,512.5	128.0	1,391.7	1,475.6	83.9	1,549.3	1,657.8	1,762.9
2	HDA Additions	4.0 L46	0.0	(81.7)	(81.7)	0.0	151.9	151.9	0.0	0.0	0.0
3	NHDA Additions	4.0 L47	0.0	(238.2)	(238.2)	0.0	(482.9)	(482.9)	0.0	0.0	0.0
4	BCTCDA Additions	4.0 L48	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5	Deferred GMS 3 COE	4.0 L49	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
6	GMS 3 Insurance Proceeds	4.0 L50	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7	Water License Variances	4.0 L51	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	Deferred Operating HDA	4.0 L52	0.0	1.9	1.9	0.0	2.5	2.5	0.0	0.0	0.0
9	Deferred Operating NHDA	4.0 L53	0.0	(10.0)	(10.0)	0.0	(9.6)	(9.6)	0.0	0.0	0.0
10	Deferred Amortization NHDA	4.0 L54	0.0	(6.1)	(6.1)	0.0	(9.1)	(9.1)	0.0	0.0	0.0
11	Deferred Taxes NHDA	4.0 L55	0.0	(2.6)	(2.6)	0.0	(3.4)	(3.4)	0.0	0.0	0.0
12	Deferred Waneta Costs	4.0 L56	15.0	15.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13	HDA Recoveries	4.0 L57	16.6	26.2	9.6	17.7	37.0	19.2	(4.7)	(4.8)	(5.1)
14	NHDA Recoveries	4.0 L58	98.0	90.6	(7.4)	104.8	117.7	12.8	179.3	185.5	194.0
15	BCTCDA Recoveries	4.0 L59	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
16	Total Current		1,514.1	1,307.6	(206.5)	1,514.3	1,279.7	(234.6)	1,723.9	1,838.6	1,951.8
	Operating Costs										
17	Total Gross	5.0 L124	1,170.8	1,303.0	132.2	1,146.6	1,251.5	104.9	1,185.0	1,250.9	1,183.4
18	Deferral Account Additions	5.0 L50	0.0	8.1	8.1	0.0	7.1	7.1	0.0	0.0	0.0
19	Deferral Account Recoveries	5.0 L43	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
20	Regulatory Account Additions	5.0 L64+L100	(339.2)	(462.5)	(123.3)	(290.0)	(394.6)	(104.7)	(242.6)	(243.8)	(156.7)
20.1	Subtotal before Recoveries		831.6	848.6	17.1	856.7	864.0	7.4	942.3	1,007.1	1,026.7
21	Regulatory Account Recoveries	5.0 L42+L115	92.0	87.4	(4.6)	121.1	121.7	0.6	34.0	(70.8)	(85.8)
22	Total Current		923.6	936.0	12.4	977.7	985.7	8.0	976.3	936.4	941.0
	Taxes										
23	Total Gross	6.0 L23	213.8	206.1	(7.7)	224.1	213.1	(11.0)	223.3	231.8	238.7
24	Deferral Account Additions	6.0 L24	0.0	2.6	2.6	0.0	3.4	3.4	0.0	0.0	0.0
25	Regulatory Account Additions	N/A	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
25.1	Subtotal before Recoveries		213.8	208.7	(5.1)	224.1	216.5	(7.7)	223.3	231.8	238.7
26	Regulatory Account Recoveries	6.0 L30	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
27	Total Current		213.8	208.7	(5.1)	224.1	216.5	(7.7)	223.3	231.8	238.7
	Amortization										
28	Total Gross	7.0 L31	698.7	691.7	(7.0)	758.0	739.5	(18.5)	785.4	825.7	855.6
29	Deferral Account Additions	7.0 L26.1	0.0	6.1	6.1	0.0	9.1	9.1	0.0	0.0	0.0
30	Regulatory Account Additions	7.0 L30+L34	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
30.1	Subtotal before Recoveries		698.7	697.8	(0.9)	758.0	748.6	(9.4)	785.4	825.7	855.6
31	Regulatory Account Recoveries	7.0 L58	32.5	42.1	9.6	38.0	55.7	17.7	77.6	96.5	107.2
32	Total Current		731.2	739.9	8.7	796.0	804.3	8.3	863.0	922.2	962.8
	Finance Charges										
33	Total Gross	8.0 L1	725.0	664.1	(60.9)	838.3	746.6	(91.7)	711.4	745.9	785.0
34	Interest on Regulatory Accounts	8.0 L29	(67.4)	(67.3)	0.1	(61.8)	(72.5)	(10.8)	(76.1)	(68.4)	(60.1)
35	Regulatory Account Additions	8.0 L10	(24.6)	22.4	47.0	(23.7)	48.4	72.1	(27.1)	(14.4)	(17.7)
35.1	Subtotal before Recoveries		633.0	619.3	(13.7)	752.9	722.4	(30.4)	608.2	663.1	707.1
36	Regulatory Account Recoveries	8.0 L34	(26.2)	(12.6)	13.6	(26.2)	3.8	30.1	(101.3)	(139.9)	(140.5)
37	Total Current		606.8	606.7	(0.1)	726.6	726.3	(0.3)	506.9	523.2	566.6

Reconciliation of Current and Gross Views
($ million)

			F2015			F2016			F2017	F2018	F2019
		Reference	RRA	Actual	Diff	RRA	Actual	Diff	Plan	Plan	Plan
Line	Column		1	2	3 = 2 - 1	4	5	6 = 5- 4	7	8	9

Reconciliation of Current and Gross Views
($ million)

Line		Reference	F2015 RRA	F2015 Actual	F2015 Diff	F2016 RRA	F2016 Actual	F2016 Diff	F2017 Plan	F2018 Plan	F2019 Plan
	Column		1	2	3 = 2 - 1	4	5	6 = 5- 4	7	8	9
	Return on Equity										
38	Total Gross	9.0 L54	581.5	580.8	(0.7)	651.9	655.0	3.2	684.7	698.4	712.4
39	Regulatory Account Additions	2.2 L70+9.0 L53	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
39.1	Subtotal before Recoveries		581.5	580.8	(0.7)	651.9	655.0	3.2	684.7	698.4	712.4
40	Regulatory Account Recoveries	2.2 L72	11.3	11.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0
41	Total Current		592.8	592.1	(0.7)	651.9	655.0	3.2	684.7	698.4	712.4
	Non-Tariff Revenue										
42	Total Gross	15.0 L32	(121.3)	(135.2)	(13.9)	(126.6)	(138.6)	(12.0)	(134.5)	(136.7)	(139.0)
43	Regulatory Account Additions	15.0 L33:L35	4.8	5.4	0.6	3.4	4.8	1.4	0.0	0.0	0.0
43.1	Subtotal before Recoveries		(116.5)	(129.8)	(13.3)	(123.3)	(133.8)	(10.6)	(134.5)	(136.7)	(139.0)
44	Regulatory Account Recoveries		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
45	Total Current	15.0 L36	(116.5)	(129.8)	(13.3)	(123.3)	(133.8)	(10.6)	(134.5)	(136.7)	(139.0)
	Inter-Segment Revenue										
46	Powerex - Business Support Allocation	3.1 L21	(3.0)	(3.0)	0.0	(3.0)	(3.0)	0.0	(2.8)	(2.8)	(2.9)
47	Mark to Market Losses (Gains)	3.1 L22	0.0	(4.8)	(4.8)	0.0	(0.5)	(0.5)	0.0	0.0	0.0
48	Other	3.1 L23	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
49	Powerex PTP Charges	3.4 L21	(23.4)	(30.4)	(7.0)	(29.2)	(6.1)	23.1	(11.8)	(10.1)	(16.6)
50	BC Hydro PTP Charges	3.4 L22	(26.2)	(12.4)	13.8	(21.3)	(46.1)	(24.8)	(47.8)	(51.4)	(45.9)
51	Total		(52.6)	(50.6)	2.0	(53.5)	(55.7)	(2.2)	(62.5)	(64.3)	(65.3)
	Regulatory Account Transfers										
52	Deferral Accounts				0.0			0.0			
53	Other Regulatory Accounts				0.0			0.0			
54	Total		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Powerex Net Income										
55	Total Gross	1.0 L17	(110.0)	(120.1)	(10.1)	(110.0)	(58.7)	51.3	(115.2)	(115.2)	(115.1)
56	TIDA Additions	2.1 L18	0.0	10.1	10.1	0.0	(51.3)	(51.3)	0.0	0.0	0.0
57	TIDA Recoveries	2.1 L20	93.9	81.3	(12.6)	100.4	54.9	(45.5)	48.9	50.6	52.9
58	Total Current		(16.1)	(28.7)	(12.6)	(9.6)	(55.1)	(45.5)	(66.3)	(64.6)	(62.2)
59	**Powertech Net Income**	1.0 L18	(4.2)	(4.4)	(0.2)	(5.1)	(4.2)	0.9	(4.5)	(4.8)	(5.1)
60	**Other Utilities Revenue**	14.0 L18	(16.2)	(18.6)	(2.4)	(16.5)	(18.2)	(1.7)	(12.6)	(12.0)	(12.1)
61	**Liquefied Natural Gas Revenue**	14.0 L19			0.0	0.0	0.0	0.0	(4.4)	(10.7)	(10.9)
62	**Deferral Rider Revenue**	14.0 L23	(208.4)	(198.1)	10.3	(223.0)	(209.5)	13.4	(223.5)	(231.3)	(241.8)
63	**Total Rate Revenue Requirement (Current)**		4,168.3	3,961.0	(207.3)	4,459.7	4,190.9	(268.8)	4,469.9	4,626.1	4,836.8

Reconciliation of Current and Gross Views
($ million)

Line	Column	Reference	F2015 RRA	F2015 Actual	F2015 Diff	F2016 RRA	F2016 Actual	F2016 Diff	F2017 Plan	F2018 Plan	F2019 Plan
			1	2	3 = 2 - 1	4	5	6 = 5- 4	7	8	9
	Summary - Current Rates View										
64	Cost of Energy	Line 16	1,514.1	1,307.6	(206.5)	1,514.3	1,279.7	(234.6)	1,723.9	1,838.6	1,951.8
65	Operating Costs	Line 22	923.6	936.0	12.4	977.7	985.7	8.0	976.3	936.4	941.0
66	Taxes	Line 27	213.8	208.7	(5.1)	224.1	216.5	(7.7)	223.3	231.8	238.7
67	Amortization	Line 32	731.2	739.9	8.7	796.0	804.3	8.3	863.0	922.2	962.8
68	Finance Charges	Line 37	606.8	606.7	(0.1)	726.6	726.3	(0.3)	506.9	523.2	566.6
69	Return on Equity	Line 41	592.8	592.1	(0.7)	651.9	655.0	3.2	684.7	698.4	712.4
70	Non-Tariff Revenue	Line 45	(116.5)	(129.8)	(13.3)	(123.3)	(133.8)	(10.6)	(134.5)	(136.7)	(139.0)
71	Inter-Segment Revenue	Line 51	(52.6)	(50.6)	2.0	(53.5)	(55.7)	(2.2)	(62.5)	(64.3)	(65.3)
72	Subsidiary Net Income	L58+L59	(20.3)	(33.1)	(12.8)	(14.7)	(59.3)	(44.6)	(70.8)	(69.3)	(67.3)
73	Other Utilities Revenue	Line 60	(16.2)	(18.6)	(2.4)	(16.5)	(18.2)	(1.7)	(12.6)	(12.0)	(12.1)
74	Liquefied Natural Gas Revenue	Line 61				0.0	0.0	0.0	(4.4)	(10.7)	(10.9)
75	Deferral Rider Revenue	Line 62	(208.4)	(198.1)	10.3	(223.0)	(209.5)	13.4	(223.5)	(231.3)	(241.8)
76	Total Rate Revenue Requirement		4,168.3	3,961.0	(207.3)	4,459.7	4,190.9	(268.8)	4,469.9	4,626.1	4,836.8
	Allocation of Current Costs										
77	Generation	3.2 L19	1,457.5	1,475.5	17.9	1,589.9	1,625.4	35.5	1,403.3	1,397.7	1,500.8
78	Transmission	3.4 L24	652.4	717.0	64.6	771.6	829.0	57.4	826.1	824.1	844.6
79	Distribution	3.5 L15	974.9	907.1	(67.8)	1,055.9	982.8	(73.1)	970.7	959.4	986.5
80	Customer Care	3.3 L18	1,328.4	1,111.1	(217.3)	1,296.4	1,040.8	(255.7)	1,581.0	1,768.2	1,837.0
81	Business Support	3.1 L25	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	0.0	0.0
82	Subsidiary Net Income	Line 72	(20.3)	(33.1)	(12.8)	(14.7)	(59.3)	(44.6)	(70.8)	(69.3)	(67.3)
83	Other Utilities Revenue	Line 73	(16.2)	(18.6)	(2.4)	(16.5)	(18.2)	(1.7)	(12.6)	(12.0)	(12.1)
84	Liquefied Natural Gas Revenue	Line 74			0.0	0.0	0.0	0.0	(4.4)	(10.7)	(10.9)
85	Deferral Rider Revenue	Line 75	(208.4)	(198.1)	10.3	(223.0)	(209.5)	13.4	(223.5)	(231.3)	(241.8)
86	Total Rate Revenue Requirement		4,168.3	3,961.0	(207.3)	4,459.7	4,190.9	(268.8)	4,469.9	4,626.1	4,836.8

Total Current Costs - Business Support
($ million)

Line	Column	Reference	F2015 RRA	F2015 Actual	F2015 Diff	F2016 RRA	F2016 Actual	F2016 Diff	F2017 Plan	F2018 Plan	F2019 Plan
			1	2	3 = 2 - 1	4	5	6 = 5- 4	7	8	9
1	**Cost of Energy**	4.0 L65	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2	**Current Operating Costs**	5.0 L130:L132	97.4	89.5	(7.9)	155.6	137.5	(18.1)	62.3	23.0	32.7
3	**Taxes**	6.0 L36	14.6	15.0	0.4	15.8	15.6	(0.2)	15.8	16.7	17.2
4	**Current Amortization**	7.0 L64	25.5	34.5	9.0	30.1	161.0	131.0	164.9	172.8	174.7
5	**Current Finance Charges**	8.0 L46	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
6	**Return on Equity**	9.0 L69	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7	**Business Support Allocation**	Line 75	(307.7)	(304.8)	2.9	(369.9)	(405.0)	(35.1)	(374.1)	(310.7)	(328.7)
8	**Non-Tariff Revenue**	15.0 L31	(11.0)	(18.0)	(7.0)	(11.2)	(18.0)	(6.8)	(16.8)	(16.6)	(16.6)
	Internal Allocations										
9	Safety, Health & Environment	3.3 L9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10	First Nations Comm Dev Fund	3.4 L14	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11	Customer Care & Power Smart	5.1 L4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12	Energy Planning & Procure	5.1 L13	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13	IPP Capital Lease Op Costs	5.1 L15	(29.4)	(29.4)	0.0	(33.8)	(34.2)	(0.4)	(28.2)	(63.6)	(54.3)
14	Technology - Depreciation		68.1	71.1	3.0	69.6	0.0	(69.6)	0.0	0.0	0.0
15	Technology	3.4 L18	108.4	108.9	0.4	110.1	107.2	(2.9)	139.5	139.7	138.9
16	Energy Planning, Econ. Development & SVP Corp. Affairs	5.1 L31	(10.2)	(9.0)	1.2	(10.2)	(9.5)	0.8	(9.9)	(10.0)	(10.1)
17	Conservation & Energy Management	5.1 L32	(0.3)	(0.4)	(0.1)	(0.3)	(0.6)	(0.3)	(0.6)	(0.6)	(0.6)
18	Allocation from Capital Infrastructure Project Delivery	3.6 L14	23.2	24.5	1.3	23.0	24.1	1.0	24.0	26.2	23.4
19	Training and Development	3.2 L17	24.3	25.8	1.5	24.3	25.3	1.0	25.9	25.9	26.3
20	Total		184.2	191.5	7.3	182.7	112.4	(70.3)	150.7	117.6	123.5
	Inter-Segment Revenue										
21	Powerex - Business Support Allocation		(3.0)	(3.0)	0.0	(3.0)	(3.0)	0.0	(2.8)	(2.8)	(2.9)
22	Mark to Market Losses (Gains)		0.0	(4.8)	(4.8)	0.0	(0.5)	(0.5)	0.0	0.0	0.0
23	Other		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
24	Total		(3.0)	(7.8)	(4.8)	(3.0)	(3.5)	(0.5)	(2.8)	(2.8)	(2.9)
25	**Total**		(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	0.0	0.0
	Business Support Allocation:										
	Building Operations										
26	Generation		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
27	Transmission		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
28	Distribution		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
29	Customer Care		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
30	Total		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	ABS Costs										
31	Generation		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
32	Transmission		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
33	Distribution		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
34	Customer Care		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
35	Total		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Total Current Costs - Business Support
($ million)

			F2015			F2016			F2017	F2018	F2019
		Reference	RRA	Actual	Diff	RRA	Actual	Diff	Plan	Plan	Plan
Line	Column		1	2	3 = 2 - 1	4	5	6 = 5- 4	7	8	9

Total Current Costs - Business Support
($ million)

Line		Reference	F2015 RRA	F2015 Actual	F2015 Diff	F2016 RRA	F2016 Actual	F2016 Diff	F2017 Plan	F2018 Plan	F2019 Plan
	Column		1	2	3 = 2 - 1	4	5	6 = 5- 4	7	8	9
	Insurance										
36	Generation		5.0	5.0	0.0	5.0	4.2	(0.8)	4.2	4.2	4.2
37	Transmission		2.7	2.7	0.0	2.7	2.5	(0.2)	2.5	2.5	2.5
38	Distribution		2.7	2.7	0.0	2.7	2.5	(0.2)	2.5	2.6	2.6
39	Customer Care		0.3	0.3	0.0	0.3	0.5	0.2	0.5	0.5	0.5
40	Total		10.7	10.7	0.0	10.7	9.7	(1.0)	9.7	9.7	9.7
	Customer Care Support and Billing System Amortization										
41	Generation		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
42	Transmission		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
43	Distribution		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
44	Customer Care		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
45	Total		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Non-Current Pension Costs										
46	Generation		23.3	23.3	0.0	17.7	13.0	(4.7)	24.2	17.1	17.1
47	Transmission		21.9	21.9	0.0	16.4	17.5	1.1	32.6	23.0	23.1
48	Distribution		24.3	24.3	0.0	18.6	17.0	(1.6)	31.7	22.3	22.2
49	Customer Care		1.3	1.3	0.0	1.0	3.5	2.5	6.4	4.5	4.5
50	Total		70.9	70.9	0.0	53.8	51.0	(2.8)	94.9	66.9	66.9
	Fleet/MMBU										
51	Generation		5.0	5.0	0.0	5.1	6.8	1.7	7.2	7.5	7.7
52	Transmission		11.2	11.2	0.0	11.4	24.2	12.7	25.2	26.1	26.7
53	Distribution		22.8	22.8	0.0	23.2	45.7	22.6	47.7	49.5	50.6
54	Customer Care		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
55	Total		39.0	39.0	0.0	39.6	76.7	37.1	80.1	83.1	85.0
	Total Direct Assignments										
56	Generation		33.3	33.3	0.0	27.8	24.0	(3.8)	35.6	28.7	28.9
57	Transmission		35.9	35.9	0.0	30.5	44.1	13.6	60.3	51.6	52.4
58	Distribution		49.8	49.8	0.0	44.5	65.3	20.8	82.0	74.4	75.4
59	Customer Care		1.6	1.6	0.0	1.3	3.9	2.6	6.9	5.0	5.0
60	Total		120.6	120.6	0.0	104.1	137.3	33.3	184.8	159.7	161.7
	Allocators for Balance - %										
61	Generation		27.8%	27.8%	0.0%	27.9%	30.1%	2.2%	29.9%	30.0%	30.1%
62	Transmission		32.2%	32.2%	0.0%	31.8%	30.7%	(1.1%)	31.0%	30.2%	30.3%
63	Distribution		31.2%	31.2%	0.0%	31.6%	30.3%	(1.3%)	30.6%	30.7%	30.6%
64	Customer Care		8.8%	8.8%	0.0%	8.8%	8.9%	0.1%	8.6%	9.2%	9.0%
65	Total		100.0%	100.0%	0.0%	100.0%	100.0%	-	100.0%	100.0%	100.0%
	Allocation of Balance										
66	Generation		52.1	51.3	(0.8)	74.1	80.5	6.4	56.6	45.3	50.3
67	Transmission		60.2	59.3	(0.9)	84.5	82.2	(2.2)	58.6	45.6	50.6
68	Distribution		58.4	57.5	(0.9)	84.0	81.2	(2.8)	57.9	46.3	51.0
69	Customer Care		16.4	16.1	(0.3)	23.3	23.8	0.5	16.2	13.9	15.0
70	Total		187.1	184.2	(2.9)	265.8	267.7	1.9	189.4	151.0	167.0

Total Current Costs - Business Support
($ million)

Line		Reference	F2015 RRA	F2015 Actual	F2015 Diff	F2016 RRA	F2016 Actual	F2016 Diff	F2017 Plan	F2018 Plan	F2019 Plan
	Column		1	2	3 = 2 - 1	4	5	6 = 5- 4	7	8	9
	Total Business Support Allocation										
71	Generation		85.4	84.6	(0.8)	101.9	104.5	2.6	92.1	74.0	79.3
72	Transmission		96.1	95.2	(0.9)	115.0	126.4	11.4	119.0	97.2	103.0
73	Distribution		108.2	107.3	(0.9)	128.5	146.5	18.0	139.9	120.7	126.4
74	Customer Care		18.0	17.8	(0.3)	24.6	27.7	3.1	23.1	18.9	20.0
75	Total		307.7	304.8	(2.9)	369.9	405.0	35.1	374.1	310.7	328.7

Total Current Costs - Generation
($ million)

Line	Column	Reference	F2015 RRA	F2015 Actual	F2015 Diff	F2016 RRA	F2016 Actual	F2016 Diff	F2017 Plan	F2018 Plan	F2019 Plan
			1	2	3 = 2 - 1	4	5	6 = 5- 4	7	8	9
1	**Cost of Energy**	4.0 L61	328.2	335.3	7.1	375.3	397.4	22.1	274.6	245.4	274.3
2	**Current Operating Costs**	5.0 L125	144.5	153.4	8.9	142.1	149.0	7.0	147.8	156.5	158.6
3	**Taxes**	6.0 L32	41.5	39.4	(2.1)	43.1	40.6	(2.5)	40.5	41.6	43.2
4	**Current Amortization**	7.0 L60	312.7	321.7	9.0	332.4	266.2	(66.2)	278.2	295.3	321.7
5	**Current Finance Charges**	8.0 L42	268.8	269.1	0.3	307.2	310.2	3.1	211.4	217.4	242.5
6	**Return on Equity**	9.0 L65	262.6	262.7	0.0	275.6	279.8	4.2	285.5	290.3	304.9
7	**Business Support Allocation**	3.1 L71	85.4	84.6	(0.8)	101.9	104.5	2.6	92.1	74.0	79.3
8	**Non-Tariff Revenue**	15.0 L5	(3.0)	(4.2)	(1.2)	(3.1)	(4.7)	(1.6)	(2.0)	(1.8)	(1.9)
	Internal Allocations										
9	GRTA Allocation	3.4 L9	43.3	43.3	0.0	43.3	43.3	0.0	43.3	43.3	43.3
10	Generation Real Time Dispatch	3.4 L11	1.7	1.7	0.0	1.8	1.8	0.0	1.6	1.5	1.6
11	Generation Ancillary Services	3.4 L16	(1.8)	(1.3)	0.5	(1.8)	(1.9)	(0.1)	(2.5)	(2.5)	(2.5)
12	Aboriginal Relations	3.4 L15	19.4	19.6	0.2	19.3	0.0	(19.3)	0.0	0.0	0.0
13	Energy Planning & Econ Dev	5.2 L10	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
14	Technology - Depreciation	3.1 L14	(68.1)	(71.1)	(3.0)	(69.6)	0.0	69.6	0.0	0.0	0.0
15	Technology		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
16	Allocation from Capital Infrastructure Project Delivery	3.6 L9	46.6	47.1	0.5	46.7	64.3	17.6	58.7	62.6	62.0
17	Training and Development	5.2 L13	(24.3)	(25.8)	(1.5)	(24.3)	(25.3)	(1.0)	(25.9)	(25.9)	(26.3)
18	Total		16.8	13.5	(3.4)	15.5	82.3	66.8	75.2	79.0	78.1
19	**Total**		1,457.5	1,475.5	17.9	1,589.9	1,625.4	35.5	1,403.3	1,397.7	1,500.8

Total Current Costs - Customer Care
($ million)

Line	Column	Reference	F2015 RRA	F2015 Actual	F2015 Diff	F2016 RRA	F2016 Actual	F2016 Diff	F2017 Plan	F2018 Plan	F2019 Plan
			1	2	3 = 2 - 1	4	5	6 = 5- 4	7	8	9
1	**Cost of Energy**	4.0 L64	1,185.9	972.3	(213.6)	1,138.9	882.2	(256.7)	1,449.3	1,593.2	1,677.6
2	**Current Operating Costs**	5.0 L128	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	**Taxes**	6.0 L35	4.8	4.8	0.0	5.8	5.6	(0.2)	2.6	4.2	2.5
4	**Current Amortization**	7.0 L63	22.8	22.8	0.0	25.8	25.8	0.0	17.0	29.4	22.8
5	**Current Finance Charges**	8.0 L45	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
6	**Return on Equity**	9.0 L68	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7	**Business Support Allocation**	3.1 L74	18.0	17.8	(0.3)	24.6	27.7	3.1	23.1	18.9	20.0
8	**Non-Tariff Revenue**	15.0 L24-L34:L35	(18.8)	(22.1)	(3.3)	(18.7)	(22.6)	(3.9)	(24.8)	(24.1)	(23.6)
	Internal Allocations										
9	Safety, Health & Environment	5.3 L4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10	Aboriginal Relations		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11	Power Smart & Customer Care	3.1 L11	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12	Energy Planning & Procurement	3.1 L12	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13	IPP Capital Lease Op Costs	3.1 L13	29.4	29.4	0.0	33.8	34.2	0.4	28.2	63.6	54.3
14	Energy Planning, Econ. Development & SVP Corp. Affairs	3.1 L16	10.2	9.0	(1.2)	10.2	9.5	(0.8)	9.9	10.0	10.1
15	Conservation & Energy Management	3.1 L17	0.3	0.4	0.1	0.3	0.6	0.3	0.6	0.6	0.6
16	Customer Service	3.4 L19	75.8	76.8	1.0	75.8	77.9	2.1	75.2	72.5	72.7
17	Total		115.7	115.6	(0.1)	120.1	122.1	2.0	113.8	146.7	137.8
18	**Total**		1,328.4	1,111.1	(217.3)	1,296.4	1,040.8	(255.7)	1,581.0	1,768.2	1,837.0

Total Current Costs - Transmission
($ million)

Line	Column	Reference	F2015 RRA	F2015 Actual	F2015 Diff	F2016 RRA	F2016 Actual	F2016 Diff	F2017 Plan	F2018 Plan	F2019 Plan
			1	2	3 = 2 - 1	4	5	6 = 5- 4	7	8	9
1	**Cost of Energy**	4.0 L62	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2	**Current Operating Costs**	5.0 L126	367.4	383.3	15.9	366.8	371.1	4.3	417.1	407.8	396.3
3	**Taxes**	6.0 L33	126.1	123.7	(2.4)	132.0	128.5	(3.4)	137.6	141.7	147.2
4	**Current Amortization**	7.0 L61	158.9	184.6	25.7	187.1	184.9	(2.2)	216.9	230.3	240.9
5	**Current Finance Charges**	8.0 L43	167.0	182.1	15.1	233.0	241.7	8.7	180.3	187.9	199.0
6	**Return on Equity**	9.0 L66	163.1	177.7	14.6	209.0	218.0	9.0	243.6	250.8	250.1
7	**Business Support Allocation**	3.1 L72	96.1	95.2	(0.9)	115.0	126.4	11.4	119.0	97.2	103.0
8	**Miscellaneous Revenue**	15.0 L12	(34.7)	(42.0)	(7.4)	(39.2)	(39.7)	(0.6)	(40.5)	(40.3)	(40.8)
	Internal Allocations:										
9	GRTA Allocation		(43.3)	(43.3)	0.0	(43.3)	**(43.3)**	0.0	**(43.3)**	**(43.3)**	**(43.3)**
10	SDA Allocation		(123.2)	(115.3)	7.9	(148.3)	**(121.2)**	27.1	**(125.0)**	**(128.5)**	**(126.1)**
11	Generation Real Time Dispatch		(1.7)	(1.7)	0.0	(1.8)	**(1.8)**	0.0	**(1.6)**	**(1.5)**	**(1.6)**
12	Distribution Real Time Dispatch		(16.7)	(16.7)	0.0	(17.1)	**(17.1)**	0.0	**(16.7)**	**(16.2)**	**(16.6)**
13	PTP Allocation to Distribution		(16.8)	(22.0)	(5.1)	(29.4)	(29.4)	(0.0)	(26.9)	(27.0)	(28.5)
14	First Nations Comm Dev Fund		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
15	Aboriginal Relations		(19.4)	(19.6)	(0.2)	(19.3)	0.0	19.3	0.0	0.0	0.0
16	Generation Ancillary Services		1.8	1.3	(0.5)	1.8	**1.9**	0.1	**2.5**	**2.5**	**2.5**
17	Allocation from Capital Infrastructure Project Delivery	3.6 L10	61.6	58.2	(3.4)	61.7	46.4	(15.4)	37.5	36.5	36.5
18	Technology	5.4 L16	(108.4)	(108.9)	(0.4)	(110.1)	(107.2)	2.9	(139.5)	(139.7)	(138.9)
19	Customer Service	5.4 L28	(75.8)	(76.8)	(1.0)	(75.8)	(77.9)	(2.1)	(75.2)	(72.5)	(72.7)
20	Total		(342.0)	(344.8)	(2.8)	(381.6)	(349.7)	31.8	(388.2)	(389.8)	(388.7)
	Inter-Segment Revenue										
21	Powerex PTP Charges		(23.4)	(30.4)	(7.0)	(29.2)	**(6.1)**	23.1	**(11.8)**	**(10.1)**	**(16.6)**
22	BC Hydro PTP Charges		(26.2)	(12.4)	13.8	(21.3)	**(46.1)**	(24.8)	**(47.8)**	**(51.4)**	**(45.9)**
23	Total		(49.6)	(42.8)	6.8	(50.5)	(52.2)	(1.7)	(59.7)	(61.5)	(62.5)
24	**Total Current Costs**		652.4	717.0	64.6	771.6	829.0	57.4	826.1	824.1	844.6
	Transmission Revenue Requirement										
25	Total Current Costs	Line 24	652.4	717.0	64.6	771.6	829.0	57.4	826.1	824.1	844.6
26	Adj to offset re-org impact		(24.2)		24.2	(24.0)		24.0			
27	Adj. Total Current Costs		628.2	717.0	88.8	747.7	829.0	81.3	826.1	824.1	844.6
28	PTP Allocation to Distribution	Line 13	16.8	22.0	5.1	29.4	29.4	0.0	26.9	27.0	28.5
29	Inter-Segment Revenue	Line 23	49.6	42.8	(6.8)	50.5	52.2	1.7	59.7	61.5	62.5
30	External OATT Revenue	Line 76	10.1	8.1	(2.0)	11.8	10.8	(1.0)	14.1	14.2	14.5
31	Total TRR		704.7	789.9	85.2	839.4	921.5	82.1	926.7	926.8	950.1

Total Current Costs - Transmission
($ million)

Line	Column	Reference	F2015 RRA	F2015 Actual	F2015 Diff	F2016 RRA	F2016 Actual	F2016 Diff	F2017 Plan	F2018 Plan	F2019 Plan
			1	2	3 = 2 - 1	4	5	6 = 5- 4	7	8	9
	NITS Charge to BC Hydro										
32	Adj. Total Current Costs	Line 27	628.2			747.7			826.1	824.1	844.6
33	Internal Ancillary Services	Line 38	0.0			0.0			0.0	0.0	0.0
34	Internal Scheduling & Dispatch	Line 40	(2.9)			(2.9)			(2.7)	(2.6)	(2.7)
35	Total		625.3	625.2	(0.1)	744.8	744.8	(0.1)	823.3	821.5	842.0
36	NITS Monthly Rate	Line 35 / 12	52.1	52.1		62.1	62.1		68.6	68.5	70.2
	Long-Term PTP Rate										
37	Total TRR	Line 31	704.7			839.4			926.7	926.8	950.1
38	Internal Ancillary Services		0.0	(0.0)	(0.0)	0.0	0.0	0.0	0.0	0.0	0.0
39	External Ancillary Services		(1.8)	(1.3)	0.5	(1.8)	(1.9)	(0.1)	(2.5)	(2.5)	(2.5)
40	Internal Scheduling & Dispatch		(2.9)	(2.3)	0.6	(2.9)	(2.3)	0.6	(2.7)	(2.6)	(2.7)
41	External Scheduling & Dispatch		(0.1)	(0.1)	0.0	(0.1)	(0.1)	0.0	(0.2)	(0.2)	(0.2)
42	Total		699.9			834.6			921.3	921.5	944.8
43	Maximum Supply (MW)		13,034			12,846			13,034	12,846	12,872
44	Long-Term Firm PTP Rate ($/MW/year)		53,698	53,698		64,968	64,968		70,687	71,738	73,397
	Maximum Price for Short-Term Firm and Non-Firm (per MW of Reserved Capacity)										
45	Monthly ($/MW/month)		4,474.87	4,474.87		5,413.99	5,413.99		5,890.60	5,978.14	6,116.40
46	Weekly ($/MW/week)		1,032.66	1,032.66		1,249.38	1,249.38		1,359.37	1,379.57	1,411.48
47	Daily ($/MW/day)		147.12	147.12		177.99	177.99		193.66	196.54	201.09
48	Hourly ($/MW/hour)		6.13	6.13		7.42	7.42		8.07	8.19	8.38
	Scheduling Fee										
49	Scheduling, Control & Dispatch	L40 + L41	3.0	2.4		3.0	2.4		2.9	2.8	2.8
50	Total Volume (GWh)		29,356	23,202		30,463	24,368		27,734	28,162	28,590
51	Scheduling Fee ($/MWh)	L49 / L50	0.102	0.102		0.099	0.099		0.105	0.099	0.099
	Long-Term PTP Volumes (GWh)										
52	Internal		8,926	9,172	246	8,926	8,977	50	8,042	8,042	8,042
53	External		1,314	1,068	(246)	1,314	1,071	(243)	1,314	1,314	1,314
54	Total		10,240	10,240	0	10,240	10,048	(192)	9,356	9,356	9,356
	Long-Term PTP Revenue										
55	Internal	L48 * L52	54.7	56.5	1.8	66.2	66.8	0.6	64.9	65.9	67.4
56	External	L48 * L53	8.1	6.6	(1.5)	9.7	8.2	(1.5)	10.6	10.8	11.0
57	Total		62.8	63.1	0.3	76.0	75.0	(1.0)	75.5	76.6	78.4
	Long-Term PTP Average Price ($/MWh)										
58	Internal	L55 / L52	6.13	6.16	0.03	7.42	7.44	0.02	8.07	8.19	8.38
59	External	L56 / L53	6.13	6.15	0.02	7.42	7.67	0.25	8.07	8.19	8.38
60	Total	L57 / L54	6.13	6.16	0.03	7.42	7.46	0.04	8.07	8.19	8.38

Total Current Costs - Transmission
($ million)

Line		Reference	F2015 RRA	F2015 Actual	F2015 Diff	F2016 RRA	F2016 Actual	F2016 Diff	F2017 Plan	F2018 Plan	F2019 Plan
	Column		1	2	3 = 2 - 1	4	5	6 = 5- 4	7	8	9
	Short-Term PTP Volumes (GWh)										
61	Internal		6,475	2,949	(3,526)	7,582	5,731	(1,851)	9,679	10,107	10,535
62	External		53	68	15	53	264	211	374	374	374
63	Total		6,528	3,017	(3,511)	7,635	5,995	(1,641)	10,052	10,480	10,909
	Short-Term PTP Revenue										
64	Internal		11.7	8.2	(3.5)	13.7	14.9	1.2	21.7	22.6	23.6
65	External		0.1	0.2	0.1	0.1	0.6	0.5	0.8	0.8	0.8
66	Total		11.8	8.4	(3.4)	13.8	15.5	1.7	22.5	23.4	24.4
	Short-Term PTP Average Price ($/MWh)										
67	Internal	L64 / L61	1.81	2.79	0.98	1.81	2.60	0.79	2.24	2.24	2.24
68	External	L65 / L62	1.81	2.24	0.43	1.81	2.27	0.46	2.24	2.24	2.24
69	Total	L66 / L63	1.81	2.78	0.97	1.81	2.58	0.77	2.24	2.24	2.24
	Total PTP Revenue										
70	Internal	L55 + L64	66.4	64.7	(1.7)	79.9	81.7	1.7	86.5	88.5	91.0
71	External	L56 + L65	8.2	6.7	(1.4)	9.8	8.8	(1.0)	11.4	11.6	11.8
72	Total		74.6	71.4	(3.1)	89.8	90.5	0.7	98.0	100.1	102.8
	Total External OATT Revenue										
73	Total External PTP	Line 71	8.2	6.7	(1.4)	9.8	8.8	(1.0)	11.4	11.6	11.8
74	External Ancillary Services	Line 39	1.8	1.3	(0.5)	1.8	1.9	0.1	2.5	2.5	2.5
75	External Scheduling & Dispatch	Line 41	0.1	0.1	(0.0)	0.1	0.1	(0.0)	0.2	0.2	0.2
76	Total		10.1	8.1	(2.0)	11.8	10.8	(1.0)	14.1	14.2	14.5

Total Current Costs - Distribution
($ million)

Line		Reference	F2015 RRA	F2015 Actual	F2015 Diff	F2016 RRA	F2016 Actual	F2016 Diff	F2017 Plan	F2018 Plan	F2019 Plan
	Column		1	2	3 = 2 - 1	4	5	6 = 5 - 4	7	8	9
1	**Cost of Energy**	4.0 L63	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2	**Current Operating Costs**	5.0 L127	219.3	216.7	(2.6)	218.3	229.4	11.1	262.4	258.5	266.7
3	**Taxes**	6.0 L34	26.9	25.9	(1.0)	27.6	26.2	(1.4)	26.8	27.5	28.6
4	**Current Amortization**	7.0 L62	211.3	176.3	(35.0)	220.6	166.4	(54.2)	186.0	194.4	202.7
5	**Current Finance Charges**	8.0 L44	171.0	155.4	(15.6)	186.4	174.3	(12.1)	115.2	117.9	125.1
6	**Return on Equity**	9.0 L67	167.1	151.7	(15.4)	167.3	157.2	(10.0)	155.6	157.3	157.3
7	**Business Support Allocation**	3.1 L73	108.2	107.3	(0.9)	128.5	146.5	18.0	139.9	120.7	126.4
8	**Non-Tariff Revenue**	15.0 L16-L33	(49.0)	(43.5)	5.5	(51.1)	(48.8)	2.3	(50.4)	(53.9)	(56.2)
	Internal Allocations										
9	SDA Allocation (Capital Infrastructure Project Delivery)	3.6 L11	3.4	4.0	0.6	3.4	5.2	1.8	2.7	2.0	1.9
10	SDA Allocation (Transmission)	3.4 L10	123.2	115.3	(7.9)	148.3	121.2	(27.1)	125.0	128.5	126.1
11	Distribution Real Time Dispatch	3.4 L12	16.7	16.7	0.0	17.1	17.1	0.0	16.7	16.2	16.6
12	PTP Allocation to Distribution	3.4 L13	16.8	22.0	5.1	29.4	29.4	0.0	26.9	27.0	28.5
13	Allocation to Capital Infrastructure Project Delivery	3.6 L12	(39.9)	(40.7)	(0.8)	(39.9)	(41.2)	(1.3)	(36.2)	(36.7)	(37.2)
14	Total		120.3	117.3	(2.9)	158.3	131.7	(26.7)	135.1	137.0	135.8
15	**Total**		974.9	907.1	(67.8)	1,055.9	982.8	(73.1)	970.7	959.4	986.5

Total Current Costs - Capital Infrastructure Project Delivery
($ million)

Line		Reference	F2015 RRA	F2015 Actual	F2015 Diff	F2016 RRA	F2016 Actual	F2016 Diff	F2017 Plan	F2018 Plan	F2019 Plan
	Column		1	2	3 = 2 - 1	4	5	6 = 5- 4	7	8	9
1	**Cost of Energy**	N/A	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2	**Current Operating Costs**	5.0 L129	95.0	93.1	(1.9)	95.0	98.7	3.6	86.7	90.5	86.6
3	**Taxes**	N/A	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	**Current Amortization**	N/A	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5	**Current Finance Charges**	N/A	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
6	**Return on Equity**	N/A	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7	**Business Support Allocation**	N/A	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	**Non-Tariff Revenue**	N/A	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Internal Allocations										
9	Generation		(46.6)	(47.1)	(0.5)	(46.7)	(64.3)	(17.6)	(58.7)	(62.6)	(62.0)
10	Transmission		(61.6)	(58.2)	3.4	(61.7)	(46.4)	15.4	(37.5)	(36.5)	(36.5)
11	SDA Allocation		(3.4)	(4.0)	(0.6)	(3.4)	(5.2)	(1.8)	(2.7)	(2.0)	(1.9)
12	Distribution		39.9	40.7	0.8	39.9	41.2	1.3	36.2	36.7	37.2
13	Customer Care		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
14	Operations Support		(23.2)	(24.5)	(1.3)	(23.0)	(24.1)	(1.0)	(24.0)	(26.2)	(23.4)
15	Total		(95.0)	(93.1)	1.9	(95.0)	(98.7)	(3.7)	(86.7)	(90.5)	(86.6)
16	**Total**		0.0	0.0	(0.0)	0.0	0.0	(0.0)	(0.0)	(0.0)	0.0
	Internal Allocation by Function:										
	Project Delivery										
17	Generation		5.9	5.6		5.9	5.5		6.1	6.9	6.4
18	Transmission		5.1	4.9		5.2	4.8		6.0	5.3	5.7
19	SDA Allocation		1.6	1.5		1.6	1.5		1.2	2.0	2.2
20	Distribution		0.1	0.1		0.1	0.1		0.2	0.0	0.0
21	Customer Care										
22	Operations Support										
23	Total		12.7	12.1		12.7	12.0		13.4	14.2	14.3
	Generation & Transmission Engineering										
24	Generation		5.5	5.9		5.5	5.5		6.2	6.3	6.4
25	Transmission		5.2	5.6		5.2	5.2		5.9	5.8	6.2
26	SDA Allocation		1.5	1.6		1.5	1.5		1.7	1.9	1.6
27	Distribution		0.2	0.2		0.2	0.2		0.2	0.2	0.2
28	Customer Care										
29	Operations Support										
30	Total		12.3	13.3		12.4	12.3		14.0	14.2	14.4

Total Current Costs - Capital Infrastructure Project Delivery
($ million)

Line		Reference	F2015 RRA	F2015 Actual	F2015 Diff	F2016 RRA	F2016 Actual	F2016 Diff	F2017 Plan	F2018 Plan	F2019 Plan
	Column		1	2	3 = 2 - 1	4	5	6 = 5- 4	7	8	9
	Environmental Risk Management										
31	Generation		16.5	17.3		16.5	17.0		17.4	17.8	18.0
32	Transmission		3.6	3.8		3.6	3.7		3.9	3.8	3.9
33	SDA Allocation		0.0	0.0		0.0	0.0		0.0	0.0	0.0
34	Distribution		5.5	5.8		5.5	5.7		5.9	5.9	5.9
35	Customer Care										
36	Operations Support										
37	Total		25.6	26.8		25.6	26.4		27.2	27.5	27.8
	Aboriginal Relations										
38	Generation		2.0	2.2		2.0	2.5		2.4	2.4	2.5
39	Transmission		3.0	3.3		3.0	3.7		3.7	3.7	3.7
40	Distribution										
41	Customer Care										
42	Operations Support										
43	Total		5.0	5.5		5.1	6.2		6.1	6.1	6.1
	Properties										
44	Generation		0.0	0.0		0.0	0.0		0.0	0.0	0.0
45	Transmission		0.0	0.0		0.0	0.0		0.0	0.0	0.0
46	Distribution		0.0	0.0		0.0	0.0		0.0	0.0	0.0
47	Customer Care										
48	Operations Support		33.2	32.9		33.0	32.9		32.2	32.5	32.8
49	Total		33.2	32.9		33.0	32.9		32.2	32.5	32.8
	Dam Safety										
50	Generation		9.5	9.4		9.5	9.7		8.8	8.9	9.0
51	Transmission		0.0	0.0		0.0	0.0		0.0	0.0	0.0
52	Distribution		0.0	0.0		0.0	0.0		0.0	0.0	0.0
53	Customer Care										
54	Operations Support										
55	Total		9.5	9.4		9.5	9.7		8.8	8.9	9.0
	Business Unit Support										
56	Generation		2.5	1.8		2.5	1.9		(0.6)	(0.6)	(0.7)
57	Transmission		(6.8)	(3.3)		(6.8)	4.5		(2.2)	(6.2)	(6.5)
58	SDA Allocation		0.3	0.9		0.3	2.2		(0.2)	(1.8)	(1.9)
59	Distribution		(45.6)	(46.8)		(45.6)	(47.2)		(42.4)	(42.9)	(43.3)
60	Customer Care										
61	Operations Support										
62	Total		(49.6)	(47.4)		(49.6)	(38.6)		(45.3)	(51.6)	(52.3)
	Regulatory - FN Recoveries										
63	Generation					0.0	17.3		13.5	16.1	15.6
64	Transmission		43.5	43.5		43.2	25.9		20.3	24.1	23.4
65	Distribution										
66	Customer Care										
67	Operations Support										
68	Total		43.5	43.5		43.2	43.2		33.8	40.2	39.0

Total Current Costs - Capital Infrastructure Project Delivery
($ million)

Line		Reference	F2015 RRA	F2015 Actual	F2015 Diff	F2016 RRA	F2016 Actual	F2016 Diff	F2017 Plan	F2018 Plan	F2019 Plan
	Column		1	2	3 = 2 - 1	4	5	6 = 5- 4	7	8	9
	Regulatory - CPI Recoveries										
69	Generation	5.0 L34	4.8	4.8		4.8	4.8		4.8	4.8	4.8
70	Transmission										
71	Distribution										
72	Customer Care										
73	Operations Support										
74	Total		4.8	4.8		4.8	4.8		4.8	4.8	4.8
	Provisions										
75	Generation		0.0	0.0		0.0	0.0		0.0	0.0	0.0
76	Transmission		8.0	0.5		8.3	(1.5)		0.0	0.0	0.0
77	Distribution		0.0	0.0		0.0	0.0		0.0	0.0	0.0
78	Customer Care		0.0	0.0		0.0	0.0		0.0	0.0	0.0
79	Operations Support		(10.0)	(8.4)		(10.0)	(8.8)		(8.2)	(6.3)	(9.4)
80	Total		(2.0)	(7.9)		(1.7)	(10.3)		(8.2)	(6.3)	(9.4)
	Total Internal Allocation by Function										
81	Generation		46.6	47.1		46.7	64.3		58.7	62.6	62.0
82	Transmission		61.6	58.2		61.7	46.4		37.5	36.5	36.5
83	SDA Allocation		3.4	4.0		3.4	5.2		2.7	2.0	1.9
84	Distribution		(39.9)	(40.7)		(39.9)	(41.2)		(36.2)	(36.7)	(37.2)
85	Customer Care		0.0	0.0		0.0	0.0		0.0	0.0	0.0
86	Operations Support		23.2	24.5		23.0	24.1		24.0	26.2	23.4
87	Total		95.0	93.1		95.0	98.7		86.7	90.5	86.6

Cost of Energy
($ million)

Line	Column	Reference	F2015 RRA	F2015 Actual	F2015 Diff	F2016 RRA	F2016 Actual	F2016 Diff	F2017 Plan	F2018 Plan	F2019 Plan
			1	2	3 = 2 - 1	4	5	6 = 5- 4	7	8	9
	Sources of Supply (GWh)										
	Heritage Energy										
1	Hydroelectric (water rentals)		46,564	40,191	(6,373)	46,312	48,945	2,633	47,985	46,626	45,781
2	Net Purchases (Sales) from Powerex		(199)	512	711	255	(6)	(261)	(267)	(253)	105
3	Market Electricity Purchases		1,224	207	(1,017)	1,553	122	(1,431)	230	747	934
4	Market Purchases to Non-Heritage		0	0	0	0	0	0	0	0	0
5	Natural Gas for Thermal Generation		290	213	(77)	301	215	(86)	224	232	234
6	Surplus Sales		(3,756)	(15)	3,741	(2,446)	(6,277)	(3,831)	(4,962)	(5,556)	(4,517)
7	Exchange Net		(530)	88	618	(204)	(976)	(772)	(115)	(323)	(354)
8	Total		43,593	41,197	(2,396)	45,771	42,022	(3,749)	43,095	41,473	42,182
	Non-Heritage Energy										
9	Waneta (water rentals)		914	1,038	124	594	407	(187)	575	593	587
10	IPPs and Long-Term Commitments		13,339	13,377	38	12,002	14,319	2,317	13,375	15,002	15,199
11	Mkt Purchases From Heritage	Line 4	0	0	0	0	0	0	0	0	0
12	Non-Integrated Area		133	115	(18)	135	111	(24)	117	119	120
13	Total		14,386	14,531	145	12,731	14,837	2,106	14,067	15,714	15,907
14	**Total Sources of Supply**	L8+L13	57,979	55,727	(2,252)	58,502	56,859	(1,643)	57,162	57,187	58,089
15	**Less Line Loss and System Use**		(4,849)	(4,529)	320	(4,742)	(5,836)	(1,094)	(5,302)	(5,349)	(5,425)
16	**Total Domestic Sales**	14.0 L10	53,130	51,199	(1,932)	53,760	51,023	(2,737)	51,860	51,838	52,664
17	**Line Loss as % of Sales**		9.13%	8.85%	-0.28%	8.82%	11.44%	2.62%	10.22%	10.32%	10.30%
	Unit Costs ($/MWh)										
18	Hydroelectric (water rentals)		8.3	9.0	0.7	8.3	7.3	(1.0)	7.9	7.5	7.6
19	Waneta (water rentals)		8.4	7.0	(1.4)	12.5	18.7	6.2	11.9	10.8	10.8
20	IPPs and Long-Term Commitments		77.1	79.5	2.4	81.3	85.8	4.5	92.3	91.3	94.7
21	Market Electricity Purchases		36.5	28.8	(7.7)	36.4	22.8	(13.7)	37.5	40.5	38.5
22	Surplus Sales		(32.6)	(10.1)	22.5	(34.4)	(27.7)	6.7	(23.8)	(27.1)	(28.6)
23	Natural Gas for Thermal Generation		91.7	112.7	20.9	89.4	93.1	3.8	66.5	45.4	45.9
24	Non-Integrated Area		247.4	222.6	(24.7)	254.1	203.9	(50.2)	209.6	229.4	258.9
25	Total Weighted Cost		26.1	29.5	3.5	25.9	28.9	3.0	29.9	32.0	33.5
	Cost of Energy ($ million)										
	Heritage Energy										
26	Hydroelectric (water rentals)		385.1	361.4	(23.7)	384.5	357.7	(26.8)	379.9	350.4	350.1
27	Market Electricity Purchases		44.7	6.0	(38.7)	56.6	2.8	(53.8)	8.6	30.2	35.9
28	Market Purchases to Non-Heritage		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
29	Natural Gas for Thermal Generation		26.6	24.0	(2.6)	26.9	20.0	(6.9)	14.9	10.5	10.7
30	Domestic Transmission		30.5	18.4	(12.1)	25.7	52.6	26.9	54.5	57.7	52.0
31	Columbia River Treaty Related Agreements		(7.8)	13.7	21.5	(19.8)	(14.4)	5.4	(23.1)	(10.4)	(7.2)
32	Surplus Sales		(122.6)	(0.2)	122.4	(84.2)	(174.1)	(89.9)	(118.1)	(150.4)	(129.2)
33	Remissions and Other		(44.9)	(34.4)	10.5	(32.1)	(38.6)	(6.5)	(37.3)	(37.8)	(33.1)
34	Total		311.6	388.9	77.3	357.6	206.1	(151.5)	279.3	250.2	279.3

Cost of Energy
($ million)

			F2015			F2016			F2017	F2018	F2019
		Reference	RRA	Actual	Diff	RRA	Actual	Diff	Plan	Plan	Plan
Line	Column		1	2	3 = 2 - 1	4	5	6 = 5- 4	7	8	9
	Non-Heritage Energy										
35	Mkt Purchases From Heritage		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
36	Waneta (water rentals)		7.7	7.3	(0.4)	7.4	7.6	0.2	6.8	6.4	6.3
37	IPPs and Long-Term Commitments		1,028.6	1,064.0	35.4	975.5	1,228.9	253.4	1,234.4	1,369.7	1,439.3
38	New Capital Leases Under IFRS		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
39	Non-Integrated Area		32.9	25.5	(7.4)	34.3	22.6	(11.7)	24.6	27.4	31.1
40	Gas & Other Transportation		11.8	10.6	(1.2)	12.1	10.5	(1.6)	10.6	10.1	6.1
41	Domestic Transmission		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
42	Net Purchases (Sales) from Powerex		(8.1)	16.2	24.3	4.8	(0.1)	(4.9)	(6.5)	(6.0)	0.7
43	Total		1,072.9	1,123.6	50.7	1,034.1	1,269.5	235.4	1,270.0	1,407.6	1,483.6
44	**Total Gross COE**	L34+L43	1,384.5	1,512.5	128.0	1,391.7	1,475.6	83.9	1,549.3	1,657.8	1,762.9
	Current Cost of Energy										
45	Gross Cost of Energy	Line 44	1,384.5	1,512.5	128.0	1,391.7	1,475.6	83.9	1,549.3	1,657.8	1,762.9
46	HDA Additions	2.1 L3	0.0	(81.7)	(81.7)	0.0	151.9	151.9	0.0	0.0	0.0
47	NHDA Additions	2.1 L10	0.0	(238.2)	(238.2)	0.0	(482.9)	(482.9)	0.0	0.0	0.0
48	BCTCDA Additions	2.1 L23	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
49	Deferred GMS 3 COE	Line 75	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
50	GMS 3 Insurance Proceeds		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
51	Water License Variances	Line 73	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
52	Deferred Operating HDA	Line 74	0.0	1.9	1.9	0.0	2.5	2.5	0.0	0.0	0.0
53	Deferred Operating NHDA	Line 87	0.0	(10.0)	(10.0)	0.0	(9.6)	(9.6)	0.0	0.0	0.0
54	Deferred Amortization NHDA	Line 88	0.0	(6.1)	(6.1)	0.0	(9.1)	(9.1)	0.0	0.0	0.0
55	Deferred Taxes NHDA	Line 89	0.0	(2.6)	(2.6)	0.0	(3.4)	(3.4)	0.0	0.0	0.0
56	Deferred Waneta Costs	2.2 L121+L122	15.0	15.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
57	HDA Recoveries	2.1 L5	16.6	26.2	9.6	17.7	37.0	19.2	(4.7)	(4.8)	(5.1)
58	NHDA Recoveries	2.1 L12	98.0	90.6	(7.4)	104.8	117.7	12.8	179.3	185.5	194.0
59	BCTCDA Recoveries		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
60	**Total Current COE**		1,514.1	1,307.6	(206.5)	1,514.3	1,279.7	(234.6)	1,723.9	1,838.6	1,951.8
	Total Current COE by Function										
61	Generation		328.2	335.3	7.1	375.3	397.4	22.1	274.6	245.4	274.3
62	Transmission		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
63	Distribution		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
64	Customer Care		1,185.9	972.3	(213.6)	1,138.9	882.2	(256.7)	1,449.3	1,593.2	1,677.6
65	Business Support		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
66	Total		1,514.1	1,307.6	(206.5)	1,514.3	1,279.7	(234.6)	1,723.9	1,838.6	1,951.8
	Heritage Payment Obligation										
67	Heritage Energy	Line 34	311.6	388.9	77.3	357.6	206.1	(151.5)	279.3	250.2	279.3
68	Costs in Operating/Amortization		15.7	15.5	(0.2)	13.0	12.9	(0.1)	12.3	12.4	12.9
69	Commodity Risk		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
70	Notional Water Rentals		(1.4)	3.7	5.1	1.9	(0.0)	(1.9)	(1.9)	(1.7)	0.7
71	Skagit and Ancillary Revenue	14.0 L18	(16.2)	(18.6)	(2.4)	(16.5)	(18.2)	(1.7)	(12.6)	(12.0)	(12.1)
72	Load Curtailment		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
73	Water License Variances	5.0 L43	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
74	Deferred Operating HDA	5.0 L48	0.0	1.9	1.9	0.0	2.5	2.5	0.0	0.0	0.0
75	Transfer to GMS 3 Reg Account		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
76	Other		43.5	43.5	0.0	43.2	44.1	0.9	28.2	36.5	36.2
77	Total		353.2	434.9	81.7	399.2	247.3	(151.9)	305.3	285.4	317.1
78	**Total System Inflow (% of Normal)**		100%	102%	2%	100%	99%	(1%)	98%	100%	100%

Cost of Energy
($ million)

Line	Column	Reference	F2015 RRA	F2015 Actual	F2015 Diff	F2016 RRA	F2016 Actual	F2016 Diff	F2017 Plan	F2018 Plan	F2019 Plan
			1	2	3 = 2 - 1	4	5	6 = 5- 4	7	8	9
	Non-Heritage COE Subject to NHDA										
79	Non-Heritage Cost of Energy	Line 43	1,072.9	1,123.6	50.7	1,034.1	1,269.5	235.4	1,270.0	1,407.6	1,483.6
80	Commodity Risk		0.0	(4.8)	(4.8)	0.0	**(0.5)**	(0.5)	0.0	0.0	0.0
81	F/X Gains on Powerex Trade		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
82	Less Domestic Transmission	Line 41	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
83	Notional Water Rental	Line 70	1.4	(3.7)	(5.1)	(1.9)	0.0	1.9	1.9	1.7	(0.7)
84	Revenue Variance		0.0	207.3	207.3	0.0	**268.9**	268.9	0.0	0.0	0.0
85	ROE Adjustment		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
86	ABSU Founding Partner Benefits		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
87	Deferred Operating NHDA	5.0 L49	0.0	(10.0)	(10.0)	0.0	(9.6)	(9.6)	0.0	0.0	0.0
88	Deferred Amortization NHDA	7.0 L26.1	0.0	(6.1)	(6.1)	0.0	(9.1)	(9.1)	0.0	0.0	0.0
89	Deferred Taxes NHDA	6.0 L22	0.0	(2.6)	(2.6)	0.0	(3.4)	(3.4)	0.0	0.0	0.0
90	Other		0.0	8.8	8.8	0.0	**(0.8)**	(0.8)	0.0	0.0	0.0
91	F11 NSA & F12-F14 Adjustments		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
92	Total		1,074.3	1,312.5	238.2	1,032.2	1,515.1	482.9	1,271.9	1,409.3	1,482.9
	IPP Summary										
93	IPP Costs in Non-Heritage COE	Line 37	1,028.6	1,064.0	35.4	975.5	1,228.9	253.4	1,234.4	1,369.7	1,439.3
94	Less COE Impact of New Leases	Line 38	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Existing Capital Leases										
95	Operating Costs	5.1 L15	29.4	29.4	0.0	33.8	34.2	0.4	28.2	63.6	54.3
96	Taxes	6.0 L12	4.8	4.8	0.0	5.8	5.6	(0.2)	2.6	4.2	2.5
97	Amortization	7.0 L23	22.8	22.8	0.0	25.8	25.8	0.0	17.0	29.4	22.8
98	Finance Charges	8.0 L20	77.3	77.3	0.0	93.9	93.9	0.0	25.1	44.7	42.4
99	Total		134.3	134.3	0.0	159.2	159.4	0.2	72.9	141.8	122.1
	New IPP Capital Leases Under IFRS										
100	Operating Costs		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
101	Taxes		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
102	Amortization		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
103	Finance Charges		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
104	Total		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
104.1	Transfers to Deferral & Regulatory Accounts		0.0	(77.4)	(77.4)	0.0	**(103.8)**	(103.8)	0.0	0.0	0.0
105	Total Costs in Revenue Requirement		1,162.9	1,120.9	(42.0)	1,134.7	1,284.5	149.8	1,307.3	1,511.5	1,561.4
106	Total Payments to IPPs		1,162.5	1,129.4	(33.1)	1,130.9	**1,292.5**	161.6	**1,312.5**	**1,509.9**	**1,547.9**
107	Difference	L105 - L106	0.4	(8.5)	(8.9)	3.8	(8.0)	(11.8)	(5.2)	1.6	13.5
	IPP Capital Leases										
	Gross Assets in Service										
108	Opening Balance		388.2	388.2	0.0	1,113.2	388.2	(725.0)	388.2	858.2	858.2
109	Adjustment to Opening Balance		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
110	Capital Additions		725.0	0.0	(725.0)	0.0	0.0	0.0	**470.0**	0.0	0.0
111	Retirements & Transfers		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
112	Closing Balance		1,113.2	388.2	(725.0)	1,113.2	388.2	(725.0)	858.2	858.2	858.2
	Accumulated Amortization										
113	Opening Balance		159.5	159.5	0.0	182.3	182.3	0.0	186.9	203.9	233.3
114	Adjustment to Opening Balance		0.0	0.0	0.0	0.0	**(9.1)**	(9.1)	0.0	0.0	0.0
115	Amortization		22.8	22.8	0.0	25.8	**13.7**	(12.1)	17.0	29.4	22.8
116	Retirements & Transfers		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
117	Closing Balance		182.3	182.3	0.0	208.1	186.9	(21.2)	203.9	233.3	256.1
118	**Net Capital Leases (Year-End)**		930.9	205.9	(725.0)	905.1	201.3	(703.8)	654.3	624.9	602.1

Operating Costs and Provisions - Total Company
($ million)

Line		Reference	F2015 RRA	F2015 Actual	F2015 Diff	F2016 RRA	F2016 Actual	F2016 Diff	F2017 Plan	F2018 Plan	F2019 Plan
	Column		1	2	3 = 2 - 1	4	5	6 = 5- 4	7	8	9
	Operating Costs by Business Group										
1	Training, Development and Generation		132.9	134.0	1.1	131.3	136.3	5.0	136.4	139.2	146.2
2	Transmission, Distribution and Customer Services		513.4	517.6	4.3	510.9	513.6	2.7	536.0	536.0	537.2
3	Customer Care		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	Capital Infrastructure Project Delivery		48.7	52.7	4.1	48.7	61.0	12.3	56.3	51.8	52.1
5	Operations Support		98.2	93.3	(5.0)	136.0	118.4	(17.6)	148.9	209.1	225.6
6	Severance Costs		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7	Non-Current PEB - Pension		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	Non-Current PEB - Other		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9	F09/F10 RRA Adjustments		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10	F11 RRA NSA Adjustment		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11	F12-F14 RRA Adjustment		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12	Total Before Regulatory Accounts		793.2	797.6	4.4	826.9	829.3	2.4	877.6	936.1	961.1
	Operating Costs by Resource										
13	Labour (excl Non-Current PEB)		471.3	482.0	10.6	478.1	478.7	0.6	489.3	499.3	509.1
14	Services - ABSU		58.9	61.5	2.6	59.0	67.2	8.1	48.7	48.0	49.3
15	Services - BCTC		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
16	Services - Other		423.9	416.6	(7.3)	427.8	412.9	(14.9)	446.4	477.1	461.5
17	Materials		40.2	43.0	2.8	40.1	44.5	4.4	40.7	40.6	40.6
18	Buildings & Equipment		48.8	53.1	4.3	49.6	53.0	3.4	58.8	58.8	58.9
19	Capitalized Overhead		(222.2)	(223.5)	(1.3)	(199.8)	(203.3)	(3.4)	(180.2)	(158.6)	(136.9)
20	External Recoveries		(27.7)	(35.0)	(7.3)	(27.8)	(23.7)	4.1	(26.2)	(29.2)	(21.5)
21	Severance Costs		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
22	Non-Current PEB - Pension		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
23	Non-Current PEB - Other		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
24	F09/F10 RRA Adjustments		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
25	F11 RRA NSA Adjustment		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
26	F12-F14 RRA Adjustment		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
27	Total Before Regulatory Accounts		793.2	797.6	4.4	826.9	829.3	2.4	877.6	936.1	961.1
	Regulatory Account Recoveries										
28	DSM - F11 RRA NSA Adjustment		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
29	First Nation Costs		43.5	43.5	0.0	43.2	43.2	(0.0)	33.8	40.2	39.0
30	Site C Clean Energy Project		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
31	Storm Restoration		(1.4)	(1.4)	0.0	(1.4)	(1.4)	(0.0)	10.8	10.4	10.0
32	PEI - F11 RRA NSA Adjustment		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
33	Procurement Enhancement		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
34	Capital Project Investigation		4.8	4.8	0.0	4.8	4.8	0.0	4.8	4.8	4.8
35	Net Employment Costs		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
36	Smart Metering & Infrastructure		30.5	30.5	(0.0)	31.3	31.3	0.0	32.5	31.7	31.0
37	Home Purchase Offer Plan		11.8	11.8	(0.0)	11.3	11.3	(0.0)	0.0	0.0	0.0
38	Minimum Reconnection Charge		0.0	0.0	0.0	0.0	0.0	0.0	0.5	0.0	0.0
39	Non-Current Pension Cost		32.6	32.6	(0.0)	15.5	15.5	0.0	59.3	31.3	31.3
40	IFRS PP&E		15.9	15.9	0.0	19.8	19.8	0.0	23.2	26.0	28.2
41	IFRS Pension		38.2	38.2	(0.0)	38.2	38.2	0.0	38.2	38.2	38.2
42	Total		176.0	175.9	(0.1)	162.9	162.9	(0.0)	203.2	182.6	182.7
	Deferral Account Recoveries										
43	Water License Variances		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Operating Costs and Provisions - Total Company
($ million)

Line	Column	Reference	F2015 RRA	F2015 Actual	F2015 Diff	F2016 RRA	F2016 Actual	F2016 Diff	F2017 Plan	F2018 Plan	F2019 Plan
			1	2	3 = 2 - 1	4	5	6 = 5- 4	7	8	9
	Current IFRS Impact										
44	New IPP Capital Leases		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
45	Other Operating Costs		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
46	Total		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
47	**Total Current Operating**	L12+L42+L43+L46	969.1	973.5	4.4	989.9	992.2	2.3	1,080.8	1,118.8	1,143.7
	Deferral Account Additions										
48	Transfers to HDA		0.0	1.9	1.9	0.0	2.5	2.5	0.0	0.0	0.0
49	Transfers to NHDA		0.0	(10.0)	(10.0)	0.0	(9.6)	(9.6)	0.0	0.0	0.0
50	Total		0.0	(8.1)	(8.1)	0.0	(7.1)	(7.1)	0.0	0.0	0.0
	Regulatory Account Additions										
51	Demand-Side Management		150.5	124.8	(25.7)	131.1	145.2	14.1	113.7	160.6	100.7
52	First Nations Costs		3.5	1.6	(1.9)	3.0	1.5	(1.5)	5.6	3.7	2.8
53	Site C Clean Energy Project		0.0	65.4	65.4	0.0	0.0	0.0	0.0	0.0	0.0
54	Storm Restoration		0.0	9.0	9.0	0.0	19.6	19.6	0.0	0.0	0.0
55	Procurement Enhancement		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
56	Capital Project Investigation		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
57	GM Shrum 3		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
58	Smart Metering & Infrastructure		28.4	22.7	(5.8)	21.5	24.5	3.0	0.0	0.0	0.0
59	Home Purchase Offer Plan		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
60	IFRS Capitalized Overhead		156.8	156.8	0.0	134.4	134.4	0.0	112.0	89.6	67.2
61	Non-Current Pension Costs		0.0	0.0	0.0	0.0	17.2	17.2	10.1	0.0	0.0
62	Outsourcing Implementation		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
63	Bad Debt (Meziadin Lake)		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
64	Total		339.2	380.3	41.0	290.0	342.3	52.4	241.4	253.8	170.7
65	**Total Gross Operating**	L12+L46+L50+L64	1,132.4	1,169.7	37.3	1,116.9	1,164.5	47.6	1,119.0	1,189.9	1,131.8
	Current Operating by Business Group										
66	Training, Development and Generation		132.9	134.0	1.1	131.3	136.3	5.0	136.4	139.2	146.2
67	Transmission (incl. Tech & CS)		359.7	362.6	2.9	359.5	342.0	(17.5)	368.2	366.9	367.0
68	Distribution		182.8	184.1	1.3	181.4	201.5	20.1	211.1	211.3	211.2
69	Customer Care		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
70	Capital Infrastructure Project Delivery		97.0	101.0	4.1	96.7	109.0	12.3	94.9	96.8	96.0
71	Operations Support		164.1	159.1	(5.0)	205.4	187.8	(17.6)	210.9	273.3	292.0
72	Severance Costs	Line 6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
73	Non-Current PEB - Pension	L7 + L39	32.6	32.6	(0.0)	15.5	15.5	0.0	59.3	31.3	31.3
74	Non-Current PEB - Other	Line 8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
75	F09/F10 RRA Adjustments	Line 9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
76	F11 RRA NSA Adjustment	Line 10	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
77	F12-F14 RRA Adjustment	Line 11	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
78	Total		969.1	973.5	4.4	989.9	992.2	2.3	1,080.8	1,118.8	1,143.7

Operating Costs and Provisions - Total Company
($ million)

Line	Column	Reference	F2015 RRA	F2015 Actual	F2015 Diff	F2016 RRA	F2016 Actual	F2016 Diff	F2017 Plan	F2018 Plan	F2019 Plan
			1	2	3 = 2 - 1	4	5	6 = 5- 4	7	8	9
	Provisions Before Regulatory Accounts										
79	Training, Development and Generation		3.5	10.8	7.4	3.6	5.8	2.2	3.7	3.8	3.6
80	Transmission (incl. Tech)		0.0	15.2	15.2	0.0	20.4	20.4	10.6	10.5	8.8
81	Distribution		21.9	20.5	(1.4)	22.7	14.0	(8.7)	24.3	25.5	26.8
82	Customer Care		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
83	Capital Infrastructure Project Delivery		8.0	2.1	(5.9)	8.3	(0.3)	(8.6)	0.0	0.0	0.0
84	Operations Support		15.1	12.4	(2.7)	5.1	4.9	(0.2)	5.3	5.5	5.9
85	Increase in Mass Asset Rtmts		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
86	FRSR Write-Off		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
87	FRSR - Training, Development and Generation		0.0	0.0	0.0	0.0	0.0	0.0	3.1	8.0	6.0
88	FRSR - Transmission		0.0	0.0	0.0	0.0	0.0	0.0	11.1	10.0	10.1
89	FRSR - Distribution		0.0	0.0	0.0	0.0	0.0	0.0	14.8	14.0	13.9
90	FRSR - Capital Infrastructure Project Delivery		0.0	0.0	0.0	0.0	0.0	0.0	1.8	3.7	0.7
91	Real Property Sales		(10.0)	(10.0)	(0.0)	(10.0)	(10.0)	(0.0)	(10.0)	(10.0)	(10.0)
92	Total		38.4	51.0	12.6	29.7	34.8	5.0	64.7	71.0	65.7
	Deferred Provisions & Other										
93	First Nations Provisions		0.0	1.4	1.4	0.0	(5.0)	(5.0)	(5.3)	0.0	0.0
94	Environmental Provisions		0.0	63.8	63.8	0.0	47.1	47.1	0.0	0.0	0.0
95	Arrow Water Divestiture Costs		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
96	Arrow Water Provision		0.0	0.0	0.0	0.0	0.7	0.7	0.0	0.0	0.0
97	Smart Metering & Infrastructure Fibre		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
98	Smart Metering & Infrastructure DSMD Write-Off		0.0	9.1	9.1	0.0	0.0	0.0	0.0	0.0	0.0
99	Real Property Sales		0.0	7.9	7.9	0.0	9.5	9.5	6.5	(10.0)	(14.0)
100	Total		0.0	82.2	82.2	0.0	52.3	52.3	1.2	(10.0)	(14.0)
101	**Total Gross Provisions**	L92 + L100	38.4	133.3	94.8	29.7	87.0	57.3	66.0	61.0	51.7
	Recovery of Deferred Provisions										
	PCB Remediation										
102	Training, Development and Generation		0.1	0.5	0.4	0.3	0.1	(0.2)	1.4	3.2	0.5
103	Transmission		7.5	5.2	(2.3)	7.1	8.6	1.4	9.3	8.7	8.5
104	Distribution		5.7	3.2	(2.5)	5.6	5.3	(0.4)	7.5	6.7	6.2
105	Operations Support		0.3	0.2	(0.1)	0.2	0.0	(0.2)	0.1	0.2	0.0
	Asbestos Remediation										
106	Training, Development and Generation		3.1	3.1	0.0	2.0	2.0	0.0	1.3	2.0	2.0
107	Transmission		0.2	0.2	0.0	0.2	0.2	0.0	17.9	11.7	2.0
108	Distribution		8.9	8.8	(0.1)	8.6	8.6	0.0	4.6	1.0	8.5
109	Operations Support		0.0	0.0	0.0	0.0	0.0	0.0	0.6	1.8	2.7
110	Rock Bay Remediation		51.5	51.5	(0.0)	50.5	50.5	(0.0)	(3.8)	(3.2)	0.0
111	Arrow Water Divestiture Costs		4.7	4.7	(0.0)	4.5	4.5	0.0	0.0	0.0	0.0
112	Arrow Water Provision		0.3	0.2	(0.1)	0.3	0.3	(0.0)	1.8	0.3	0.3
113	F12-F14 Rate Smoothing		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
114	Rate Smoothing		(166.2)	(166.2)	(0.0)	(121.2)	(121.2)	0.0	(210.0)	(285.9)	(299.4)
115	Total		(84.0)	(88.5)	(4.5)	(41.9)	(41.2)	0.6	(169.2)	(253.4)	(268.4)
116	**Total Current Provisions**	L92 + L115	(45.6)	(37.5)	8.1	(12.1)	(6.5)	5.7	(104.5)	(182.4)	(202.8)

Operating Costs and Provisions - Total Company
($ million)

Line		Reference	F2015 RRA	F2015 Actual	F2015 Diff	F2016 RRA	F2016 Actual	F2016 Diff	F2017 Plan	F2018 Plan	F2019 Plan
	Column		1	2	3 = 2 - 1	4	5	6 = 5- 4	7	8	9
	Current Provisions by Business Group										
117	Training, Development and Generation		11.6	19.4	7.8	10.8	12.7	2.0	11.4	17.3	12.5
118	Transmission		7.7	20.7	13.0	7.3	29.1	21.8	48.9	41.0	29.4
119	Distribution		36.4	32.6	(3.9)	36.9	27.9	(9.0)	51.3	47.2	55.4
120	Customer Care		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
121	Capital Infrastructure Project Delivery		(2.0)	(7.9)	(5.9)	(1.7)	(10.3)	(8.6)	(8.2)	(6.3)	(9.4)
122	Operations Support		(99.3)	(102.2)	(2.8)	(65.4)	(65.8)	(0.4)	(207.8)	(281.6)	(290.7)
123	Total		(45.6)	(37.5)	8.1	(12.1)	(6.5)	5.7	(104.5)	(182.4)	(202.8)
124	**Total Gross Operating & Provisions**		1,170.8	1,303.0	132.2	1,146.6	1,251.5	104.9	1,185.0	1,250.9	1,183.4
	Total Current Operating & Provisions										
125	Training, Development and Generation		144.5	153.4	8.9	142.1	149.0	7.0	147.8	156.5	158.6
126	Transmission (incl. Tech & CS)		367.4	383.3	15.9	366.8	371.1	4.3	417.1	407.8	396.3
127	Distribution		219.3	216.7	(2.6)	218.3	229.4	11.1	262.4	258.5	266.7
128	Customer Care		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
129	Capital Infrastructure Project Delivery		95.0	93.1	(1.9)	95.0	98.7	3.6	86.7	90.5	86.6
130	Operations Support		64.8	56.9	(7.9)	140.0	122.0	(18.1)	3.0	(8.3)	1.4
131	Severance Costs		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
132	Non-Current PEB - Pension		32.6	32.6	(0.0)	15.5	15.5	0.0	59.3	31.3	31.3
133	Non-Current PEB - Other		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
134	F09/F10 RRA Adjustments		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
135	F11 RRA NSA Adjustment		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
136	F12-F14 RRA Adjustment		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
137	Total		923.6	936.0	12.4	977.7	985.7	8.0	976.3	936.4	941.0

Operating Costs and Provisions - Total Company - Supplemental Schedule
($ million)

Line	Column	Reference	F2015 RRA	F2015 Actual	F2015 Diff	F2016 RRA	F2016 Actual	F2016 Diff	F2017 Plan	F2018 Plan	F2019 Plan
			1	2	3 = 2 - 1	4	5	6 = 5- 4	7	8	9
	Gross Operating Costs Including Regulatory Account Additions										
1	Labour (excl Non-Current PEB)	L79 + L87	511.0	532.9	21.9	515.7	537.2	21.5	521.2	521.1	531.4
2	Services - ABSU	L80 + L88	48.5	52.2	3.7	47.7	60.7	13.1	49.1	48.4	49.6
3	Services - Other	L81 + L89	565.2	576.0	10.8	545.7	549.8	4.1	542.8	618.6	541.9
4	Materials	L82 + L90	40.4	44.6	4.1	40.1	49.5	9.4	41.1	41.0	40.9
5	Buildings & Equipment	L83 + L91	60.4	65.8	5.4	61.0	63.3	2.3	59.0	59.0	59.2
			1,225.5	1,271.5	46.0	1,210.1	1,260.5	50.4	1,213.3	1,288.1	1,223.0
	Less:										
6	Eligible Capital Overhead	L84 + L94	(65.4)	(66.7)	(1.3)	(65.4)	(68.9)	(3.4)	(68.2)	(69.0)	(69.7)
7	External Recoveries	L85 + L92	(27.7)	(35.0)	(7.3)	(27.8)	(27.1)	0.7	(26.2)	(29.2)	(21.5)
8	**Total Gross Operating Costs Including Regulatory Account Additions**	5.0 L65	**1,132.4**	**1,169.7**	**37.3**	**1,116.9**	**1,164.5**	**47.6**	**1,119.0**	**1,189.9**	**1,131.8**
9	**Total Gross Provision & Other Including Regulatory Account Additions**	5.0 L101	38.4	133.3	94.8	29.7	87.0	57.3	66.0	61.0	51.7
10	**Total Gross Operating Cost and Provision & Other Including Regulatory Account Additions**	5.0 L124 (or 3.0 L17)	**1,170.8**	**1,303.0**	**132.2**	**1,146.6**	**1,251.5**	**104.9**	**1,185.0**	**1,250.9**	**1,183.4**
	Less Regulatory Account Additions										
	Demand-Side Management										
11	Labour		(29.6)	(28.5)	1.1	(29.2)	**(26.5)**	2.7	**(21.4)**	**(21.3)**	**(21.8)**
12	Services - ABSU		(0.5)	(0.5)	(0.0)	(0.5)	**(1.7)**	(1.2)	**(0.3)**	**(0.3)**	**(0.3)**
13	Services - Other		(119.8)	(94.9)	24.9	(100.7)	**(116.1)**	(15.4)	**(91.4)**	**(138.4)**	**(78.1)**
14	Materials		(0.4)	(0.5)	(0.2)	(0.3)	**(0.4)**	(0.0)	**(0.4)**	**(0.4)**	**(0.4)**
15	Buildings & Equipment		(0.3)	(0.4)	(0.1)	(0.3)	**(0.4)**	(0.1)	**(0.2)**	**(0.2)**	**(0.2)**
	First Nations Costs										
16	Labour		(0.5)	(0.6)	(0.1)	(0.5)	**(0.6)**	(0.1)	**(0.5)**	**(0.5)**	**(0.5)**
17	Services - ABSU		(0.1)	(0.0)	0.0	(0.1)	**(0.0)**	0.1	**(0.0)**	**(0.0)**	**(0.0)**
18	Services - Other		(2.9)	(1.0)	2.0	(2.4)	**(0.9)**	1.5	**(5.0)**	**(3.1)**	**(2.2)**
19	Materials		0.0	(0.0)	(0.0)	0.0	**(0.0)**	(0.0)	0.0	0.0	0.0
20	Buildings & Equipment		0.0	(0.0)	(0.0)	0.0	**(0.0)**	(0.0)	0.0	0.0	0.0
	Site C Clean Energy Project										
21	Labour		0.0	(12.1)	(12.1)	0.0	0.0	0.0	0.0	0.0	0.0
22	Services - ABSU		0.0	(0.1)	(0.1)	0.0	0.0	0.0	0.0	0.0	0.0
23	Services - Other		0.0	(50.6)	(50.6)	0.0	0.0	0.0	0.0	0.0	0.0
24	Materials		0.0	(0.2)	(0.2)	0.0	0.0	0.0	0.0	0.0	0.0
25	Buildings & Equipment		0.0	(2.4)	(2.4)	0.0	0.0	0.0	0.0	0.0	0.0
	Storm Restoration										
26	Labour		0.0	(1.7)	(1.7)	0.0	**(4.3)**	(4.3)	0.0	0.0	0.0
27	Services - ABSU		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
28	Services - Other		0.0	(7.1)	(7.1)	0.0	**(14.6)**	(14.6)	0.0	0.0	0.0
29	Materials		0.0	(0.2)	(0.2)	0.0	**(0.7)**	(0.7)	0.0	0.0	0.0
30	Buildings & Equipment		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Operating Costs and Provisions - Total Company - Supplemental Schedule
($ million)

Line		Reference	F2015 RRA	F2015 Actual	F2015 Diff	F2016 RRA	F2016 Actual	F2016 Diff	F2017 Plan	F2018 Plan	F2019 Plan
	Column		1	2	3 = 2 - 1	4	5	6 = 5- 4	7	8	9
	Smart Metering & Infrastructure										
31	Labour		(9.5)	(7.3)	2.2	(7.9)	(7.6)	0.2	0.0	0.0	0.0
32	Services - ABSU		11.0	9.9	(1.0)	11.9	8.1	(3.8)	0.0	0.0	0.0
33	Services - Other		(18.6)	(15.0)	3.6	(14.8)	(18.3)	(3.5)	0.0	0.0	0.0
34	Materials		0.1	(0.3)	(0.4)	0.4	(0.2)	(0.6)	0.0	0.0	0.0
35	Buildings & Equipment		(11.3)	(10.0)	1.4	(11.1)	(9.9)	1.2	0.0	0.0	0.0
36	External Recoveries				0.0		3.5	3.5			
	Non-Current Pension Cost										
37	Labour		0.0	0.0	0.0	0.0	(17.2)	(17.2)	(10.1)	0.0	0.0
38	Services - ABSU		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
39	Services - Other		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
40	Materials		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
41	Buildings & Equipment		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
42	**IFRS Capitalized Overhead**	5.0 -L60	(156.8)	(156.8)	(0.0)	(134.4)	(134.4)	0.0	(112.0)	(89.6)	(67.2)
43	**Total Regulatory Account Additions**	5.0 -L64	(339.2)	(380.3)	(41.0)	(290.0)	(342.3)	(52.4)	(241.4)	(253.8)	(170.7)
	Less Deferred Provisions										
44	First Nations Provisions	5.0 -L93	0.0	(1.4)	(1.4)	0.0	5.0	5.0	5.3	0.0	0.0
45	Environmental Provisions	5.0 -L94	0.0	(63.8)	(63.8)	0.0	(47.1)	(47.1)	0.0	0.0	0.0
46	Arrow Water Divestiture Costs	5.0 -L95	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
47	Arrow Water Provision	5.0 -L96	0.0	0.0	0.0	0.0	(0.7)	(0.7)	0.0	0.0	0.0
48	Smart Metering & Infrastructure DSMD Write-Off	5.0 -L98	0.0	(9.1)	(9.1)	0.0	0.0	0.0	0.0	0.0	0.0
49	Real Property Sales	5.0 -L99	0.0	(7.9)	(7.9)	0.0	(9.5)	(9.5)	(6.5)	10.0	14.0
50	**Total Deferred Provisions**	5.0 -L100	0.0	(82.2)	(82.2)	0.0	(52.3)	(52.3)	(1.2)	10.0	14.0
51	**Total Deferred Costs**	L43 + L40 (or 3.0 L20)	(339.2)	(462.5)	(123.3)	(290.0)	(394.6)	(104.6)	(242.6)	(243.8)	(156.7)
	Less Deferral Account Additions										
	Transfers to HDA										
52	Labour		0.0	(0.2)	(0.2)	0.0	(0.1)	(0.1)	0.0	0.0	0.0
53	Services - Other		0.0	(1.6)	(1.6)	0.0	(2.2)	(2.2)	0.0	0.0	0.0
54	Materials		0.0	(0.1)	(0.1)	0.0	(0.2)	(0.2)	0.0	0.0	0.0
	Transfers to NHDA										
55	Labour		0.0	(0.5)	(0.5)	0.0	(2.1)	(2.1)	0.0	0.0	0.0
56	Services - Other		0.0	10.8	10.8	0.0	15.2	15.2	0.0	0.0	0.0
57	Materials		0.0	(0.3)	(0.3)	0.0	(3.5)	(3.5)	0.0	0.0	0.0
58	**Total Deferral Account Additions**	5.0 L50 (or 3.0 L18)	0.0	8.1	8.1	0.0	7.1	7.1	0.0	0.0	0.0

Operating Costs and Provisions - Total Company - Supplemental Schedule
($ million)

Line		Reference	F2015 RRA	F2015 Actual	F2015 Diff	F2016 RRA	F2016 Actual	F2016 Diff	F2017 Plan	F2018 Plan	F2019 Plan
	Column		1	2	3 = 2 - 1	4	5	6 = 5- 4	7	8	9
	Add Regulatory Account Recoveries										
59	First Nation Costs	5.0 L29	43.5	43.5	0.0	43.2	43.2	(0.0)	33.8	40.2	39.0
60	Storm Restoration	5.0 L31	(1.4)	(1.4)	0.0	(1.4)	(1.4)	(0.0)	10.8	10.4	10.0
61	Capital Project Investigation	5.0 L34	4.8	4.8	0.0	4.8	4.8	0.0	4.8	4.8	4.8
62	Smart Metering & Infrastructure	5.0 L36	30.5	30.5	(0.0)	31.3	31.3	0.0	32.5	31.7	31.0
63	Home Purchase Offer Plan	5.0 L37	11.8	11.8	(0.0)	11.3	11.3	(0.0)	0.0	0.0	0.0
64	Minimum Reconnection Charge	5.0 L38	0.0	0.0	0.0	0.0	0.0	0.0	0.5	0.0	0.0
65	Non-Current Pension Cost	5.0 L39	32.6	32.6	(0.0)	15.5	15.5	0.0	59.3	31.3	31.3
66	IFRS PP&E	5.0 L40	15.9	15.9	0.0	19.8	19.8	0.0	23.2	26.0	28.2
67	IFRS Pension	5.0 L41	38.2	38.2	(0.0)	38.2	38.2	0.0	38.2	38.2	38.2
68	**Total Regulatory Account Recoveries before Provisions & Other**	5.0 L42	176.0	175.9	(0.1)	162.9	162.9	(0.0)	203.2	182.6	182.7
69	PCB Remediation	5.0 L102 : L105	13.6	9.2	(4.5)	13.3	13.9	0.6	18.3	18.9	15.3
70	Asbestos Remediation	5.0 L106 : L109	12.1	12.1	0.0	10.8	10.8	0.0	24.4	16.6	15.3
71	Rock Bay Remediation	5.0 L110	51.5	51.5	(0.0)	50.5	50.5	(0.0)	(3.8)	(3.2)	0.0
72	Arrow Water Divestiture Costs	5.0 L111	4.7	4.7	(0.0)	4.5	4.5	0.0	0.0	0.0	0.0
73	Arrow Water Provision	5.0 L112	0.3	0.2	(0.1)	0.3	0.3	(0.0)	1.8	0.3	0.3
74	F12-F14 Rate Smoothing	5.0 L113	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
75	Rate Smoothing	5.0 L114	(166.2)	(166.2)	(0.0)	(121.2)	(121.2)	0.0	(210.0)	(285.9)	(299.4)
76	**Total Provisions & Other Regulatory Account Recoveries**	5.0 L115	(84.0)	(88.5)	(4.5)	(41.9)	(41.2)	0.6	(169.2)	(253.4)	(268.4)
77	**Total Regulatory Account Recoveries**	L68 + L76 (or 3.0 L21)	92.0	87.4	(4.6)	121.1	121.7	0.6	34.0	(70.8)	(85.8)
78	**Total Current Operating Costs & Provisions & Other**	5.0 L137 (or 3.0 L22)	**923.6**	**936.0**	**12.4**	**977.7**	**985.7**	**8.0**	**976.3**	**936.4**	**941.0**

Operating Costs and Provisions - Total Company - Supplemental Schedule
($ million)

Line	Column	Reference	F2015 RRA	F2015 Actual	F2015 Diff	F2016 RRA	F2016 Actual	F2016 Diff	F2017 Plan	F2018 Plan	F2019 Plan
			1	2	3 = 2 - 1	4	5	6 = 5- 4	7	8	9
	SUMMARY OF OPERATING COSTS ABOVE										
	Operating Costs Before Deferrals										
79	Labour (excl Non-Current PEB)	5.0 L13	471.3	482.0	10.6	478.1	478.7	0.6	489.3	499.3	509.1
80	Services - ABSU	5.0 L14	58.9	61.5	2.6	59.0	67.2	8.1	48.7	48.0	49.3
81	Services - Other	5.0 L16	423.9	416.6	(7.3)	427.8	412.9	(14.9)	446.4	477.1	461.5
82	Materials	5.0 L17	40.2	43.0	2.8	40.1	44.5	4.4	40.7	40.6	40.6
83	Buildings & Equipment	5.0 L18	48.8	53.1	4.3	49.6	53.0	3.4	58.8	58.8	58.9
	Less:										
84	Capital Overhead	5.0 L19	(222.2)	(223.5)	(1.3)	(199.8)	(203.3)	(3.4)	(180.2)	(158.6)	(136.9)
85	External Recoveries	5.0 L20	(27.7)	(35.0)	(7.3)	(27.8)	(23.7)	4.1	(26.2)	(29.2)	(21.5)
86	**Total Operating Costs Before Deferrals**	5.0 L27	**793.2**	**797.6**	**4.4**	**826.9**	**829.3**	**2.4**	**877.6**	**936.1**	**961.1**
	Deferred Operating Costs										
87	Labour (excl Non-Current PEB)	-(L11+L16+L21+L26 +L31+L37+L52+L55)	39.6	50.9	11.3	37.6	58.5	20.9	31.9	21.8	22.3
88	Services - ABSU	-(L12+L17+L22+L27 +L32+L38)	(10.4)	(9.2)	1.2	(11.4)	(6.4)	4.9	0.4	0.4	0.3
89	Services - Other	-(L13+L18+L23+L28 +L33+L39+L53+L56)	141.3	159.4	18.1	117.9	136.9	19.0	96.5	141.5	80.3
90	Materials	-(L14+L19+L24+L29 +L34+L40+L54+L57)	0.2	1.6	1.3	(0.0)	5.0	5.0	0.4	0.4	0.4
91	Buildings & Equipment	-(L15+L20+L25+L30 +L35+L41)	11.6	12.7	1.1	11.4	10.3	(1.1)	0.2	0.2	0.2
92	External Recoveries	L36	0.0	0.0	0.0	0.0	(3.5)	(3.5)	0.0	0.0	0.0
93	**Total Deferred Operating Costs**		**182.4**	**215.3**	**32.9**	**155.6**	**200.8**	**45.3**	**129.4**	**164.2**	**103.5**
94	**IFRS Capitalized Overhead**	5.0 L60	156.8	156.8	0.0	134.4	134.4	0.0	112.0	89.6	67.2
95	**Total Operating Costs Including Deferrals**	L8	**1,132.4**	**1,169.7**	**37.3**	**1,116.9**	**1,164.5**	**47.6**	**1,119.0**	**1,189.9**	**1,131.8**
96	**Provisions & Other**	L9	38.4	133.3	94.8	29.7	87.0	57.3	66.0	61.0	51.7
97	**Total Gross Operating Cost and Provision & Other Including Deferrals**	L10 (or 5.0 L124)	**1,170.8**	**1,303.0**	**132.2**	**1,146.6**	**1,251.5**	**104.9**	**1,185.0**	**1,250.9**	**1,183.4**
	Less										
98	**Deferral Account Additions**	L43 + L58	(339.2)	(372.1)	(32.9)	(290.0)	(335.2)	(45.3)	(241.4)	(253.8)	(170.7)
99	**Deferred Provisions & Other**	L50	0.0	(82.2)	(82.2)	0.0	(52.3)	(52.3)	(1.2)	10.0	14.0
	Add										
100	**Regulatory Account Recoveries Bf Provisions & Other**	L68	176.0	175.9	(0.1)	162.9	162.9	(0.0)	203.2	182.6	182.7
101	**Provisions & Other Regulatory Account**	L76	(84.0)	(88.5)	(4.5)	(41.9)	(41.2)	0.6	(169.2)	(253.4)	(268.4)
102	**Total Current Operating Costs & Provisions & Other**	L78	**923.6**	**936.0**	**12.4**	**977.7**	**985.7**	**8.0**	**976.3**	**936.4**	**941.0**
103	**Operating Costs Referenced in Chapter 5 Table 5-11**	L86+L100 (or 5.0 L47)	**969.1**	**973.5**	**4.4**	**989.9**	**992.2**	**2.3**	**1,080.8**	**1,118.8**	**1,143.7**

Operating Costs - Operations Support
($ million)

Line		Reference	F2015 RRA	F2015 Actual	F2015 Diff	F2016 RRA	F2016 Actual	F2016 Diff	F2017 Plan	F2018 Plan	F2019 Plan
	Column		1	2	3 = 2 - 1	4	5	6 = 5- 4	7	8	9
	Operating Costs by KBU										
1	Executive		0.7	0.8	0.1	0.7	**0.8**	0.1	**0.9**	**1.0**	**1.0**
2	Sustainability		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	Communications		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	Customer Care and Power Smart		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5	Corporate Human Resources		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
6	Safety, Health & Environment		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7	Safety, Security, Emergency Management		25.6	24.4	(1.2)	25.7	**29.2**	3.5	**30.0**	**30.0**	**30.0**
8	Human Resources		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9	Finance & Corporate Resources		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10	Finance & Supply Chain		108.2	104.5	(3.7)	108.1	**112.6**	4.5	**119.4**	**120.2**	**121.6**
11	Corporate Services & General Counsel		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12	General Counsel		12.2	11.6	(0.6)	12.2	**11.0**	(1.2)	**12.2**	**12.3**	**12.3**
13	Energy Planning & Procurement		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
14	Economic & Business Development		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
15	IPP Capital Lease Operating Costs		29.4	29.4	0.0	33.8	**34.2**	0.4	**28.2**	**63.6**	**54.3**
16	Smart Metering & Infrastructure		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
17	Corporate Affairs		53.7	50.4	(3.3)	53.8	**51.1**	(2.6)	**53.1**	**53.3**	**53.9**
18	Corporate Costs		(131.6)	(127.9)	3.7	(98.3)	**(120.6)**	(22.3)	**(94.8)**	**(71.2)**	**(47.5)**
19	Total		98.2	93.3	(5.0)	136.0	118.4	(17.6)	148.9	209.1	225.6
	Operating Costs by Resource										
20	Labour		122.9	131.7	8.8	128.8	**118.0**	(10.7)	**122.7**	**124.6**	**126.6**
21	Services - ABSU		9.3	8.7	(0.6)	9.4	**9.0**	(0.3)	**8.8**	**8.7**	**8.9**
22	Services - BCTC		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
23	Services - Other		106.7	97.9	(8.8)	116.1	**107.2**	(8.9)	**110.9**	**147.0**	**138.9**
24	Materials		14.6	14.8	0.2	14.6	**16.5**	1.9	**16.7**	**16.7**	**16.7**
25	Buildings & Equipment		1.6	2.0	0.5	1.6	**2.2**	0.7	**1.8**	**1.8**	**1.8**
26	Capitalized Overhead		(156.8)	(156.8)	0.0	(134.4)	**(134.4)**	0.0	**(112.0)**	**(89.6)**	**(67.2)**
27	External Recoveries		0.0	(5.1)	(5.1)	0.0	**(0.2)**	(0.2)	0.0	0.0	0.0
28	Total		98.2	93.3	(5.0)	136.0	118.4	(17.6)	148.9	209.1	225.6

Operating Costs - Training, Development & Generation
($ million)

Line	Reference	F2015 RRA	F2015 Actual	F2015 Diff	F2016 RRA	F2016 Actual	F2016 Diff	F2017 Plan	F2018 Plan	F2019 Plan
	Column	1	2	3 = 2 - 1	4	5	6 = 5- 4	7	8	9
	Operating Costs by KBU									
1	Engineering	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2	Dam Safety	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	Generation Asset Mgmt.	2.3	1.8	(0.5)	2.3	**1.9**	(0.4)	**2.2**	**2.2**	**2.3**
4	Generation Maintenance	4.7	3.9	(0.8)	4.7	**4.3**	(0.4)	**6.0**	**8.0**	**8.1**
5	Generation Project Delivery	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
6	Generation Operations	85.0	86.2	1.1	85.1	**85.3**	0.3	**81.2**	**81.7**	**88.0**
7	Operational Safety	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	Environmental Risk Management	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9	Generation Resource Mgmt	13.2	12.9	(0.3)	13.3	**13.9**	0.6	**14.5**	**14.7**	**14.8**
10	Energy Planning & Econ Development	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11	Aboriginal Relations	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12	Business Unit Support	3.4	3.4	0.0	1.6	**5.6**	4.0	**6.6**	**6.6**	**6.7**
13	Training and Development	24.3	25.8	1.5	24.3	**25.3**	1.0	**25.9**	**25.9**	**26.3**
14	Technology	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
15	Total	132.9	134.0	1.1	131.3	136.3	5.0	136.4	139.2	146.2
	Operating Costs by Resource									
16	Labour	86.4	86.9	0.5	86.5	**90.4**	3.8	**89.3**	**90.9**	**92.6**
17	Services - ABSU	0.2	0.2	(0.0)	0.2	**0.6**	0.4	**0.3**	**0.3**	**0.3**
18	Services - BCTC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
19	Services - Other	37.5	34.2	(3.3)	35.7	**33.5**	(2.3)	**38.8**	**40.1**	**45.3**
20	Materials	6.8	8.8	2.0	6.8	**8.2**	1.3	**6.5**	**6.4**	**6.4**
21	Buildings & Equipment	2.0	3.9	1.9	2.0	**3.7**	1.7	**1.6**	**1.5**	**1.5**
22	Capitalized Overhead	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
23	External Recoveries	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
24	Total	132.9	134.0	1.1	131.3	136.3	5.0	136.4	139.2	146.2

Operating Costs - Customer Care
($ million)

Line	Column	Reference	F2015 RRA	F2015 Actual	F2015 Diff	F2016 RRA	F2016 Actual	F2016 Diff	F2017 Plan	F2018 Plan	F2019 Plan
			1	2	3 = 2 - 1	4	5	6 = 5- 4	7	8	9
	Operating Costs by KBU										
1	Power Smart & Customer Care		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2	Energy Planning & Procurement		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	Chief Technology Office		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	Safety, Health & Environment		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5	Aboriginal Relations & Negotiations		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
6	Economic & Business Development		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7	Business Unit Support		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	IPP Capital Lease Operating Costs		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9	Total		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Operating Costs by Resource										
10	Labour		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11	Services - ABSU		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12	Services - BCTC		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13	Services - Other		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
14	Materials		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
15	Buildings & Equipment		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
16	Capitalized Overhead		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
17	External Recoveries		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
18	Total		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Operating Costs - Transmission, Distribution and Customer Services (TDCS)
($ million)

Line		F2015 RRA	F2015 Actual	F2015 Diff	F2016 RRA	F2016 Actual	F2016 Diff	F2017 Plan	F2018 Plan	F2019 Plan
	Reference / Column	1	2	3 = 2 - 1	4	5	6 = 5 - 4	7	8	9
	Operating Costs by KBU									
1	Distribution Operations	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2	Customer Service & Distribution Design	90.1	92.9	2.8	90.1	94.5	4.4	88.0	85.7	86.2
3	Transmission & Construction Services	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	Operational Support Services	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5	Transmission Owner	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
6	Field Operations & Safety	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7	Grid Operations	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	Field & Grid Operations	138.0	138.9	0.9	137.7	140.1	2.4	146.4	147.9	149.6
9	Asset Investment Management	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10	Asset Management & Dist Eng	152.8	162.3	9.5	151.7	155.1	3.4	158.1	158.6	158.1
11	Project & Program Delivery	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12	Program & Contract Management	12.2	11.8	(0.4)	12.2	10.9	(1.3)	12.9	13.1	13.3
13	Engineering and Design	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
14	Aboriginal Relations	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
15	Smart Metering & Infrastructure	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
16	Technology	108.4	108.9	0.4	110.1	107.2	(2.9)	139.5	139.7	138.9
17	Business Unit Support	11.9	2.9	(9.0)	9.0	5.8	(3.2)	(8.9)	(8.9)	(8.9)
18	Total	513.4	517.6	4.3	510.9	513.6	2.7	536.0	536.0	537.2
	Operating Costs by Resource									
19	Labour	214.6	213.6	(1.0)	215.0	218.3	3.3	222.0	227.0	232.3
20	Services - ABSU	46.9	49.2	2.3	46.9	53.5	6.5	36.3	35.7	36.8
21	Services - BCTC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
22	Services - Other	208.5	214.1	5.6	204.8	196.7	(8.1)	224.2	219.9	214.6
23	Materials	17.2	17.2	0.0	17.1	18.1	1.0	16.1	16.0	16.0
24	Buildings & Equipment	35.9	37.7	1.9	36.9	37.7	0.8	48.3	48.3	48.3
25	Capitalized Overhead	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
26	External Recoveries	(9.8)	(14.3)	(4.5)	(9.9)	(10.7)	(0.8)	(10.8)	(10.8)	(10.8)
27	Total	513.4	517.6	4.3	510.9	513.6	2.7	536.0	536.0	537.2
	Operating Costs by Function									
28	Customer Service	75.8	76.8	1.0	75.8	77.9	2.1	75.2	72.5	72.7
29	Technology	108.4	108.9	0.4	110.1	107.2	(2.9)	139.5	139.7	138.9
30	Balance - T&D Allocation	329.1	332.0	2.9	325.0	328.5	3.4	321.3	323.8	325.6
31	Allocation to Transmission (%)	53.3%	53.3%		53.4%	47.8%		47.8%	47.8%	47.7%
32	Transmission Allocation	175.4	177.0	1.5	173.6	156.9	(16.7)	153.5	154.7	155.4
33	Distribution Allocation	153.7	155.0	1.3	151.4	171.6	20.1	167.8	169.2	170.2
34	Customer Service	75.8	76.8	1.0	75.8	77.9	2.1	75.2	72.5	72.7
35	Technology	108.4	108.9	0.4	110.1	107.2	(2.9)	139.5	139.7	138.9
36	Transmission	175.4	177.0	1.5	173.6	156.9	(16.7)	153.5	154.7	155.4
37	Transmission Total	359.7	362.6	2.9	359.5	342.0	(17.5)	368.2	366.9	367.0
38	Distribution	153.7	155.0	1.3	151.4	171.6	20.1	167.8	169.2	170.2
39	Distribution Total	153.7	155.0	1.3	151.4	171.6	20.1	167.8	169.2	170.2
40	Total	513.4	517.6	4.3	510.9	513.6	2.7	536.0	536.0	537.2

Operating Costs - Capital Infrastructure Project Delivery
($ million)

Line	Reference / Column	F2015 RRA	F2015 Actual	F2015 Diff	F2016 RRA	F2016 Actual	F2016 Diff	F2017 Plan	F2018 Plan	F2019 Plan
		1	2	3 = 2 - 1	4	5	6 = 5- 4	7	8	9
	Operating Costs by KBU									
1	Project Delivery	12.7	12.1	(0.6)	12.7	12.0	(0.8)	13.4	14.2	14.3
2	Generation & Transmission Engineering	12.3	13.3	1.0	12.4	12.3	(0.1)	14.0	14.2	14.4
3	Dam Safety	9.5	9.4	(0.0)	9.5	9.7	0.2	8.8	8.9	9.0
4	Environmental Risk Management	25.6	26.8	1.3	25.6	26.4	0.8	27.2	27.5	27.8
5	Aboriginal Relations	5.0	5.5	0.5	5.1	6.2	1.1	6.1	6.1	6.1
6	Properties	33.2	32.9	(0.3)	33.0	32.9	(0.1)	32.2	32.5	32.8
7	Business Unit Support	(49.6)	(47.4)	2.3	(49.6)	(38.6)	11.1	(45.3)	(51.6)	(52.3)
8	Site C Clean Energy Project	0.0	(0.0)	(0.0)	0.0	0.0	0.0	0.0	0.0	0.0
9	Total	48.7	52.7	4.1	48.7	61.0	12.3	56.3	51.8	52.1
	Operating Costs by Resource									
10	Labour	47.5	49.8	2.3	47.8	52.0	4.3	55.4	56.9	57.7
11	Services - ABSU	2.4	3.3	0.9	2.5	4.1	1.6	3.3	3.3	3.4
12	Services - BCTC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13	Services - Other	71.2	70.4	(0.8)	71.1	75.5	4.3	72.5	70.1	62.7
14	Materials	1.5	2.1	0.6	1.5	1.7	0.2	1.5	1.5	1.5
15	Buildings & Equipment	9.3	9.4	0.1	9.1	9.3	0.2	7.2	7.2	7.4
16	Capitalized Overhead	(65.4)	(66.8)	(1.3)	(65.4)	(68.9)	(3.4)	(68.2)	(69.0)	(69.7)
17	External Recoveries	(17.9)	(15.6)	2.3	(17.9)	(12.8)	5.1	(15.3)	(18.4)	(10.7)
18	Total	48.7	52.7	4.1	48.7	61.0	12.3	56.3	51.8	52.1

Taxes
($ million)

Line	Column	Reference	F2015 RRA	F2015 Actual	F2015 Diff	F2016 RRA	F2016 Actual	F2016 Diff	F2017 Plan	F2018 Plan	F2019 Plan
			1	2	3 = 2 - 1	4	5	6 = 5- 4	7	8	9
	Generation										
1	Grants in Lieu		23.1	22.6	(0.6)	24.3	23.4	(0.9)	23.8	24.4	25.4
2	School Taxes		18.3	16.8	(1.5)	18.8	17.2	(1.6)	16.7	17.3	17.8
3	Total		41.5	39.4	(2.1)	43.1	40.6	(2.5)	40.5	41.6	43.2
	Transmission										
4	Grants in Lieu		45.0	45.1	0.1	46.8	47.5	0.7	51.9	54.0	57.2
5	School Taxes		81.1	78.6	(2.5)	85.2	81.1	(4.1)	85.7	87.7	90.0
6	Total		126.1	123.7	(2.4)	132.0	128.5	(3.4)	137.6	141.7	147.2
	Distribution										
7	Grants in Lieu		6.9	6.9	(0.0)	7.2	7.0	(0.2)	7.4	7.8	8.4
8	School Taxes		20.0	19.0	(0.9)	20.4	19.2	(1.2)	19.4	19.8	20.3
9	Total		26.9	25.9	(1.0)	27.6	26.2	(1.4)	26.8	27.5	28.6
	Customer Care										
10	Grants in Lieu		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11	School Taxes		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12	Existing IPP Capital Leases		4.8	4.8	0.0	5.8	5.6	(0.2)	2.6	4.2	2.5
13	New Capital Leases Under IFRS		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
14	Total		4.8	4.8	0.0	5.8	5.6	(0.2)	2.6	4.2	2.5
	Business Support										
15	Grants in Lieu		9.3	9.5	0.2	10.2	10.0	(0.1)	10.5	11.3	11.7
16	School Taxes		5.3	5.5	0.2	5.6	5.5	(0.0)	5.3	5.4	5.6
17	Total		14.6	15.0	0.4	15.8	15.6	(0.2)	15.8	16.7	17.2
	Total Before Regulatory Accounts										
18	Grants in Lieu		84.4	84.0	(0.4)	88.5	87.9	(0.6)	93.6	97.5	102.6
19	School Taxes		124.7	120.0	(4.7)	129.9	123.0	(6.9)	127.1	130.2	133.6
20	IPP Capital Leases		4.8	4.8	0.0	5.8	5.6	(0.2)	2.6	4.2	2.5
21	Total		213.8	208.7	(5.1)	224.1	216.5	(7.7)	223.3	231.8	238.7
	Deferral Account Additions										
22	Transfers to NHDA		0.0	(2.6)	(2.6)	0.0	(3.4)	(3.4)	0.0	0.0	0.0
23	**Total Gross Taxes**	L21+L22	213.8	206.1	(7.7)	224.1	213.1	(11.0)	223.3	231.8	238.7
	Deferral Account Additions										
24	Transfers to NHDA		0.0	2.6	2.6	0.0	3.4	3.4	0.0	0.0	0.0
	Regulatory Account Recoveries										
25	Generation		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
26	Transmission		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
27	Distribution		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
28	Customer Care		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
29	Business Support		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
30	Total		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
31	**Total Current Taxes**	L23+L24+L30	213.8	208.7	(5.1)	224.1	216.5	(7.7)	223.3	231.8	238.7
	Allocation of Current Taxes										
32	Generation		41.5	39.4	(2.1)	43.1	40.6	(2.5)	40.5	41.6	43.2
33	Transmission		126.1	123.7	(2.4)	132.0	128.5	(3.4)	137.6	141.7	147.2
34	Distribution		26.9	25.9	(1.0)	27.6	26.2	(1.4)	26.8	27.5	28.6
35	Customer Care		4.8	4.8	0.0	5.8	5.6	(0.2)	2.6	4.2	2.5
36	Business Support		14.6	15.0	0.4	15.8	15.6	(0.2)	15.8	16.7	17.2
37	Total		213.8	208.7	(5.1)	224.1	216.5	(7.7)	223.3	231.8	238.7

Depreciation and Amortization
($ million)

Line		Reference	F2015 RRA	F2015 Actual	F2015 Diff	F2016 RRA	F2016 Actual	F2016 Diff	F2017 Plan	F2018 Plan	F2019 Plan
	Column		1	2	3 = 2 - 1	4	5	6 = 5- 4	7	8	9
	Amortization of Capital Assets										
1	Generation	12.2 L8:L10	246.8	257.7	10.9	257.4	194.7	(62.7)	198.0	208.3	226.7
2	Transmission	12.4 L8:L10	151.6	177.5	25.9	178.8	177.0	(1.8)	208.0	220.6	230.3
3	Distribution	12.5 L8:L9	217.6	182.6	(35.0)	225.3	171.1	(54.2)	185.3	191.2	197.8
4	Customer Care	12.3 L8:L9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5	Business Support	12.1 L8:L9	35.3	34.8	(0.5)	39.5	155.8	116.3	168.4	176.3	178.0
6	Total		651.3	652.6	1.3	701.0	698.6	(2.4)	759.8	796.3	832.8
	Amortization of Contributions										
7	Generation		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	Transmission		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9	Distribution		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10	Total		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Dismantling Costs										
11	Generation		8.7	4.9	(3.8)	9.5	(0.4)	(9.9)	0.9	0.0	0.0
12	Transmission		7.3	5.2	(2.1)	10.7	8.9	(1.8)	3.4	0.0	0.0
13	Distribution		8.7	10.9	2.2	10.9	14.5	3.6	3.8	0.0	0.0
14	Customer Care		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
15	Business Support		0.0	1.4	1.4	0.0	1.2	1.2	0.5	0.0	0.0
16	Total		24.6	22.4	(2.2)	31.2	24.2	(7.0)	8.6	0.0	0.0
	Capital Asset Write-Offs										
17	Generation		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
18	Transmission		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
19	Distribution		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
20	Customer Care		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
21	Business Support		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
22	Total		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	IPP Capital Leases										
23	Existing IPP Capital Leases		22.8	22.8	0.0	25.8	25.8	0.0	17.0	29.4	22.8
24	New Capital Leases Under IFRS		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
25	Total		22.8	22.8	0.0	25.8	25.8	0.0	17.0	29.4	22.8
26	**Other Net IFRS Impact**		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Deferral Account Additions										
26.1	Transfers to NHDA		0.0	(6.1)	(6.1)	0.0	(9.1)	(9.1)	0.0	0.0	0.0
	Regulatory Account Additions										
27	F07/F08 RRA Depr Study		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
28	Deferred Smart Metering & Infrastructure Amortization		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
29	Deferred Environmental Liability		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
30	Total		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
31	**Total Gross Amortization**		698.7	691.7	(7.0)	758.0	739.5	(18.5)	785.4	825.7	855.6

Depreciation and Amortization
($ million)

Line		Reference	F2015 RRA	F2015 Actual	F2015 Diff	F2016 RRA	F2016 Actual	F2016 Diff	F2017 Plan	F2018 Plan	F2019 Plan
	Column		1	2	3 = 2 - 1	4	5	6 = 5- 4	7	8	9
	Other Regulatory Account Additions										
32	Deferred PEI Amortization		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
33	Deferred Smart Metering & Infrastructure Amortization		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
34	Total		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Regulatory Account Recoveries										
	DSM Amortization										
35	Generation - 90%	(2.2 L5:L6) * 90%	65.9	64.0	(2.0)	75.0	71.5	(3.5)	80.2	87.0	95.0
36	Transmission - 10%	(2.2 L5:L6) * 10%	7.3	7.1	(0.2)	8.3	7.9	(0.4)	8.9	9.7	10.6
37	Total		73.3	71.1	(2.2)	83.3	79.4	(3.9)	89.1	96.7	105.5
	Depr Study Amortization										
38	Generation		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
39	Transmission		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
40	Distribution		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
41	Customer Care		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
42	Business Support		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
43	Total		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	FRSR Amortization										
44	Generation	Line 11	(8.7)	(4.9)	3.8	(9.5)	0.4	9.9	(0.9)	0.0	0.0
45	Transmission	Line 12	(7.3)	(5.2)	2.1	(10.7)	(8.9)	1.8	(3.4)	0.0	0.0
46	Distribution	Line 13	(8.7)	(10.9)	(2.2)	(10.9)	(14.5)	(3.6)	(3.8)	0.0	0.0
47	Customer Care	Line 14	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
48	Business Support	Line 15	0.0	(1.4)	(1.4)	0.0	(1.2)	(1.2)	(0.5)	0.0	0.0
49	Adjustment		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
50	Total		(24.6)	(22.4)	2.2	(31.2)	(24.2)	7.0	(8.6)	0.0	0.0
51	**Pre-1996 CIAC Amortization**		(6.3)	(6.3)	0.0	(4.7)	**(4.7)**	(0.0)	**0.7**	**3.2**	**4.9**
	Capital Additions Regulatory Account										
52	Generation		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
53	Transmission		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
54	Distribution		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
55	Customer Care		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
56	Business Support		(9.8)	(0.3)	9.5	(9.4)	5.2	14.7	**(3.6)**	**(3.4)**	**(3.3)**
57	Total		(9.8)	(0.3)	9.5	(9.4)	5.2	14.7	(3.6)	(3.4)	(3.3)
58	**Total Recoveries**		32.5	42.1	9.6	38.0	55.7	17.7	77.6	96.5	107.2
59	**Total Current Amortization**		731.2	739.9	8.7	796.0	804.3	8.3	863.0	922.2	962.8
	Allocation of Current Amortization										
60	Generation		312.7	321.7	9.0	332.4	266.2	(66.2)	278.2	295.3	321.7
61	Transmission		158.9	184.6	25.7	187.1	184.9	(2.2)	216.9	230.3	240.9
62	Distribution		211.3	176.3	(35.0)	220.6	166.4	(54.2)	186.0	194.4	202.7
63	Customer Care		22.8	22.8	0.0	25.8	25.8	0.0	17.0	29.4	22.8
64	Business Support		25.5	34.5	9.0	30.1	161.0	131.0	164.9	172.8	174.7
65	Total		731.2	739.9	8.7	796.0	804.3	8.3	863.0	922.2	962.8

Finance Charges
($ million)

Line	Column	Reference	F2015 RRA	F2015 Actual	F2015 Diff	F2016 RRA	F2016 Actual	F2016 Diff	F2017 Plan	F2018 Plan	F2019 Plan
			1	2	3 = 2 - 1	4	5	6 = 5- 4	7	8	9
1	**Total Gross Finance Charges**	L10+L26	725.0	664.1	(60.9)	838.3	746.6	(91.7)	711.4	745.9	785.0
	Regulatory Account Additions										
2	FX Gains/Losses		1.0	17.7	16.7	(0.1)	3.2	3.3	5.8	(6.8)	(3.5)
3	Deferred IPP Capital Leases		0.0	(54.6)	(54.6)	0.0	(72.8)	(72.8)	0.0	0.0	0.0
4	Net Smart Metering & Infrastructure Impact		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5	Deferred HPOP Finance Chrgs	Line 19	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
6	IFRS Reduced IDC Capitalized		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7	Accretion - First Nations		17.5	8.6	(8.9)	17.7	17.3	(0.4)	17.2	17.2	17.4
8	Accretion - Environmental		6.0	5.7	(0.3)	6.0	3.8	(2.2)	3.9	3.8	3.7
9	Accretion - Arrow Water		0.1	0.1	0.0	0.1	0.1	0.0	0.2	0.2	0.2
10	Total		24.6	(22.4)	(47.0)	23.7	(48.4)	(72.1)	27.1	14.4	17.7
11	**Adj. for Regulatory Account Additions**		700.4	686.6	(13.9)	814.6	795.0	(19.7)	684.2	731.6	767.2

Finance Charges
($ million)

Line	Column	Reference	F2015 RRA	F2015 Actual	F2015 Diff	F2016 RRA	F2016 Actual	F2016 Diff	F2017 Plan	F2018 Plan	F2019 Plan
			1	2	3 = 2 - 1	4	5	6 = 5- 4	7	8	9
	Total Before Regulatory Accounts										
12	Sinking Fund Income	Line 76	(4.1)	(6.9)	(2.8)	(4.2)	(8.0)	(3.8)	(5.5)	(5.6)	(5.6)
13	Long-Term Debt Costs	Line 93	634.2	637.4	3.2	677.0	700.1	23.1	746.9	793.8	825.8
14	Short-Term Debt Costs	Line 102	50.5	32.8	(17.7)	94.2	16.2	(78.0)	19.2	36.6	52.8
15	Interest Capitalized	Line 107	(68.8)	(89.3)	(20.5)	(61.3)	(81.1)	(19.8)	(92.9)	(128.7)	(152.1)
16	Swaps		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
17	Other (Income) / Loss		7.1	(20.9)	(28.0)	13.6	**16.0**	2.4	**(3.0)**	**(10.6)**	**4.6**
18	Deferred Smart Metering & Infrastructure Finance Charges		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
19	Deferred HPOP Finance Charges		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
20	Existing IPP Capital Leases		77.3	77.3	0.0	93.9	**93.9**	0.0	**25.1**	**44.7**	**42.4**
21	New Capital Leases Under IFRS		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
22	IFRS Reduced IDC Capitalized		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
23	Accretion - ARO		1.3	1.2	(0.1)	1.3	**1.0**	(0.3)	**1.0**	**1.1**	**1.1**
24	Non-Current PEB		2.9	55.0	52.1	0.1	**56.9**	56.8	**(6.6)**	**0.2**	**(1.8)**
25	F2013 Correction		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
26	Total		700.4	686.6	(13.9)	814.6	795.0	(19.7)	684.2	731.6	767.2
	Interest on Regulatory Accounts										
27	Interest on Deferral Accounts	2.1 L34	(30.2)	(30.6)	(0.4)	(23.8)	(36.8)	(13.0)	(41.7)	(34.3)	(26.6)
28	Interest on Other Reg Accounts	2.2 L218	(37.1)	(36.6)	0.5	(38.0)	(35.7)	2.2	(34.4)	(34.1)	(33.6)
29	Total		(67.4)	(67.3)	0.1	(61.8)	(72.5)	(10.8)	(76.1)	(68.4)	(60.1)
	Regulatory Account Recoveries										
30	Amort. of FX Gains/Losses		(0.7)	(0.3)	0.4	(0.7)	**0.9**	1.6	**0.6**	**(38.1)**	**(38.6)**
31	Non-Current Pension		0.0	(52.1)	(52.1)	0.0	**(56.8)**	(56.8)	0.0	0.0	0.0
32	Total Finance Charges		(25.5)	39.7	65.3	(25.5)	59.7	85.2	**(101.8)**	**(101.8)**	**(101.8)**
33	F2013 Correction		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
34	Total		(26.2)	(12.6)	13.6	(26.2)	3.8	30.1	(101.3)	(139.9)	(140.5)
35	**Total Current Finance Chrgs**	L26+L29+L34	606.8	606.7	(0.1)	726.6	726.3	(0.3)	506.9	523.2	566.6
	Portion of Rate Base										
36	Generation	10.0 L28	44.3%	44.4%	0.1%	42.3%	42.7%	0.4%	41.7%	41.6%	42.8%
37	Transmission	10.0 L29	27.5%	30.0%	2.5%	32.1%	33.3%	1.2%	35.6%	35.9%	35.1%
38	Distribution	10.0 L30	28.2%	25.6%	(2.6%)	25.7%	24.0%	(1.7%)	22.7%	22.5%	22.1%
39	Customer Care	10.0 L31	-	-	-	-	-	-	-	-	-
40	Business Support	10.0 L32	-	-	-	-	-	-	-	-	-
41	Total		100.0%	100.0%	0.0%	100.0%	100.0%	0.0%	100.0%	100.0%	100.0%
	Allocation of Current Finance Charges										
42	Generation		268.8	269.1	0.3	307.2	310.2	3.1	211.4	217.4	242.5
43	Transmission		167.0	182.1	15.1	233.0	241.7	8.7	180.3	187.9	199.0
44	Distribution		171.0	155.4	(15.6)	186.4	174.3	(12.1)	115.2	117.9	125.1

Finance Charges
($ million)

Line	Column	Reference	F2015 RRA	F2015 Actual	F2015 Diff	F2016 RRA	F2016 Actual	F2016 Diff	F2017 Plan	F2018 Plan	F2019 Plan
			1	2	3 = 2 - 1	4	5	6 = 5- 4	7	8	9
45	Customer Care		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
46	Business Support		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
47	Total		606.8	606.7	(0.1)	726.6	726.3	(0.3)	506.9	523.2	566.6
	Net Debt										
48	Sinking Funds	Line 77	(125.2)	(155.2)	(30.0)	(129.3)	(166.6)	(37.3)	(179.5)	(175.8)	(176.2)
49	Temporary Investments		(10.0)	(39.2)	(29.2)	(10.0)	**(44.4)**	(34.4)	**(10.0)**	**(10.0)**	**(10.0)**
50	Long-Term Debt	Line 88	12,743.1	13,329.2	586.1	13,379.4	15,836.6	2,457.2	16,885.1	18,788.3	19,060.2
51	Short-Term Debt	Line 97	4,164.3	3,546.9	(617.4)	4,303.0	2,376.0	(1,927.0)	2,961.4	2,267.5	2,938.2
52	Subtotal		16,772.2	16,681.7	(90.5)	17,543.1	18,001.6	458.5	19,657.1	20,870.1	21,812.2
53	IDC Adjustments		87.8	133.3	45.6	96.2	**159.2**	63.0	**144.5**	**146.3**	**151.8**
54	End of Year		16,859.9	16,815.0	(44.9)	17,639.3	18,160.8	521.5	19,801.6	21,016.4	21,964.0
55	Mid-Year Balance		16,249.3	16,224.6	(24.7)	17,249.6	17,487.9	238.3	18,981.2	20,409.0	21,490.2
	Weighted Average Cost of Debt										
56	Total Gross Finance Charges		725.0	664.1	(60.9)	838.3	746.6	(91.7)	711.4	745.9	785.0
57	IDC Adjustments		(40.3)	6.1	46.4	(67.1)	**(32.5)**	34.6	**55.9**	**82.2**	**102.9**
58	Total		684.7	670.2	(14.5)	771.2	714.1	(57.1)	767.3	828.1	887.8
59	Weighted Average Cost of Debt		4.21%	4.13%	(0.08%)	4.47%	4.08%	(0.39%)	4.04%	4.06%	4.13%
	Increase in Cash										
60	Net Income	9.0 L54	581.5	580.8	(0.7)	651.9	655.0	3.2	684.7	698.4	712.4
61	Dividend (One Year Lag)	9.0 L4	(154.5)	(167.1)	(12.6)	(278.6)	(264.1)	14.5	(325.6)	(270.8)	(170.8)
62	Amortization	7.0 L31	698.7	691.7	(7.0)	758.0	739.5	(18.5)	785.4	825.7	855.6
63	Deferral Account Additions	2.1 L33	0.0	(309.8)	(309.8)	0.0	(382.3)	(382.3)	0.0	0.0	0.0
64	Deferral Account Recoveries	2.1 L35	208.4	198.1	(10.4)	223.0	209.5	(13.4)	223.5	231.3	241.8
65	Regulatory Account Additions	2.2 L217	(359.0)	(489.3)	(130.3)	(310.3)	(414.3)	(104.0)	(269.8)	(258.2)	(174.4)
66	Regulatory Account Recoveries	2.2 L219	124.5	197.8	73.2	132.9	254.1	121.2	10.3	(114.2)	(119.1)
67	First Nations Provisions	2.2 L16	0.0	1.4	1.4	0.0	(5.0)	(5.0)	(5.3)	0.0	0.0
68	Environmental Provisions	2.2 L128	0.0	63.8	63.8	0.0	47.1	47.1	0.0	0.0	0.0
69	Capital Expenditures	13.0 L26	(2,252.3)	(2,159.8)	92.5	(1,939.2)	(2,296.0)	(356.8)	(2,603.9)	(2,411.9)	(2,424.6)
70	Contributions in Aid	11.0 L49	85.1	334.4	249.3	124.1	133.8	9.7	86.4	100.2	106.4
71	Change in Sinking Funds	Line 75	(1.0)	(19.7)	(18.7)	0.1	(3.4)	(3.5)	(7.4)	9.3	5.2
72	Change in Working Cap & Other		(148.5)	(101.0)	47.5	(136.9)	**(10.5)**	126.4	**(212.3)**	**(19.1)**	**24.9**
73	Total		(1,217.0)	(1,178.7)	38.3	(775.0)	(1,336.5)	(561.5)	(1,633.9)	(1,209.3)	(942.6)
	Sinking Funds										
74	Beginning of Year		120.1	128.6	8.5	125.2	155.2	30.0	166.6	179.5	175.8
75	Change in Sinking Funds		1.0	19.7	18.7	(0.1)	**3.4**	3.5	**7.4**	**(9.3)**	**(5.2)**
76	Sinking Fund Income		4.1	6.9	2.8	4.2	**8.0**	3.8	**5.5**	**5.6**	**5.6**
77	End of Year		125.2	155.2	30.0	129.3	166.6	37.3	179.5	175.8	176.2
78	Mid-Year Balance		122.7	141.9	19.2	127.3	160.9	33.6	173.0	177.6	176.0

Finance Charges
($ million)

Line	Column	Reference	F2015 RRA	F2015 Actual	F2015 Diff	F2016 RRA	F2016 Actual	F2016 Diff	F2017 Plan	F2018 Plan	F2019 Plan
			1	2	3 = 2 - 1	4	5	6 = 5- 4	7	8	9
	Long-Term Debt										
79	Beginning of Year		11,871.5	11,935.3	63.8	12,743.1	13,329.2	586.1	15,836.6	16,885.1	18,788.3
80	Adjustment to Opening Balance		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
81	Bonds Retired		(325.0)	(325.0)	0.0	(150.0)	**(150.0)**	0.0	0.0	**(40.0)**	**(1,279.4)**
82	Bonds Issued		0.0	1,665.0	1,665.0	0.0	**2,691.0**	2,691.0	**200.0**	0.0	0.0
83	Bonds Planned Issues		1,200.0	0.0	(1,200.0)	800.0	0.0	(800.0)	**800.0**	**2,025.0**	**1,600.0**
84	Revaluation of US $ Debt		8.8	164.6	155.8	(1.2)	**28.0**	29.2	**58.2**	**(70.5)**	**(38.2)**
85	Revaluation to Fair Value		0.0	(2.4)	(2.4)	0.0	**(2.2)**	(2.2)	0.0	0.0	0.0
86	Premiums/(Discounts) on Issues		0.0	(99.8)	(99.8)	0.0	**(50.2)**	(50.2)	**1.4**	0.0	0.0
87	Amortization of Issue Costs		(12.2)	(8.5)	3.7	(12.5)	**(9.2)**	3.3	**(11.1)**	**(11.3)**	**(10.5)**
88	End of Year		12,743.1	13,329.2	586.1	13,379.4	15,836.6	2,457.2	16,885.1	18,788.3	19,060.2
89	Mid-Year Balance		12,307.3	12,632.3	325.0	13,061.3	14,582.9	1,521.7	16,360.9	17,836.7	18,924.3
90	Interest Rate - Planned Issues		4.05%			5.00%			**2.96%**	**3.67%**	**4.60%**
91	Debt Costs - Excluding Planned		609.9	637.4	27.5	608.4	**700.1**	91.7	**735.1**	**733.0**	**691.0**
92	Debt Costs - Planned Issues		24.3	0.0	(24.3)	68.6	0.0	(68.6)	11.8	60.8	134.8
93	Total Long-Term Debt Costs		634.2	637.4	3.2	677.0	700.1	23.1	746.9	793.8	825.8
	Short-Term Debt										
94	Beginning of Year		3,818.9	3,762.1	(56.8)	4,164.3	3,546.9	(617.4)	2,376.0	2,961.4	2,267.5
95	Increase in Cash Requirement	Line 73	1,217.0	1,178.7	(38.3)	775.0	1,336.5	561.5	1,633.9	1,209.3	942.6
96	Change in Long-Term Debt	L79-L88	(871.6)	(1,393.9)	(522.3)	(636.3)	(2,507.4)	(1,871.1)	(1,048.5)	(1,903.2)	(271.9)
97	End of Year		4,164.3	3,546.9	(617.4)	4,303.0	2,376.0	(1,927.0)	2,961.4	2,267.5	2,938.2
98	Mid-Year Balance		3,991.6	3,654.5	(337.1)	4,233.6	2,961.4	(1,272.2)	2,668.7	2,614.5	2,602.9
99	Interest Rate		1.28%			2.23%			**0.72%**	**1.40%**	**2.03%**
100	Debt Costs - Interest		51.1	32.8	(18.3)	94.4	**16.2**	(78.2)	19.2	36.6	52.8
101	Debt Costs - Other		(0.6)	0.0	0.6	(0.2)	0.0	0.2	0.0	0.0	0.0
102	Total Short-Term Debt Costs		50.5	32.8	(17.7)	94.2	16.2	(78.0)	19.2	36.6	52.8
	Interest Capitalized										
103	Unfinished Construction	13.0 L62	2,978.6	2,970.0	(8.6)	2,387.4	2,709.0	321.6	2,894.0	3,788.1	4,267.5
104	Less Not Subject to IDC		(1,345.8)	(808.3)	537.6	(1,016.3)	**(723.0)**	293.3	**(595.8)**	**(617.0)**	**(585.0)**
105	Unfinished Subject to IDC		1,632.8	2,161.7	529.0	1,371.1	1,986.0	614.9	2,298.2	3,171.1	3,682.5
106	Interest Rate	Line 59	4.21%	4.13%	(0.08%)	4.47%	4.08%	(0.39%)	4.04%	4.06%	4.13%
107	Interest Capitalized		68.8	89.3	20.5	61.3	81.1	19.8	92.9	128.7	152.1

Return on Equity
($ million)

Line	Column	Reference	F2015 RRA	F2015 Actual	F2015 Diff	F2016 RRA	F2016 Actual	F2016 Diff	F2017 Plan	F2018 Plan	F2019 Plan
			1	2	3 = 2 - 1	4	5	6 = 5- 4	7	8	9
	Shareholder's Equity										
1	Retained Earnings - Beginning of Year		3,819.7	3,811.8	(7.9)	4,122.6	4,128.5	5.9	4,458.0	4,871.9	5,399.5
2	Adjustment to Opening Balance		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	Gross Return on Equity	Line 54	581.5	580.8	(0.7)	651.9	655.0	3.2	684.7	698.4	712.4
4	Dividend to Province	Line 16	(278.6)	(264.1)	14.5	(459.1)	(325.6)	133.5	(270.8)	(170.8)	(70.8)
5	Distribution to Province		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
6	Retained Earnings - End of Year		4,122.6	4,128.5	5.9	4,315.4	4,458.0	142.6	4,871.9	5,399.5	6,041.0
7	Accum Other Comp Income		70.4	(222.5)	(292.9)	70.4	(26.1)	(96.5)	378.1	42.4	42.4
8	OCI Deferred (Pension)		0.0	264.5	264.5	0.0	68.5	68.5	(335.7)	0.0	0.0
9	Total Shareholder's Equity		4,193.0	4,170.5	(22.5)	4,385.8	4,500.4	114.6	4,914.3	5,441.9	6,083.5
	Dividend to Province										
10	Net Income	Line 54	581.5			651.9			684.7	698.4	712.4
11	IDC (net of amortization)		0.0			0.0			0.0	0.0	0.0
12	Distributable Surplus		581.5			651.9			684.7	698.4	712.4
13	Maximum Dividend Percentage		85.0%			85.0%			85.0%		
14	Maximum Dividend Amount		494.3			554.1			582.0		
15	Minimum Equity Percentage		20.0%			20.0%			20.0%		
16	Dividend to Province		278.6			459.1			270.8	170.8	70.8
	Deferred Revenue										
17	Skagit - Beginning of Year										
18	Payments Received										
19	Interest										
20	Revenues Earned										
21	Skagit - End of Year										
	Return on Equity										
22	Shareholder's Equity	Line 9									
23	Deferred Revenue	Line 21									
24	Contributions - Columbia River										
25	Contributions - EARG										
26	Contributions - Field Operations										
27	Contributions - Transmission										
28	Pre-1996 CIAC Adjustment										
29	Total Equity										
	Capitalization										
30	Net Debt	8.0 L52	16,772.2	16,681.7	(90.5)	17,543.1	18,001.6	458.5	19,657.1	20,870.1	21,812.2
31	Shareholder's Equity	Line 9	4,193.0	4,170.5	(22.5)	4,385.8	4,500.4	114.6	4,914.3	5,441.9	6,083.5
32	Total		20,965.2	20,852.2	(113.0)	21,928.9	22,502.0	573.2	24,571.4	26,312.0	27,895.7
	Capital Structure										
33	Net Debt		80.0%	80.0%	(0.0%)	80.0%	80.0%	(0.0%)	80.0%	79.3%	78.2%
34	Equity		20.0%	20.0%	0.0%	20.0%	20.0%	0.0%	20.0%	20.7%	21.8%
35	Total		100.0%	100.0%	-	100.0%	100.0%	-	100.0%	100.0%	100.0%

Return on Equity
($ million)

Line	Column	Reference	F2015 RRA	F2015 Actual	F2015 Diff	F2016 RRA	F2016 Actual	F2016 Diff	F2017 Plan	F2018 Plan	F2019 Plan
			1	2	3 = 2 - 1	4	5	6 = 5- 4	7	8	9
	Deemed Equity										
36	Rate Base	10.0 L26	17,116.0	16,596.1	(519.9)	19,215.9	18,613.1	(602.8)	19,540.2	20,209.0	21,665.3
37	Pre-1996 Customer Contns	2.2 L42	(87.4)	(87.4)	0.0	(92.1)	(92.1)	0.0	(91.4)	(88.2)	(83.3)
38	Powerex & Powertech Assets		24.4	50.7	26.3	26.6	**41.2**	14.6	**42.4**	**43.2**	**43.6**
39	Columbia River Treaty Contns	11.0 L10	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
40	Allowance for Working Capital		250.0	250.0	0.0	250.0	**250.0**	0.0	**250.0**	**250.0**	**250.0**
41	Total		17,303.0	16,809.4	(493.6)	19,400.4	18,812.2	(588.2)	19,741.2	20,413.9	21,875.6
42	Deemed Equity Percentage		30.0%	30.0%	0.0%	30.0%	**30.0%**	0.0%	**30.0%**	**30.0%**	**30.0%**
43	Year-End Deemed Equity		5,190.9	5,042.8	(148.1)	5,820.1	5,643.7	(176.5)	5,922.4	6,124.2	6,562.7
44	Mid-Year Deemed Equity		4,911.7	4,855.1	(56.6)	5,505.5	5,343.2	(162.3)	5,783.0	6,023.3	6,343.4
45	Achieved ROE			11.96%			12.26%				
46	Allowed ROE / Derived ROE (F18-F19)		11.84%			11.84%			**11.84%**	11.60%	11.23%
47	Return on Equity		581.5	580.8	(0.7)	651.9	655.0	3.2	684.7	698.4	712.4
48	BC CPI Actual									**2.0%**	**2.0%**
49	Return on Equity incl. CPI Adjustment								684.7	698.4	712.4
50	F11 RRA NSA Adjustment		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
51	Amortize PEI Reg Acct		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
52	IFRS ROE Impact		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
53	Deferred Smart Metering & Infrastructure ROE		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
54	Gross Return on Equity		581.5	580.8	(0.7)	651.9	655.0	3.2	684.7	698.4	712.4
	F2010 ROE Regulatory Account Transfers										
55	Additions		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
56	Recoveries		(11.3)	(11.3)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
57	Total		(11.3)	(11.3)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
58	**Current Return on Equity**		592.8	592.1	(0.7)	651.9	655.0	3.2	684.7	698.4	712.4
	Portion of Rate Base										
59	Generation	10.0 L28	44.3%	44.4%	0.1%	42.3%	42.7%	0.4%	41.7%	41.6%	42.8%
60	Transmission	10.0 L29	27.5%	30.0%	2.5%	32.1%	33.3%	1.2%	35.6%	35.9%	35.1%
61	Distribution	10.0 L30	28.2%	25.6%	(2.6%)	25.7%	24.0%	(1.7%)	22.7%	22.5%	22.1%
62	Customer Care	10.0 L31	-	-	-	-	-	-	-	-	-
63	Business Support	10.0 L32	-	-	-	-	-	-	-	-	-
64	Total		100.0%	100.0%	0.0%	100.0%	100.0%	0.0%	100.0%	100.0%	100.0%
	Allocation of ROE										
65	Generation		262.6	262.7	0.0	275.6	279.8	4.2	285.5	290.3	304.9
66	Transmission		163.1	177.7	14.6	209.0	218.0	9.0	243.6	250.8	250.1
67	Distribution		167.1	151.7	(15.4)	167.3	157.2	(10.0)	155.6	157.3	157.3
68	Customer Care		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
69	Business Support		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
70	Total		592.8	592.1	(0.7)	651.9	655.0	3.2	684.7	698.4	712.4

Rate Base
($ million)

Line		Reference	F2015 RRA	F2015 Actual	F2015 Diff	F2016 RRA	F2016 Actual	F2016 Diff	F2017 Plan	F2018 Plan	F2019 Plan
	Column		1	2	3 = 2 - 1	4	5	6 = 5- 4	7	8	9
	Generation										
1	Net Assets in Service	12.2 L15	6,315.8	6,200.9	(114.9)	6,732.6	6,368.7	(363.9)	6,680.0	6,855.1	7,957.1
2	Net Contributions	11.0 L21	(2.7)	(3.3)	(0.6)	(2.3)	(3.4)	(1.1)	(3.1)	(2.8)	(2.4)
3	90% of Net DSM	2.2 L7 x 90%	808.0	757.3	(50.7)	851.0	816.5	(34.5)	838.6	896.1	891.8
4	Total		7,121.1	6,954.9	(166.2)	7,581.3	7,181.8	(399.6)	7,515.5	7,748.4	8,846.4
5	Mid-Year		6,866.6	6,797.0	(69.6)	7,351.2	7,068.3	(282.9)	7,348.6	7,632.0	8,297.4
	Transmission										
6	Net Assets in Service	12.4 L15	5,043.4	5,406.2	362.8	6,535.7	6,495.5	(40.2)	6,924.2	7,141.3	7,360.9
7	Net Contributions	11.0 L32	(285.9)	(528.1)	(242.2)	(324.3)	(534.0)	(209.6)	(530.3)	(537.8)	(549.6)
8	10% of Net DSM	2.2 L7 x 10%	89.8	84.1	(5.6)	94.6	90.7	(3.8)	93.2	99.6	99.1
9	Total		4,847.3	4,962.3	115.0	6,306.0	6,052.3	(253.7)	6,487.2	6,703.0	6,910.4
10	Mid-Year		4,265.2	4,599.0	333.8	5,576.6	5,507.3	(69.3)	6,269.7	6,595.1	6,806.7
	Distribution										
11	Net Assets in Service	12.5 L16	5,363.4	4,963.4	(400.0)	5,493.8	4,983.4	(510.4)	5,145.8	5,328.5	5,517.0
12	Net Contributions	11.0 L46	(949.0)	(964.5)	(15.5)	(984.6)	(1,039.3)	(54.7)	(1,079.8)	(1,121.3)	(1,164.1)
13	Total		4,414.4	3,998.8	(415.6)	4,509.2	3,944.1	(565.1)	4,066.0	4,207.2	4,352.9
14	Mid-Year		4,368.1	3,925.8	(442.3)	4,461.8	3,971.5	(490.3)	4,005.0	4,136.6	4,280.0
	Customer Care										
15	Net Assets in Service	12.3 L14	(0.0)	(0.0)	0.0	(0.0)	(0.0)	0.0	(0.0)	(0.0)	(0.0)
16	Net Contributions		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
17	Total		(0.0)	(0.0)	0.0	(0.0)	(0.0)	0.0	(0.0)	(0.0)	(0.0)
18	Mid-Year		(0.0)	(0.0)	0.0	(0.0)	(0.0)	0.0	(0.0)	(0.0)	(0.0)
	Business Support										
19	Net Assets in Service	12.1 L14	733.2	680.1	(53.1)	819.4	1,435.0	615.6	1,471.6	1,550.4	1,555.6
20	Net Contributions		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
21	Total		733.2	680.1	(53.1)	819.4	1,435.0	615.6	1,471.6	1,550.4	1,555.6
22	Mid-Year		683.3	656.8	(26.5)	776.3	1,057.6	281.2	1,453.3	1,511.0	1,553.0
	Total										
23	Net Assets in Service		17,455.9	17,250.6	(205.3)	19,581.6	19,282.6	(299.0)	20,221.6	20,875.1	22,390.5
24	Net Contributions		(1,237.7)	(1,496.0)	(258.3)	(1,311.3)	(1,576.7)	(265.5)	(1,613.2)	(1,661.9)	(1,716.1)
25	Net DSM		897.8	841.4	(56.3)	945.6	907.2	(38.4)	931.8	995.7	990.9
26	Total		17,116.0	16,596.1	(519.9)	19,215.9	18,613.1	(602.8)	19,540.2	20,209.0	21,665.3
27	Mid-Year		16,183.2	15,978.5	(204.7)	18,165.9	17,604.6	(561.4)	19,076.7	19,874.6	20,937.1
	Portion of Rate Base										
28	Generation		44.3%	44.4%	0.1%	42.3%	42.7%	0.4%	41.7%	41.6%	42.8%
29	Transmission		27.5%	30.0%	2.5%	32.1%	33.3%	1.2%	35.6%	35.9%	35.1%
30	Distribution		28.2%	25.6%	(2.6%)	25.7%	24.0%	(1.7%)	22.7%	22.5%	22.1%
31	Customer Care		-	-	-	-	-	-	-	-	-
32	Business Support		-	-	-	-	-	-	-	-	-
33	Total		100.0%	100.0%	0.0%	100.0%	100.0%	0.0%	100.0%	100.0%	100.0%

Contributions
($ million)

Line	Column	Reference	F2015 RRA	F2015 Actual	F2015 Diff	F2016 RRA	F2016 Actual	F2016 Diff	F2017 Plan	F2018 Plan	F2019 Plan
			1	2	3 = 2 - 1	4	5	6 = 5- 4	7	8	9
	Contributions - Columbia River Treaty										
1	Gross Contns - Beginning of Year		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2	Adjustment to Opening Balance		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	Retirements		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	Gross Contns - End of Year		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5	Accum Amort - Beginning of Year		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
6	Adjustment to Opening Balance		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7	Amortization		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	Retirements		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9	Accum Amort - End of Year		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10	Net Contribution - End of Year		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Contributions in Aid - Generation										
11	Gross Contns - Beginning of Year		8.9	9.0	0.1	8.9	9.4	0.5	9.8	9.8	9.7
12	Adjustment to Opening Balance		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13	Additions		0.0	0.4	0.4	0.0	**0.4**	0.4	0.0	0.0	0.0
14	Retirements & Transfers		0.0	0.0	0.0	0.0	0.0	0.0	0.0	**(0.1)**	**(0.0)**
15	Gross Contns - End of Year		8.9	9.4	0.5	8.9	9.8	0.9	9.8	9.7	9.7
16	Accum Amort - Beginning of Year		5.8	5.8	0.0	6.2	6.1	(0.1)	6.4	6.7	7.0
17	Adjustment to Opening Balance		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
18	Amortization		0.4	0.3	(0.1)	0.4	**0.3**	(0.1)	**0.3**	**0.3**	**0.3**
19	Retirements & Transfers		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
20	Accum Amort - End of Year		6.2	6.1	(0.1)	6.6	6.4	(0.2)	6.7	7.0	7.3
21	Net Contributions - End of Year		2.7	3.3	0.6	2.3	3.4	1.1	3.1	2.8	2.4
	Contributions in Aid - Transmission										
22	Gross Contns - Beginning of Year		358.1	379.6	21.5	377.8	620.3	242.5	638.0	647.7	668.9
23	Adjustment to Opening Balance		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
24	Additions		19.8	242.8	223.0	49.3	**19.5**	(29.8)	**9.8**	**21.8**	**26.2**
25	Retirements & Transfers		(0.1)	(2.1)	(2.0)	(0.1)	**(1.8)**	(1.7)	**(0.1)**	**(0.6)**	**(0.7)**
26	Gross Contns - End of Year		377.8	620.3	242.5	427.0	638.0	210.9	647.7	668.9	694.4
27	Accum Amort - Beginning of Year		83.9	84.8	0.9	91.9	92.2	0.3	104.0	117.4	131.0
28	Adjustment to Opening Balance		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
29	Amortization		8.0	8.3	0.3	10.8	**13.0**	2.2	**13.4**	**13.6**	**13.7**
30	Retirements & Transfers		0.0	(0.9)	(0.9)	0.0	**(1.2)**	(1.2)	0.0	0.0	0.0
31	Accum Amort - End of Year		91.9	92.2	0.3	102.7	104.0	1.3	117.4	131.0	144.8
32	Net Contributions - End of Year		285.9	528.1	242.2	324.3	534.0	209.6	530.3	537.8	549.6

Contributions
($ million)

Line	Column	Reference	F2015 RRA	F2015 Actual	F2015 Diff	F2016 RRA	F2016 Actual	F2016 Diff	F2017 Plan	F2018 Plan	F2019 Plan
			1	2	3 = 2 - 1	4	5	6 = 5- 4	7	8	9
	Contributions in Aid - Distribution										
33	Gross Contns - Beginning of Year		1,515.3	1,502.5	(12.8)	1,578.0	1,590.3	12.3	1,700.1	1,773.3	1,846.5
34	Adjustment to Opening Balance		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
35	Additions		65.3	91.2	25.9	74.8	**113.9**	39.1	**76.6**	**78.4**	**80.3**
36	Smart Metering & Infrastructure Legacy Meters		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
37	Retirements & Transfers		(2.6)	(3.4)	(0.8)	(2.7)	**(4.1)**	(1.4)	**(3.4)**	**(5.1)**	**(5.6)**
38	Gross Contns - End of Year		1,578.0	1,590.3	12.3	1,650.1	1,700.1	50.0	1,773.3	1,846.5	1,921.3
39	Accum Amort - Beginning of Year		592.7	590.5	(2.2)	628.9	625.7	(3.2)	660.8	693.4	725.3
40	Adjustment to Opening Balance		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
41	Amortization		29.9	29.7	(0.2)	31.8	**31.4**	(0.4)	**33.3**	**35.1**	**36.9**
42	Amortization of Pre-1996 CIAC	2.2 L41	6.3	6.3	(0.0)	4.7	4.7	0.0	(0.7)	(3.2)	(4.9)
43	Smart Metering & Infrastructure Legacy Meters		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
44	Retirements & Transfers		0.0	(0.8)	(0.8)	0.0	**(1.0)**	(1.0)	0.0	0.0	0.0
45	Accum Amort - End of Year		628.9	625.7	(3.2)	665.4	660.8	(4.7)	693.4	725.3	757.2
46	Net Contributions - End of Year		949.0	964.5	15.5	984.6	1,039.3	54.7	1,079.8	1,121.3	1,164.1
	Contributions in Aid - Total										
47	Gross Contns - Beginning of Year		1,882.3	1,891.0	8.7	1,964.7	2,219.9	255.2	2,347.8	2,430.7	2,525.1
48	Adjustment to Opening Balance		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
49	Additions		85.1	334.4	249.3	124.1	133.8	9.7	86.4	100.2	106.4
50	Smart Metering & Infrastructure Legacy Meters		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
51	Retirements & Transfers		(2.7)	(5.5)	(2.8)	(2.8)	(5.9)	(3.1)	(3.5)	(5.8)	(6.2)
52	Gross Contns - End of Year		1,964.7	2,219.9	255.2	2,086.0	2,347.8	261.9	2,430.7	2,525.1	2,625.3
53	Accum Amort - Beginning of Year		682.4	681.1	(1.3)	727.0	724.0	(3.1)	771.1	817.5	863.3
54	Adjustment to Opening Balance		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
55	Amortization		38.3	38.3	0.0	43.0	44.7	1.7	47.1	49.0	50.9
56	Amortization of Pre-96 CIAC		6.3	6.3	(0.0)	4.7	4.7	0.0	(0.7)	(3.2)	(4.9)
57	Smart Metering & Infrastructure Legacy Meters		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
58	Retirements & Transfers		0.0	(1.7)	(1.7)	0.0	(2.2)	(2.2)	0.0	0.0	0.0
59	Accum Amort - End of Year		727.0	724.0	(3.1)	774.7	771.1	(3.6)	817.5	863.3	909.2
60	Net Contributions - End of Year		1,237.7	1,496.0	258.3	1,311.3	1,576.7	265.5	1,613.2	1,661.9	1,716.1

Assets - Total (Excluding DSM and IPP Capital Leases)
($ million)

Line		Reference	F2015 RRA	F2015 Actual	F2015 Diff	F2016 RRA	F2016 Actual	F2016 Diff	F2017 Plan	F2018 Plan	F2019 Plan
	Column		1	2	3 = 2 - 1	4	5	6 = 5- 4	7	8	9
	Gross Assets in Service										
1	Opening Balance		17,340.1	17,458.7	118.6	19,817.5	19,559.9	(257.6)	22,245.4	23,944.1	25,393.9
2	Adjustment to Opening Balance		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	Capital Additions		2,511.7	2,153.7	(358.0)	2,862.2	2,782.6	(79.6)	1,737.6	1,489.9	2,387.8
4	Retirements & Transfers		(34.2)	(52.5)	(18.3)	(35.4)	(97.2)	(61.8)	(38.9)	(40.1)	(39.7)
5	Closing Balance		19,817.5	19,559.9	(257.6)	22,644.3	22,245.4	(398.9)	23,944.1	25,393.9	27,742.1
	Accumulated Amortization										
6	Opening Balance		1,710.4	1,675.6	(34.8)	2,361.7	2,309.3	(52.4)	2,962.7	3,722.5	4,518.8
7	Adjustment to Opening Balance		0.0	0.0	0.0	0.0	0.3	0.3	0.0	0.0	0.0
8	Amortization on Existing Assets		616.6	627.4	10.8	594.3	606.6	12.3	730.4	711.1	681.0
9	Amortization on Additions		34.7	25.2	(9.5)	106.7	92.0	(14.7)	29.4	85.2	151.8
10	Amort on CRT Contribution		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10.1	Accelerated Amort on Burrard		0.0	3.0	3.0	0.0	3.0	3.0	0.0	0.0	0.0
11	Smart Metering & Infrastructure New Assets		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12	Smart Metering & Infrastructure Legacy Meters		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13	Capital Asset Write-Offs		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
14	Depn Study Adjustment		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
15	Retirements & Transfers		0.0	(21.9)	(21.9)	0.0	(48.5)	(48.5)	0.0	0.0	0.0
16	Closing Balance		2,361.7	2,309.3	(52.4)	3,062.7	2,962.7	(100.0)	3,722.5	4,518.8	5,351.6
17	**Net Assets in Service (Year-End)**		17,455.9	17,250.6	(205.3)	19,581.6	19,282.6	(299.0)	20,221.6	20,875.1	22,390.5

Assets - Business Support
($ million)

Line	Column	Reference	F2015 RRA	F2015 Actual	F2015 Diff	F2016 RRA	F2016 Actual	F2016 Diff	F2017 Plan	F2018 Plan	F2019 Plan
			1	2	3 = 2 - 1	4	5	6 = 5- 4	7	8	9
	Gross Assets in Service										
1	Opening Balance		725.8	726.9	1.1	860.9	805.9	(55.0)	2,036.1	2,241.1	2,496.2
2	Adjustment to Opening Balance		0.0	0.0	0.0	0.0	**933.1**	933.1	0.0	0.0	0.0
3	Capital Additions	13.0 L98	135.1	84.3	(50.8)	125.7	329.8	204.1	205.2	255.4	183.8
4	Retirements & Transfers		0.0	(5.3)	(5.3)	0.0	**(32.7)**	(32.7)	**(0.3)**	**(0.3)**	**(0.5)**
5	Closing Balance		860.9	805.9	(55.0)	986.6	2,036.1	1,049.5	2,241.1	2,496.2	2,679.4
	Accumulated Amortization										
6	Opening Balance		92.4	93.4	1.0	127.7	125.8	(1.9)	601.1	769.6	945.8
7	Adjustment to Opening Balance		0.0	0.0	0.0	0.0	**349.2**	349.2	0.0	0.0	0.0
8	Amortization on Existing Assets		32.8	34.2	1.4	31.7	**130.5**	98.8	**159.3**	**147.6**	**128.1**
9	Amortization on Additions	13.0 L104	2.5	0.6	(1.9)	7.8	25.3	17.5	9.2	28.7	49.9
10	Capital Asset Write-Offs		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11	Depr Study Adjustment		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12	Retirements & Transfers		0.0	(2.4)	(2.4)	0.0	**(29.7)**	(29.7)	0.0	0.0	0.0
13	Closing Balance		127.7	125.8	(1.9)	167.2	601.1	434.0	769.6	945.8	1,123.8
14	**Net Assets in Service (Year-End)**		733.2	680.1	(53.1)	819.4	1,435.0	615.6	1,471.6	1,550.4	1,555.6

Assets - Generation
($ million)

Line	Column	Reference	F2015 RRA	F2015 Actual	F2015 Diff	F2016 RRA	F2016 Actual	F2016 Diff	F2017 Plan	F2018 Plan	F2019 Plan
			1	2	3 = 2 - 1	4	5	6 = 5- 4	7	8	9
	Gross Assets in Service										
1	Opening Balance		6,558.3	6,597.4	39.1	7,244.2	7,118.1	(126.1)	7,249.3	7,758.6	8,141.9
2	Adjustment to Opening Balance		0.0	0.0	0.0	0.0	**(397.3)**	(397.3)	0.0	0.0	0.0
3	Capital Additions	13.0 L94	689.5	531.4	(158.1)	677.9	534.5	(143.4)	513.1	387.2	1,332.3
4	Retirements & Transfers		(3.6)	(10.7)	(7.1)	(3.7)	**(6.0)**	(2.3)	**(3.7)**	**(3.8)**	**(3.6)**
5	Closing Balance		7,244.2	7,118.1	(126.1)	7,918.4	7,249.3	(669.2)	7,758.6	8,141.9	9,470.6
	Accumulated Amortization										
6	Opening Balance		681.6	664.2	(17.4)	928.4	917.2	(11.2)	880.6	1,078.6	1,286.9
7	Adjustment to Opening Balance		0.0	0.0	0.0	0.0	**(231.2)**	(231.2)	0.0	0.0	0.0
8	Amortization on Existing Assets		234.5	246.5	12.0	220.8	**174.2**	(46.6)	**190.9**	**188.7**	**183.4**
9	Amortization on Additions	13.0 L100	12.3	11.2	(1.1)	36.6	20.5	(16.1)	7.1	19.6	43.3
10	Amort on CRT Contribution		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10.1	Accelerated Amort on Burrard		0.0	3.0	3.0	0.0	**3.0**	3.0	0.0	0.0	0.0
11	Capital Asset Write-Offs		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12	Depr Study Adjustment		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13	Retirements & Transfers		0.0	(7.7)	(7.7)	0.0	**(3.1)**	(3.1)	0.0	0.0	0.0
14	Closing Balance		928.4	917.2	(11.2)	1,185.8	880.6	(305.2)	1,078.6	1,286.9	1,513.5
15	**Net Assets in Service (Year-End)**		6,315.8	6,200.9	(114.9)	6,732.6	6,368.7	(363.9)	6,680.0	6,855.1	7,957.1

Assets - Customer Care
($ million)

Line	Column	Reference	F2015 RRA	F2015 Actual	F2015 Diff	F2016 RRA	F2016 Actual	F2016 Diff	F2017 Plan	F2018 Plan	F2019 Plan
			1	2	3 = 2 - 1	4	5	6 = 5- 4	7	8	9
	Gross Assets in Service										
1	Opening Balance		(0.0)	(0.0)	0.0	(0.0)	(0.0)	0.0	(0.0)	(0.0)	(0.0)
2	Adjustment to Opening Balance		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	Capital Additions	13.0 L97	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	Retirements & Transfers		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5	Closing Balance		(0.0)	(0.0)	0.0	(0.0)	(0.0)	0.0	(0.0)	(0.0)	(0.0)
	Accumulated Amortization										
6	Opening Balance		(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
7	Adjustment to Opening Balance		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	Amortization on Existing Assets		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9	Amortization on Additions	13.0 L103	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10	Capital Asset Write-Offs		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11	Depr Study Adjustment		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12	Retirements & Transfers		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13	Closing Balance		(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
14	**Net Assets in Service (Year-End)**		(0.0)	(0.0)	0.0	(0.0)	(0.0)	0.0	(0.0)	(0.0)	(0.0)

Assets - Transmission
($ million)

Line	Column	Reference	F2015 RRA	F2015 Actual	F2015 Diff	F2016 RRA	F2016 Actual	F2016 Diff	F2017 Plan	F2018 Plan	F2019 Plan
			1	2	3 = 2 - 1	4	5	6 = 5- 4	7	8	9
	Gross Assets in Service										
1	Opening Balance		4,291.2	4,916.0	624.8	5,611.0	6,042.4	431.5	7,226.1	7,862.8	8,300.5
2	Adjustment to Opening Balance		0.0	0.0	0.0	0.0	**(286.6)**	(286.6)	0.0	0.0	0.0
3	Capital Additions	13.0 L95	1,328.4	1,133.4	(195.0)	1,680.1	1,506.0	(174.1)	647.3	448.1	458.8
4	Retirements & Transfers		(8.7)	(7.0)	1.7	(9.0)	**(35.7)**	(26.7)	**(10.6)**	**(10.5)**	**(8.8)**
5	Closing Balance		5,611.0	6,042.4	431.5	7,282.1	7,226.1	(55.9)	7,862.8	8,300.5	8,750.5
	Accumulated Amortization										
6	Opening Balance		415.9	464.3	48.4	567.5	636.2	68.7	730.6	938.6	1,159.2
7	Adjustment to Opening Balance		0.0	0.0	0.0	0.0	**(75.1)**	(75.1)	0.0	0.0	0.0
8	Amortization on Existing Assets		137.1	168.0	30.9	132.5	**142.4**	9.9	**199.3**	**197.4**	**195.2**
9	Amortization on Additions	13.0 L101	14.5	9.5	(5.0)	46.3	34.6	(11.7)	8.7	23.2	35.1
10	Amortization Adjustment		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11	Capital Asset Write-Offs		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12	Depr Study Adjustment		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13	Retirements & Transfers		0.0	(5.6)	(5.6)	0.0	**(7.5)**	(7.5)	0.0	0.0	0.0
14	Closing Balance		567.5	636.2	68.7	746.3	730.6	(15.7)	938.6	1,159.2	1,389.5
15	**Net Assets in Service (Year-End)**		5,043.4	5,406.2	362.8	6,535.7	6,495.5	(40.2)	6,924.2	7,141.3	7,360.9

BC Hydro
F17-F19 RRA

Assets - Distribution
($ million)

Line	Column	Reference	F2015 RRA	F2015 Actual	F2015 Diff	F2016 RRA	F2016 Actual	F2016 Diff	F2017 Plan	F2018 Plan	F2019 Plan
			1	2	3 = 2 - 1	4	5	6 = 5- 4	7	8	9
	Gross Assets in Service										
1	Opening Balance		5,764.7	5,218.4	(546.4)	6,101.5	5,593.5	(508.0)	5,733.8	6,081.6	6,455.4
2	Adjustment to Opening Balance		0.0	0.0	0.0	0.0	(249.2)	(249.2)	0.0	0.0	0.0
3	Capital Additions	13.0 L96	358.6	404.6	46.0	378.5	412.3	33.8	372.1	399.3	413.0
4	Retirements & Transfers		(21.9)	(29.5)	(7.6)	(22.7)	(22.8)	(0.1)	(24.3)	(25.5)	(26.8)
5	Closing Balance		6,101.5	5,593.5	(508.0)	6,457.2	5,733.8	(723.4)	6,081.6	6,455.4	6,841.6
	Accumulated Amortization										
6	Opening Balance		520.5	453.7	(66.8)	738.1	630.1	(108.0)	750.4	935.8	1,126.9
7	Adjustment to Opening Balance		0.0	0.0	0.0	0.0	(42.6)	(42.6)	0.0	0.0	0.0
8	Amortization on Existing Assets		212.2	178.7	(33.5)	209.3	159.5	(49.8)	180.9	177.5	174.3
9	Amortization on Additions	13.0 L102	5.4	3.9	(1.5)	16.0	11.6	(4.4)	4.5	13.7	23.5
10	Smart Metering & Infrastructure New Assets		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11	Smart Metering & Infrastructure Legacy Meters		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12	Capital Asset Write-Offs		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13	Depr Study Adjustment		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
14	Retirements & Transfers		0.0	(6.2)	(6.2)	0.0	(8.2)	(8.2)	0.0	0.0	0.0
15	Closing Balance		738.1	630.1	(108.0)	963.4	750.4	(213.0)	935.8	1,126.9	1,324.7
16	**Net Assets in Service (Year-End)**		5,363.4	4,963.4	(400.0)	5,493.8	4,983.4	(510.4)	5,145.8	5,328.5	5,517.0

Capital Expenditures and Additions
($ million)

Line		Reference	F2015 RRA	F2015 Actual	F2015 Diff	F2016 RRA	F2016 Actual	F2016 Diff	F2017 Plan	F2018 Plan	F2019 Plan
	Column		1	2	3 = 2 - 1	4	5	6 = 5- 4	7	8	9
	Capital Expenditures										
1	Hydroelectric Generation		0.0	0.0	0.0	0.0		0.0			
2	Thermal Generation - Diesel		0.0	0.0	0.0	0.0		0.0			
3	Thermal Generation - Natural Gas		0.0	0.0	0.0	0.0		0.0			
4	Generation Growth		116.1	108.0	(8.1)	71.2	61.2	(10.0)	20.0	2.4	0.7
5	Generation Sustain		516.5	418.2	(98.3)	535.8	436.9	(98.9)	530.0	534.1	424.3
6	Transmission							0.0			
7	Transmission Lines		0.0	0.0	0.0	0.0		0.0			
8	Transmission Substations		0.0	0.0	0.0	0.0		0.0			
9	SDA Substations		0.0	0.0	0.0	0.0		0.0			
10	Transmission Growth		810.9	822.3	11.4	488.4	382.7	(105.7)	417.0	222.0	192.7
11	Transmission Sustain		175.4	193.9	18.5	256.8	235.0	(21.8)	255.5	326.3	373.9
12	Distribution		0.0	0.0	0.0	0.0		0.0			
13	Distribution Growth		161.3	206.7	45.4	191.4	224.7	33.3	224.7	233.4	209.5
14	Distribution Sustain		182.2	138.5	(43.7)	164.6	192.5	27.9	185.0	160.1	187.6
15	Site C Clean Energy Project		0.0	25.2	25.2	0.0	489.4	489.4	742.5	716.5	829.2
16	Information Technology & Telecommunication										
17	Information Technology		(0.0)	0.0	0.0	0.0		0.0			
18	Telecommunications		(0.0)	0.0	0.0	0.0		0.0			
19	Information Technology & Telecommunication		164.1	115.2	(48.9)	109.3	122.3	13.0	83.9	93.4	78.8
20	Vehicles		0.0	0.0	0.0	0.0		0.0			
21	Properties and Other Capital		(0.0)	0.0	0.0	0.0		0.0			
22	Properties		96.3	83.9	(12.4)	85.1	78.8	(6.3)	95.7	75.0	88.3
23	Smart Metering & Infrastructure		0.0	0.0	0.0	0.0		0.0			
24	HPOP Properties for Resale		0.0	0.0	0.0	0.0		0.0			
25	Other		29.7	47.9	18.3	36.6	72.5	35.9	49.7	48.6	39.6
26	Total		2,252.3	2,159.8	(92.5)	1,939.2	2,296.0	356.8	2,603.9	2,411.9	2,424.6

Capital Expenditures and Additions
($ million)

Line	Column	Reference	F2015 RRA	F2015 Actual	F2015 Diff	F2016 RRA	F2016 Actual	F2016 Diff	F2017 Plan	F2018 Plan	F2019 Plan
			1	2	3 = 2 - 1	4	5	6 = 5- 4	7	8	9
	Total Capital Additions										
27	Hydroelectric Generation		0.0	0.0	0.0	(0.0)		0.0			
28	Thermal Generation - Diesel		0.0	0.0	0.0	0.0		(0.0)			
29	Thermal Generation - Natural Gas		0.0	0.0	0.0	(0.0)		0.0			
30	Generation		613.2	483.0	(130.2)	604.3	534.5	(69.8)	513.1	387.2	1,332.3
31	Transmission Lines		0.0	0.0	0.0	(0.0)		0.0			
32	Substations										
33	Transmission Substations		0.0	0.0	0.0	0.0		(0.0)			
34	SDA Substations		0.0	0.0	0.0	0.0		0.0			
35	Transmission		1,328.4	1,127.8	(200.6)	1,680.1	1,506.0	(174.1)	647.3	448.1	458.8
36	Distribution		0.0	0.0	0.0	0.0		(0.0)			
37	Distribution		314.9	350.6	35.7	347.2	412.3	65.1	372.1	399.3	413.0
38	Information Technology										
39	Generation		0.0	0.0	0.0	(0.0)		0.0			
40	Transmission		0.0	0.0	0.0	0.0		0.0			
41	Distribution		0.0	0.0	0.0	0.0		(0.0)			
42	Customer Care		0.0	0.0	0.0	0.0		0.0			
43	Corporate Groups		0.0	0.0	0.0	0.0		0.0			
44	Site C Clean Energy Project		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
45	Information Technology & Telecommunication		113.7	82.3	(31.4)	103.0	145.2	42.2	81.6	91.1	112.6
46	Vehicles		0.0	0.0	0.0	0.0		0.0			
47	Telecom, Properties and Other										
48	Generation		0.0	0.0	0.0	(0.0)		0.0			
49	Transmission		0.0	0.0	0.0	0.0		(0.0)			
50	Distribution		0.0	0.0	0.0	0.0		(0.0)			
51	Customer Care		0.0	0.0	0.0	0.0		0.0			
52	Corporate Groups		0.0	0.0	0.0	0.0		0.0			
53	Properties		113.4	83.6	(29.8)	92.4	160.9	68.5	68.3	118.2	25.5
54	Smart Metering & Infrastructure		0.0	0.0	0.0	0.0		0.0			
55	HPOP Properties for Resale	Line 24	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
56	Other		28.0	26.5	(1.5)	35.2	23.7	(11.5)	55.3	46.1	45.7
57	Total		2,511.7	2,153.8	(357.9)	2,862.2	2,782.6	(79.6)	1,737.6	1,489.9	2,387.8
	Unfinished Construction										
58	Beginning of Year		3,108.3	2,982.8	(125.5)	2,848.9	2,957.2	108.3	2,460.8	3,327.1	4,249.1
59	Adjustment to Opening Balance		0.0	(31.6)	(31.6)	0.0	(9.8)	(9.8)	0.0	0.0	0.0
60	Change in Unfinished		(259.4)	6.0	265.4	(923.0)	(486.6)	436.4	866.3	921.9	36.8
61	End of Year		2,848.9	2,957.2	108.3	1,925.9	2,460.8	534.9	3,327.1	4,249.1	4,285.8
62	Mid-Year Balance		2,978.6	2,970.0	(8.6)	2,387.4	2,709.0	321.6	2,894.0	3,788.1	4,267.5

Capital Expenditures and Additions
($ million)

Line		Reference	F2015 RRA	F2015 Actual	F2015 Diff	F2016 RRA	F2016 Actual	F2016 Diff	F2017 Plan	F2018 Plan	F2019 Plan
	Column		1	2	3 = 2 - 1	4	5	6 = 5- 4	7	8	9
	Amortization on Additions										
63	Hydroelectric Generation	2.12%	(0.0)	0.0	0.0	0.0		(0.0)			
64	Thermal Generation - Diesel	3.36%	(0.0)	0.0	0.0	(0.0)		0.0			
65	Thermal Generation - Nat Gas	3.09%	0.0	0.0	(0.0)	(0.0)		0.0			
66	Generation		6.6	6.3	(0.3)	19.7	20.5	0.8	7.1	19.6	43.3
67	Transmission	1.91%	(0.0)	0.0	0.0	(0.0)		0.0			
68	Substations		0.0								
69	Transmission Substations	2.55%	0.0	0.0	(0.0)	0.0		(0.0)			
70	SDA Substations	2.55%	0.0	0.0	0.0	0.0		0.0			
71	Transmission		14.5	9.5	(5.0)	46.3	34.6	(11.7)	8.7	23.2	35.1
72	Distribution	2.40%	0.0	0.0	(0.0)	0.0		(0.0)			
73	Distribution		3.8	3.6	(0.2)	11.7	11.6	(0.1)	4.5	13.7	23.5
74	Information Technology		0.0								
75	Generation	15.05%	0.0	0.0	(0.0)	0.0		(0.0)			
76	Transmission	15.05%	0.0	0.0	0.0	0.0		0.0			
77	Distribution	15.05%	0.0	0.0	(0.0)	(0.0)		0.0			
78	Customer Care	15.05%	0.0	0.0	0.0	0.0		0.0			
79	Corporate Groups	15.05%	0.0	0.0	(0.0)	0.0		(0.0)			
80	Site C Clean Energy Project		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
81	Information Technology & Telecommunication		7.2	4.7	(2.5)	21.4	14.0	(7.4)	6.5	20.3	36.6
82	Vehicles	6.42%	0.0	0.0	(0.0)	0.0		(0.0)			
83	Telecom, Properties and Other		0.0								
84	Generation	3.10%	0.0	0.0	(0.0)	(0.0)		0.0			
85	Transmission	3.10%	(0.0)	0.0	0.0	(0.0)		0.0			
86	Distribution	6.78%	0.0	0.0	(0.0)	(0.0)		0.0			
87	Customer Care	3.10%	0.0	0.0	0.0	0.0		0.0			
88	Corporate Groups	3.10%	0.0	0.0	0.0	0.0		(0.0)			
89	Properties		1.8	0.5	(1.3)	4.9	5.2	0.3	1.2	4.6	7.2
90	Smart Metering & Infrastructure	5.00%	0.0	0.0	0.0	0.0		0.0			
91	HPOP Properties for Resale	0.00%	0.0	0.0	0.0	0.0		0.0			
92	Other		0.7	0.6	(0.1)	2.6	6.1	3.5	1.4	3.9	6.1
93	Total		34.7	25.2	(9.5)	106.7	92.0	(14.7)	29.4	85.2	151.8

Capital Expenditures and Additions
($ million)

Line	Reference	F2015 RRA	F2015 Actual	F2015 Diff	F2016 RRA	F2016 Actual	F2016 Diff	F2017 Plan	F2018 Plan	F2019 Plan
	Column	1	2	3 = 2 - 1	4	5	6 = 5- 4	7	8	9
	Summary of Additions									
94	Generation	689.5	531.4	(158.1)	677.9	534.5	(143.4)	513.1	387.2	1,332.3
95	Transmission	1,328.4	1,133.4	(195.0)	1,680.1	1,506.0	(174.1)	647.3	448.1	458.8
96	Distribution	358.6	404.6	46.0	378.5	412.3	33.8	372.1	399.3	413.0
97	Customer Care	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
98	Business Support	135.1	84.3	(50.8)	125.7	329.8	204.1	205.2	255.4	183.8
99	Total	2,511.7	2,153.7	(358.0)	2,862.2	2,782.6	(79.6)	1,737.6	1,489.9	2,387.8
	Summary of Amortization on Additions									
100	Generation	12.3	11.2	(1.1)	36.6	20.5	(16.1)	7.1	19.6	43.3
101	Transmission	14.5	9.5	(5.0)	46.3	34.6	(11.7)	8.7	23.2	35.1
102	Distribution	5.4	3.9	(1.5)	16.0	11.6	(4.4)	4.5	13.7	23.5
103	Customer Care	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
104	Business Support	2.5	0.6	(1.9)	7.8	25.3	17.5	9.2	28.7	49.9
105	Total	34.7	25.2	(9.5)	106.7	92.0	(14.7)	29.4	85.2	151.8
	Composite Depreciation Rate									
106	Generation							2.76%	2.78%	2.76%
107	Transmission							2.68%	2.60%	2.67%
108	Distribution							2.40%	2.40%	2.40%
109	Site C Clean Energy Project							0.00%	0.00%	0.00%
110	Information Technology & Telecommunication							15.98%	15.84%	16.26%
111	Properties							3.65%	3.50%	4.32%
112	Other							5.03%	4.85%	4.57%

Domestic Energy Sales and Revenu

Line	Column	Reference	F2015 RRA	F2015 Actual	F2015 Diff	F2016 RRA	F2016 Actual	F2016 Diff	F2017 Plan	F2018 Plan	F2019 Plan
			1	2	3 = 2 - 1	4	5	6 = 5- 4	7	8	9
	Domestic Energy Sales (GWh)										
1	Residential		18,805	17,047	(1,758)	18,743	17,331	(1,412)	18,036	18,112	18,250
2	Light Industrial and Commercial		18,277	18,564	287	18,346	18,421	75	18,832	18,785	18,899
3	Large Industrial		14,444	14,020	(423)	15,032	13,669	(1,363)	13,323	13,184	13,743
4	Irrigation		79	66	(13)	79	90	11	67	67	67
5	Street Lighting		228	230	2	230	232	3	234	237	239
6	New Westminster & Tongass		470	444	(26)	476	455	(22)	476	484	491
7	Fortis		516	522	6	541	516	(25)	524	521	527
8	Seattle City Light		310	305	(5)	312	308	(4)	310	310	310
9	Liquefied Natural Gas		0	0	0	0	0	0	57	139	139
10	Total		53,130	51,199	(1,932)	53,760	51,023	(2,737)	51,860	51,838	52,664
	Domestic Revenues ($ million)										
11	Residential		1,812.0	1,630.8	(181.2)	1,917.6	1,754.2	(163.4)	1,841.1	1,850.1	1,865.2
12	Light Industrial and Commercial		1,512.4	1,521.1	8.8	1,608.3	1,604.7	(3.6)	1,637.7	1,633.6	1,643.2
13	Large Industrial		744.0	712.9	(31.1)	826.1	730.0	(96.1)	715.6	709.7	748.6
14	Irrigation		5.7	4.8	(0.9)	6.0	6.1	0.0	4.5	4.5	4.5
15	Street Lighting		35.9	35.6	(0.3)	38.4	37.8	(0.6)	38.2	38.6	39.0
16	New Westminster & Tongass		25.5	24.3	(1.2)	27.4	26.1	(1.3)	27.3	27.8	28.3
17	Fortis		32.8	31.5	(1.4)	35.9	32.0	(3.9)	33.6	33.4	33.7
18	Seattle City Light		16.2	18.6	2.4	16.5	18.2	1.7	12.6	12.0	12.1
19	Liquefied Natural Gas		0.0	0.0	0.0	0.0	0.0	0.0	4.4	10.7	10.9
20	F11 Credit Rider		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
21	Smart Metering & Infrastructure Impact		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
22	Subtotal		4,184.5	3,979.5	(204.9)	4,476.2	4,209.1	(267.1)	4,314.9	4,320.5	4,385.6
23	Revenue from Deferral Rider		208.4	198.1	(10.3)	223.0	209.5	(13.4)	223.5	231.3	241.8
24	Total		4,392.9	4,177.6	(215.3)	4,699.2	4,418.7	(280.5)	4,538.4	4,551.8	4,627.4
25	**F11 Credit Rider**										
26	**Deferral Account Rate Rider**		5.0%	5.0%		5.0%	5.0%		5.0%	5.0%	5.0%
	Average Revenues ($/MWh)										
27	Residential		96.4	95.7	(0.7)	102.3	101.2	(1.1)	102.1	102.1	102.2
28	Light Industrial and Commercial		82.7	81.9	(0.8)	87.7	87.1	(0.5)	87.0	87.0	86.9
29	Large Industrial		51.5	50.8	(0.7)	55.0	53.4	(1.5)	53.7	53.8	54.5
30	Irrigation		72.0	72.5	0.5	76.3	67.5	(8.8)	67.5	67.5	67.5
31	Street Lighting		157.6	154.9	(2.6)	167.0	162.5	(4.5)	163.2	163.1	163.1
32	New Westminster & Tongass		54.2	54.8	0.5	57.4	57.3	(0.1)	57.4	57.4	57.6
33	Fortis		63.6	60.2	(3.4)	66.3	62.0	(4.3)	64.1	64.2	64.0
34	Seattle City Light		52.1	60.8	8.7	52.9	59.1	6.2	40.5	38.8	38.9
35	Liquefied Natural Gas		0.0	0.0	0.0	0.0	0.0	0.0	76.2	77.2	78.8
36	Total (Excluding Misc Rev)		82.7	81.6	(1.1)	87.4	86.6	(0.8)	87.5	87.8	87.9
	Peak Demand (MW)										
37	Distribution		7,976	7,893	(84)	7,920	7,920	(0)	7,945	8,020	8,108
38	Transmission		1,575	1,511	(64)	1,657	1,657	(0)	1,458	1,509	1,521
39	Other		429	422	(7)	431	431	0	425	426	428
40	Losses		803	680	(122)	805	805	(0)	668	677	684
41	Total		10,783	10,506	(278)	10,813	10,813	(0)	10,496	10,632	10,741

Miscellaneous Revenue
($ million)

Line	Column	Reference	F2015 RRA	F2015 Actual	F2015 Diff	F2016 RRA	F2016 Actual	F2016 Diff	F2017 Plan	F2018 Plan	F2019 Plan
			1	2	3 = 2 - 1	4	5	6 = 5- 4	7	8	9
	Generation										
1	Interconnected Operations Services		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2	FX Loss - Cost of Energy		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	Amortization of Contributions	11.0 L18	0.4	0.3	(0.1)	0.4	0.3	(0.1)	0.3	0.3	0.3
4	Other		2.6	3.9	1.3	2.7	4.4	1.7	1.7	1.6	1.6
5	Total		3.0	4.2	1.2	3.1	4.7	1.6	2.0	1.8	1.9
	Transmission										
6	External OATT	3.4 L76	10.1	8.1	(2.0)	11.8	10.8	(1.0)	14.1	14.2	14.5
7	FortisBC Wheeling Agreement		5.0	5.0	0.0	4.8	4.8	(0.0)	4.7	4.9	5.0
8	Secondary Revenue		7.4	8.8	1.4	7.5	6.2	(1.4)	5.1	5.1	5.0
9	Interconnections		4.0	10.6	6.6	4.2	4.3	0.2	3.0	1.9	1.9
10	Amortization of Contributions	11.0 L29:L30-L25	8.1	9.5	1.4	10.9	13.7	2.8	13.6	14.2	14.4
11	Other		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12	Total		34.7	42.0	7.4	39.2	39.7	0.6	40.5	40.3	40.8
	Distribution										
13	Secondary Use Revenue & Other		16.5	11.2	(5.3)	16.6	14.4	(2.2)	13.6	13.7	13.8
14	Amortization of Contributions	11.0 L41+L44-L37	32.5	32.3	(0.2)	34.5	34.4	(0.1)	36.7	40.2	42.4
15	Legacy Meter Contributions	11.0 L36+L43	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
16	Total		49.0	43.5	(5.5)	51.1	48.8	(2.3)	50.4	53.9	56.2
	Customer Care										
17	Meter/Trans Rents & Power Factor Surcharges		10.4	11.7	1.3	10.5	12.2	1.7	12.7	13.1	13.4
18	Terasen Meter Reading		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
19	Smart Metering & Infrastructure Impact		4.8	5.4	0.6	3.4	5.3	2.0	4.6	3.8	3.0
20	Diversion Net Recoveries		1.2	0.7	(0.5)	0.9	0.3	(0.6)	0.4	0.1	0.1
21	FX Loss - Cost of Energy		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
22	Other Operating Recoveries		5.8	7.2	1.5	5.9	6.6	0.7	4.7	4.7	4.8
23	Other		1.5	2.5	1.1	1.5	3.0	1.5	2.4	2.4	2.4
24	Total		23.6	27.5	3.9	22.1	27.4	5.3	24.8	24.1	23.6
	Business Support										
25	Corporate General Rents		3.5	3.2	(0.3)	3.6	3.7	0.1	3.5	3.3	3.2
26	Diversion Net Recoveries		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
27	Net Gains on Property Sales		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
28	Late Payment Charges		7.5	8.2	0.7	7.6	7.0	(0.6)	6.9	7.1	7.2
28.1	MMBU Secondary Revenue		0.0	5.7	5.7	0.0	5.9	5.9	5.4	5.4	5.4
29	BCTC Recoveries		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
30	Other		0.1	0.9	0.8	(0.0)	1.4	1.4	1.0	0.8	0.8
31	Total		11.0	18.0	7.0	11.2	18.0	6.8	16.8	16.6	16.6
32	**Total Gross Non-Tariff Revenue**		121.3	135.2	13.9	126.6	138.6	12.0	134.5	136.7	139.0
	Regulatory Account Additions										
33	Legacy Meter Contributions	Line 15	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
34	Smart Metering & Infrastructure Impact	Line 19	4.8	5.4	0.6	3.4	5.3	2.0	0.0	0.0	0.0
35	Minimum Reconnection Charge		0.0	0.0	0.0	0.0	(0.5)	(0.5)	0.0	0.0	0.0
36	**Total Current Non-Tariff Revenue**		116.5	129.8	13.3	123.3	133.8	10.6	134.5	136.7	139.0

Full-Time Equivalents (FTEs)

Line		Reference	F2015 RRA	F2015 Actual	F2015 Diff	F2016 RRA	F2016 Actual	F2016 Diff	F2017 Plan	F2018 Plan	F2019 Plan
	Column		1	2	3 = 2 - 1	4	5	6 = 5- 4	7	8	9
	Training, Development & Generation										
1	Engineering		0	0	0	0	0	0	0	0	0
2	Dam Safety		0	0	0	0	0	0	0	0	0
3	Generation Asset Mgmt.		9	9	(0)	9	8	(1)	9	9	9
4	Generation Project Delivery		0	0	0	0	0	0	0	0	0
5	Generation Operations		493	488	(4)	493	494	1	447	447	447
6	Operational Safety		0	0	0	0	0	0	0	0	0
7	Environmental Risk Management		0	0	0	0	0	0	0	0	0
8	Generation Resource Mgmt		67	64	(2)	67	65	(1)	64	64	64
9	Generation Maintenance		58	50	(8)	58	50	(8)	52	52	52
10	Training and Development		404	435	31	404	469	64	434	434	434
11	Energy Planning & Econ Development		0	0	0	0	0	0	0	0	0
12	Aboriginal Relations		0	0	0	0	0	0	0	0	0
13	Business Unit Support		3	3	0	3	3	(0)	3	3	3
14	Technology		0	0	0	0	0	0	0	0	0
15	Total		1,033	1,050	17	1,033	1,088	55	1,010	1,010	1,010
	Transmission, Distribution and Customer Services (TDCS)										
16	Distribution Operations		0	0	0	0	0	0	0	0	0
17	Customer Service & Distribution Design		424	425	1	421	447	26	458	458	458
18	Transmission & Construction Services		0	0	0	0	0	0	0	0	0
19	Operational Support Services		0	0	0	0	0	0	0	0	0
20	Field Operations & Safety		0	0	0	0	0	0	0	0	0
21	Grid Operations		0	0	0	0	0	0	0	0	0
22	Field & Grid Operations		1,903	1,881	(22)	1,907	1,809	(98)	1,817	1,817	1,817
23	Asset Investment Management		0	0	0	0	0	0	0	0	0
24	Asset Management & Dist Eng		280	282	2	280	281	1	273	273	273
25	Project & Program Delivery		0	0	0	0	0	0	0	0	0
26	Program & Contract Management		180	181	2	180	186	6	208	212	212
27	Engineering and Design		0	0	0	0	0	0	0	0	0
28	Aboriginal Relations		0	0	0	0	0	0	0	0	0
29	Smart Metering & Infrastructure		53	53	(0)	0	25	25	0	0	0
30	Technology		166	153	(14)	168	158	(11)	162	177	188
31	Business Unit Support		4	3	(0)	4	4	1	4	4	4
32	Total		3,010	2,978	(31)	2,960	2,910	(50)	2,922	2,941	2,952

Full-Time Equivalents (FTEs)

Line		Reference	F2015 RRA	F2015 Actual	F2015 Diff	F2016 RRA	F2016 Actual	F2016 Diff	F2017 Plan	F2018 Plan	F2019 Plan
	Column		1	2	3 = 2 - 1	4	5	6 = 5- 4	7	8	9
	Customer Care										
33	Power Smart & Customer Care		0	0	0	0	0	0	0	0	0
34	Energy Planning & Procurement		0	0	0	0	0	0	0	0	0
35	Chief Technology Office		0	0	0	0	0	0	0	0	0
36	Safety, Health & Environment		0	0	0	0	0	0	0	0	0
37	Aboriginal Relations & Negotiations		0	0	0	0	0	0	0	0	0
38	Economic & Business Development		0	0	0	0	0	0	0	0	0
39	Business Unit Support		0	0	0	0	0	0	0	0	0
40	IPP Capital Lease Operating Costs		0	0	0	0	0	0	0	0	0
41	Smart Metering & Infrastructure		0	0	0	0	0	0	0	0	0
42	Total		0	0	0	0	0	0	0	0	0
	Operations Support										
43	Executive		2	3	1	2	3	1	4	4	4
44	Sustainability		0	0	0	0	0	0	0	0	0
45	Communications		0	0	0	0	0	0	0	0	0
46	Customer Care and Power Smart		0	0	0	0	0	0	0	0	0
47	Corporate Human Resources		0	0	0	0	0	0	0	0	0
48	Safety, Health & Environment		0	0	0	0	0	0	0	0	0
49	Safety, Security, Emergency Management		137	126	(11)	137	125	(12)	131	133	133
50	Human Resources		0	0	0	0	0	0	0	0	0
51	Finance & Corporate Resources		0	0	0	0	0	0	0	0	0
52	Finance & Supply Chain		593	604	11	586	584	(2)	579	579	579
53	Corporate Services & General Counsel		0	0	0	0	0	0	0	0	0
54	General Counsel		38	38	(0)	38	37	(2)	37	37	37
55	Energy Planning & Procurement		0	0	0	0	0	0	0	0	0
56	Corporate Affairs		419	425	6	412	389	(23)	369	365	365
57	Economic & Business Development		0	0	0	0	0	0	0	0	0
58	IPP Capital Lease Operating Costs		0	0	0	0	0	0	0	0	0
59	Smart Metering & Infrastructure		0	0	0	0	0	0	0	0	0
60	Site C Clean Energy Project		0	0	0	0	0	0	0	0	0
61	Efficiency Projects		0	0	0	0	0	0	0	0	0
62	Total		1,190	1,196	6	1,175	1,137	(38)	1,121	1,119	1,119
	Capital Infrastructure Project Delivery										
63	Project Delivery		318	306	(12)	318	284	(34)	340	368	368
64	Generation & Transmission Engineering		422	429	7	422	429	7	443	443	443
65	Dam Safety		35	36	1	35	37	2	35	35	35
66	Environmental Risk Mgmt		80	78	(1)	80	85	5	83	83	83
67	Aboriginal Relations		35	36	2	35	48	13	47	47	47
68	Properties		110	106	(4)	110	104	(5)	106	106	106
69	Site C Clean Energy Project		158	97	(61)	198	109	(89)	186	189	199
70	Business Unit Support		0	0	0	0	3	3	3	3	3
71	Total		1,157	1,088	(69)	1,196	1,099	(97)	1,243	1,275	1,285
72	**Total**		6,390	6,312	(77)	6,365	6,234	(131)	6,296	6,344	6,365

Full-Time Equivalents (FTEs)

Line		Reference	F2015 RRA	F2015 Actual	F2015 Diff	F2016 RRA	F2016 Actual	F2016 Diff	F2017 Plan	F2018 Plan	F2019 Plan
	Column		1	2	3 = 2 - 1	4	5	6 = 5- 4	7	8	9
	Summary										
73	Regular Hour FTEs (excl. Smart Metering & Infrastructure & Site C Clean Energy Project)		5,556	5,512	(44)	5,534	5,462	(72)	5,547	5,592	5,603
74	Regular Hour Headcount from BCTC		0	0	0	0	0	0	0	0	0
75	Smart Metering & Infrastructure (SMI)		92	83	(9)	50	67	17	0	0	0
76	Site C Clean Energy Project		156	96	(60)	198	106	(92)	174	177	182
77	Subtotal Regular Hour FTEs		5,804	5,690	(114)	5,781	5,635	(146)	5,721	5,769	5,785
78	Overtime Hour FTEs (excl. Smart Metering & Infrastructure & Site C Clean Energy Project)		583	619	36	583	594	11	563	563	563
79	Smart Metering & Infrastructure (OT Hour FTEs)		0	2	2	0	2	2	0	0	0
80	Site C Clean Energy Project (OT Hour FTEs)		2	1	(1)	0	3	3	12	12	17
81	Total		6,390	6,312	(77)	6,365	6,234	(131)	6,296	6,344	6,365
	Summary of FTE's by Function										
	Regular Hour FTEs										
82	Operating		3,707	3,725	17	3,693	3,714	21	3,656	3,666	3,669
83	Capital		1,813	1,567	(246)	1,811	1,668	(143)	1,910	1,951	1,964
84	Deferred		284	399	115	278	254	(24)	154	152	152
85	Total		5,804	5,690	(114)	5,781	5,635	(146)	5,721	5,769	5,785
	Overtime Hour FTEs										
86	Operating		242	311	69	242	329	87	216	215	215
87	Capital		341	305	(37)	339	267	(72)	359	360	364
88	Deferred		2	6	4	2	3	1	1	1	1
89	Total		585	622	37	583	598	15	575	575	580
	Total FTEs by Function										
90	Operating		3,949	4,036	86	3,935	4,042	108	3,872	3,881	3,884
91	Capital		2,154	1,872	(283)	2,150	1,934	(215)	2,269	2,311	2,329
92	Deferred		286	405	119	280	257	(23)	155	152	152
93	Total		6,390	6,312	(77)	6,365	6,234	(131)	6,296	6,344	6,365

Fiscal 2017 to Fiscal 2019
Revenue Requirements Application

Appendix B

Draft Order

British Columbia Utilities Commission

Sixth floor, 900 Howe Street
Vancouver, BC Canada V6Z 2N3
TEL: (604) 660-4700
BC Toll Free: 1-800-663-1385
FAX: (604) 660-1102

ORDER NUMBER
G-xx-xx

IN THE MATTER OF
the *Utilities Commission Act*, RSBC 1996, Chapter 473

and

British Columbia Hydro and Power Authority (BC Hydro)
Application by British Columbia Hydro and Power Authority
for Review of its Fiscal 2017 – Fiscal 2019 Revenue Requirements (the **Application**)

BEFORE:
Commissioner
Commissioner
Commissioner

on Date

ORDER

WHEREAS:

A. On February 26, 2016 British Columbia Hydro and Power Authority (BC Hydro) filed an application with the British Columbia Utilities Commission (Commission), pursuant to section 9(1) of Direction No. 7 to the Commission (Direction No. 7), sections 58 to 60, 89 and 90 of the Utilities Commission Act (the Act) and section 15 of the Administrative Tribunals Act, for approval of an interim refundable rate increase of 4.0 per cent, including interim refundable Open Access Transmission Tariff (OATT) rates, effective April 1, 2016 (Interim Rates Application);

B. On March 22, 2016, the Commission issued Order No. G-40-16 approving the Interim Rates Application and approving an interim refundable rate increase of 4 per cent and interim refundable OATT rates, effective April 1, 2016;

C. On July 28, 2016 BC Hydro filed its Fiscal 2017 to Fiscal 2019 Revenue Requirements Application (the Application) pursuant to sections 58 to 61 of the Act requesting, among other relief:

    (i) final approval to increase rates by an average of 4.0 per cent effective April 1, 2016, 3.5 per cent effective April 1, 2017 and 3.0 per cent effective April 1, 2018, which reflect the rate caps in section 9(1) of Direction No. 7, to be applied as set out in Appendix T to the Application;

    (ii) final approval of OATT Rates effective April 1, 2017, April 1, 2018 and April 1, 2019 as set out in Appendix T to the Application;

D. The Application also seeks approval of total revenue requirements of $4,679.0 million for fiscal 2017, $4,912.0 million for fiscal 2018 and $5,136.2 million for fiscal 2019.

.../2

E. The Application seeks approval to place into the Rate Smoothing Regulatory Account the difference between the total revenue requirements set out in D above and the forecast revenue that BC Hydro is expected to earn under the rate increases set out in C(i) above, all as set out in Table 1-8 of the Application and in accordance with subsection 9(2) of Direction No. 7;

F. The Application also seeks approval, pursuant to sections 58 to 60 of the Act and section 7 of Direction No. 7, of changes to existing deferral and regulatory accounts and associated financial treatment as described in Chapter 7 and summarized in Table 7-8 of the Application;

G. The Application also seeks approval of depreciation rates for certain property, plant and equipment at the Burrard Synchronous Condense facility as set out in Table 8-1 of the Application;

H. The Application also seeks acceptance pursuant to section 44.2 of the Act of BC Hydro's demand-side management expenditure schedule for fiscal 2017, fiscal 2018 and fiscal 2019 as set out in Table 10-1 of the Application;

I. On XXXX XX, 2016, the Commission issued Order G-XX-16 establishing the Regulatory Timetable for the Application, including a procedural conference on XXXX XX, 2016 and two round of information requests;

J. On XXXX XX, 2016, the Commission held a procedural conference and issued Order G-XX-16;

K. On XXXX XX, 2016, BC Hydro responded to the first round of information requests from the Commission and interveners in the proceeding;

L. On XXXX XX, 2016, BC Hydro responded to the second round of information requests from the Commission and interveners in the proceeding;

M. [Other recitals as required.]

N. The Commission has determined that the orders sought are just and reasonable.

NOW THEREFORE the Commission orders as follows:

1. The requested final rate increases of 4 .0 per cent, 3.5 per cent and 3.0 per cent, to be applied as set out in Appendix T of the Application, are approved effective April 1, 2016, April 1, 2017 and April 1, 2018, respectively.

2. The requested final OATT rates for fiscal 2017, fiscal 2018, and fiscal 2019 as set out in Appendix T of the Application, are approved effective April 1, 2016, April 1, 2017 and April 1, 2018, respectively. The difference between the final OATT rates and the interim refundable OATT rates is to be collected from applicable OATT customers through a one-time charge as described in Chapter 9 of the Application.

3. BC Hydro is directed to record the following amounts into the Rate Smoothing Regulatory account for each year:

    - Fiscal 2016 - $210 million
    - Fiscal 2017 - $285.9 million

Filepath

- Fiscal 2018 – $299.4 million

4. The requested depreciation rates for property, plant and equipment at the Burrard Synchronous Condense facility as set out in Table 8-1 of the Application are approved.

5. The requested changes to deferral and regulatory accounts and associated financial treatment, as described in Chapter 7 and summarized in Table 7-9 of the Application, are approved.

6. The requested demand-side management expenditure schedule for fiscal 2017, fiscal 2018 and fiscal 2019, as set out in Table 10-1 of the Application, is accepted.

7. BC Hydro will comply with all other directives in the Decision accompanying this Order.

DATED at the City of Vancouver, in the Province of British Columbia, this (XX) day of (Month Year).

BY ORDER

(X. X. last name)
Commissioner

Attachment Options

BC Hydro
Power smart

Fiscal 2017 to Fiscal 2019
Revenue Requirements Application

Appendix C

Government Regulations

PROVINCE OF BRITISH COLUMBIA

ORDER OF THE LIEUTENANT GOVERNOR IN COUNCIL

Order in Council No. 095 *, Approved and Ordered* March 05, 2014

Judith I Guichon
Lieutenant Governor

Executive Council Chambers, Victoria

On the recommendation of the undersigned, the Lieutenant Governor, by and with the advice and consent of the Executive Council, orders that the Heritage Special Directive No. HC1 to the British Columbia Hydro and Power Authority, Order in Council 1125/2003, is amended as set out in the attached Appendix.

WRBennett
Minister of Energy and Mines and Minister Responsible for Core Review

Teresa Wat
Presiding Member of the Executive Council

(This part is for administrative purposes only and is not part of the Order.)

Authority under which Order is made:

Act and section: *Hydro and Power Authority Act*, R.S.B.C. 1996, s. 212, s. 35

Other:

February 18, 2014 O/79/2014/27

page 1 of 2

APPENDIX

1 *Section 3 of the Heritage Special Directive No. HC1 to the British Columbia Hydro and Power Authority, Order in Council 1125/2003, is repealed and the following substituted:*

Annual payment

3 (1) On or before June 30 of the years 2014, 2015, 2016 and 2017, the directors of the authority must cause the authority to pay to the government an amount equal to

(a) 85% of the distributable surplus for the previous fiscal year of the authority, or

(b) if the payment required under this section would result in the debt/equity ratio of the authority exceeding 80:20, the greatest amount that can be paid by the authority without causing the authority's debt/equity ratio, after the payment is made, to exceed 80:20.

(2) On or before June 30 of each year after 2017, until and including the year in which the payment required by this Special Directive equals zero, the directors of the authority must cause the authority to pay to the government the greater of the following 2 amounts:

(a) zero;

(b) the payment required by this Special Directive in the immediately preceding year less $100 million.

(3) On or before June 30 of each year after the year in which the payment required by this Special Directive equals zero, the directors of the authority must cause the authority to pay to the government an amount equal to

(a) 85% of the distributable surplus for the previous fiscal year of the authority, or

(b) if the payment required under this section would result in the debt/equity ratio of the authority exceeding 60:40, the greatest amount that can be paid by the authority without causing the authority's debt/equity ratio, after the payment is made, to exceed 60:40.

PROVINCE OF BRITISH COLUMBIA

ORDER OF THE LIEUTENANT GOVERNOR IN COUNCIL

Order in Council No. 096 *, Approved and Ordered* March 05, 2014

Lieutenant Governor

Executive Council Chambers, Victoria

On the recommendation of the undersigned, the Lieutenant Governor, by and with the advice and consent of the Executive Council, orders that the attached Direction No. 6 to the British Columbia Utilities Commission is made.

DEPOSITED

March 6, 2014

B.C. REG. 29/2014

Minister of Energy and Mines and
Minister Responsible for Core Review

Presiding Member of the Executive Council

(This part is for administrative purposes only and is not part of the Order.)

Authority under which Order is made:

Act and section: *Utilities Commission Act*, R.S.B.C. 1996, c. 473, s. 3

Other: OIC 1123/2003; OIC 1125/2003

February 18, 2014 R/112/2014/27

page 1 of 12

DIRECTION NO. 6 TO THE BRITISH COLUMBIA UTILITIES COMMISSION

Contents

Definitions

1 In this direction:

"**Act**" means the *Utilities Commission Act*;

"**amortization of capital additions**" means the portion of the authority's annual amortization expense that is subject to the amortization of capital additions regulatory account;

"**amortization of capital additions regulatory account**" means the regulatory account established under commission order G-16-09 and the direction in section 5.5.7 of the reasons that accompany that order;

"**arrow water divestiture costs regulatory account**" means the regulatory account established under paragraph 1 of commission order G-90-11;

"**arrow water provision regulatory account**" means the regulatory account established under paragraph 2 of commission order G-90-11;

"**asbestos remediation costs**" has the same meaning as in Direction No. 7 to the British Columbia Utilities Commission;

"**asbestos remediation regulatory account**" has the same meaning as in Direction No. 7 to the British Columbia Utilities Commission;

"**deemed equity**" has the same meaning as in Direction No. 7 to the British Columbia Utilities Commission;

"**electric tariff rates**" means the rates in the schedules to the authority's electric tariff;

"**F2014**" has the same meaning as in Direction No. 7 to the British Columbia Utilities Commission;

"**F2015**" has the same meaning as in Direction No. 7 to the British Columbia Utilities Commission;

"**F2016**" has the same meaning as in Direction No. 7 to the British Columbia Utilities Commission;

"**first nations costs regulatory account**" means the regulatory account established under commission order G-53-02;

"heritage payment obligation" has the same meaning as in Direction No. 7 to the British Columbia Utilities Commission;

"home purchase option plan regulatory account" means the regulatory account established under commission order G-55-09;

"IFRS pension regulatory account" means the regulatory account established under paragraph 1 (xxii) of commission order G-77-12A;

"IFRS PP&E regulatory account" means the regulatory account established under paragraph 1 (xxi) of commission order G-77-12A;

"non-current pension costs" has the same meaning as in Direction No. 7 to the British Columbia Utilities Commission;

"non-current pension costs regulatory account" has the same meaning as in Direction No. 7 to the British Columbia Utilities Commission;

"non-heritage cost of energy subject to deferral" means the portion of the authority's annual cost of energy that is subject to the non-heritage deferral account;

"non-heritage deferral account" has the same meaning as in Direction No. 7 to the British Columbia Utilities Commission;

"OATT rates" means the rates in schedules 00, 01 and 03 to the authority's open access transmission tariff;

"rate smoothing regulatory account" has the same meaning as in Direction No. 7 to the British Columbia Utilities Commission;

"real property gain/loss" means the net gain or net loss in a fiscal year incurred by the authority from the sale of its real property;

"related equipment" means the related equipment described in section 3 (b) of the Smart Meters and Smart Grid Regulation;

"Rock Bay costs" has the same meaning as in Direction No. 7 to the British Columbia Utilities Commission;

"Rock Bay remediation regulatory account" has the same meaning as in Direction No. 7 to the British Columbia Utilities Commission;

"Site C regulatory account" means the regulatory account established under commission order G-143-06 and section 25 of Appendix A attached to that order;

"smart meter" has the same meaning as in section 17 of the *Clean Energy Act*;

"smart metering and infrastructure program" means the authority's program to install and operate smart meters and related equipment and the program referred to in section 17 (4) of the *Clean Energy Act*;

"SMI regulatory account" has the same meaning as in Direction No. 7 to the British Columbia Utilities Commission;

"storm restoration costs" means the costs that are subject to the storm restoration regulatory account;

"storm restoration regulatory account" means the regulatory account established under commission order G-16-09 and the direction in section 5.5.4 of the reasons that accompany that order;

"total finance charges" means the portion of the authority's annual finance charges that is subject to the total finance charges regulatory account;

"total finance charges regulatory account" means the regulatory account established under commission order G-16-09 and the direction in section 5.5.2 of the reasons that accompany that order;

"total rate revenue" means the portion of the authority's annual revenues that is subject to the non-heritage deferral account;

"trade income" has the same meaning as in Direction No. 7 to the British Columbia Utilities Commission.

Application

2 This direction is issued to the commission under section 3 of the Act.

Orders

3 Within 20 days of the date on which the authority files an application with the commission to request final orders in regard to the authority's F2014, F2015 and F2016 rates, the commission must issue final orders as follows:

(a) the commission must accept the schedule of expenditures in regard to demand-side measures for F2014, F2015 and F2016 as set out in Appendix A to this direction;

(b) the commission must confirm the authority's rates for F2014, set by commission order G-77-12A, as final and no longer subject to refund;

(c) the commission must set the electric tariff rates for F2015 and F2016 as set out in Appendix B to this direction;

(d) the commission must set the OATT rates for F2015 and F2016 as set out in Appendix C to this direction;

(e) the commission must approve the following forecasts and planned expenditures for F2015:

(i) heritage payment obligation: $353.2 million;

(ii) non-heritage cost of energy subject to deferral: $1 074.3 million;

(iii) total rate revenue: $4 168.3 million;

(iv) trade income: $110.0 million;

(v) non-current pension costs: $2.9 million;

(vi) storm restoration costs: $3.9 million;

(vii) total finance charges: $602.6 million;

(viii) amortization of capital additions: $34.7 million;

(ix) real property gain/loss: $10.0 million;

(x) asbestos remediation costs: $1.8 million;

(f) the commission must approve the following forecasts and planned expenditures for F2016:

(i) heritage payment obligation: $399.2 million;
(ii) non-heritage cost of energy subject to deferral: $1 032.2 million;
(iii) total rate revenue: $4 459.7 million;
(iv) trade income: $110.0 million;
(v) non-current pension costs: $0.1 million;
(vi) storm restoration costs: $3.9 million;
(vii) total finance charges: $725.2 million;
(viii) amortization of capital additions: $106.7 million;
(ix) real property gain/loss: $10.0 million;
(x) asbestos remediation costs: $0.9 million;

(g) the commission must order, in regard to the first nations costs regulatory account, that the authority amortize from that account $43.5 million and $43.3 million in F2015 and F2016, respectively;

(h) the commission must order, in regard to the Site C regulatory account, that the authority defer to that account operating costs it incurs in regard to the Site C project in F2015 and F2016;

(i) the commission must order, in regard to the storm restoration regulatory account, that the authority amortize from that account $1.4 million in each of F2015 and F2016;

(j) the commission must order, in regard to the amortization of capital additions regulatory account, that the authority amortize from that account $9.8 million and $9.4 million in F2015 and F2016, respectively;

(k) the commission must order, in regard to the total finance charges regulatory account, that the authority amortize from that account $25.5 million in each of F2015 and F2016;

(l) the commission must order, in regard to the SMI regulatory account, that

(i) the authority amortize from that account $30.5 million and $31.3 million in F2015 and F2016, respectively, and
(ii) the authority defer to that account net operating costs incurred in F2015 and F2016 arising from the smart metering and infrastructure program and net operating costs arising from commission order G-166-13;

(m) the commission must order, in regard to the home purchase option plan regulatory account, that the authority amortize from that account $11.8 million and $11.3 million in F2015 and F2016, respectively;

(n) the commission must order, in regard to the non-current pension costs regulatory account, that the authority amortize from that account $32.6 million and $15.5 million in F2015 and F2016, respectively;

(o) the commission must order, in regard to the Rock Bay remediation regulatory account, that the authority amortize from that account $51.5 million and $50.5 million in F2015 and F2016, respectively;

(p) the commission must order, in regard to the IFRS PP&E regulatory account, that

(i) the authority amortize from that account $15.9 million and $19.8 million in F2015 and F2016, respectively, and

(ii) the authority defer to that account $156.8 million and $134.4 million in F2015 and F2016, respectively;

(q) the commission must order, in regard to the IFRS pension regulatory account, that the authority amortize from that account $38.2 million in each of F2015 and F2016;

(r) the commission must order, in regard to the arrow water divestiture costs regulatory account, that the authority amortize from that account $4.7 million and $4.5 million in F2015 and F2016, respectively;

(s) the commission must order, in regard to the arrow water provision regulatory account, that the authority amortize from that account $0.3 million in each of F2015 and F2016;

(t) the commission must order, in regard to the asbestos remediation regulatory account, that the authority amortize from that account $12.1 million and $10.7 million in F2015 and F2016, respectively;

(u) the commission must order, in regard to the rate smoothing regulatory account, that the authority defer to that account $166.2 million and $121.2 million in F2015 and F2016, respectively;

(v) the commission must, despite section 5 of Direction No. 3 to the British Columbia Utilities Commission, direct the authority to defer to the non-heritage deferral account the amount that is determined by subtracting the amount in subparagraph (ii) from the amount in subparagraph (i)

(i) the forecast return on deemed equity in F2014 calculated on the basis of an annual rate of return on deemed equity in that year of 11.84%, and

(ii) the forecast return on deemed equity in F2014 calculated on the basis of an annual rate of return on deemed equity in that year that is greater than or less than 11.84% as a result of the commission's order arising from the generic cost of capital proceeding initiated by commission order G-20-12.

APPENDIX A

F2014 – F2016 DSM Expenditure Schedule

$ MILLION	F2014	F2015	F2016
Codes and Standards	2.4	4.0	4.2
Rate Structures	6.5	2.0	1.7
Programs			
Residential	30.4	17.7	18.9
Commercial	66.4	39.5	40.0
Industrial	101.9	64.3	42.9
Total Programs	198.7	121.5	101.8
Supporting Initiatives	28.7	20.6	20.3
Total Energy Efficiency Portfolio	236.3	148.0	128.0
Capacity Focused DSM	0.0	2.4	3.1
Total	236.3	150.5	131.1

APPENDIX B

Electric Tariff Rates – F2015 and F2016

Rate Class	Rate Schedule	Rate	F2015	F2016
Residential	1101/1121	Basic Charge($/day)	0.1664	0.1764
		Step 1 energy rate ($/kWh)	0.0752	0.0797
		Step 2 energy rate ($/kWh)	0.1127	0.1195
Residential	1105 (closed)	Energy rate ($/kWh)	0.0492	0.0522
		Energy rate during period of interruption ($/kWh)	0.2865	0.3037
Residential Zone II	1107/1127	Basic Charge ($/day)	0.1775	0.1882
		Step 1 energy rate ($/kWh)	0.0901	0.0955
		Step 2 energy rate ($/kWh)	0.1548	0.1641
Residential	1148 (closed)	Basic Charge($/day)	0.1775	0.1882
		Energy rate ($/kWh)	0.0901	0.0955
Residential	1151/1161	Basic Charge ($/day)	0.1775	0.1882
		Energy rate ($/kWh)	0.0901	0.0955
Exempt General Service	1200/1201/ 1210/1211	Basic Charge($/day)	0.2129	0.2257
		Demand rate – Step 1 ($/kW)	0	0
		Demand rate – Step 2 ($/kW)	5.19	5.50
		Demand rate – Step 3 ($/kW)	9.95	10.55

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Rate Class	Rate Schedule	Rate	F2015	F2016
		Energy Rate – Tier 1 ($/kWh)	0.1012	0.1073
		Energy Rate – Tier 2 ($/kWh)	0.0486	0.0515
General Service	1205/1206/ 1207	Energy rate – Tier 1 ($/kWh)	0.0492	0.0522
		Energy rate – Tier 2 ($/kWh)	0.0323	0.0342
		Energy rate during period of interruption ($/kWh)	0.2865	0.3037
Small General Service Zone II	1234	Basic Charge ($/day)	0.2129	0.2257
		Energy rate – Tier 1 ($/kWh)	0.1012	0.1073
		Energy rate – Tier 2 ($/kWh)	0.1686	0.1787
Distribution Service	1253	Monthly Minimum energy charge ($/month)	39.03	41.37
Distribution Service	1268	Energy charge ($/kWh)	0.00157	0.00166
Power Service	1278 (Closed)	$/kVA	2.526	2.678
		Energy charge ($/kWh)	0.06604	0.07
		Monthly minimum greater of $/kVA or ($)	4.93 9868.64	5.23 10460.76
Large General Service Zone II	1255/1256/ 1265/1266	Basic Charge ($/day)	0.2129	0.2257
		Energy charge – Tier 1 ($/kWh)	0.1012	0.1073
		Energy charge – Tier 2 ($/kWh)	0.1686	0.1787
Net Metering Service	1289	Energy rate ($/kWh)	0.0999	0.0999
Small General Service	1300/1301/ 1310/1311	Basic Charge ($/day)	0.2129	0.2257
		Energy Charge ($/kWh)	0.1012	0.1073
Irrigation	1401/1402	Irrigation season energy rate ($/kWh)	0.0487	0.0516
		Non-irrigation season energy charge – Tier 1 ($/kWh)	0.0487	0.0516
		Non-irrigation season energy rate Tier 2 ($/kWh)	0.3864	0.4096

Rate Class	Rate Schedule	Rate	F2015	F2016
		Minimum charge irrigation season ($/kW)	4.87	5.16
		Non-irrigation season if consumption >500 kWh ($per kW)	38.98	41.32
Medium General Service	1500/1501/ 1510/1511	Basic Charge ($/day)	0.2129	0.2257
		Demand rate – Step 1 ($/kW)	0.00	0.00
		Demand rate – Step 2 ($/kW)	5.19	5.50
		Demand rate – Step 3 ($/kW)	9.95	10.55
		Part 1 Energy Rate – Tier 1 ($/kWh)	0.0934	0.0989
		Part 1 Energy Rate – Tier 2 ($/kWh)	0.0651	0.0690
		Part 2 Energy Rate ($/kWh)	0.0971	0.0990
		Minimum Energy Rate ($/kWh)	0.0311	0.0330
Large General Service	1600/1601/ 1610/1611	Basic Charge ($/day)	0.2129	0.2257
		Demand rate – Step 1 ($/kW)	0.00	0.00
		Demand rate – Step 2 ($/kW)	5.19	5.50
		Demand rate – Step 3 ($/kW)	9.95	10.55
		Part 1 Energy Rate Tier 1 ($/kWh)	0.1010	0.1066
		Part 1 Energy Rate– Tier 2 ($/kWh)	0.0486	0.0513
		Part 2 Energy Rate ($/kWh)	0.0971	0.0990
		Minimum Energy Charge ($/kWh)	0.0311	0.0330
Large General Service (150kW and over) for Distribution Utilities	2600/2601/ 2610/2611	Basic Charge ($/day)	0.2129	0.2257

Rate Class	Rate Schedule	Rate	F2015	F2016
		Demand rate – Step 1 ($/kW)	0.00	0.00
		Demand rate – Step 2 ($/kW)	5.19	5.50
		Demand rate – Step 3 ($/kW)	9.95	10.55
		Part 2 Energy Rate $/kWh (RS1600)	0.0971	0.0990
		Embedded Cost Rate $/kWh	0.0501	0.0531
		Discount ($/kWh)	-0.0037	-0.0039
Street Lighting	1701	100 SV fixture rate ($/month)	15.61	16.55
		150 SV fixture rate ($/month)	18.61	19.73
		200 SV fixture rate ($month)	21.49	22.78
		175 MV fixture rate ($/month)	17.15	18.18
		250 MV fixture rate ($/month)	19.76	20.95
		400 MV fixture rate ($/month)	25.48	27.01
Street Lighting	1702	Each Unmetered Fixture ($/watt per month)	0.03	0.0318
		Each Metered Fixture ($/kWh)	0.0901	0.0955
Street Lighting	1703	Energy rate ($/watt per month)	0.03	0.0318
		Contact rate ($/contact per month)	0.9057	0.96
Street Lighting	1704	Energy rate ($/kWh)	0.0901	0.0955
Street Lighting	1755 (closed)	1. Pole owned by Customer		
		175 MV or 100SV fixture charge ($ per month)	14.63	15.51
		400 MV or 150SV fixture charge ($ per month)	25.22	26.73
		2. Pole on public property		
		175 MV or 100SV fixture charge ($ per month)	15.54	16.47
		400 MV or 150SV fixture charge ($ per month)	26.13	27.70
		3. Pole paid by BC Hydro		
		175 MV or 100SV fixture charge ($ per month)	19.13	20.28
		400 MV or 150SV fixture charge ($ per month)	30.11	31.92

Rate Class	Rate Schedule	Rate	F2015	F2016
Transmission Service	1823	Demand rate ($/kVA)	6.925	7.341
		Energy rate A ($/kWh)	0.04059	0.04303
		Energy rate B Tier 1 ($/kWh)	0.03619	0.03836
		Energy rate B Tier 2 ($/kWh)	0.08022	0.08503
		Minimum demand ($/kVA)	6.925	7.341
Transmission Service	1825	Demand rate ($/kVA)	6.925	7.341
		Winter HLH energy rate (below 90%) ($/kWh)	0.03619	0.03836
		Winter HLH energy rate (above 90%) ($/kWh)	0.08952	0.09489
		Winter LLH energy rate (below 90%) ($/kWh)	0.03619	0.03836
		Winter LLH energy rate (above 90%) ($/kWh)	0.08113	0.08600
		Spring energy rate (below 90%) ($/kWh)	0.03619	0.03836
		Spring energy rate (above 90%) ($/kWh)	0.07226	0.07660
		Remaining energy rate (below 90%) ($/kWh)	0.03619	0.03836
		Remaining energy rate (above 90%) ($/kWh)	0.07923	0.08398
Transmission Service	1827	Demand rate ($/kVA)	6.925	7.341
		Energy rate ($/kWh)	0.04059	0.04303
		Minimum demand ($/kVA)	6.925	7.341
Transmission Service	1852	Excess demand rate ($/kVA)	6.925	7.341
Transmission Service	1853	Minimum Monthly Charge ($/month)	39.03	41.37
Transmission Service	1880	Administrative Charge per Period of Use ($)	150.00	150.00
		Energy charge ($/kWh)	0.08022	0.08503
Transmission Service FortisBC	3808	Demand Charge ($/kW)	6.925	7.341

Rate Class	Rate Schedule	Rate	F2015	F2016
		Energy rate ($/kWh)	4.059	4.303

APPENDIX C
BC Hydro OATT Rates – F2015 and F2016

Service	Rate Schedule in Authority's Open Access Transmission Tariff	F2015 Rate	F2016 Rate
Network Integration Transmission Service	00	$52.1 million/month	$62.1 million/month
Long-term Firm Point to Point Transmission Service	01	$53 698/MW/year	$64 968/MW/year
Monthly Short-term Firm and Non-firm Point to Point Transmission Service	01	$4 474.87/MW/month	$5 413.99/MW/month
Weekly Short-term Firm and Non-firm Point to Point Transmission Service	01	$1 032.66/MW/week	$1 249.38/MW/week
Daily Short-term Firm and Non-firm Point to Point Transmission Service	01	$147.12/MW/day	$177.99/MW/day
Hourly Short-term Firm and Non-firm Point to Point Transmission Service	01	$6.13/MW/hour	$7.42/MW/hour
Scheduling, System Control, and Dispatch Service Fee	03	$0.102/MWh	$0.099/MWh

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PROVINCE OF BRITISH COLUMBIA

ORDER OF THE LIEUTENANT GOVERNOR IN COUNCIL

Order in Council No. 097 *, Approved and Ordered* March 05, 2014

Lieutenant Governor

Executive Council Chambers, Victoria

On the recommendation of the undersigned, the Lieutenant Governor, by and with the advice and consent of the Executive Council, orders that

(a) the Heritage Special Direction No. HC2 to the British Columbia Utilities Commission, B.C. Reg. 158/2005, is repealed, and

(b) the attached Direction No. 7 to the British Columbia Utilities Commission is made.

DEPOSITED
March 6, 2014
B.C. REG. 28/2014

Minister of Energy and Mines and
Minister Responsible for Core Review

Presiding Member of the Executive Council

(This part is for administrative purposes only and is not part of the Order.)

Authority under which Order is made:

Act and section: *Utilities Commission Act*, R.S.B.C. 1996, c. 473, s. 3;
BC Hydro Public Power Legacy and Heritage Contract Act, S.B.C. 2003, c. 86, s. 4

Other: OIC 1123/2003

February 18, 2014 R/113/2014/27

DIRECTION NO. 7 TO THE BRITISH COLUMBIA UTILITIES COMMISSION

Contents

Definitions

1 In this direction:

"Act" means the *Utilities Commission Act*;

"asbestos remediation costs" means the costs that are subject to the asbestos remediation regulatory account;

"asbestos remediation regulatory account" means the regulatory account established under commission order G-7-13;

"base line rate change" means, for each of F2017, F2018 and F2019, the year-over-year increase in the authority's average rates that the commission determines it would have ordered but for section 9 (1) of this direction, expressed as a percentage;

"Burrard costs" means the costs incurred by the authority in F2014 or a later fiscal year arising from the decommissioning of those portions of Burrard Thermal that are not required for transmission support services, including, without limitation, employee retention costs incurred as a result of the decommissioning, costs incurred as penalties or damages that arise in consequence of the decommissioning, and the net increase in amortization expense in F2015 and F2016 arising from a commission order under section 15 of this direction;

"Burrard Thermal" has the same meaning as in the *Clean Energy Act*;

"California settlements" means the settlement of litigation between Powerex Corp. and various California parties arising from events and transactions in the

California power market during 2000 and 2001, as approved by the Federal Energy Regulatory Commission (US) on October 4, 2013;

"debt" has the same meaning as in Heritage Special Directive No. HC1 to the British Columbia Hydro and Power Authority;

"deemed equity" means, for any fiscal year, the product obtained by multiplying the rate base relating to that year by 30%;

"deferral account rate rider" means the surcharge, expressed as a percentage, as set out in rate schedule 1901 of the authority;

"distributable surplus" has the same meaning as in Heritage Special Directive No. HC1 to the British Columbia Hydro and Power Authority;

"DSM regulatory account" means the regulatory account of the authority established under commission order G-55-95;

"F2014" means the authority's fiscal year commencing April 1, 2013 and ending March 31, 2014;

"F2015" means the authority's fiscal year commencing April 1, 2014 and ending March 31, 2015;

"F2016" means the authority's fiscal year commencing April 1, 2015 and ending March 31, 2016;

"F2017" means the authority's fiscal year commencing April 1, 2016 and ending March 31, 2017;

"F2018" means the authority's fiscal year commencing April 1, 2017 and ending March 31, 2018;

"F2019" means the authority's fiscal year commencing April 1, 2018 and ending March 31, 2019;

"First Nations settlements" means the settlement of litigation between the authority and the Tsay Keh Dene and Kwadacha First Nations, and the settlement of damages claims by the St'at'imc First Nation against the authority, as agreed to between the authority and the first nation on August 31, 2009, November 27, 2008 and May 10, 2011, respectively;

"government policy directive" means a directive in writing to the authority from the minister responsible for the administration of the *Hydro and Power Authority Act*;

"heritage contract" means the document attached as Appendix A to this direction;

"heritage deferral account" means the Heritage Payment Obligation Deferral Account established under commission order G-96-04 and the direction in section 4.5 of the reasons that accompany that order;

"heritage energy" has the same meaning as in the heritage contract;

"heritage payment obligation" has the same meaning as in the heritage contract;

"heritage resources" has the same meaning as in the heritage contract;

"non-current pension costs" means the costs that are subject to the non-current pension costs regulatory account;

"non-current pension costs regulatory account" means the regulatory account established under commission order G-16-09 and the direction in section 5.5.5 of the reasons that accompany that order;

"non-heritage deferral account" means the Non Heritage Deferral Account established under commission order G-96-04 and the direction in section 4.5 of the reasons that accompany that order;

"public awareness program" has the same meaning as in the Demand-Side Measures Regulation;

"rate base" means, in relation to a fiscal year of the authority, the amount determined in accordance with the following equation and notes:

$$RB = WCA + (A+B+C)/2 - (D + E + F)/2$$

where

RB =	rate base;
WCA =	working capital amount of $250 million;
A, B, D, E and F =	the sum of an amount the authority forecasts will be listed as follows in the authority's audited financial statements at the end of the previous fiscal year and the amount the authority forecasts will be similarly listed at the end of the applicable fiscal year:
A	is the amount listed as property, plant and equipment in service, less accumulated amortization;
B	is the amount listed as intangible assets in service, less accumulated amortization;
D	is the amount listed as contributions in aid of construction;
E	is the amount listed as contributions arising from the Columbia River Treaty;
F	is the amount listed as leased assets included in A, less accumulated amortization;
C =	the sum of the balance the authority forecasts for DSM regulatory account at the beginning of the fiscal year and the balance the authority forecasts for the same account at the end of the fiscal year.

Notes:

1 In determining rate base for a fiscal year, the amounts A, B and F must have subtracted from them any amount included in them that is an expenditure incurred by the authority on or after April 1, 2011, that the commission determines under the Act must not be recovered by the authority in rates.

2 In determining rate base for a fiscal year, the amount D must have subtracted from it any amount included in it that is related to an expenditure referred to in note 1;

"rate smoothing regulatory account" means the regulatory account the commission must allow the authority to establish under section 7 (h) (i) of this direction;

"real property sales regulatory account" means the regulatory account the commission must allow the authority to establish under section 7 (h) (ii) of this direction;

"retail access program" has the same meaning as in commission order G-39-12;

"Rock Bay costs" means the costs of the authority in F2014 or a later fiscal year subject to the Rock Bay remediation regulatory account;

"Rock Bay remediation regulatory account" means the regulatory account established under commission order G-75-11;

"Rock Bay settlement" means the settlement of litigation between the authority and the Attorney General of Canada as concluded through the issuance of a consent dismissal order in favour of the authority on June 1, 2012;

"SMI regulatory account" means the regulatory account established under commission order G-64-09;

"specified demand-side measure" has the same meaning as in the Demand-Side Measures Regulation;

"trade income" means,

(a) for all of the authority's fiscal years except F2014, the greater of the following:

(i) the amount that is equal to the authority's consolidated net income, less the authority's net income, less the net income of the authority's subsidiaries except Powerex Corp., less the amount that the authority's consolidated net income changes due to foreign currency translation gains and losses on intercompany balances between the authority and Powerex Corp;.

(ii) zero, and

(b) for F2014, the amount that is equal to the authority's consolidated net income, less the authority's net income, less the net income of the authority's subsidiaries except Powerex Corp., less the amount that the authority's consolidated net income changes due to foreign currency transaction gains and losses on intercompany balances between the authority and Powerex Corp.;

"trade income deferral account" means the regulatory account established under commission order G-96-04 and the direction in section 4.6 of the reasons that accompany that order;

"transmission rate customers" means industrial or commercial customers of the authority who are eligible for service under rates designed by the commission under section 3 (1).

Application

2 This direction is issued to the commission under section 3 of the Act.

Consideration in designing rates for transmission rate customers

3 (1) In designing rates for the authority's transmission rate customers, the commission must ensure that those rates are consistent with recommendations #8

to #15 inclusive in the commission's report and recommendations to the Lieutenant Governor in Council dated October 17, 2003.

(2) Without limiting subsection (1), the commission must ensure the following:

(a) the rates for the authority's transmission rate customers are subject to

(i) the terms and conditions found in Supplements 5 and 6 to the authority's tariff, and

(ii) any other terms and conditions the commission considers appropriate for those rates;

(b) customers who own multiple plants under common ownership may engage in load aggregation for energy, if each plant

(i) is in operation, and

(ii) meets the requirements to be a transmission rate customer that are set out in the authority's electric tariff, or is otherwise authorized by the commission to be treated as a transmission rate customer.

Basis for establishing authority revenue requirements

4 Subject to section 7, in regulating and setting rates for the authority, the commission must ensure that those rates allow the authority to collect sufficient revenue in each fiscal year to enable the authority to

(a) provide reliable electricity service,

(b) meet all of its debt service, tax and other financial obligations,

(c) comply with government policy directives, including, without limitation, government policy directives requiring the authority to construct, operate or extend a plant or system, and

(d) achieve an annual rate of return on deemed equity

(i) for F2015, F2016 and F2017, that is equal to 11.84%,

(ii) for F2018 and subsequent fiscal years the annual rate of return on deemed equity that would be necessary to yield a distributable surplus in the applicable fiscal year equal to the product of

(A) the distributable surplus in the immediately preceding fiscal year, and

(B) 100% plus the percentage change in the British Columbia consumer price index in the applicable fiscal year.

Determining the cost of energy

5 In setting the authority's rates, the commission

(a) must treat the heritage contract as if it were a legally binding agreement between 2 arms-length parties,

(b) must determine the energy required by the authority to meet its domestic service obligations and must determine the cost to the authority of the portion of that required energy that is in excess of the energy supplied under the heritage contract,

(c) may employ any mechanism, formula or other method authorized by section 60 (1) (b.1) of the Act, and

(d) unless a different mechanism, formula or method is employed under paragraph (c), must ensure that electricity used by the authority to meet its domestic service obligations is provided to customers on a cost-of-service basis.

Use of trade income in setting rates

6 In setting rates for the authority, the commission must include the net income of the authority's subsidiaries, assuming that the net income of Powerex Corp. equals trade income.

Regulatory accounts

7 When regulating and setting rates for the authority, the commission

(a) must allow the authority to continue to defer to the heritage deferral account the variances between the actual and forecast heritage payment obligation,

(b) must allow the authority to continue to defer to the trade income deferral account the variances between actual and forecast trade income,

(c) must, in regard to the non-heritage deferral account, allow the authority to

(i) continue to defer to that account the variances between actual and forecast cost of energy arising from differences between actual and forecast domestic customer load, and

(ii) defer to that account the Burrard costs,

(d) must, in regard to the DSM regulatory account, allow the authority to

(i) defer to that account the authority's costs arising from its development, implementation and administration of demand-side measures, including costs arising from specified demand-side measures and public awareness programs, and

(ii) amortize from that account in each fiscal year an amount equal to the sum of

(A) the amount amortized in the immediately preceding fiscal year less the amortization in that year associated with costs incurred more than 15 fiscal years prior to that year, and

(B) the product of the amount deferred to that account in the immediately preceding fiscal year and 1/15,

(e) must allow the authority to continue to defer to the Rock Bay remediation regulatory account the Rock Bay costs,

(f) must allow the authority to continue to defer to the asbestos remediation regulatory account the variances between actual and forecast asbestos remediation costs,

(g) must allow the authority to continue to defer to the non-current pension costs regulatory account the variances between actual and forecast non-current pension costs,

(h) must allow the authority to establish the following regulatory accounts:

(i) an account to defer for recovery in rates in future fiscal years of the authority those portions of the authority's allowed revenue requirement in a particular fiscal year that were not or are not to be recovered in rates in that particular fiscal year;

(ii) an account to defer the variances between the authority's actual and forecast real property gain/loss,

(i) must allow the following regulatory accounts to accrue interest in a fiscal year at the authority's weighted average cost of debt in that year:

(i) the first nations costs regulatory account;

(ii) the real property sales regulatory account,

(j) may allow the authority to establish one or more other regulatory accounts for other purposes, and

(k) subject to section 9 (1) of this direction, must set the authority's rates in such a way as to allow the regulatory accounts to be cleared from time to time and within a reasonable period.

Annual distributable surpluses allowed

8 When regulating and setting rates for the authority, the commission must ensure that those rates allow the authority to allocate annual distributable surpluses in the manner specified by the Lieutenant Governor in Council under section 4 of the *BC Hydro Public Power Legacy and Heritage Contract Act* or section 35 of the *Hydro and Power Authority Act.*

F2017, F2018 and F2019 rates

9 (1) When regulating and setting rates for the authority for F2017, F2018 and F2019, under sections 4, 5, 6, 7, 9 (2), 10 (3) and 11 of this direction, the commission must not allow the rates to increase by more than 4% in F2017, 3.5% in F2018 and 3% in F2019, on average, compared to the rates of the authority immediately before the increase.

(2) If the base line rate change exceeds 4% in F2017, 3.5% in F2018 or 3% in F2019, the commission must order the authority to defer to the rate smoothing regulatory account the amount that is determined by subtracting the amount in paragraph (b) from the amount in paragraph (a)

(a) the forecast revenue that the authority would have earned under a base line rate change, and

(b) the forecast revenue that the authority is expected to earn under this direction.

Deferral account rate rider

10 (1) The commission must set the deferral account rate rider for F2015 and future fiscal years of the authority at 5%.

(2) The commission must not order any change to the deferral account rate rider, except on application by the authority.

(3) The commission must allow the authority, in regard to a fiscal year of the authority, to account for the forecast revenue from the deferral account rate rider as follows:

(i) a portion of the forecast revenue from the deferral account rate rider is to be accounted for as revenue in that fiscal year in accordance with equation 1 and the following table;

(ii) a portion of the forecast revenue from the deferral account rate rider is to be amortized from the forecast net balance of the heritage deferral account, the non-heritage deferral account and the trade income deferral account at the end of the immediately preceding fiscal year in accordance with equation 2 and the following table:

Equation 1: DARR (Rev) = DARR – (X/5) x DARR

Equation 2: DARR(DA) = (X/5) x DARR

where

DARR (Rev) = the portion of forecast revenue from the deferral account rate rider in the applicable fiscal year of the authority that is to be accounted for as revenue;

DARR(DA) = the portion of forecast revenue from the deferral account rate rider in the applicable fiscal year of the authority that is to be amortized from the net balance of the heritage deferral account, the non-heritage deferral account and the trade income deferral account at the end of the immediately preceding fiscal year;

DARR = forecast revenue from the deferral account rate rider in the applicable fiscal year of the authority;

X = the number in column X of the following table that corresponds to the forecast net balances of the heritage deferral account, the non-heritage deferral account and the trade income deferral account at the end of the immediately preceding fiscal year that is between the values shown in columns A and B of the following table:

Table

A ($ million)	B ($ million)	X
< -500	-500	-5.0
-500	-450	-4.5
-450	-400	-4.0

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Table		
A ($ million)	B ($ million)	X
-400	-350	-3.5
-350	-300	-3.0
-300	-250	-2.5
-250	-200	-2.0
-200	-150	-1.5
-150	-100	-1.0
-100	-50	-0.5
-50	0	0.0
0	50	0.0
50	100	0.5
100	150	1.0
150	200	1.5
200	250	2.0
250	300	2.5
300	350	3.0
350	400	3.5
400	450	4.0
450	500	4.5
500	> 500	5.0

(iii) the portion of forecast revenue from the deferral account rate rider in the applicable fiscal year of the authority that is amortized from the net balance of the heritage deferral account, the non-heritage deferral account and the trade income deferral account at the end of the immediately preceding fiscal year must be amortized from the respective balances of those accounts in proportion to the ratios of the balances of those accounts to the net balance of all 3.

Commission reviews

11 When setting rates for the authority under the Act, the commission must not disallow for any reason the recovery in rates of the costs that were incurred by the authority or Powerex Corp. in consequence of decisions of either with respect to

(a) the construction of extensions to the authority's plant or system that come into service before F2017,

(b) energy supply contracts entered into before F2017,

(c) the Rock Bay settlement,

(d) the First Nations settlements,

(e) the California settlements,

(f) the Burrard costs, and

(g) the costs deferred to the SMI regulatory account.

Expenditures for export

12 The commission must refrain from performing its duty under section 4 (5) of the *Clean Energy Act* when setting rates for the authority for F2014, F2015, F2016, F2017 and F2018.

Powerex Corp.

13 The commission may not exercise any power under Part 3 of the Act in regard to the gas and electricity trading activities of Powerex Corp.

Retail access

14 (1) By March 23, 2014, the commission must issue orders as follows:

(a) the commission must accept a withdrawal by the authority of any obligation to offer unbundled transmission services under the authority's open access transmission tariff to retail customers in British Columbia, and a withdrawal of any obligation to offer such services to those who supply such customers;

(b) the commission must order the cancellation of the retail access program.

(2) Except on application by the authority, the commission must not set rates for the authority that would result in the direct or indirect provision of unbundled transmission services to retail customers in British Columbia, or to those who supply such customers.

Burrard Thermal

15 On application by the authority the commission must

(a) grant permission to the authority under section 41 of the Act to cease operating those portions of Burrard Thermal that are not required for transmission support services, and

(b) set depreciation rates for the classes of property, plant and equipment at Burrard Thermal as shown in Appendix B to this direction.

Rates

16 (1) The commission may not reconsider, vary or rescind the orders it issues under this direction or Direction No. 6 to the British Columbia Utilities Commission, except on application by the authority.

(2) For F2014, F2015 and F2016, the commission must not issue any orders in regard to the authority's regulatory accounts, except on application by the authority.

(3) In setting the authority's rates for F2015, F2016, F2017, F2018 and F2019, the commission must exercise its powers and perform its duties consistently with the orders it issues under Direction No. 6 to the British Columbia Utilities Commission, except on application by the authority.

(4) Nothing in this section prevents the commission from making determinations on applications made by the authority respecting revenue-cost ratios, rate design and regulatory accounts, including interim rate orders in regard to one or more of the authority's customers.

APPENDIX A – HERITAGE CONTRACT

Definitions

1 In this Agreement:

"Agreement" means this Heritage Contract including Schedule A;

"Ancillary Service Requirements" means services necessary to deliver energy;

"BC Hydro" means the British Columbia Hydro and Power Authority;

"BCH Distribution" means BC Hydro's distribution line-of-business;

"BCH Generation" means BC Hydro's generation line-of-business;

"Commission" means the British Columbia Utilities Commission;

"heritage electricity" means the capacity, energy and ancillary services that BCH Generation is required to supply to BCH Distribution under this Agreement;

"heritage energy" means

(a) subject to paragraph (b), 49 000 GW.h per year less the energy generated for delivery under the Skagit Valley Treaty, or

(b) the quantity of energy determined by the Commission under section 8 of this Agreement to be heritage energy;

"heritage payment obligation" means

(a) subject to paragraph (b), the annual payment determined in accordance with the procedure set out in Schedule A to this Agreement, or

(b) the annual payment determined by the Commission under section 8 of this Agreement to be the heritage payment obligation;

"heritage resources" means the Electric Facilities and Thermal Facilities described in Schedule A to the Terms of Reference, together with

(a) the related civil works and plant, and

(b) potential future investments that increase the capacity, energy or ancillary service capability of such facilities, including potential future units 5 and 6 at Mica and potential future units 5 and 6 at Revelstoke;

"Order" means an order of the Commission;

"Terms of Reference" means Schedule A, Terms of Reference, to Order in Council 253/2003;

"Transfer Pricing Agreement" means the Transfer Pricing Agreement for Electricity and Gas dated April 1, 2003 between BC Hydro and Powerex Corp. as amended from time to time;

"Year" means fiscal year.

Electricity supply

2 BCH Generation must provide the full capacity of the heritage resources to BCH Distribution on a priority call basis.

Obligation to supply

3 BCH Generation must supply to BCH Distribution, in each Year, the heritage energy or such lesser amount of energy as may be required by BCH Distribution.

Obligation to deliver

4 BCH Generation will deliver the heritage energy to BCH Distribution at the various points of interconnection of the generating stations included in the heritage resources with the BC Hydro transmission grid or at points of interconnection with other utilities, as appropriate.

Responsibility for obtaining transmission services

5 BCH Distribution will be responsible for obtaining transmission services for energy provided to BCH Distribution.

Ancillary services

6 The parties may use the capacity available to them under section 2 to deliver energy to meet customer demand and to satisfy the parties' Ancillary Service Requirements, regardless of whether provision for self-supply is made under any tariff.

Payment

7 BCH Distribution must, on or before the end of each Year, pay to BCH Generation an amount equal to the heritage payment obligation.

Adjustment

8 The parties acknowledge that

(a) the Commission may, by Order, modify one or both of the definitions of "heritage energy" and "heritage payment obligation" if the Commission is satisfied that a change in circumstances has permanently affected

(i) the capability of the heritage resources to provide one or both of capacity and energy, or

(ii) the authority's cost of generating the heritage energy, and

(b) any such modification will automatically modify the heritage energy or the heritage payment obligation, as the case may be, without further action by the parties.

Information exchange and cooperation

9 Each party will continue to freely provide the other with any requested information to facilitate the coordinated and optimal operation of the BC Hydro system.

Dispute resolution

10 (1) The parties will make reasonable efforts to resolve disputes arising in relation to this Agreement at the staff level.

(2) As needed, issues may be dealt with by management levels within each party to achieve timely resolution.

(3) Issues that cannot be resolved in a timely manner at senior management levels may be referred by either party to the commission for resolution.

Term

11 This Agreement commenced on April 1, 2004.

SCHEDULE A TO APPENDIX A – HERITAGE PAYMENT OBLIGATION

1 The heritage payment obligation for any Year is the amount determined by

(a) adding those of the following costs incurred by BCH Generation in the Year that the Commission orders may be included in the heritage payment obligation:

(i) cost of energy such as the cost of water rentals and energy purchases, including purchases of gas and electricity, required to supply heritage electricity;

(ii) operating costs such as the costs of operating and maintaining the heritage resources, including an allocation of corporate costs;

(iii) all costs of owning the heritage resources, including, without limitation, depreciation, interest, finance charges and other asset related expenses;

(iv) all costs or payments related to generation-related transmission access required by the heritage resources, and

(b) subtracting from the sum obtained under paragraph (a) any revenues BCH Generation receives from other services provided from the heritage resources, including, without limitation,

(i) revenues related to Skagit Valley Treaty obligations,

(ii) revenues from provision of ancillary services to the transmission operator in respect of third party use of the transmission system, and

(iii) revenues from the sale of surplus hydro electricity under section 5 of the Transfer Pricing Agreement.

APPENDIX B – BURRARD DEPRECIATION RATES

Class of Property, Plant and Equipment at Burrard Thermal	F2015 Depreciation Rate (%/year)	F2016 Depreciation Rate (%/year)
C12101 Tracks, Railway	100.0%	N/A
C12401 Drainage System Yard	9.1%	10.0%
C21901 Roofs	9.1%	10.0%
C22001 Plant Concrete Steel	15.8%	18.8%
C22002 Comm Concrete Steel	9.1%	10.0%
C22005 Building, Comp Pool	9.1%	10.0%
C22006 Equipment Shelter	19.0%	23.5%
C22009 Building-HVAC Sys&Cp	10.1%	11.1%
C22101 Off Trailer/Mob Home	9.3%	10.0%
C23801 Cranes	9.1%	10.0%
C24402 Ramp, Boat/Barge	85.7%	100.0%
C25101 Structure Supp Steel	9.1%	10.0%
C25301 Foundations	9.1%	10.0%
C25401 Ducts & Trenches	9.1%	10.0%
C25601 Barriers & Enclos	20.0%	25.0%
C30101 Casing, Boiler	50.0%	100.0%
C30102 Insulation, Boiler	14.3%	16.7%
C30103 Roof, Boiler	50.0%	100.0%
C30203 Superheater HighTemp	50.0%	100.0%
C30204 Superheater Low Temp	54.5%	100.0%
C30205 Reheater, Boiler	50.0%	100.0%
C30301 Header / Drum	50.3%	100.0%
C30401 Valves, Safety	14.5%	17.0%
C30501 Piping, High Press	33.4%	41.5%
C30601 Fan, Forced Draft	50.0%	100.0%
C30602 Breaching / Flue Sys	54.5%	100.0%
C30603 Stack, Flue Gases	50.0%	100.0%
C30605 Burner, Fuel	50.0%	100.0%
C30606 Instrument, Boiler	51.3%	98.6%
C30607 DNU - Asbe Abatement	9.1%	10.0%
C30611 Desuperheater System	50.0%	100.0%
C30612 Refractory, Boiler	54.5%	100.0%
C30613 Boiler, Package	54.5%	100.0%

Class of Property, Plant and Equipment at Burrard Thermal	F2015 Depreciation Rate (%/year)	F2016 Depreciation Rate (%/year)
C30701 Equip, Water Treat	50.0%	100.0%
C30801 Transfer Sys Ammonia	92.3%	100.0%
C30802 Water Sys Ammonia	92.3%	100.0%
C30803 Vapouriser, Ammonia	92.3%	100.0%
C30804 Comp Vapour, Ammonia	92.3%	100.0%
C30805 Piping Sys, Ammonia	50.0%	100.0%
C30901 Monitor Equip, Cem	54.5%	100.0%
C30903 Deliver Sys, Ammonia	55.5%	100.0%
C31001 Water Intk/DisStruct	9.1%	10.0%
C31002 Protection, Cathodic	9.1%	10.0%
C31003 Gates, Inlet/Outlet	9.1%	10.0%
C31005 Conduit, Intake/Disc	9.1%	10.0%
C33001 Heat Exch, Shell Tube	50.0%	100.0%
C33002 Pump And Motor	50.0%	100.0%
C33004 Condenser, Boiler	50.0%	100.0%
C34004 Turbine, Comp Pool	22.2%	28.5%
C34005 Coils, Stator	9.3%	10.3%
C34006 Rotor, Generator	9.1%	10.0%
C34007 Generator, Comp Pool	28.6%	40.1%
C34008 Supervisory Sys Turb	70.9%	55.8%
C34009 Cooling Sys Hydrogen	15.8%	18.7%
C34015 Turbine Blades Sets	31.7%	46.4%
C42004 Major Maint.-Rewedge	25.3%	33.8%
C42102 Exciter, Static	42.7%	74.6%
C46701 Heat Exchanger	50.0%	100.0%
C47201 Turbine, Gas	50.0%	100.0%
C47202 Major Maint.-Gas Tur	80.0%	100.0%
C48003 Generator, Composite	29.7%	42.3%
C48004 Generator, Diesel	25.8%	34.8%
C49001 Pump	44.4%	77.8%
C49002 Motor	12.3%	14.1%
C51001 Condensor, SyncRotary	9.1%	10.0%
C52104 Transformer, <100Mva	50.0%	100.0%
C52105 Transformer, Stn Ser	10.5%	10.0%
C52302 Reactor, Dry Type	99.9%	100.0%
C52405 Transformer, Curr, Com	35.3%	54.6%

Class of Property, Plant and Equipment at Burrard Thermal	F2015 Depreciation Rate (%/year)	F2016 Depreciation Rate (%/year)
C52504 Trans, Volt, Encaps.	9.1%	10.0%
C54101 Breaker, Air/Magnetic	9.1%	10.0%
C54201 Use.Ind.Disconnect	20.0%	25.0%
C55401 Buswork & StnConduct	9.1%	10.0%
C55501 Grounding Systems	9.1%	10.0%
C56001 Insulators	9.1%	10.0%
C59001 Power Supp Uninterr	39.4%	65.1%
C59101 Regulator FeederCirc	9.1%	10.0%
C59201 Charger/System, Batt	13.8%	15.3%
C61001 Fencing	9.1%	10.0%
C61101 Alarm/Security Sys	9.1%	10.0%
C62001 Fire Protection Sys	12.0%	13.6%
C62501 Firefighting Equip	33.3%	50.0%
C65001 Panels/Cubicles, P&C	13.0%	14.9%
C67003 Contain Fac, Concret	9.1%	10.0%
C67005 Oil Spill Containmen	9.1%	10.0%
C68202 Term Unit, Rem(Slave)	23.1%	30.0%
C68204 Distributed Ctrl Sys	30.4%	42.9%
C68301 Radio, MW, Analog	9.1%	10.0%
C68901 Tele Equip, Pbx/Pax	100.0%	N/A
C70104 Instrumentation-Digi	9.1%	10.0%
C74001 Motor-Generator Sets	92.3%	100.0%
C75104 Compressor, Air	18.3%	21.3%
C75201 Tanks, Steel, Air/Fuel	9.1%	10.0%
C75202 Tank, Fibrglas, DBIB	9.1%	10.0%
C75301 Water Supply System	9.1%	10.0%
C82504 Loader/Backhoe	8.3%	9.0%
C82513 Manlift	66.7%	100.0%
C82550 Tools/Work EquipMisc	12.3%	14.0%
C82551 DNU - Tools/Work Equ	21.7%	27.1%
C82601 Test/Calibration	43.9%	73.2%
C82603 Manufacturing/Test	24.4%	12.5%
C88002 Lab Equipment, Misc	30.8%	27.3%

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PROVINCE OF BRITISH COLUMBIA

ORDER OF THE LIEUTENANT GOVERNOR IN COUNCIL

Order in Council No. 123 , *Approved and Ordered* February 29, 2016

Lieutenant Governor

Executive Council Chambers, Victoria

On the recommendation of the undersigned, the Lieutenant Governor, by and with the advice and consent of the Executive Council, orders that the attached Direction to the British Columbia Utilities Commission Respecting Mining Customers is made.

DEPOSITED

March 1, 2016

B.C. REG. 47/2016

Minister of Energy and Mines and Minister Responsible for Core Review

Presiding Member of the Executive Council

(This part is for administrative purposes only and is not part of the Order.)

Authority under which Order is made:

Act and section: *Utilities Commission Act*, R.S.B.C. 1996, c. 473, s. 3

Other:

February 24, 2016 R/76/2016/27

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DIRECTION TO THE BRITISH COLUMBIA UTILITIES COMMISSION RESPECTING MINING CUSTOMERS

Contents

Definitions

1 In this direction:

"account balance", in relation to each applicable mine of a mining customer, means an amount determined as follows:

$$\text{account balance} = (TSA + I) - (TAA + A)$$

where

TSA = the total amount that would have been payable under rate schedule 1823, but for the application of the supplement, during the period beginning on the date the supplement begins to apply to the mining customer and ending on the date of making the determination of the account balance;

I = interest accumulated on the account balance as of the date of making the determination of the account balance, calculated in accordance with section 3 (1) (f);

TAA = the total of all adjusted amounts paid;

A = any payments made in addition to an adjusted amount;

"Act" means the *Utilities Commission Act*;

"adjusted amount" means an amount, calculated in accordance with section 3 (1) (b), paid under the supplement by a mining customer to the authority;

"applicable mine" means any of the following mines:

(a) Coal Mountain;
(b) Copper Mountain;
(c) Elkview;
(d) Fording River;
(e) Gibraltar;
(f) Greenhills;
(g) Highland Valley;
(h) Huckleberry;
(i) Line Creek;
(j) Mount Milligan;
(k) Mount Polley;
(l) New Afton;
(m) Red Chris;

page 2 of 5

"application period" means the period that begins on the date the supplement begins to apply to a mining customer and ends on the closing date;

"billing month" means the month in which the authority issues a bill to a mining customer for electricity service respecting an applicable mine;

"closing date" means the date that is 5 years after the date the supplement comes into effect;

"eligible customer" means a customer of the authority who, immediately before this direction comes into force, was receiving electricity service from the authority respecting an applicable mine;

"mining customer" means an eligible customer who has made a request referred to in section 3 (1) (a) (i) and to whom the supplement applies;

"prime" means the prime lending rate of the principal banker of the authority on the date interest is calculated in accordance with subsection 3 (1) (f);

"service price" means the total that would have been payable by a mining customer in accordance with the first 2 years of bills that would have been issued to the mining customer under rate schedule 1823, but for the application of the supplement, while the supplement applies to the mining customer;

"settlement price period", in relation to a mining customer, means a period that

(a) begins 30 days before the day referred to in paragraph (b) (i) or (ii), as applicable, and

(b) ends on a day that is either

(i) the 15th day of the month that immediately precedes the billing month, if the authority issues the bill before the 15th day of the billing month, or

(ii) the 15th day of the billing month, if the authority issues the bill on or after that day;

"supplement" means the supplement to be added in accordance with section 3 (1).

Application

2 This direction is issued to the commission under section 3 of the Act.

Rate

3 (1) Within 10 days of the date of an application by the authority for the purposes of this section, the commission must issue an order so that the authority's Electric Tariff Supplement No. 5 is amended by adding a supplement that

(a) applies only to a mining customer who,

(i) as an eligible customer, requests that the supplement apply respecting amounts that will be payable to the authority for electricity service provided for the operation of an applicable mine that is, on the date of the request, a producing mine, and

(ii) has no overdue bills with the authority on the date of the request,

(b) subject to paragraphs (c) and (d), requires a mining customer, for each bill issued during the application period, to pay an adjusted amount, in Canadian dollars, calculated as follows:

adjusted amount = SA+ (SA x AP)

where

SA is the amount that would have been payable under rate schedule 1823 but for the application of the supplement;

AP is, subject to the Rule below, the applicable of the following adjustment amounts:

AP for a mining customer who operates a copper mine	=	[(settlement price - 3.40) x 208] / 100
AP for a mining customer who operates a coal mine	=	[(settlement price - 134) x 5] / 100

where

settlement price calculated for a mining customer who operates a copper mine is the average of the daily settlement price of copper, in pounds, as reported by the London Metal Exchange, for the settlement price period, converted into Canadian currency by using the Bank of Canada's average daily closing exchange rate over that period;

settlement price calculated for a mining customer who operates a coal mine is the average of the daily settlement price of Hard Coking Coal (Premium Low Vol) FOB Australia, in tonnes, as reported by Platts (Coal Trader International), for the settlement price period, converted into Canadian currency by using the Bank of Canada's average daily closing exchange rate over that period;

Rule: If an AP is calculated to be more than 0.75, the adjusted amount must be calculated using an AP of 0.75, and if an AP is calculated to be less than -0.75, the adjusted amount must be calculated using an AP of -0.75,

(c) provides that if a mining customer's account balance, once adjusted to subtract amounts representing interest, is, on the date the authority issues a bill to the mining customer, equal to 75% of the service price, the mining customer must pay

(i) the amounts required under rate schedule 1823 instead of the adjusted amounts, if the AP calculated in accordance with paragraph (b) is less than zero, and

(ii) the adjusted amount, if the AP calculated in accordance with paragraph (b) is zero or more,

(d) provides that if a mining customer's account balance is, on the date a bill is issued to the mining customer, equal to zero, the mining customer must pay

(i) the amounts required under rate schedule 1823 instead of the adjusted amounts, if the AP calculated in accordance with paragraph (b) is zero or more, and

(ii) the adjusted amount, if the AP calculated in accordance with paragraph (b) is less than zero,

(e) requires a mining customer who has a positive account balance to pay the amount of that balance to the authority on the closing date, unless the mining customer and the authority agree that payment of that amount will be made over a period specified in the agreement,

(f) provides that the interest included in the account balance of a mining customer is compounded monthly and is calculated by applying the following annualized interest rates to the account balance:

(i) prime plus 5% for the mining customers operating a mine referred to in paragraphs (a) to (g) and (i) to (m) of the definition of "applicable mine" in section 1;

(ii) 12% for the mining customer operating the mine referred to in paragraph (h) of the definition of "applicable mine" in section 1, and

(g) on request by a mining customer, allows the authority to cease applying the supplement to amounts payable by the mining customer, if at the time of the request the mining customer's account balance is zero.

(2) The commission must allow the authority

(a) to establish a regulatory account to defer to future fiscal years of the authority amounts equal to the sum of the following:

(i) the account balances of mining customers, if those account balances are impaired;

(ii) any other amounts that are payable to the authority by mining customers before the closing date and that are impaired;

(iii) any taxes paid by the authority on behalf of mining customers on the account balances referred to in subparagraph (i) and the amounts referred to in subparagraph (ii),

(b) to reduce the account referred to in paragraph (a) by an amount collected from an applicable mining customer, and

(c) to include in the account referred to in paragraph (a) interest determined in a fiscal year at a rate equal to the authority's weighted average cost of debt in that fiscal year.

(3) After the closing date, the commission must allow the authority to recover in rates, over a period determined by the authority, the amounts in the regulatory account referred to in subsection (2).

(4) The commission may not cancel, suspend or amend the supplement or require the authority to retire the regulatory account referred to in subsection (2), except on application by the authority.

PROVINCE OF BRITISH COLUMBIA

ORDER OF THE LIEUTENANT GOVERNOR IN COUNCIL

Order in Council No. 539 *, Approved and Ordered* July 19, 2016

Lieutenant Governor

Executive Council Chambers, Victoria

On the recommendation of the undersigned, the Lieutenant Governor, by and with the advice and consent of the Executive Council, orders that the section 12 of Direction No. 7 to the British Columbia Utilities Commission, B.C. Reg. 28/2014, is amended by striking out "and F2018." and substituting ", F2018 and F2019."

Minister of Energy and Mines and Minister Responsible for Core Review

Presiding Member of the Executive Council

(This part is for administrative purposes only and is not part of the Order.)

Authority under which Order is made:

Act and section: *Utilities Commission Act*, R.S.B.C. 1996, c. 473, s.3

Other:

February 11, 2016 R/123/2016/27

BC Hydro
Power smart

Fiscal 2017 to Fiscal 2019
Revenue Requirements Application

Appendix D

Shareholder's Letter of Expectations

BRITISH
COLUMBIA

Ref.: 93799

Mr. W. J. Brad Bennett
Chair
Board of Directors
BC Hydro
18th Floor, 333 Dunsmuir Street
Vancouver, BC V6B 5R3

Dear Mr. Bennett:

This Mandate Letter confirms your organization's mandate, provides Government's annual strategic direction and sets out key performance expectations for the 2016/17 fiscal year.

On behalf of the Province of British Columbia, thank you for your leadership and the contributions made by the BC Hydro and Power Authority (BC Hydro) over the past year, and congratulations on the efforts made towards the following achievements:

- Completing all 50 recommendations from the 2011 Government Review, including the reduction of operating costs by $391 million over three years.
- Implementing the 10-Year Plan to keep electricity rates low and predictable, ensuring customers continue to have among the most competitive rates in North America.
- Delivering an ambitious capital plan, including advancing the Site C Clean Energy Project.
- Working closely with First Nations to build a better, more transparent and collaborative relationship.

Last year, the Government established a common set of principles for British Columbia Public Sector Organizations (PSOs). The intent of the Taxpayer Accountability Principles (TAP) is to strengthen accountability and promote cost control. These principles instill a common frame of reference to inform decisions and ensure that the actions taken and services provided meet public policy objectives established by the Government on behalf of the citizens of British Columbia. All PSOs are expected to understand the responsibility they have to the citizens of this province and how it is complimentary to the fiduciary duty to their organizations.

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Ministry of Energy and Mines and Minister Responsible for Core Review

Office of the Minister

Mailing Address:
PO Box 9060, Stn Prov Govt
Victoria, BC V8W 9E2

Telephone: 250 387-5896
Facsimile: 250 356-2965

One of Government's core values is respect for the taxpayer's dollar. It is critical that PSOs operate as efficiently as possible, in order to ensure British Columbians are provided with effective services at the lowest cost possible. This requires constant focus on maintaining a cost-conscious and principled culture through the efficient delivery of services that stand the test of public scrutiny and help develop a prosperous economy in an environmentally sustainable manner. The foundation of this work is the Government's commitment to controlling spending and balancing the budget.

Government provided the following mandate direction to BC Hydro under the *Hydro and Power Authority Act*:

Provide reliable, affordable, clean electricity throughout British Columbia, safely. To achieve this mandate, BC Hydro is directed to take the following strategic actions:

- Continue to implement the 10-Year Plan to keep electricity rates low and predictable by optimizing resources and advancing its Revenue Requirements and Rate Design Applications.
- Deliver your overall capital plan portfolio on time and on budget to maintain the reliability of the system, support British Columbia's economic growth and meet the needs of customers.
- Deliver the Site C project on time and on budget and ensure First Nations and local communities have the ability to participate in economic development opportunities arising from the construction of the project.
- Work with Clean Energy BC to identify further opportunities for clean energy producers in British Columbia.
- Improve customer satisfaction by providing timely and responsive service and exploring innovative energy conservation solutions such as load curtailment rates.
- Implement the five-year safety plan to ensure the safety of your workforce and the public.

To achieve this, several actions as detailed in the 2014 TAP Transition Letter, are to continue to be implemented and refined, such as: on-going orientation, the joint strategic engagement plan, and the evaluation plan. For detailed information about TAP directives, please refer to the following link, Taxpayer Accountability Principles.

In addition, it is expected that your organization will continue to be diligent in ensuring familiarity with and adherence to statutory obligations and policies that have broad application across the public sector. Please refer to the following link for a summary of these accountabilities, PSO Accountability Summary.

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Government is committed to continuing to revitalize the relationship between the Government and PSOs. This strong focus on increased two-way communication supports and ensures a common understanding of Government's expectations. Timely communication of any issues which may affect the business of BC Hydro and/or the interests of Government is critical to building trust and the effective delivery of public services, including information on any risks to achieving financial forecasts and performance targets.

Each Board member is required to acknowledge the direction provided in the Mandate Letter by signing this letter. The Mandate Letter is to be posted publicly on your organization's website and a copy signed by all Board members provided to the ministry and made available to the public upon request.

I look forward to our regular meetings focusing on strategic priorities, performance against the TAP, key results and working together to protect the public interest at all times.

Sincerely,

Bill Bennett

Date: March 14/16

Bill Bennett
Minister

Attachment

Brad Bennett
Chair, BC Hydro

Bill Adsit
Director
BC Hydro

Jamie Brown
Director
BC Hydro

James Hatton
Director
BC Hydro

John Knappett
Director
BC Hydro

Valerie Lambert
Valerie Lambert
Director
BC Hydro

Janine North
Janine North
Director
BC Hydro

Tracy Redies
Director
BC Hydro

John Ritchie
Director
BC Hydro

Jack Weisgerber
Director
BC Hydro

pc: Honourable Christy Clark
Premier

Mr. John Dyble
Deputy Minister to the Premier and Cabinet Secretary

Ms. Kim Henderson
Deputy Minister and Secretary to Treasury Board
Ministry of Finance

Ms. Cheryl Wenezenki-Yolland
Associate Deputy Minister
Ministry of Finance

Ms. Elaine McKnight
Deputy Minister
Ministry of Energy and Mines

Mr. Bill Adsit
Director
BC Hydro

Mr. Jamie Brown
Director
BC Hydro

Mr. James Hatton
Director
BC Hydro

Mr. John Knappett
Director
BC Hydro

Ms. Valerie Lambert
Director
BC Hydro

Ms. Janine North
Director
BC Hydro

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Ms. Tracy Redies
Director
BC Hydro

Mr. John Ritchie
Director
BC Hydro

Mr. Jack Weisgerber
Director
BC Hydro

Ms. Jessica McDonald
Chief Executive Officer
BC Hydro

Fiscal 2017 to Fiscal 2019
Revenue Requirements Application

Appendix E

BC Hydro Service Plan

BC Hydro and Power Authority

2016/17 – 2018/19
SERVICE PLAN

BRITISH
COLUMBIA

For more information on BC Hydro contact:

333 Dunsmuir Street

Vancouver, BC

V6B 5R3

Lower Mainland

604 BCHYDRO

(604 224 9376)

Outside Lower Mainland

1 800 BCHYDRO

(1 800 224 9376)

BC Hydro
Power smart

bchydro.com

BC Hydro's Service Plan can be found online at BC Hydro's Service Plan

Accountability Statement

The 2016/17 - 2018/19 BC Hydro service plan was prepared under the Board’s direction in accordance with the *Budget Transparency and Accountability Act* and the BC Reporting Principles. The plan is consistent with government's strategic priorities and fiscal plan. The Board and Management are accountable for the contents of the plan, including what has been included in the plan and how it has been reported. The Board is responsible for the validity and reliability of the information included in the plan.

All significant assumptions, policy decisions, events and identified risks, as of January 31, 2016 have been considered in preparing the plan. The performance measures presented are consistent with the Taxpayer Accountability Principles, BC Hydro’s mandate and goals, and focus on aspects critical to the organization’s performance. The targets in this plan have been determined based on an assessment of BC Hydro’s operating environment, forecast conditions, risk assessment and past performance.

W.J. Brad Bennett

Board Chair

Table of Contents

Strategic Direction and Context

Strategic Direction

BC Hydro is one of the largest electric utilities in Canada. We generate and provide electricity to 95 per cent of British Columbia's population and serve over four million people. The electricity generated and transmitted to our customers throughout the province has consistently powered B.C.'s economy and quality of life.

BC Hydro's mission is: **To provide our customers with reliable, affordable, clean electricity throughout B.C., safely.** BC Hydro has set out a three-year road map with strategies, performance measures and targets to fulfill our mission on behalf of the Province and our customers; aligned with the objectives set out in the B.C. Government's Mandate Letter, the 10 Year Rates Plan and the Taxpayer Accountability Principles.

BC Hydro is filing rate design and revenue requirement applications to the BC Utilities Commission to support low and predictable rates for customers, and is continuing to implement the government-approved 2013 Integrated Resource Plan to meet growing electricity demand. Key components of the plan include the 10 Year Capital Plan Forecast and the Site C Clean Energy Project, as well as energy conservation programs and other demand side management measures that will exceed the *Clean Energy Act* target to meet 66% of new demand through energy conservation from 2008 to 2020.

BC Hydro will continue to refurbish and expand the electrical system to meet customer requirements today and tomorrow, as well as improve our responsiveness to evolving customer expectations and reduce electricity use through technology and tailored solutions to meet specific customer needs.

Operating Environment

Power Smart is BC Hydro's new brand. It reflects our goal to be Smart about Power in All We Do and underscores our commitment as an organization to work together to meet new and evolving needs from our customers, our workforce and our shareholder.

We have identified four key goals that reflect what success will look like when we deliver on our mission - customers will experience reliable and responsive service; their rates will continue to be affordable; we will fulfill the province's commitment to lead with clean and renewable power; and our workforce and the public will be safe.

Under the framework of the Province's 10 Year Rates Plan and the Taxpayer Accountability Principles, BC Hydro continues to emphasize cost-consciousness and process improvement across our operations and within our workforce. Examples include enhancing work delivery methods and standardizing project management processes.

Hydro-Québec conducts an annual comparison of electricity rates in 21 major North American cities and BC Hydro's rates continue to be among the most affordable in North America. In 2015, BC Hydro ranked third lowest for residential rates, fourth lowest for commercial rates and fifth lowest for industrial rates.

Although we consistently achieve high customer satisfaction ratings, we can improve the way we interact with our customers and deliver our services. We are identifying what our customers will want and may need in the future so we can start to make changes now. This includes the implementation of a multi-faceted customer strategy from technology to service changes to make it easier for our customers to do business with us.

We are also implementing ambitious plans to renew and expand our generation, transmission and distribution system, as well as making operational investments in areas like technology and vehicle fleet, spending on average $2.4 billion per year. Over the past five years, BC Hydro has delivered 563 capital projects at a total cost of $3.94 billion, which is 1.8% under budget in aggregate. Implementing these system projects across the province concurrently can result in competing objectives and resources. We will work across teams, suppliers, and experts to ensure thoughtful assessment of how to successfully deliver these projects on time and on budget while respecting the unique community, environmental and cultural aspects of each project. Through leading practices such as the Progressive Aboriginal Relations designation, BC Hydro will achieve tangible and long term results in areas such as Aboriginal employment, business development, community investment and engagement.

The electricity generated and transmitted throughout British Columbia meets a high standard of reliability. Unlike most other jurisdictions, our electricity generation in British Columbia is over 93% clean due to our system of large hydroelectric facilities and our important partnership with the independent power sector. British Columbia is also a leader in conservation and investments in smart meters and a smart grid are providing our customers with the information they need to be smart about their electricity use and ultimately use less. With continued investments in technology, we will help customers to meet their energy conservation goals while also delivering sustained energy savings that will reduce costs for all ratepayers.

Achieving the results we've set out in our Service Plan isn't possible without our employees and a workforce that can execute their work in a safe manner. As a utility that operates in a high hazard industry, safety is top of mind and we are continuously working to improve our performance through understanding hazards and ensuring appropriate design of assets and related work procedures, while building our safety culture and competencies.

With thoughtful planning, efficient execution of our strategies and investment in strong and respectful relationships, BC Hydro is well positioned to continue to deliver reliable, affordable, clean electricity throughout B.C., safely today and into the future.

Performance Plan

Goals, Strategies, Measures and Targets

BC Hydro’s mission is: **To provide our customers with reliable, affordable, clean electricity throughout B.C., safely.** Four strategic goals guide our actions, each supported by corresponding strategies, performance measures and targets. Each performance measure has a definition and rationale, as well as relevant benchmarking measures that allow a comparison of performance over time. These measures track our progress on delivering our core mission to our customers and the shareholder.

BC Hydro's management is responsible for measuring performance against targets, and results are reported to the Board on a quarterly basis and publicly in the Annual Report. The mission and its associated values and strategic goals support transparency and accountability as required by Government under the Taxpayer Accountability Principles.

Goal 1: Set the Standard for Reliable and Responsive Service

BC Hydro will reliably meet the electricity requirements of customers and respond to their evolving expectations by planning and investing in the system to meet future needs and by consistently improving our service.

Strategies

- Ensure the reliability of the generation, transmission and distribution system by effectively implementing capital and maintenance programs to manage overall asset health and secure supply to meet customer load throughout the year.
- Identify and address vulnerabilities in our operating system and develop well practiced emergency response plans to improve overall system reliability.
- Through external benchmarking of North American transmission interconnection practices, review and implement appropriate recommendations to meet customer requirements as identified in the Industrial Electricity Policy Review.
- Make it easier for customers to do business with us through a series of internal and external improvements such as bills that are easier to read, access to critical information including outages, and customer-focussed training for our staff to enhance the overall customer service experience.
- Explore innovative energy conservation solutions such as load curtailment rates.
- Sustain gold-level certification under the Progressive Aboriginal Relations program by maintaining leading practices focused on Aboriginal employment, business development, community investment and community engagement.
- Through early engagement and emphasizing collaboration, respect and mutually beneficial relationships with First Nations, BC Hydro will improve the transparency of its operations and identify their interests in the delivery of our capital projects.

Performance Measures 1-5[1]

Performance Measures	Four Year Avg.	Actual 2013/14	Actual 2014/15	Target 2015/16	**Forecast 2015/16**	Target 2016/17	Target 2017/18	Target 2018/19
SAIDI (duration)[2] [total outage duration (in hours) experienced by an average customer in a year]	3.25	3.59[3]	3.07	3.22	**3.06**	3.22	3.20	3.20
SAIFI (frequency)[2] [Number of sustained disruptions per year] (excluding major events)	1.43	1.56	1.30	1.40	**1.46**	1.40	1.35	1.35

Key Generating Facility Forced Outage Factor[4]	2.0	1.6	1.5[5]	NR[6]	**NR**	2.0	2.0	1.8
CSAT Index [Customer Satisfaction Index: % of customers satisfied or very satisfied]	86.8	85.0	86.0	85.0	**85.0**	85.0	85.0	85.0
Progressive Aboriginal Relations Designation[7]	Gold	Gold	Gold	Gold	**Gold**	Gold	Gold	Gold

[1] Performance Measure descriptions, rationale, data source information and benchmarking is available online at www.bchydro.com/performance.

[2] Annual targets are based on a number of factors including long-term historic reliability trending, current year performance, previous years investments and future years investment plans. The 2017/18 target for SAIDI has been adjusted to reflect these factors but remains in line with historical performance.

Note: Reliability targets are based on specific values, however performance within 10 per cent is considered acceptable given the wide range of variations in weather patterns and uncontrollable elements that can significantly disrupt the electrical system. BC Hydro measures reliability under normal circumstances, because major events are not predictable and largely uncontrollable. The reliability measure is therefore based on data that excludes major events. BC Hydro reviews performance during major events and takes the performance into consideration in reliability improvement initiatives.

[3] 2013/14 actuals have been calculated based on the latest available data and may be different than previously stated.

[4] A forced outage occurs when a generating unit is unable to start generating or doesn't stay on line as long as needed. Forced Outage Factor is defined as the total forced outage time in a period relative to the total number of hours in the same period (usually one year). Annually, the Forced Outage Factor can be relatively volatile and through applying the historical five year rolling average it can smooth the range to provide a more stable measure for which targets can be set. Therefore, the strategy is to keep the Force Outage Factor below 2% of the total number of hours per year. There are seven Key Generating Facilities, representing those plants with installed capacity greater than 200MW. Together they provide 90% of the average annual electricity generated by BC Hydro's facilities. This measurement will show the trend of how the assets are performing and aligns with how asset management investments decisions are made to maintain asset reliability that is reflected in a low forced outage factor.

[5] This is a new measure introduced for 2016/17; however, historical information has been provided for context.

[6] NR (Not Reported) as this is a new measure, there were no targets set for the 2015/16 year.

[7] BC Hydro attained a gold-level designation from the Canadian Council for Aboriginal Business in 2015/16 which is valid for a three year period. In 2018/19, BC Hydro will apply for the next certification.

Discussion New Measure - Key Generating Facility Forced Outage Factor replaces the previous Winter Generation Availability measure. With recent additions of capacity resources and long term planning criteria of capacity self-sufficiency, the risk to winter service reliability has decreased and in response, BC Hydro is removing the Winter Generation measure. Given the aging generating assets, BC Hydro is now refocussing on the performance of the Key Generating Facility units by measuring their Forced Outage Factor. This factor is one indicator of the units' health and provides both leading and lagging information on the effectiveness of BC Hydro's maintenance and capital investment programs. Forced Outage Factor is commonly used by electric utilities and industry benchmarks exist for comparative performance assessment. This new measure will allow for optimal outage planning throughout the year, including winter.

Goal 2: Ensure Rates are Among the Most Affordable in North America

BC Hydro customers will continue to have low, predictable rates while we efficiently manage our costs and make important investments to maintain and expand our system.

Strategies

- Prudently implement the Integrated Resource Plan recommendations and the 10 Year Capital Plan while keeping electricity rates low and predictable which will be reflected in the Revenue Requirements and Rate Design Applications to the BC Utilities Commission.
- Improve how we operate by focusing on safety, operational excellence, efficiency and reliability by enhancing work delivery methods as well as resourcing and supply chain strategies.
- Build Site C - a third dam and generating station on the Peace River, which is the most cost-effective way to meet the long–term need for energy and dependable capacity - on time and on budget.
- Implement a scalable and consistent project delivery practice to actively manage project risks and apply industry best practices to deliver projects on time and on budget.

Performance Measure 6-7[1]

Performance Measures	Four Year Avg.	Actual 2013/14	Actual 2014/15	Target 2015/16	**Forecast 2015/16**	Target 2016/17	Target 2017/18	Target 2018/19
Competitive Rates[2]	1st quartile	1st quartile	1st quartile	1st quartile	**1st quartile**	1st quartile	1st quartile	1st quartile
Project Budget to Actual Cost[3]	-1.8% on $3.94 billion[4]	-4.75% on $3.33 billion[5]	-1.8% on $3.94 billion[4]	Within +5% to -5% of budget excluding project reserve amounts	**Within +5% to -5% of budget excluding project reserve amounts**	Within +5% to -5% of budget excluding project reserve amounts	Within +5% to -5% of budget excluding project reserve amounts	Within +5% to -5% of budget excluding project reserve amounts

[1] Performance Measure definitions, rationales, data sources, and benchmarking information are available at www.bchydro.com/performance.

[2] Based on BC Hydro's ranking in the residential category in the annual HydroQuebec Report on Electricity Rates in North America. BC Hydro calculates a relative index for each usage level within the residential category and then calculates an average of the index to create an overall ranking. The rankings of the 21 participating utilities are then divided into quartiles to determine BC Hydro's ranking. Based on this same methodology, BC Hydro's rates for commercial and industrial customers rank fourth and fifth lowest in the report.

[3] The data includes Generation, Substation and Transmission Line projects managed by Project Delivery. Annually, BC Hydro reflects the past five years' performance in delivering capital projects. This is a five year rolling data set of actual costs compared to original approved full scope implementation budgets not including project reserve amounts, for capital projects that were put into service during the period.

[4] This is a five year rolling average reflecting 2010/11 to 2014/15.

[5] This is a five year rolling average reflecting 2009/10 to 2013/14.

Discussion - Project Budget to Actual Cost is an important measure for evaluating financial performance in delivering large capital projects. The measure captures a five year rolling data set of actual costs compared to original approved full scope implementation budgets excluding project reserve funds, for capital projects that were put into service during the period. The +/- 5% target is the same over the plan period as it is the objective to have the entire project portfolio (Generation, Substation and Transmission Line) in-service within this financial range. Over the past five years, BC Hydro has delivered 563 capital projects at a total cost of $3.94 billion, which is 1.8% under budget in aggregate.

Goal 3: Continue British Columbia's Leading Commitment to Renewable, Clean Power

BC Hydro will strengthen its legacy of renewable, clean power and energy conservation investments by implementing its energy conservation plan and by identifying and securing new competitively priced energy and capacity options to meet future customer needs.

Strategies

- Meet the *Clean Energy Act* objective that at least 93 percent of electricity generation be from renewable, clean resources by implementing the Integrated Resource Plan recommendations, including renewing expiring electricity purchase agreements (EPAs) on a cost of service basis and by implementing the Memorandum of Understanding with Clean Energy BC which includes exploring opportunities to acquire dependable capacity resources through the Standing Offer Program.
- Implement the energy conservation plan, which will exceed the *Clean Energy Act* objective to meet at least two-thirds of future demand growth through conservation and other energy management measures by 2020.
- Continue to provide opportunities for First Nations in non-integrated areas through established renewable energy programs.

Performance Measures 8-9[1]

Performance Measures	Four Year Avg.	Actual 2013/14	Actual 2014/15	Target 2015/16	**Forecast 2015/16**	Target 2016/17	Target 2017/18	Target 2018/19
Energy Conservation Portfolio (New Incremental GWh/year)[2]	800	500	700[3]	NR[4]	**NR**	700	700	600
Clean Energy (%)[5]	97.8	97.1	97.9	93.0	**98.6**	93.0	93.0	93.0

[1] Performance Measure descriptions, rationale, data source information and benchmarking is available online at www.bchydro.com/performance.

[2] Reflects the annual new incremental electricity savings resulting from DSM portfolio results including programs, codes and standards and conservation rates. This metric is a reflection of performance within the current period and as such is not impacted by past performance and/or adjustments made to energy savings in prior years (e.g., persistence, evaluations, measurement and verification).

[3] This is a new measure introduced for 2016/17; however, historical information has been provided for context.

[4] NR (Not Reported) as this is a new measure, there were no targets set for the 2015/16 year.

[5] 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. BC Hydro's forecast is based on expected generation and is consistent with previous years.

Discussion New Measure - New Incremental Energy Conservation Portfolio Energy Savings (GWh/yr) replaces the previous Cumulative Demand Side Management Energy Savings. BC Hydro continues to implement its plan to achieve or exceed the *Clean Energy Act* target to meet at least 66% of incremental demand from 2008 to 2020 through conservation. This new metric is a better reflection of performance within the operating period because it is based on the new incremental energy savings from programs, codes and standards and conservation rates that are implemented within the period. In some cases, the implementation date for anticipated codes and standards can shift, which will cause actual incremental energy savings to vary from the targets that have been set for the period.

Goal 4: Safety Above All

BC Hydro's number one priority is ensuring its workforce goes home safely every day and that the public is safe around our system.

Strategies

- Implement the five-year safety strategy with key elements that include:
    - Maintaining a culture where safety is a core value through demonstrating seen and felt safety leadership; supporting the courage to intervene where anyone can stop unsafe work; improving safety awareness and communication; and, learning from injury and near miss incidents to prevent re-occurrence.
    - Enhance frontline accountability for safety by establishing clear roles and accountabilities; developing a leading-class safety management system; and, continuing to leverage the joint health and safety committees to identify hazards and risks.
    - Strengthening safety competencies for employees and contractors around our: Life Saving Rules, Arc flash, asbestos and confined space hazards; improving job planning, hazard identification and the use of multiple barriers; and providing frontline and crew leadership training.
    - Incorporating safety into the strategy and planning process by reviewing and considering safety risks to our employees, contractors and the public in maintenance budgets and designs for capital projects.

Performance Measures 10-12[1]

Performance Measures	Four Year Avg.	Actual 2013/14	Actual 2014/15	Target 2015/16	**Forecast 2015/16**	Target 2016/17	Target 2017/18	Target 2018/19
Zero Fatality & Serious Injury[2] [Loss of life or the injury has resulted in a permanent disability]	0.75	0	1[3]	0	**0**	0	0	0
Lost Time Injury Frequency[2,4] [Number of employee injury incidents resulting in lost time (beyond the day of the injury) per 200,000 hours worked]	1.1	1.1[5]	1.0	1.0	**1.2**	1.0	0.9	0.8
Timely Completion of Corrective Actions (%)[6]	84%	84%	78%[7]	NR[8]	NR	85%	90%	95%

[1]Performance Measure descriptions, rationale, data source information and benchmarking is available online at www.bchydro.com/performance

[2] BC Hydro's safety performance measures do not include contractor or public safety injuries or fatalities.

[3]The 2014/15 actual reflects that a serious injury from an electrical contact occurred November 2014.
[4] Focusing on Lost Time Injury Frequency encourages managers to identify modified work duties for job categories and locations where workers experience injury, enabling injured workers to stay on the job while they recover. The earlier an injured worker is able to safely return to productive employment and maintain his or her positive connection to the workplace, the more likely he or she is of obtaining maximum recovery. With the increased granularity this metric provides, the organization is better able to focus its efforts on managing the hazards that can lead to Lost Time injuries.
[5] Prior years' results have been calculated based on the latest available data and may be different than previously stated.
[6] New Measure – defined as the percentage of safety corrective actions closed within 30 days of the original scheduled due date on an annual basis, with an aim to improve over time.
[7] This is a new measure introduced for 2016/17; however, historical information has been provided for context.
[8] NR (Not Reported) as this is a new measure, there were no targets set for the 2015/16 year.

Discussion New Measure – Timely Completion of Corrective Actions. The purpose of this measure is to track corrective actions that have been put in place from safety incidents (injuries and near misses) to improve our safety performance. It demonstrates that we are a learning organization with a focus on improving practices in a timely way from identified deficiencies that have a direct impact on the safety of our workforce. By implementing this measure, we will see systemic deficiencies corrected and our workforce will experience lower frequency of recurring issues. This measure tracks the percentage of safety corrective actions closed within 30 days of the original scheduled due date on an annual basis. The target is to increase the percentage of corrective actions completed within 30 days of the original due date by five percent per year for each of the next three years.

Measures removed from 2016/17 - 2018/19 Service Plan

BC Hydro removed 10 measures from its Service Plan to reflect the Service Plan guidelines and changes in business strategy and focus. The Service Plan is an accountability requirement for the Province and upon review, many of the performance measures are better suited for internal reporting purposes, or through other public mechanisms such as our website at bchydro.com.
For a list of the measures removed, see Appendix A.

Financial Plan

Summary Financial Outlook

Consolidated Statement of Operations[1] ($ millions)	2014/15 Actual	2015/16 Forecast	2016/17 Forecast	2017/18 Forecast	2018/19 Forecast
Revenues ($000)					
Domestic	4,829	5,052	5,334	5,513	5,754
Trade	919	593	614	623	614
Total Revenues	**5,748**	**5,645**	**5,949**	**6,136**	**6,368**
Expenses ($000)					
Operating Costs					
Cost of Energy	2,203	1,844	2,135	2,184	2,223
Personnel expenses, materials & external services [2]	868	902	974	1,022	1,050
Amortization	1,205	1,248	1,202	1,228	1,297
Finance charges	632	751	627	679	736
Grants and taxes	209	216	230	239	244
Other Operating Costs	50	30	87	78	98
Total	**5,167**	**4,992**	**5,256**	**5,430**	**5,648**
Net Income	**581**	**653**	**692**	**706**	**720**
Net Debt[3]	**16,682**	**17,979**	**19,710**	**20,803**	**21,903**
Equity	**4,170**	**4,495**	**4,928**	**5,474**	**6,135**
Capital Expenditures	**2,169**	**2,337**	**2,832**	**2,448**	**2,713**

[1] Table may not add due to rounding.

[2] These amounts are net of capitalized overhead and consists of the following:

	2014/15	2015/16	2016/17	2017/18	2018/19
Domestic Base Operating Costs	710	713	752	752	764
Other	158	190	223	270	286
	868	902	974	1,022	1,050

Commencing in 2016/17, Domestic Base Operating Costs include net sustainment costs related to the Smart Metering & Infrastucture Program which were incurred in previous years but which were subject to regulatory deferral in those years. For 2016/17, these net sustainment costs are $22 million. Other largely consists of Powerex & Powertech operating costs, operating costs related to energy purchase agreements accounted for as capital leases, and the transitioning of IFRS-ineligible capital overhead into operating costs over a 10-year period.

[3] Debt figures are net of sinking funds and cash and cash equivalents.

Key Forecast Assumptions

Key Assumptions	2014/15 Actual	2015/16 Forecast	2016/17 Forecast	2017/18 Forecast	2018/19 Forecast
Growth and Load					
B.C. Real Gross Domestic Product Growth (%)[1]	2.2	2.3	2.4	2.3	2.3
Domestic Sales Load Growth (%)[2,3]	(3.41)	14.20	(3.06)	0.69	1.27
Residential Sales Load Growth (%)[2]	(5.11)	3.57	3.62	0.40	0.60
Light Industrial and Commercial Sales Load Growth (%)[2]	0.34	1.39	0.03	0.38	0.62
Large Industrial Sales Load Growth (%)[2]	0.19	(1.24)	3.35	4.68	7.64
Domestic Load (GWh):					
Domestic Sales Volume (GWh)[3]	51,213	58,483	56,692	57,083	57,805
Line Loss and System Use (GWh)	4,529	5,173	5,199	5,256	5,373
Total Domestic Load (GWh)	55,742	63,656	61,890	62,339	63,178
Energy Generation					
Total System Water Inflows (% of average)	102	94	100	100	100
Sources of Supply to Meet Domestic Load:					
Net Hydro Generation (GWh)	41,830	49,115	46,495	45,987	46,633
Market Electricity Purchases (GWh)[4]	207	544	962	846	1,123
Independent Power Producers and Long-term Purchases (GWh)	13,377	13,651	14,092	15,155	15,069
Thermal Generation (GWh)	328	346	341	351	353
Sources of Supply for Domestic Load (GWh)	55,742	63,656	61,890	62,339	63,178
Average Mid-C Price (U.S.$/MWh)	27.16	25.93	24.15	25.34	26.79
Average Natural Gas Price at Sumas (U.S.$/MMBTU)	3.55	2.44	2.46	2.62	2.78
Financial					
Canadian Short-Term Interest Rates (%)[5]	1.22	0.58	0.68	1.10	1.98
Canadian Long-Term Interest Rates (%)[5]	2.83	2.57	3.05	3.67	4.55
Foreign Exchange Rate (U.S.$:Cdn$)[5]	0.8782	0.7659	0.7646	0.7941	0.8111

[1] Economic assumption based on calendar year, from Ministry of Finance 2015 February Budget.
[2] Includes the impact of Demand-Side Management programs.
[3] Includes surplus sales volume, which can vary year to year based on level and timing of inflows, risk of spill and market conditions. Forecast surplus sales are higher in 2015/16 due to high storage levels at the end of 2014/15 and the need to manage reservoir levels to reduce spill risk, as well as to meet Columbia River Treaty obligations in 2015/16.
[4] Assumes that gas fired power generation capability available to service domestic demand is sometimes displaced by more cost-effective market purchases.
[5] 2014/15 three months rate for short term and 10 years for long term. 2015/16 to 2018/19, financial assumptions from Ministry of Finance, October 2015.

Sensitivity Analysis

Factor	Change	Approximate change in 2016/17 earnings before regulatory account transfers (in $ millions)
Hydro Generation (GWh)[1]	+/- 1%	10
Electricity trade margins	+/- 10%	20
Interest rates	+/- 100 basis points	40
Exchange rates (US/ CDN)	$0.01	5
Weather	10% change in normal degree days	35

[1] Assumes a change in hydro generation is offset by corresponding change in energy imports. (i.e. increase in hydro generation is offset by decrease in energy imports.)

Management Perspective on Future Financial Outlook

In November 2013, the Province, as part of the 10 Year Rates Plan, announced rate increases for BC Hydro in 2014/15 and 2015/16 of 9 per cent and 6 per cent, respectively, with rate increases for 2016/17 to 2018/19 capped at 4 per cent, 3.5 per cent and 3 per cent. The 10 Year Rates Plan included several actions to reduce pressure on rates, including eliminating tier three water rental rates, lowering the return on equity, reducing dividends and smoothing general rate increases through the use of a regulatory account.

BC Hydro prepared the current financial projections for revenues and expenses through 2018/19 which were approved by the Board and submitted to the Ministry of Finance in January 2016. These financial projections are consistent with the 10 Year Rates Plan.

Capital Plan and Major Projects

Capital Expenditure by Year and Type and Function

($millions)	2014/15 Actual	2015/16 Forecast	2016/17 Forecast	2017/18 Forecast	2018/19 Forecast
Capital Expenditures by Type[1]					
Sustaining	1,005	1,165	1,282	1,343	1,325
Growth	1,164	1,172	1,550	1,105	1,388
Subtotal – BC Hydro Capital Expenditures before CIA	2,169	2,337	2,832	2,448	2,713
Contributions-in-Aid (CIA)[2]	(334)	(94)	(124)	(148)	(163)
Total – BC Hydro Capital Expenditures net of CIA	1,835	2,243	2,708	2,300	2,550
Generation	526	552	520	595	597
Transmission and Distribution	1,367	1,119	1,166	984	1,081
Properties, Technology and Other	251	284	285	293	259
Site C	25	382	861	576	776
Subtotal – BC Hydro Capital Expenditures before CIA	2,169	2,337	2,832	2,448	2,713
CIA	(334)	(94)	(124)	(148)	(163)
Total BC Hydro Capital Expenditures net of CIA	1,835	2,243	2,708	2,300	2,550

[1] BC Hydro classifies capital expenditures as either sustaining capital or growth capital:

- Sustaining capital includes expenditures to ensure the continued availability and reliability of generation, transmission and distribution facilities. It also includes expenditures to support the business, such as vehicles and information technology.
- Growth capital is required to meet customer load growth and other business investments. Growth capital expenditures relate to the expansion of existing generation assets as well as expansion and reinforcement of the transmission and distribution system, and includes Site C.

[2] Contributions in aid of construction are amounts paid by certain customers toward the cost of property, plant and equipment required for the extension of services to supply electricity.

Projects over $50 million

BC Hydro has the following projects, each with capital costs expected to exceed $50 million, listed according to targeted completion date. These projects have been approved by the Board of Directors.

Capital Project	Targeted Completion Date (calendar year)	Approved Anticipated Total Cost ($ millions)	Life to Date (LTD) Cost as of December 31, 2015 ($ millions)
Projects Recently Put Into Service			
G.M. Shrum Units 1 to 5 Turbine Replacement Replace the Units 1 to 5 turbines to reduce the risk of runner failure, decrease maintenance costs and improve operating efficiency.	October 2015 In-Service	$185	$167
Hugh Keenleyside Spillway Gate Reliability Upgrade Upgrade the spillway gates at the Hugh Keenleyside Dam to increase public and employee safety by ensuring the gates meet flood discharge reliability requirements. *Spillway gates control the amount of water that can be discharged from the reservoir. They are generally used in times of flood to pass high inflows.*	October 2015 In-Service	$123	$106
Dawson Creek/Chetwynd Area Transmission Project The project will expand the Peace Region 230 kV transmission system to the Dawson Creek/Chetwynd Area to supply the area's load growth. The solution will include the construction of new 230 kV lines between Dawson Creek and Bear Mountain Terminal (BMT), and from BMT to a new substation called Sundance Lake Substation, located approximately 19 km east of Chetwynd.	November 2015 In-Service	$296	$280

Capital Project	Targeted Completion Date (calendar year)	Approved Anticipated Total Cost ($ millions)	Life to Date (LTD) Cost as of December 31, 2015 ($ millions)
Projects Recently Put Into Service			
Long Beach Area Reinforcement Expansion of Long Beach and Great Central Lake substations with two new transformers at each and capacitor banks at Long Beach to support the load growth and provide voltage support in the area.	October 2015 In-Service	$56	$35
Merritt Area Transmission Project Construct a new 138 kV transmission line between the Merritt and Highland substations; add a new Merritt Substation and new equipment at the Highland Substation to meet the increased demand for power in the Merritt area.	November 2015 In-Service	$65	$55
Interior to Lower Mainland Transmission Line Project Construct a new 500 kV transmission line, approximately 247 km in length, between the Nicola Substation near Merritt and the Meridian Substation in Coquitlam and build a new series capacitor station at Ruby Creek near Agassiz to help meet domestic load growth in the Lower Mainland. * The forecasted budget for the project increased by $18 million. The revised budget is still within the upper cost limit submitted to the BC Utilities Commission in 2007. The project cost increase is a result of schedule delays by the primary contractor and challenges related to building a line in some of the most challenging terrain in North America.	December 2015 In-Service	$743*	$699

Capital Project	Targeted Completion Date (calendar year)	Approved Anticipated Total Cost ($ millions)	Life to Date (LTD) Cost as of December 31, 2015 ($ millions)
Projects Recently Put Into Service			
Smart Metering & Infrastructure Program The Smart Metering and Infrastructure Program includes the installation of 1.9 million smart meters in homes and businesses across the province, an advanced telecommunications infrastructure to support electricity system management and customer applications, and information technology to support customer billing, load forecasting and outage management systems. *Smart Metering & Infrastructure Program amount includes both capital costs and operating expenditures subject to regulatory deferral.*	December 2015 In-Service	$780	$762
Upper Columbia Capacity Additions at Mica – Units 5 & 6 Install two additional 500 MW generating units into existing unit bays at the Mica Generating Station. The new units are similar to the four existing units, but with more efficient turbines.	December 2015 In-Service	$714	$557
Ongoing			
Surrey Area Substation Project Construct a new 200 MVA 230/25 kV substation in the Fleetwood area of Surrey. The station will be supplied from the adjacent 230 kV transmission line and will allow for future expansion to 400 MVA to service high load growth in the Fraser Valley West area. Construction of this new Fleetwood Substation will also allow for the decommissioning of four ageing substations in the Surrey/Langley area.	2016 Targeted In-Service	$94	$72

Capital Project	Targeted Completion Date (calendar year)	Approved Anticipated Total Cost ($ millions)	Life to Date (LTD) Cost as of December 31, 2015 ($ millions)
Ongoing			
Big Bend Substation The South Burnaby, Big Bend area requires a new, 100 MVA, 69/12 kV substation to meet local residential and commercial load growth. * BC Hydro updated the cost estimate for the Big Bend Substation Project from $56 million to $67 million, prior to the start of construction to reflect new information from geotechnical investigations of the site and higher market prices for construction.	2017 Targeted In-Service	$67*	$31
Ruskin Dam Safety and Powerhouse Upgrade Improve seismically deficient dam and rehabilitation/replacement of powerhouse equipment that was brought into service between 1930 and 1950. The project includes: upgrading of the right abutment; redeveloping the dam and powerhouse to meet current seismic standards for earthquakes; and replace major generation equipment which is in poor unsatisfactory condition.	2017 Targeted In-Service	$748	$390
Horne Payne Substation Project (NEW) Expand the Horne Payne Substation with the addition of two 230/25kV, 150MVA transformers, gas-insulated (GIS) feeder sections, and a new control building. This project will increase the firm capacity of the substation, add needed feeder positions, facilitate the gradual conversion of the area supply voltage from 12kV to 25kV, and allow for the implementation of an open-loop distribution system.	2018 Targeted In-Service	$93	$3

Capital Project	Targeted Completion Date (calendar year)	Approved Anticipated Total Cost ($ millions)	Life to Date (LTD) Cost as of December 31, 2015 ($ millions)
Ongoing			
Cheakamus Unit 1 and Unit 2 Generator Replacement Replace the two generators at Cheakamus generating station (in operation since 1957) to address the poor condition and known deficiencies which will increase the capacity of each unit from 70 MW to 90 MW.	2019 Targeted In-Service	$74	$5
John Hart Generating Station Replacement Replace the existing six-unit 126 MW generating station (in operation since 1947) and add integrated emergency bypass capability to ensure reliable long-term generation and to mitigate earthquake risk and environmental risk to fish and fish habitat.	2019 Targeted In-Service	$1,093	$403
Fort St. John and Taylor Electric Supply (NEW) This project will maintain adequate supply capability, reduce line losses and improve reliability to the loads in the Fort St. John and Taylor areas by re-terminating 138kV transmission lines 1L360 and 1L374 at the new Site C switchyard.	2019 Targeted In-Service	$53	$Nil

Capital Project	Targeted Completion Date (calendar year)	Approved Anticipated Total Cost ($ millions)	Life to Date (LTD) Cost as of December 31, 2015 ($ millions)
Ongoing			
G.M. Shrum G1-G10 Control System Upgrade (NEW) The condition of the legacy controls for GMS generating units, which were originally installed in the 1960s and 1970s, is of growing concern due to increasing maintenance requirements, lack of spare parts availability and decreasing reliability. The controls are well beyond their expected life, cause operating problems and increase the risk of damage to major equipment. The project will replace the controls equipment, provide full remote control capability from the remote control center and rectify deficiencies in the current system.	2021 Targeted In-Service	$60 (Partial Implementation Funding)	$7
Site C Clean Energy Project Site C will be a third dam and hydroelectric generating station on the Peace River approximately seven kilometres southwest of Fort St. John. It will be capable of producing approximately 5,100 gigawatt-hours of electricity annually and 1,100 megawatts of capacity. Site C project was approved by the Provincial Government in December 2014. Site C will provide clean, renewable and cost-effective power in B.C. for more than 100 years. **Planned in-service date for all units. This timeline reflects the project's current schedule and is subject to change based on a review of the construction schedule.* ***Site C forecast and life-to-date amounts include both capital costs and expenditures subject to regulatory deferral. Total cost excludes the Project Reserve of $440 million (established by Government to account for events outside of BC Hydro's control that could occur during construction) which is held by the Treasury Board.*	2024* Targeted In-Service	$8,335**	$694

Appendix A:

Corporate Governance

Information about Corporate Governance can be found at:
http://www.bchydro.com/about/accountability_reports/financial_reports/service_plan.html.

This includes links to information regarding:

- Board of Directors
- Executive Team
- Code of Conduct

Operating Environment

Information about BC Hydro's Operating Environment can be found at:
http://www.bchydro.com/about/accountability_reports/financial_reports/service_plan.html.

This includes links to information regarding:

- About BC Hydro: Organizational Overview
- Mandate and Legislation
- Risks and Opportunities
- Performance Measures Data Analysis, Benchmarking and Rationale

Measures removed from the 2016/17 – 2018/19 Service Plan

- CAIDI
- CEMI-4
- Severity
- Billing Accuracy
- First Call Resolution
- Electricity Production GHG Emissions
- Employee Engagement
- Carbon Neutral Program Emissions
- Operating Costs
- Net Income

Appendix B:

Subsidiaries and Operating Segments

Active Subsidiaries

BC Hydro has created or retained a number of other subsidiaries for various purposes, including holding licenses in other jurisdictions, to manage real estate holdings and to manage various risks.

Powerex Corp.

Powerex Corp. is a wholly-owned subsidiary of BC Hydro and a key participant in energy markets across North America, buying and supplying wholesale power, renewable energy, natural gas, ancillary services, and financial energy products and services. Established in 1988, its export, marketing and trade activities help manage BC Hydro's electric system resources and provide significant economic benefits to British Columbia.

Powerex supports BC Hydro's electric system requirements through importing and exporting energy as required in addition to meeting its own trade commitments. Powerex also markets, on behalf of the Province, the Canadian Entitlement to the Downstream Benefits of the Columbia River Treaty.

The Chief Executive Officer (CEO) of Powerex reports directly to the Board of Directors of Powerex through the Chair of Powerex and works closely with the President & CEO of BC Hydro as a member of the Executive Team. The Chair of the Powerex Board, the Powerex CEO and BC Hydro's Chief Executive Officer (who is also a member of the Powerex Board), ensure the Board of BC Hydro is informed of Powerex's key strategies and business activities.

Powerex operates in complex and volatile energy-markets, which can cause net income in any given year to vary significantly. Market and economic conditions, reduced BC Hydro system flexibility, income timing differences and the strength of the Canadian dollar can materially impact Powerex net income. Over the previous five years, Powerex income has ranged from $72 to $142 million (2010/11 to 2014/15). The Service Plan forecast includes annual net income from Powerex of approximately $120 million per year for 2016/17 to 2018/19. For more information, visit powerex.com.

Powertech Labs Inc.

Powertech Labs, operating in Surrey since its inception in 1979, is a wholly-owned subsidiary of BC Hydro. Powertech is internationally recognized as holding expertise in various fields of operation, and provides research and development, testing, technical services and advanced technology services to the international energy community including BC Hydro.

Powertech's revenue in 2014/15 was $30 million with a net income of $4.2 million. The Service Plan forecast includes annual net income from Powertech ranging from $4.0 million to $6 million for 2015/16 to 2018/19. For more information, visit powertechlabs.com.

All the staff and management needs of the active subsidiaries below are fulfilled by BC Hydro employees, who perform these duties without additional remuneration. Three of these subsidiaries are considered active:

BCHPA Captive Insurance Company Ltd

Procures insurance products and services on behalf of BC Hydro.

Columbia Hydro Constructors Ltd

Administers and supplies the labour force to specified projects.

Tongass Power and Light Company

Provides electrical power to Hyder, Alaska due to its remoteness from the Alaska electrical system.

Nominee Holding Companies and/or Inactive/Dormant Subsidiaries

BC Hydro's remaining subsidiaries either serve as nominee holding companies (indicated with an *) or are considered to be inactive/dormant. The inactive/dormant subsidiaries do not carry on active operations. As of December 31, 2015, these other subsidiaries consisted of the following:

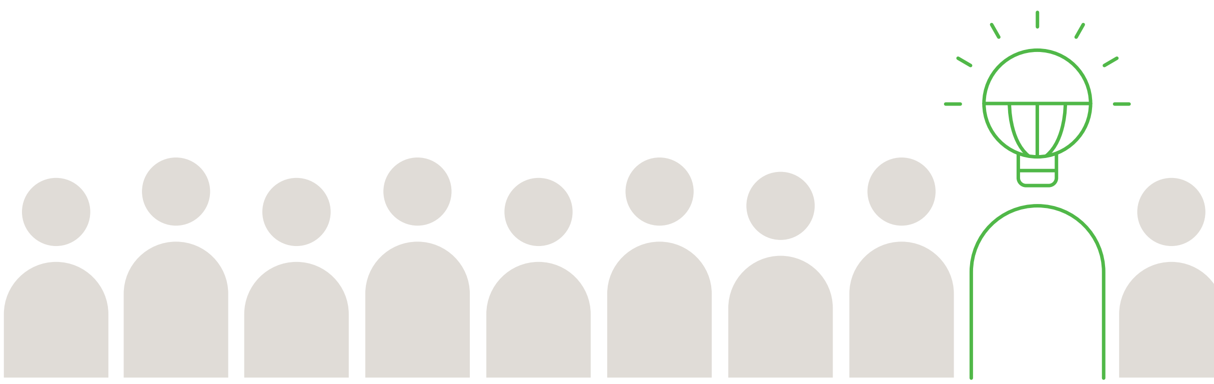
1. British Columbia Hydro International Limited
2. British Columbia Power Exchange Corporation
3. British Columbia Power Export Corporation
4. British Columbia Transmission Corporation
5. Columbia Estate Company Limited*
6. Edmonds Centre Developments Limited*
7. Fauquier Water and Sewerage Corporation
8. Hydro Monitoring (Alberta) Inc.*
9. Waneta Holdings (US) Inc.*
10. Victoria Gas Company Limited

Fiscal 2017 to Fiscal 2019
Revenue Requirements Application

Appendix F

BC Hydro Workforce Plan

Workforce Plan
Fiscal Years 2016-2025



BC Hydro
Power smart

Our Workforce Plan: Highlights

We are taking action to ensure our workforce, our greatest asset, is performing at its best in pursuit of BC Hydro's objectives.

A high performance workforce is imperative now, more than ever, as the company is in an unprecedented period of infrastructure development. At the same time, we must maintain & upgrade our ageing system so we can serve an increasing population and contribute to a growing economy.

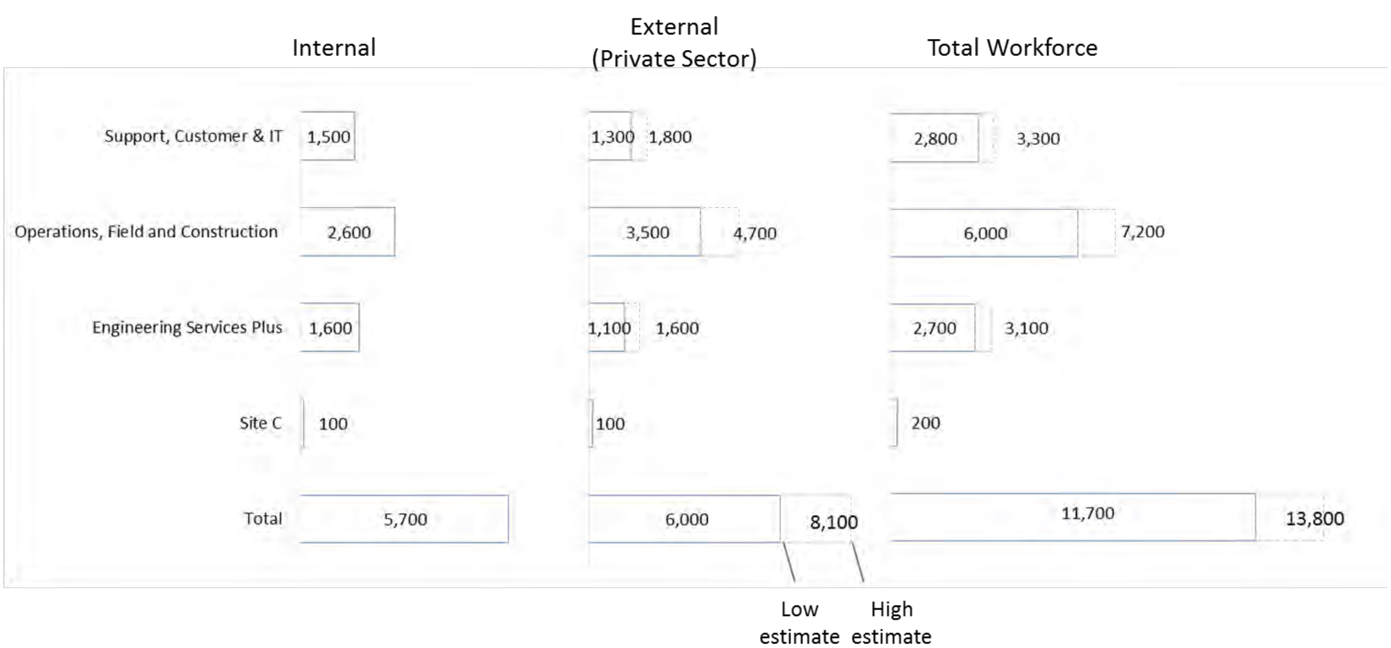
Succeeding in this environment will only be possible with the right-sized, right-skilled workforce comprised of the right mix of internal and external resources.

Our workforce plan is a proactive response to delivering on the work we need to complete in the coming years. Highlights of the plan are below and more details are available in the full report that follows.

Our Workforce in F2015

Our internal workforce as of the end of F2015 was approximately 5,700 full-time equivalents (FTEs). Our external workforce in F2015 was estimated to be in the order of 6,000-8,100 FTEs. The largest segment of external resources supports the company in operations, field and construction capacities.

Estimated F2015 Workforce (FTEs)



2

Both internal and external resources comprise BC Hydro's 'workforce'. Each type of resource brings benefits when used appropriately. External resources will remain an important component of our workforce as they can provide benefits in terms of flexibility, access to specialized skills and improved value.

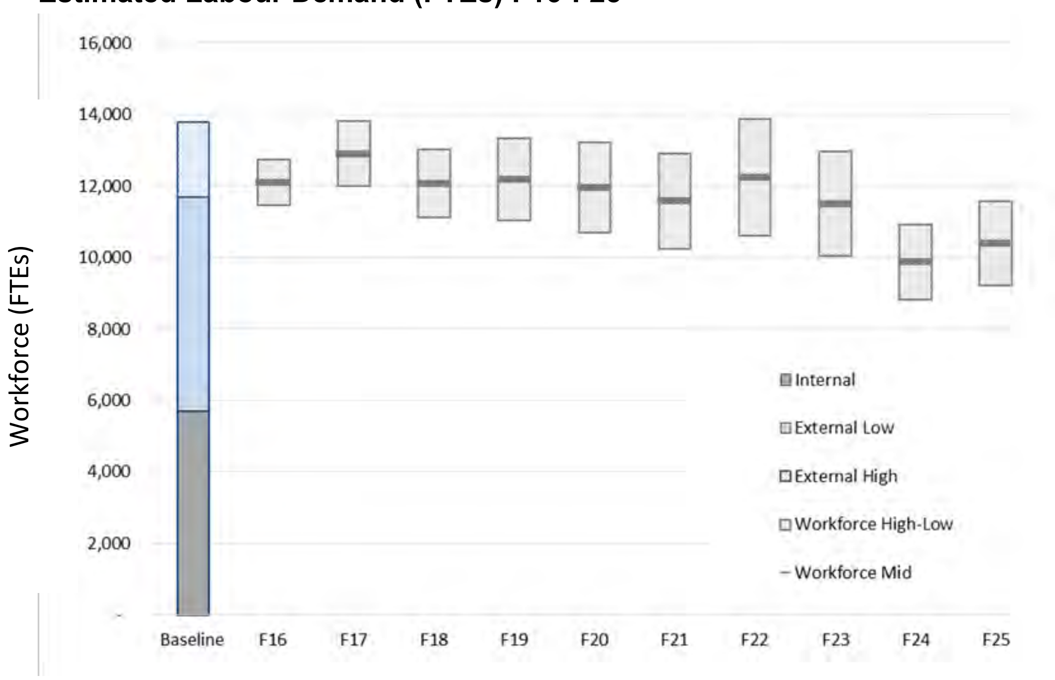
An important focus in managing our workforce is determining the right labour mix, which we describe in Chapter 4 of this plan. For example, BC Hydro will remain a 'Knowledgeable Owner' so we can properly manage risks and safely design, operate, and maintain the assets. This means moving away from situations where external resources are managing other external resources, and maintaining sufficient internal work so that we can maintain the expertise to effectively oversee work.

We have initiated a process to evaluate where work contracted out would be more appropriately done in-house to reduce costs and risk. Approximately 200 FTEs have already been identified for conversion between fiscal years 2016-2019.

Workforce Projections

Sustained, high levels of investment are expected for the next 10 years and beyond.

Estimated Labour Demand (FTEs) F16-F25



Our workforce projections will change with our detailed investment plans. Resource requirements and resource intensities differ across portfolios of work. As such, even if overall investment levels remain similar, the variation in the type of work means different types of resources may be required over time.

Factors Impacting our Workforce Plan

Just as the mix and nature of our work will vary over time, so too will the internal and external factors that impact our work and our workforce. Proactively monitoring and responding to these factors is key to the success of our workforce plan. The factors below are discussed in further detail in Chapter 2 of this plan.

	Labour Demand (Work to be done)	Labour Supply (Available workforce)
External Factors	• Increasing First Nations & stakeholder expectations • Technological change	• Improved labour availability • Remote location challenges • Rising utility-specific training enrollment
Internal Factors	• 10 Year Rates Plan • Sustained high levels of investment • New strategic direction	• Stable workforce • Retirement eligibility • More support needed for training & career development

Our Action Plan

Ensuring a right-sized workforce

Strong sources of qualified candidates, streamlining tasks and improving employee engagement are strategies that help us optimize the size of our workforce. We will continue to refine our trainee and apprenticeship programs, build close partnerships with educational institutions, focus on regional opportunities, and build capacity in First Nations to enable greater participation in our workforce. Our process improvements and the application of technology will help streamline work and reduce the effort required to get jobs done. We know that an engaged workforce is a productive and efficient workforce. Our employees have told us we need to do a better job of setting a clear direction for the company. Based on this feedback, we have developed a new roadmap centred on our new vision and priorities. Ensuring employees understand how these impact their work and contributions will be ongoing.

1. ***Maintain our focus on trainee/apprenticeship programs***
2. ***Provide opportunities for First Nations and other local workers***
3. ***Engage our workforce***
4. ***Streamline work***

Ensuring our workforce has the knowledge it needs

We have also heard that more opportunities for training and career development would increase employee engagement. We need to make space and create opportunities for internal career progression. The implementation of our Training & Development Roadmap will ensure that both our employees and suppliers have the skills they need. Knowledge transfer and development opportunities will further build the capabilities of our people.

5. ***Implement our Training & Development Roadmap***
6. ***Provide development and knowledge transfer opportunities through the Capital Plan***

Ensuring we have the right resource mix

Finally, given the volume of capital and other work we must complete in the coming years, we will ensure we have the right mix of internal and external resources. There are many factors to consider in determining what work is best completed internally and externally. Ultimately, however, our employees must maintain the skills needed to safely design, operate and maintain our system. We are examining opportunities to adjust our mix in areas where costs or business risks can be reduced. A systematic examination of our spend categories will also inform our internal/external resource mix and will drive more targeted sourcing and supplier management so that our suppliers can provide the external workforce required to meet our needs.

7. ***Adjust our resource mix in accordance with our Labour Mix Principles***
8. ***Implement Supply Chain Category Management***
9. ***Ensure alignment of the workforce with new priorities***

A Cohesive Approach

To succeed in the years ahead, focus on planning and managing our workforce will be paramount. Building on workforce planning discipline already in place, we have created a centralized workforce planning function. This will ensure we have the appropriate governance and discipline to proactively manage our overall workforce.

Our Workforce Plan: Analysis & Details

Contents

1. Introduction to Workforce Planning

Workforce planning is the analysis of forecasted work (labour demand) – driven by strategy, planning & funding – against the forecasted availability of workers (labour supply) over a set period of time. Size, skills and mix of the workforce are all considered. Actions to close gaps between labour supply and demand are identified so that work can be completed efficiently and effectively. Much like budgeting, which sets out the financial resources required to achieve a company's plan, workforce planning defines and optimizes the human capital needed to execute an organization's priorities.

Our approach to workforce planning includes elements of 'operational' or 'capacity' planning and 'strategic workforce planning'. Workforce planning happens in various areas across the company. A central workforce planning function helps align workforce planning practices and principles into a cohesive approach and takes a cross-enterprise perspective.

Demand Forecasting

The greatest clarity in BC Hydro's long-term work requirements comes from its capital and operational plans for the electricity system. To avoid shortages in key segments of the workforce involved in field, operational, engineering and project delivery work, 10-year work forecasts are produced annually and may be updated as investment plans change.

The demand for specific professions, engineering disciplines, and trades is projected using the following methods:

- the translation of financial plans into projected labour hours using conversion factors generated from historical, comparable work, and;
- the aggregation of project-level, resource-loaded schedules where this level of detail is available.

Other areas of the business who perform more supporting roles do not have such lengthy planning horizons. In these areas, shorter-term demand planning is done through annual planning and budgeting.

Supply Forecasting

Projections for hiring and attrition (including retirement) within BC Hydro's internal workforce are calculated using pension data, historical hiring and attrition trends. Further insights are provided by examining how factors such as age and length of service relate to outcomes including attrition and engagement (see the Appendix for relevant statistics on the internal workforce).

We also monitor external labour market dynamics to watch for supply tightness and price escalation. External labour market models provided by groups such as Build Force and the BC Government are watched closely. Relationships with external suppliers and Labour Associations also provide useful insights into what is happening externally.

Labour Mix Principles

We have developed a set of high-level guiding principles to inform what work we do internally and externally. These principles seek to balance the often competing objectives of minimizing risk and cost.

BC Hydro will remain a 'Knowledgeable Owner' so we can properly manage risks and safely design, operate, and maintain the assets (see Chapter 6 of the Revenue Requirements Application for more details). This mandate guides the level of involvement and oversight required for work on our electricity system. Enough work must be retained internally such that BC Hydro can maintain and sustain a base of skills that are necessary to fulfill its mandate to be a Knowledgeable Owner.

The following considerations help determine whether work should be completed by internal or external resources. Table 1 illustrates how these considerations align with specific resourcing decisions.

Characteristics of the Work:

- Frequency: how often the work occurs – may also consider predictability, variability, sustainability and urgency
- Complexity: how integrated the work is with BC Hydro's system, how many stakeholders must be engaged, the technical skills required to complete the work, and clarity in how the work should be completed
- Business Risk: the degree to which the work could impact BC Hydro's ability to deliver on its mission, priorities and 'Knowledgeable Owner' status[1]

Characteristics of the Internal and External Workforce:

- Capacity: having enough resources to complete the work
- Capability: having the skills and competencies required to complete the work to the required level of quality
- Efficiency: combined time and cost required to complete the work to the specified level of quality

Table 1: Labour Mix Principles

	Work Characteristics	Workforce Characteristics
Completed Primarily Internally	• Frequent & complex • High business risk	• High internal capacity & capability • High internal efficiency
Completed Primarily Externally	• Infrequent & complex (niche expertise, time-limited requirement)	• High external capacity & capability • High external efficiency

[1] In determining if work presents a risk to our 'Knowledgeable Owner' status, an assessment of internal workforce capabilities must also be performed. It may be that internal personnel have not recently been exposed to a particular type of work or that they must re-familiarize themselves to provide better oversight or perform the work directly.

Where the characteristics of the work and the workforce both point to the same, clear resourcing option, the suggested solution is evident. In cases where the characteristics point to opposed or unclear resourcing options (effectively putting the work in a 'grey' area), a more detailed structured decision making approach may be required. In these situations, steps may also be taken to shift the work and workforce characteristics:

i. Internal or external capacity, capability and efficiency may be developed over the medium term if this shift would provide stronger alignment with the characteristics of the work. Although the decision to focus on capacity building may not provide an immediate solution, providing internal career development opportunities is an area of focus (see the next chapter). Pursuing such opportunities can lead to better outcomes for our employees and for the company.
ii. Where internal capacity, capability or efficiency are not sufficient to complete high risk work, mitigation and management measures may help decrease risk associated with the work and enable external delivery.

While the guidelines above provide broad direction, they also encompass more discipline-specific decision making approaches at the operational level. An example of this would be the 'Owner's Engineer Plus' model, driven by the Knowledgeable Owner strategy – it provides guidance around the use of internal and external engineering resources. Both the high-level principles and discipline-specific approaches will be revisited and refreshed regularly for alignment with our objectives.

2. Environmental Scan

There are a number of internal and external forces affecting the work we must do (labour demand) and the workforce available to complete it (labour supply). These are explained in more detail below.

Table 2: Contextual Factors

	Labour Demand (Work to be done)	Labour Supply (Available workforce)
External Factors	• Increasing First Nations & stakeholder expectations • Technological change	• Improved labour availability • Remote location challenges • Rising utility-specific training enrollment
Internal Factors	• 10 Year Rates Plan • Sustained high levels of investment • New strategic direction	• Stable workforce • Retirement eligibility • More support needed for training & career development

External Factors Affecting the Work

Increasing First Nations & Stakeholder Expectations: BC Hydro operates with diverse expectations from First Nations, customers, partners, the public, interest groups, the regulator, our Shareholder and others. Engagement with these groups is increasing as court rulings and public opinion call for organizations to properly inform, consult and involve those affected. Maintaining strong relationships is resource intensive, but pays dividends in enabling smooth operations, work and improved outcomes throughout the Province.

Technological change: New technology is automating the ways people do things and is enabling us to unbundle and reassign work. Technology is also enabling higher worker productivity, more flexible work arrangements and new options around education and training[i].

Examples of technology changing work at BC Hydro include initiatives such as smart metering, grid automation and ongoing systems implementation. These types of changes, and the need to equip our employees with updated skills, will continue to accelerate.

Internal Factors Affecting the Work

10-Year Rates Plan: BC Hydro's workplan is guided by the 10-Year Rates Plan. Our Rates Plan informs budgeting, which in turn drives the prioritization of BC Hydro's asset and operational plans. These plans directly influence our demand for labour.

Sustained high levels of investment: We are in an unprecedented period of infrastructure development. Our asset-related capital and maintenance plans are the main drivers of work demand. As demand for electricity continues to increase and our asset base expands and ages, significant investments are required. Capital expenditures, including Site C, are forecast to remain above $2 billion annually for the next 10 years.

New strategic direction: As organizations shift direction, their labour compositions and capabilities will change accordingly.

In response to our employee engagement survey, our new mission, vision and priorities were launched in September of 2015. The mission describes our core business: *provide our customers with reliable, affordable, clean electricity throughout B.C., safely*. The organization we aspire to be is articulated in the vision: *to be the most trusted, innovative utility company in North America by being smart about power in all we do*.

Five organizational priorities outline where we focus our efforts to achieve the vision. The most direct connections to workforce planning are highlighted below:

1. *Make it easy for our customers to do business with us*
2. *Deliver capital budgets on time and on budget*
    - Includes a commitment to: ensure the right mix of employees, contractors and resources to get the job done
3. *Explore the full potential of energy conservation*
4. *Strengthen our proud and valued workforce*
    - Includes commitments to: encourage personal development and act on results from the Employee Engagement Survey
5. *Continue to improve the way we operate*
    - Includes commitments around process improvements (streamline work) and greater quality and value from key supply chain categories (external workforce)

As plans underpinning the priorities are implemented, workforce requirements will continue to evolve. This new strategic direction is reshaping work and areas of emphasis across the business.

External Factors Affecting the Workforce

Improved Labour Availability: B.C.'s positive economic outlook makes it a destination for workers from the Prairie provinces and other areas of the country where the outlook is not as bright. Recent declines in the oil & gas sector have further improved labour availability in B.C.

Supporting this is the fact that B.C.'s interprovincial migration has been historically positive (i.e. we attract more people than we lose to other provinces). After a reversal of this trend in 2014, it returned to positive in 2015 and is forecasted to continue as such.

While this is promising for B.C., Ontario also has a positive economic outlook and will compete for labour. Further, it is not clear to what extent the skills and qualifications of incoming workers will match BC Hydro's requirements.[ii]

Remote location challenges: Despite the recent improvement in provincial labour availability, we still face staffing challenges in the Northern Interior and other remote areas of the province. Attracting and keeping employees in these areas can be challenging, due to high migration, declining working age populations, and the lack of available of goods and services.

Rising utility-specific training enrollment: Our requirement for utility-specific workers can be a constraint to our capital and project plans – accessing technical skills and trades can be challenging. This is particularly true for Power Line Technicians; Electricians; Communications, Protection & Control Technologists; Engineer Technologists and Engineers.

Countering this, enrollment in post-secondary programs (I.e. electrical engineering degrees and diploma programs in engineering technology with power options) that provide utility-related training is on the rise, building talent pools with the right skills and an interest in our industry.[iii]

Internal Factors Affecting the Workforce

Stable workforce: Our workforce has been relatively stable. Average attrition from F2009 to F2015 was 6.2% for all forms of attrition, comfortably below the 10% threshold that we use as our risk benchmark.

People stay at BC Hydro for several reasons: our competitive total reward package and high employee engagement (82% 'Sustainable Engagement' in F2015 – compares favourably to Tower Watson's Global Utility Companies Norm) both create a 'sticky floor' for our employees that keeps them productive, engaged and willing to invest their careers with us. In addition, BC Hydro benefits from the fact that we compete more nationally than locally for much of our utility-specific expertise. The prospect of uprooting one's family to pursue an opportunity in another province can be daunting. Service also plays a role in attrition: BC Hydro has analyzed attrition data from 2008 to 2015 - employees who work beyond 6 years of service have a much higher tendency to stay with us through retirement.

Changes in the external market may create temporary spikes in attrition for specific roles. These are often short-lived, and can be mitigated through career pathing, succession planning, and apprentice/trainee programs.

Retirement eligibility: BC Hydro, like many other utilities, has a significant proportion of employees that could retire within the next 10 years with an unreduced pension. 11% of BC Hydro's F15 year-end employees could have already taken an unreduced pension but had yet to retire. An additional 28% of that workforce will gain unreduced pension status before F25. This means 39% of the F15 year-end workforce will have reached their 'pensionable' date by F25.

This 'delayed retirement' trend has been observed at BC Hydro over the last several years and is consistent with the broader trend of Canadians working for longer periods of time. Statistics Canada found that Canadians are working an average of three years longer since the late 1990s, which in turn has mitigated the effect of Canada's aging workforce on labour markets and productivity.[iv]

More support needed for training & career development: In our recent engagement and exit surveys, employees have emphasized that more support for training and career development is required. This is a critical aspect of BC Hydro's employment offer, as it can have a positive impact on attrition—and therefore stable workforce supply—and on engagement, which boosts productivity.

3. Labour Supply & Demand Outlook

Labour Supply

Both internal and external resources comprise BC Hydro's 'workforce'. Each type of resource brings benefits when used appropriately.

Our internal workforce as of the end of F2015 was approximately 5,700 full-time equivalents ('FTEs'; including Site C and Smart Metering). Round, comparable estimates for internal FTEs in Fiscal years 2016-2019 according to internal labour budgets are as follows:

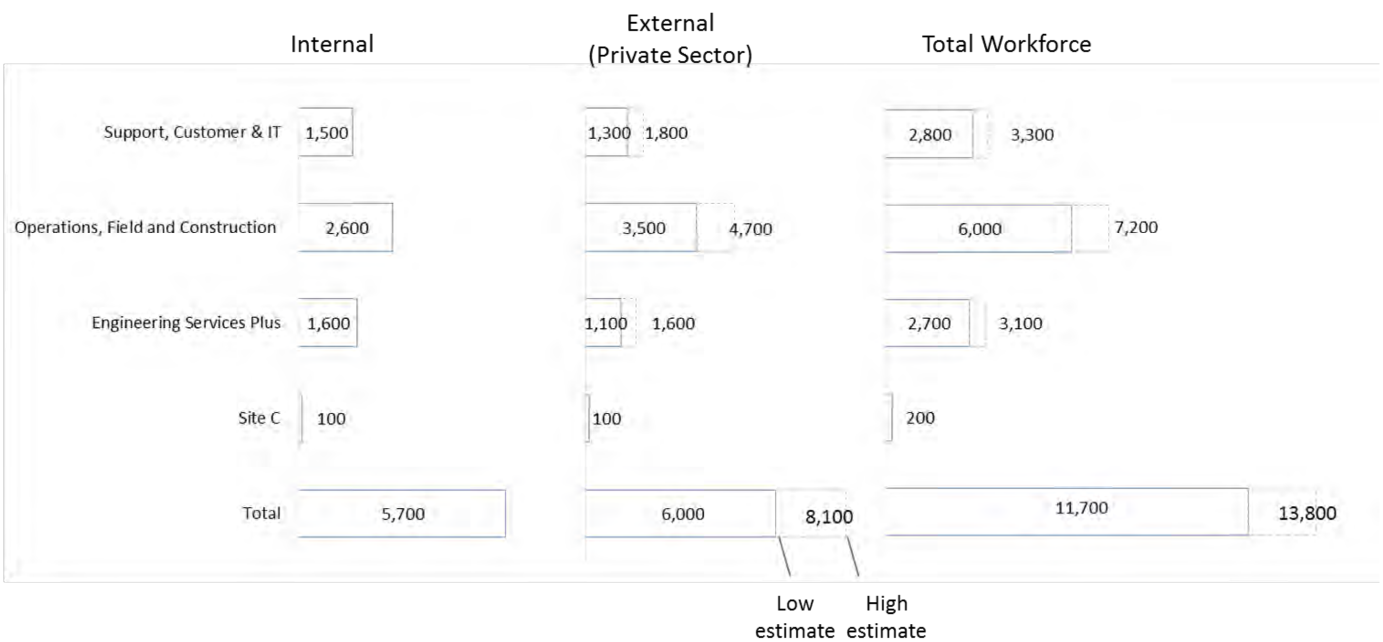
- F16 5,700
- F17 5,700
- F18 5,800
- F19 5,800

As reflected in the Labour Mix Principles, suppliers can provide benefits in terms of flexibility, access to specialized skills and improved value. Consistent with other businesses, we rely on an external workforce to complete work that outstrips our internal supply of labour. Our external workforce in F2015 was roughly estimated to be in the order of 6,000-8,100 FTEs (see figure below). The largest segment of external resources supports the company in operations, field and construction capacities.

The external workforce estimate was generated primarily through an assessment of F2015 spend. Spending categories assumed to be non-labour related (e.g. materials & goods) were removed. Within the remaining categories, further assumptions were used to estimate the extent of services spending. The remaining estimated 'services' spending was converted into estimated full-time equivalents (FTEs) of labour. Scope of the analysis encompasses contingent labour to outsourcing arrangements, service providers such as Amec FW and Accenture and services from legal counsel to construction.

The resulting estimate of the external workforce is directional – precise measures are not available.

Chart 1: Estimated F2015 Workforce (FTEs)



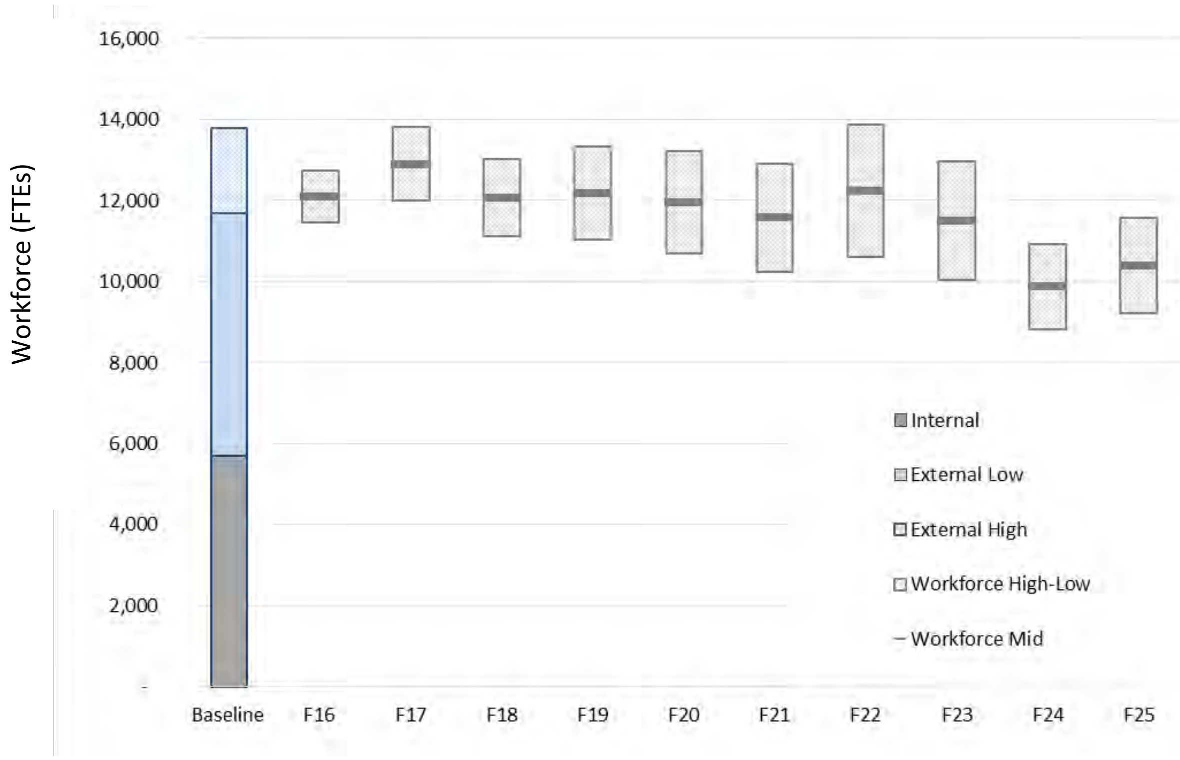
Labour Demand

On the demand side, sustained, high levels of investment are expected for the next 10 years and beyond. Work for the next 10 years (see figure below, includes Site C) was estimated using:

- Specific forecasts for trades and professional requirements most directly involved in capital project delivery and system operation (e.g. Engineers, Power-line technicians etc.)
- A flat forecast for roles less directly involved in project delivery and operations (e.g Finance, Legal, Administration etc).

The F15 baseline shown on the left side of the following chart reflects the total workforce estimate detailed above and helps demonstrate how forecasted demand, for the same scope of work, compares to BC Hydro's current labour supply.

Chart 2: Estimated Labour Demand (FTEs) F16-F25



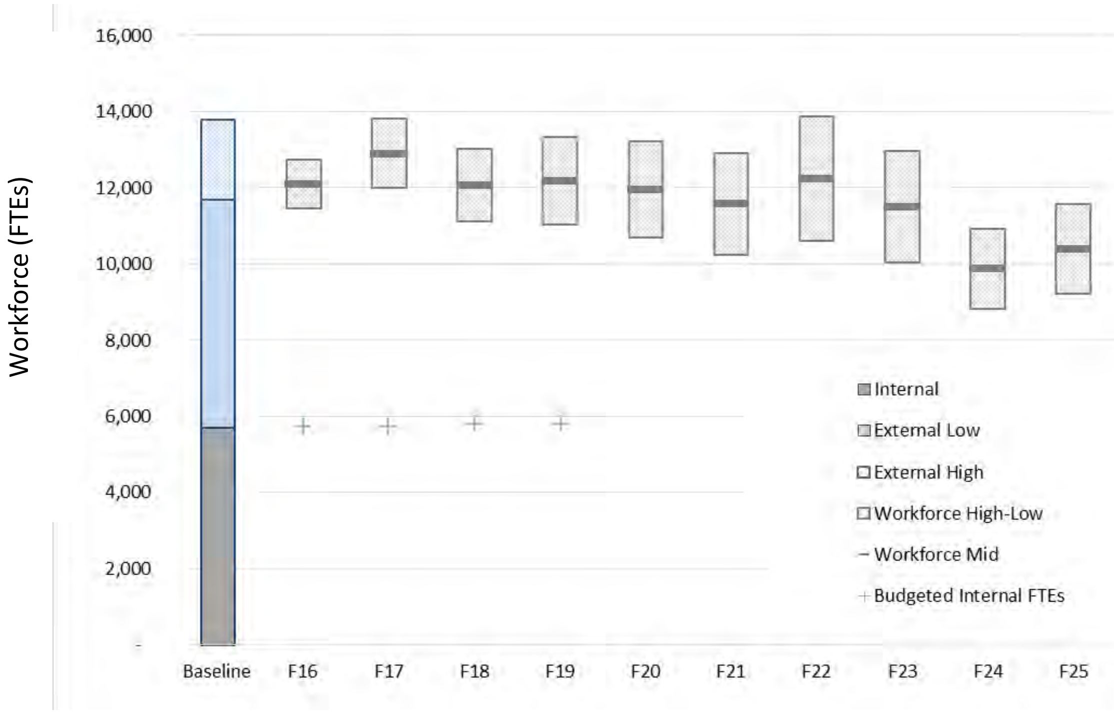
Although our capital investment levels in F24 and F25 are similar to those of today, inflation accounts for an increasing portion of overall investment in the later years. Because inflation does not represent additional work, uninflated plans were used in the demand forecasting approach. Thus, work in 'real' terms in later years may be slightly lower than today. This, coupled with the completion of Site C in the later years, explains the small decline in the projected workforce over the 10 year period. In addition, there is greater variability in BC Hydro's capital plans in later years, and there may be capital-related work that either emerges or falls off of the plan in later years that may cause labour projections to rise or fall, accordingly.

Our workforce projections will change with our detailed investment plans. Resource requirements and resource intensities differ across portfolios of work. As such, even if overall investment levels were to remain the same, a change in the mix of underlying portfolios will result in different resource requirements.

Gap Analysis

Taken together, the forecasted demand and near-term internal supply of labour for BC Hydro is as follows:

Chart 3: Estimated Labour Demand and Budgeted Internal Workforce (FTEs) F16-F25



The implied labour mix for F16-19 reflects early decisions made through a newly launched 'workforce optimization' approach. This process aims to reduce business risk and costs by adjusting our workforce mix. Early decisions in this regard total ~200 additional internal FTEs over F16-19 with an offsetting reduction in the use of external resources. Further adjustments are anticipated over the next few years. Our Labour Mix Principles will guide the composition of our workforce.

While the discussion has focused on addressing the labour gap through supply side decisions, adjustments to the work can also contribute to a multi-pronged solution. Work may be streamlined, reassigned or ultimately delayed, although delaying work is considered only in short-term situations. Workforce planning with a longer-term outlook should help avoid such 'last resort' measures which could ultimately increase business risk.

4. Action Plan

Based on the Environmental Scan and capacity-focused Gap Analysis, we will focus on the following areas to ensure we have the right people in the right place, at the right time and right cost to complete our work. Most actions are already underway and will continue over the next few years.

Capacity Gaps: Ensuring a right-sized workforce

1. ***Maintain our focus on trainee/apprenticeship programs*** - Our best access to external labour markets for technical roles is via new career entrants. BC Hydro provides comprehensive trainee/apprenticeship programs at our Trades Training Centre (TTC) and

through partnerships with educational institutes. Our approach enables BC Hydro to successfully attract high quality, new-career entrants graduating from high schools (for trades roles) and post-secondary institutions (for trades upgrading their high school credentials, technologists and engineers). BC Hydro also has opportunities for high-school students to become familiar with the career options available at BC Hydro in their communities through outreach programs and our six-week Youth Hire summer work program. Maintaining and continuing to develop strategic relationships with educational institutions around B.C. will ensure BC Hydro has conduits to candidates in technical and specialized fields.

BC Hydro will continue to use labour planning data—e.g. projected retirements, resignations of apprentices and journeypersons, desired labour mix—to better plan the optimal level of trainees (e.g. EITs). This will help mitigate risks related to resourcing work at BC Hydro, as well as provide schools and students a clearer view of available opportunities.

An increasingly critical part of these efforts is to work with school boards, educational institutions, and First Nations to increase our intake of candidates into these programs from the Northern region.

2. ***Provide opportunities for First Nations and other local workers*** – While we have seen overall success in recruiting and retaining people, there are regions in B.C. where it is difficult to find and keep people with the right skills. BC Hydro will build capacity and use strategic partnerships and incentives to create the workers we need, where we need them.

   The core of this strategy is to approach critical First Nations and educational institutions that are geographically closest to our work plans to develop candidates where they are needed most while improving BC Hydro's diversity and representation in the community. Specifically:
   - BC Hydro's Aboriginal Employment and Business Development Strategy includes a plan to improve aboriginal talent representation within BC Hydro by leveraging relationships with key First Nations affected by our Capital Plan.
   - BC Hydro will continue to partner with school boards and educational institutions in the North to build more capacity within this labour market for utility-oriented skillsets. This will improve the field of candidates that BC Hydro has to choose from for roles in hard-to-fill areas.
   - BC Hydro will continue to provide and revise its incentive programs designed to support, attract and retain employees in remote work locations.

3. ***Engage our workforce*** – More engaged employees are more productive contributors. Engaged employees are also more likely to provide additional discretionary effort to their role, and less likely to be tempted to look for work elsewhere. These benefits impact BC Hydro's resource capacity, and BC Hydro's continued emphasis on improving employee engagement is a key part of our action planning.

BC Hydro's action plan in response to the F2015 Employee Engagement Survey was developed to target areas where the Executive Team could make tangible improvements. Highlights of this plan are:

- Create a Strong Vision – by detailing and communicating BC Hydro's vision & priorities
- Improve Opportunities for Development – by helping managers better engage with & develop their teams, and by clearly communication how training budgets are allocated
- Improve Opportunities for Dialogue – by integrating employee feedback on engagement into the business planning cycle, and conducting employee focus groups on development needs
- Improve Employee Autonomy and Workload – by identifying decision-making protocols that negatively impact business operations, and by identifying the most painful administrative tasks currently performed by front-line managers and finding ways to minimize them

Progress on the actions outlined above will be assessed and results of the F2016 Employee Engagement Survey will shape the next iteration of the plan.

4. ***Streamline work*** – BC Hydro's Work Smart program, utilizing Lean principles, is our structured approach to improving business processes. Employees are examining processes from end-to-end, with a view to improving quality, cost and cycle times. This includes streamlining by eliminating non value-added steps and reducing touch points.

   These types of initiatives, and others, like applying technology and improving work planning and scheduling in the field, are expected to improve outcomes over the longer term.

Capability Gaps: Ensuring our workforce has the knowledge it needs

5. ***Implement our Training & Development Roadmap*** **–** Through effective training and development opportunities, BC Hydro will build our internal capacity to meet strategic goals and position our organization for the future. Our 10-Year Roadmap (F2015-2025) describes how we will:
   1. Enable a safe workforce
   2. Enable a competent and productive workforce while providing opportunities for career development
   3. Deliver operational excellence within the Training & Development department

   Focus areas range from technical to leadership development, internal programs to strategic partnerships and include training for both our employees and suppliers. The Roadmap will be refreshed regularly to ensure it remains aligned with workforce needs.

6. ***Provide development and knowledge transfer opportunities through the Capital Plan*** – Complex projects and programs like those detailed in the Capital Plan draw on resources from across BC Hydro for successful delivery, and often rely on the extensive knowledge of experienced, technically knowledgeable employees. Many of these employees are close to,

or on the verge of becoming, retirement eligible, meaning we need to ensure BC Hydro's institutional knowledge is transferred to younger employees.

BC Hydro will use cross-company opportunities for integrated team work and exposure to develop its people and build knowledge of the assets it is maintaining, building, replacing or improving. In addition to ensuring core knowledge stays within BC Hydro, this will also have positive impacts on employee engagement and attrition. This work will build on efforts that BC Hydro has already begun, specifically in creating Career Pathing documentation and information for specific roles (e.g. engineering).

Ensuring we have the right resource mix

7. ***Adjust our resource mix in accordance with our Labour Mix Principles*** – BC Hydro's Labour Mix Principles represent the highest-level principles within frameworks already used by several areas of the business to make resourcing decisions. More work will be done to ensure all parts of the business can benefit from a consistent resourcing approach and are able to develop their own, business-specific interpretations where needed.

8. ***Implement Supply Chain Category Management*** - We are implementing an approach to help us more strategically manage our 40-50 consolidated spend categories and related suppliers critical to the achievement of our mission and priorities. This process will help business groups work together on decisions about internal/external market mix in relevant categories and drive how we source and manage our suppliers. As category management is implemented, we will improve collaboration and information sharing with our key suppliers. This will help ensure our suppliers are capable of providing the external workforce to meet our needs.

9. ***Ensure alignment of the workforce with new priorities*** – As we pursue our new priorities, we will continue to adjust the relative capacities and capabilities required for success. Organizational design changes may also improve business outcomes. Early moves in this regard include the formation of the Capital Infrastructure Project Delivery business unit and the relocation of our Customer Care organization within Transmission & Distribution.

5. Monitoring & Evaluation

Proactive workforce planning will help ensure our workforce is performing at its best and that we can deliver on our priorities. We will continue to monitor work forecasts and utilization for roles most closely aligned with project delivery and field work. Work forecasting will also be developed for more supporting functions. Employee engagement levels, attrition, employee movement, vacancy rates, time-to-fill-vacancies, external labour market trends and supplier performance will also be tracked.

Opportunities to share learnings, and more deeply integrate workforce planning with other planning processes, will be pursued. Overarching governance and metrics will also be revisited to guide the evolution of our workforce. Our Workforce Plan will be refreshed annually.

6 Appendix: Internal Workforce Statistics

1. Demographics (Age, Gender, Service):

A. Age & Gender

BC Hydro Employees by Age & Gender, end of F2015 (HCE)			
Age Cohort:	Female	Male	Total
Age 25 and Under	45	182	226
Age 26-30	135	372	506
Age 31-35	205	536	741
Age 36-40	228	522	750
Age 41-45	272	526	798
Age 46-50	292	588	880
Age 51-55	281	537	818
Age 56-60	116	451	567
Age 61-65	64	230	294
Age 66+	11	103	114
Grand Total	1648	4046	5694

B. Service

BC Hydro Employees by Service, end of F2015 (HCE)	
Service Cohorts	BC Hydro Employees
Less than 1 Year	315
1-4 Years	1101
5-9 Years	2032
10-14 Years	798
15-19 Years	335
20-24 Years	506
24-29 Years	294
30 Years and Above	313
Grand Total	5694

2. Attrition (Employee Exits)

A. Employee Attrition: Retirement, Resignations, Involuntary Exits, & Trends

Regular Employee Exits: F2009 to F2015 (Employees)				
Fiscal Year	**Involuntary**	**Retirement**	**Voluntary**	**Total**
F2009	46	129	86	261
F2010	43	103	66	212
F2011	73	97	46	216
F2012	83	122	132	337
F2013	57	146	128	331
F2014	72	108	112	292
F2015	96	95	67	258
Total	**541**	**1104**	**802**	**2447**

BC Hydro Attrition from F2009 to F2015							
Category	F09	F10	F11	F12	F13	F14	F15
Retirement	3.2%	2.1%	2.3%	2.9%	3.0%	2.4%	2.2%
Voluntary	2.0%	1.4%	1.5%	2.8%	2.7%	2.5%	1.6%
Involuntary	1.0%	0.8%	1.5%	2.0%	1.7%	1.5%	1.3%
Death	0.0%	0.1%	0.3%	0.2%	0.1%	0.2%	0.1%
Total Attrition	6.2%	4.4%	5.4%	7.8%	7.4%	6.5%	5.3%

3. Employment mix by employee type

A. Employee Status and Affiliation, end of F2015

BC Hydro Employees by Affiliation & Status (HCE)				
Status	**BCH M&P**	**BCH IBEW**	**BCH COPE**	**BCH Total**
Full Time Regular	2132	1557	1362	5051
Full Time Temporary	30	401	155	586
Part Time Regular	19		31	50
Casual	1		6	7
BC Hydro Total:	**2182**	**1958**	**1554**	**5694**

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[i] Richard Dobbs, James Manyika and Jonathan Woetzel, *No Ordinary Disruption* (New York: Public Affairs, 2015), 151.

[ii] Jock Finlayson, BC Economic Outlook 2015 and BC Economic Outlook 2014 (Presentations), (Vancouver, BC, Business Council of BC, October 2015 & October 2014), and Pedro Antunes, British Columbia Economic Outlook: In a class of its own (Presentation), (Ottawa, ON, Conference Board of Canada, November 2015)

[iii] Electricity Sector Council, *Power in Motion: Labour Market Information Study*, (Ottawa: Electricity Human Resources Canada), 2011).

[iv] Carriere, Yves and Galarneau, Diane. "Delayed Retirement: A New Trend?", *Perspectives on Labour & Income*, (Ottawa, ON, Statistics Canada, October 2011)

Fiscal 2017 to Fiscal 2019

Revenue Requirements Application

Appendix G

Ten Year Capital Forecast

Discussion/Information

Board briefing - BC Hydro 10 Year Capital Forecast Update (July 2016)

Executive summary

The purpose of this document is to provide BC Hydro's Board of Directors (Board) with an update to BC Hydro's 10 Year Capital Forecast (July 2016 Update) as a result of the change in filing date for the F2017-F2019 Revenue Requirements Application.

BC Hydro updates the 10 Year Capital Forecast on an annual basis. The capital forecast for the three years from F2017 to F2019 will form the basis of the F2017-F2019 Revenue Requirements Application. Individual capital projects requiring Board approval will continue to follow the normal approval process.

In January 2015, the 10 Year Capital Forecast update was prepared for the period F2016 to F2025 (January 2015 Update) as part of the forecast process for the February 2015 Service Plan Forecast. The draft 10 Year Capital Forecast prepared as part of the 2016 Service Plan Forecast has been replaced with this update. The July 2016 update includes the F2015 and F2016 actual capital results, and the capital forecasts for the 10 year period F2017 to F2026. This briefing compares the July 2016 Update to the January 2015 Update and the capital information included in the original 10 Year Rates Plan.

This update is the final version of the 2016 10 Year Capital Forecast and is for information purposes only. Board approval is not being requested as relevant information from this update is included in other documents that will be approved by the Board (i.e., the Five Year Forecast).

10 Year Capital Forecast update

BC Hydro reviews and updates the 10 Year Capital Forecast on an annual basis. The updated capital forecast is typically used to update the five year forecast and the capital information presented in the annual Service Plan. This capital forecast for the three years from F2017 to F2019 will form the basis of the capital information included in the F2017/F2019 Revenue Requirements Application.

Due the nature of the capital forecast and related projects, project information is updated on an ongoing basis. For example, cashflows are refined from pre-release allowances as alternatives are selected and designs develop, particularly in the early phases. This 10 Year Capital Forecast Update includes projects in the future, identification, definition and implementation phases. As a result, the level of confidence and accuracy vary significantly for total project estimates, forecasted annual cashflow and in-service dates.

This update is also based on a "point in time" forecast update and as projects progress through their project life-cycle, the information used in this update could change significantly. For this update, a specific date was selected to ensure the forecast information and related assumptions used by the various capital portfolios across BC Hydro were as of the same date. The forecasts for the 10 year period F2017 to F2026 are as of March 2016, and this corresponds to the planning date for capital used in the F17-F19 RRA.

As part of the capital forecast update process, a guiding principle was that the capital forecast update for the period F2015 to F2024 included in the original 10 Year Rates Plan should not be exceeded on a total basis. In addition, for the years outside the 10 Year Rates Plan (F2025 and F2026), annual expenditures for these years should be reasonably consistent with the capital expenditures in F2024.

Updated 10 Year Capital Forecast (F2017 to F2026)

Based on the work completed to update the 10 Year Capital Forecast for the period F2017 to F2026, BC Hydro is forecasting an annual average capital net expenditure of approximately $2.3 billion per

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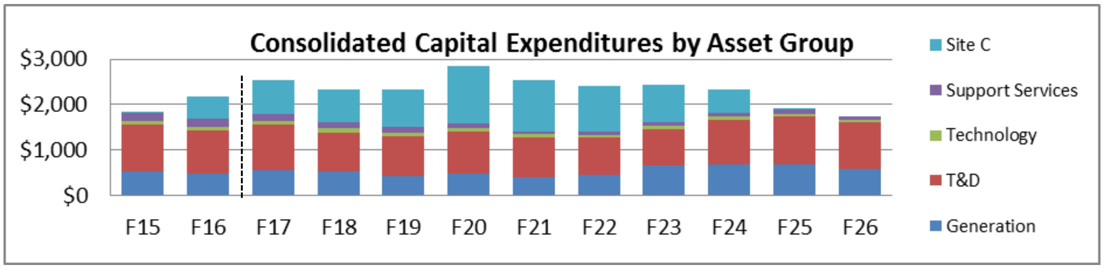
year or total capital net expenditures of $23.4 billion for the same 10 year period. See Figure 1 below for the annual capital net expenditures by the key capital asset groupings (Site C, Generation, Transmission and Distribution, Technology and Support Services).

These annual investments will continue to refurbish, upgrade and expand our generation, transmission, distribution, property and technology assets.

Figure 1: Consolidated Capital Expenditures by Asset Group ($M)



For ease of presentation, the Smart Meter Initiative (completed in F2016) has been captured within the Support Services Asset Group

	F15	F16	F17	F18	F19	F20	F21	F22	F23	F24	F25	F26
Site C	25	489	743	717	829	1,258	1,136	1,020	833	529	39	-
Support Services	179	181	144	123	131	111	64	67	76	79	87	86
Technology	70	77	81	92	76	69	64	65	60	55	63	61
T&D	1,041	939	1,017	860	872	926	878	825	819	986	1,046	1,013
Generation	522	486	542	529	418	481	407	445	645	685	685	589
Total	1,836	2,172	2,527	2,321	2,328	2,845	2,549	2,422	2,433	2,334	1,920	1,749

Comparison to original 10 Year Rates Plan (F2015 – F2014)

The original 10 Year Rates Plan included a 10 year capital forecast for the period F2015 to F2024. The 10 year capital forecast included in the 10 Year Rates Plan had a net capital forecast of $17.1 billion not including Site C as Site C was not yet approved at the time of the 10 Year Rates Plan. The July 2016 Update has a total 10 year forecasted net capital expenditure of $16.2 billion for the same F2015 to F2024 period. Therefore, this update does not exceed the total capital net expenditures included in the 10 Year Rates Plan.

Comparison to January 2015 update - same 10 year period (F2016 – F2025)

The 10 Year Forecast update last year (January 2015 Update) for the period F2016 to F2025, including Site C, had a total capital forecast of $24.2 billion, or an average annual capital spend of $2.4 billion.

The July 2016 Update has a total capital forecast of $23.9 billion which is a decrease of approximately $300 million over the 10 year period or 1.3% decrease. This net decrease consists of the following changes in the following asset groups:

- Generation: A decrease of $342 million in the total forecast and shifting of certain capital expenditures within the 10 year period.
- Transmission and Distribution: Net forecast increase of $149 million primarily driven by increased sustaining and distribution customer driven capital expenditures.

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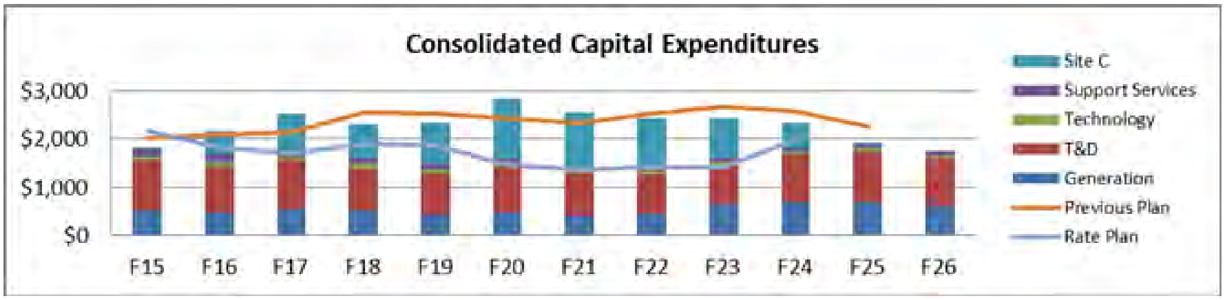
- Technology and Support Services: A forecast decrease of $109 million primarily due to decreased forecasts in Technology and Properties.

The Figure 2 below provides a comparison of the July 2016 Update by asset group compared to the total annual capital amounts included in the 10 Year Rates Plan and January 2015 Update.

Figure 2: July 2016 Update vs. 10 Year Rates Plan and January 2015 Update, including Site C ($M)



Revenue requirement rate impacts

The updated capital expenditure and in-service additions forecasts in the July 2016 Update reflect actions taken as part of the overall cost reduction work to mitigate rate pressures during the 10 Year Rates Plan period.

Capital Forecast Drivers

The drivers of the July 2016 Update remain unchanged from the prior year. The common attributes of BC Hydro's capital assets, which influence the asset management plans and drive the magnitude and timing of the investments in the 10 year capital expenditure forecast, include the following:

Ageing Assets - A large portion of BC Hydro's system was built in the 1960s and 1970s and is reaching or exceeding expected end-of-life. A significant proportion of the risks facing BC Hydro's major assets can be attributed to their age. The physical condition along with the performance, maintenance and repair cost history, and criticality of equipment and facilities are significant drivers for planning and prioritizing refurbishment or replacement. Equipment health assessments are an industry standard approach to assessing the reliability risk associated with capital equipment. BC Hydro continually evaluates the condition of its assets, which informs the reliability risk associated with those assets. For example, there are currently a number of major generating components that are in Poor or Unsatisfactory condition and have a high likelihood of failing within the next 10 years. Transmission and Distribution Asset Management assessed that 12 per cent of its over 4 million individual assets are in poor or very poor condition and should be addressed in the next 10 years.

System Growth - BC Hydro will experience load growth over the next 20 years and to meet this increased demand while operating the system safely and reliably will influence asset management and capital expenditure decisions. This growth in load is driving the addition of Site C, the expansion of existing generating capacity, the expansion of bulk and regional transmission facilities, and the integrated information technology improvements needed to support expansion in a changing environment.

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Financial, Resource and Other Considerations

BC Hydro needs to align its goal to maintain competitive rates over the long-term with its investment and maintenance strategies when considering the extent and timing of capital expenditures. The methodology used to determine the forecast capital expenditures included in the July 2016 Update followed the capital expenditure prioritization framework, and considered resource and capacity constraints.

Prioritization Methodology - The proposed investments in the July 2016 Update have been risk assessed and scored by each Business Groups in accordance with the corporate risk framework. The framework provides a standardized approach to applying BC Hydro's corporate risk matrix for capital investments. As part of the annual planning process, representatives from the different teams met to review the proposed investments in their respective capital investment portfolios to ensure that it had been applied consistently. In addition to the portfolios being prioritized based on risk, other factors were taken into account. Dependencies between projects, opportunities to bundle work for more efficient delivery and resource strategies are some of the factors that were considered to optimize each portfolio of investments. Please refer to page 12 for further details on the prioritization approach employed to develop the July 2016 Update.

Financial and Resource Capacity - The Original 10 Year Rates Plan provides the upper bound for capital expenditures in the 10 year period F2015 – F2024 so that rate increases are within the required limits. The July 2016 Update has some movement of expenditures between years but still meet the overall targets of the 10 Year Rates Plan. For F2025 and F2026, expenditure increases from F2024 approximate inflation rates.

With respect to resource considerations, each group has assumed resources over the 10 year period will remain at levels similar to those of F2016 but additional resources would be available if required. The near-term portion of the business unit capital plans has been carefully scrutinized to ensure that the plans can be successfully delivered.

Other Planning Considerations –The July 2016 Update is aligned with BC Hydro's Integrated Resource Plan, which was approved by Government in November 2013. Transmission and Distribution Growth Capital is also aligned with the Updated 2012 System Demand Load Forecast and the 2015 Distribution Substation Load Forecast. Where available and appropriate, Energy Demand Load Forecast updates have also been considered.

Financial, resource and other considerations resulted in modifications to the scope of the capital projects, generally extending the recommended investments out over time.

Each Asset Group at BC Hydro has prepared a 10-year capital expenditure forecast reflecting their respective asset management methodologies, system characteristics and criticality, and resource constraints. The proposed expenditures will:

- Improve the condition of critical assets already with unsatisfactory or poor equipment health assessments
- Manage the predicted decline of deteriorating or ageing assets in the coming 10 years
- Reduce the risk of unplanned in-service failures of critical equipment
- Meet forecast customer and load growth
- Facilitate implementation of the BC Hydro Integrated Resource Plan recommendations.
- Reduce the largest known seismic risks associated with water retaining structures
- Improve the asset health of properties to provide a safe and efficient work environment

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- Build, integrate and maintain technology capabilities to mitigate risk and generate business value

The July 2016 Update has undergone an internal peer review process to ensure consistency of approach, assumptions, and capital prioritization across Asset Groups. This forecast supports and aligns with BC Hydro's safety value and includes the necessary capital expenditures to ensure that the safety of our employees and the public can remain the highest priority for BC Hydro.

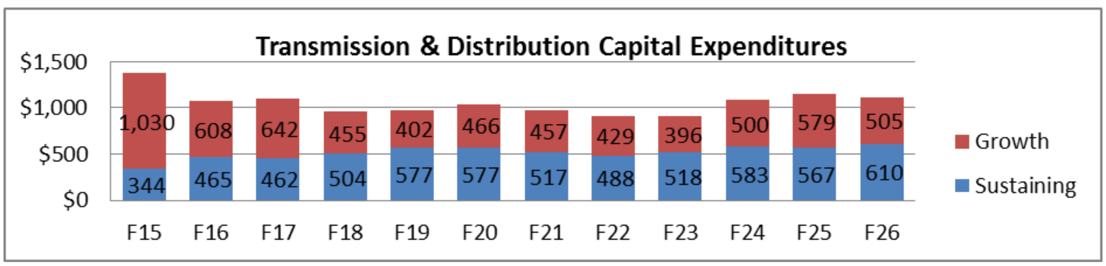
Capital Expenditure Forecast by Asset Group

The following provide brief summaries of the July 2016 Update for BC Hydro's four main capital intensive groups: Transmission and Distribution, Generation, Technology, and Properties.

The explanations for changes between the January 2015 and July 2016 Updates included in this section are based on a 10 year rolling basis, which is a different comparison from those discussed earlier.

Transmission & Distribution

The main business issues facing Transmission & Distribution are ageing assets, industrial and commercial load growth in certain regions of the province and the need to sustain current trends in customer reliability. The graph below excludes Contribution in Aid and is $M.



The Transmission & Distribution capital expenditure in the July 2016 Update totals approximately $10.2 billion for F2017 to F2026, split between sustaining ($5.4 billion) and growth ($4.8 billion) expenditures. Sustaining capital remains high during the period to address ageing assets. The higher level in F2019 and F2020 is to replace multiple power equipment and circuit breakers at Mainwaring, Esquimalt, Barnard, Horsey and Newell substations. There are significant increases in F2025 and F2026 needed to continue to address ageing assets. There is a reduction in growth expenditures after F2017 following the completion of the Interior to Lower Mainland, Dawson Creek / Chetwynd Area Transmission, and Surrey Area Substation projects in F2016. Growth expenditure levels will vary over the period as other major projects enter the implementation phase.

The overall objective and benefit of Transmission & Distribution capital investment strategy is to:

- Address load and system growth.
- Manage assets reaching end of life through targeted investments to address critical assets and the highest asset risks.
- Continue to address the worst performing circuits and install automated devices to improve reliability.
- Invest in safety and environmental risk mitigation

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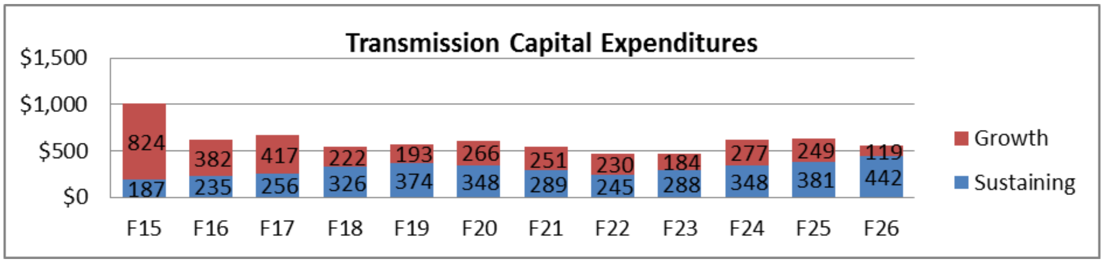
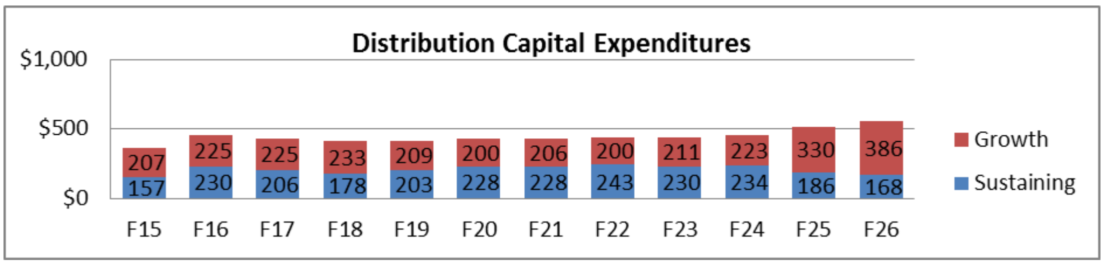
The Transmission and Distribution Growth and Sustaining expenditures are presented separately in the following charts which are in $M:





The main objective of the Sustaining Capital Portfolio is to cost-effectively sustain a reliable Transmission & Distribution system and mitigate asset risks including life-safety, environmental, extreme weather, seismic and fire. These expenditures will replace end-of-life assets, manage reliability trends in the Distribution system and address other risks.

Most of the expenditures are for the replacement of component parts (e.g. circuit breakers and wood poles) with varied life expectancies and, where cost effective, for the replacement of complete assets. The end-of-life expenditures are managed to maximize the life cycle value of the Transmission & Distribution assets. While in most instances end-of-life replacements are done through proactive replacements, in some asset classes “run to failure” is used to minimize the life cycle cost of managing the assets where the associated risk of failure is low. Examples are overhead distribution transformers and transmission line insulators.

To understand long-term trends in asset replacement needs, Transmission & Distribution uses the asset health index together with a Sustainment Investment Model. The latter uses asset survival curves and demographic data to support decisions around the required rate of asset replacements. The replacement of assets at end-of-life constitutes the bulk of the sustaining portfolio, totalling approximately $4.3 billion over the forecast period, comprised of $2.9 billion and $1.4 billion for Transmission and Distribution End-of-Life assets respectively. It should be noted that the average age of assets will continue to rise over the ten year period and the number of assets in poor or very poor condition is expected to increase. Therefore the reliability risk associated with some components of the T&D system is also expected to increase. Transmission & Distribution will minimize this risk by targeting investments to critical assets and the highest asset risks, and by monitoring system reliability to determine whether the level of end-of-life replacements needs to be adjusted.

Customer reliability expenditures are also part of the Sustaining Capital Portfolio. These expenditures contribute to maintaining the overall distribution system reliability by installing automated devices such as circuit reclosers, and by targeting the distribution circuits that are performing poorly. The scope of customer reliability projects may include new standby feeders, feeder ties, as well as circuit undergrounding or reconfiguration, line relocations and protection upgrades. The level of investments in this area is approximately $0.5 billion.

The Growth Capital Portfolio reinforces the Transmission & Distribution system to meet increasing firm domestic load and provide generator interconnections and dispatch flexibility. The size of the portfolio is reflective of a domestic load that continues to grow in a number of areas across the province and the generation resources added to the system. The total forecast for all Transmission & Distribution Growth Capital projects included in the forecast is approximately $4.8 billion over the next ten years. The distribution growth portfolio is increasing across the ten year period while the transmission growth portfolio has variable expenditures over the period depending on when major projects are expected to reach implementation. The Transmission & Distribution Growth Capital Portfolio is aligned with recommendations of the Integrated Resource Plan, the Updated 2012 System Load Forecast and the 2015 Distribution Substation Load Forecast. Projects within this portfolio cover bulk transmission system facilities, regional transmission system facilities, transmission load and Independent Power Producer interconnections and local distribution system facilities.

The Transmission & Distribution Other Capital Portfolio includes expenditures for the Control Centres, non-integrated areas and general capital. The total forecast for Transmission & Distribution Other Capital over the next ten years is $171 million.

Key Changes from the January 2015 Update

Transmission & Distribution's forecast capital expenditures are $81 million higher in the July 2016 Update compared with the January 2015 Update on a rolling 10 year basis, driven by increasing sustaining and distribution customer driven expenditures. Key changes at the portfolio level are as follows:

- Sustaining Capital investments increased $360 million over the January 2015 Update, mostly in the later years of the period, to address the increasing number of assets reaching end of life.
- Growth Capital Investments decreased $207 million compared to the January 2015 Update (decreased $57 million net of Contributions in Aid). The decreases are mainly due to the completion or winding down of some major projects, namely, Interior to Lower Mainland, Dawson Creek / Chetwynd Area Transmission and Surrey Area Substation, and elimination from the forecast of highly uncertain third-party driven transmission load interconnection projects. The decreases are offset by the Distribution Customer Connection forecasts which have increased $370 million. Distribution Customer Connections forecast is based on historical level of activities and the increase is due to higher expenditures in recent years. There is an increase in the forecast Contributions in Aid as well.
- Transmission & Distribution Other Capital Portfolio has decreased by almost $72 million relative to the January 2015 Update mostly due to the completion of the Smart Metering & Infrastructure Project.

Generation

The Generation capital expenditure forecast in the July 2016 Update totals approximately $5.4 billion (excluding Site C) for F2017 to F2026. These expenditures are to address a number of known risks in three areas: Sustaining Plant and Equipment Portfolio ($3.4 billion), Dam Safety and Seismic Portfolio ($1.5 billion) and Growth Portfolio ($0.5 billion). Graph below excludes Site C and is $M.

BC Hydro
Power smart

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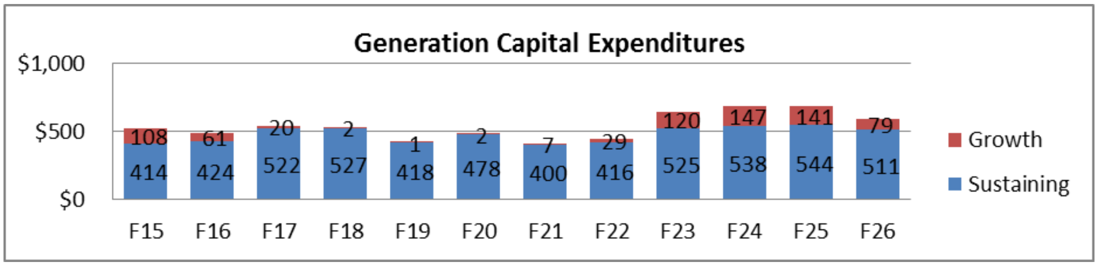

The benefits of the capital investment strategy will be realized over the coming 10 years and are outlined below:

- Mitigate high priority Dam Safety sustainment, flood, seismic, and spillway risks by addressing approximately 40 - 50% of the current known vulnerabilities over the next 10 years, and a further 15 - 25% over the subsequent 10 year period,
- Replace or begin to replace existing Unsatisfactory and Poor equipment at Key facilities,
- Mitigate major component risks at Bridge River (Key facility) and John Hart and Ruskin facilities (Strategic facilities),
- Effect discrete investments at Strategic Facilities, addressing the highest risk equipment to mitigate the risk of units being forced out of service,
- Improved condition of and access to water passages fleet-wide,
- Demonstrated commitment to safety, environmental, and reputational risk mitigation, asbestos abatement, buildings & grounds, and other projects through a continuing level of investment,
- Additional 500MW capacity, as Revelstoke Unit 6 is forecasted to go in-service in F2026.

The Sustaining Portfolio constitutes the bulk of Generation investment over the 10 Year Generation Capital Forecast period. To develop the Sustaining Portfolio, BC Hydro developed a 10 year asset management strategy to mitigate the key portfolio risks in a time-appropriate manner and to maximize the economic life of the generation assets. The portfolio includes investments to address: major generating equipment risks, dam safety risks (including the safe storage and passage of water, spillway gates reliability, as well as seismic risk), penstock refurbishment work, and single device isolation.

Mica Unit 5 and Unit 6 are in-service. Excluding Site C, the Generation Growth Portfolio is primarily made up of a significant investment to install an additional unit (Unit 6) at the Revelstoke Generating Facility with an in-service date of F2026. This date may be subject to change as the Energy Planning Team continues to review the load forecast to better understand possible future shortfalls in capacity.

Key Changes from the January 2015 Update

Generation's forecast capital expenditures are $5.4 billion for the F2017 to F2026 period. This is a reduction when compared to the January 2015 Update which had $5.7 billion for the period of F2016 to F2025. The forecast profile reflects a reduction in capital expenditures till F2022 and increases in remaining years.

Significant increases in capital expenditures when comparing the Generation 10 Year July 2016 Update to the January 2015 Update are highlighted below:

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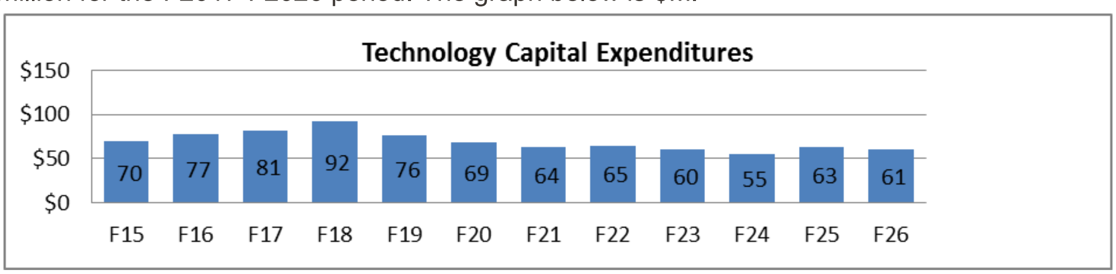
- The in-service date of Revelstoke Unit 6 was advanced to F2026, and associated work on the GIS bus was also advanced.
- Following a review of the strategy for the Mica facility, a major project to replace the Mica Units 1 to 4 generator transformers was added to the 10 year capital forecast, and the start date for the Mica Units 1 and 2 turbine overhaul project was advanced by two years to align outages at Mica.

Those projects noted above represent the significant increases in capital expenditures in the 10 year timeframe. However, a number of changes have also taken place to offset these increases:

- The Revelstoke G3 and G4 stator replacement project's construction phase was delayed to after the installation of Revelstoke Unit 6.
- The overall investment strategy for the Available Energy facilities was reviewed and a more reactive strategy was adopted to reduce the likelihood of over investment in these facilities prior to a potential future redevelopment (generally outside the 10 year window). A number of investments were delayed to later years or removed from the capital forecast (for example, significant investments in the generating units and civil assets at Falls River).
- An increased level of scrutiny was placed on the duration and timing of the larger proposed projects, as well as the portfolio as a whole. This activity more realistically reflects the likely time needed to undertake the Identification and Definition phases of the large and complex projects, and adjusted the portfolio to more accurately reflect the level of cost and schedule uncertainty associated with delivering the large portfolio over the 10 year period. As a result, the capital expenditure skewed more heavily towards the latter portion of the 10 Year Forecast, and a quantity moved outside the 10 year window entirely.

Technology

The Technology capital expenditure forecast in the Updated Forecast totals approximately $687 million for the F2017-F2026 period. The graph below is $M.



The Technology capital expenditures are designed to support BC Hydro's strategic objectives, operational effectiveness and compliance objectives. This is done by providing improved communications, automation of specific activities or processes and decision support. Strategic expenditures include information systems for supply chain, customer strategy, work management, asset management and the integration of systems and devices. Foundational expenditures include the implementation and sustainment of software platforms and applications, information technology infrastructure and telecommunications, cyber security, analytics and mobility support. Additional expenditures are to build out and maintain a portfolio of specialized business applications.

The benefits of the capital investment plan are expected to be:

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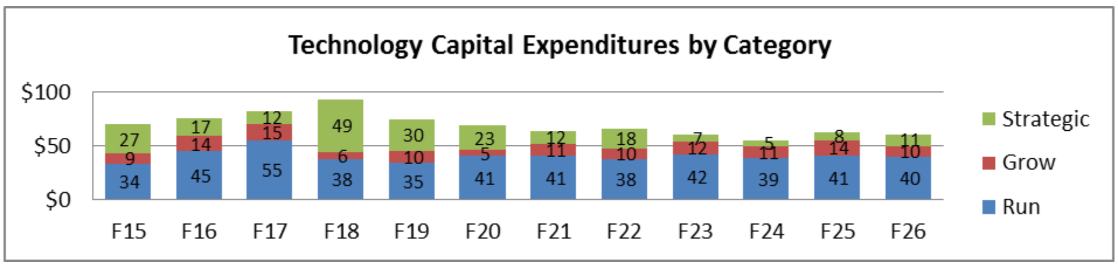
- Support for strategic objectives including supply chain and customer strategy
- Mitigation of technology risks in order to address business continuity and broader operational risks
- Greater operational efficiency through improved communication, automation and decision support
- Direct financial benefits including cost savings and avoidance, and positive revenue impacts
- Improved operating performance and flexibility through well-designed foundational technology
- Improved services to customers, work force, suppliers and stakeholders

Technology capital expenditures are separated into Run IT, Grow IT and Strategic IT categories, providing a balanced view of IT needs. The graph below is in $M.



Run projects address business changes, obsolescence, risk reduction, performance optimization and cost savings. Grow projects modernize or extend technology solutions in support of current business operations. Build projects enable new or significantly improved business capabilities typically through large scale initiatives. Run projects tend to provide operational risk mitigation with lower level of return risk, while Build projects tend to provide positive revenue or cash flow impacts at a higher level of return risk.

Key Changes from the January 2015 Update

Technology's forecast capital expenditures are $124 million lower in the July 2016 Update compared with the January 2015 Update on a rolling 10 year basis. The decrease is driven by reductions to help meet the 10 Year Rates Plan commitments.

Properties

Properties is responsible for the supply, operations and maintenance of approximately 100 headquarters and field facilities that house BC Hydro field crews and a wide range of critical functions including system operations, telecommunications, emergency operations, customer contact and security command centres that contribute to BC Hydro meeting its safety and reliability targets. These facilities must be operational for 24-7 emergency response in the worst of conditions and in many ways are similar to fire halls and police stations in the provision of critical services to BC communities and local industry. BC Hydro - owned facilities are on average 30 years old, with close to 40% of the facilities over 40 years old.

The Properties portfolio is managed through a consistent application of life-cycle asset management principles and practices. The goal of the asset management process is to balance many competing objectives including:

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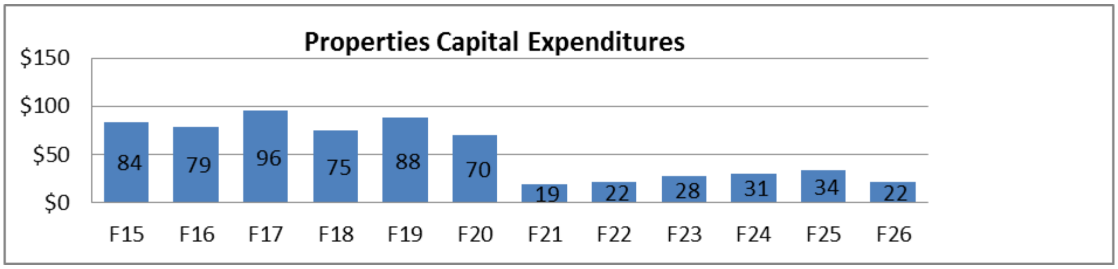
- The evolving business requirements of BC Hydro that over time change demands on the facilities;
- Operation and maintenance of assets in a manner that maximizes their useful economic life and reliability;
- Addressing operational and worker life safety risks; and
- Value-based opportunities (e.g. densification of owned office space allowing for lease consolidation).



The Properties capital expenditure forecast in the July 2016 Update totals approximately $484 million for F2017 to F2026, and aims to maintain efficient and effective operation of BC Hydro's building assets to limit costly and disruptive failures and achieve the organization's objectives through strategic capital investments in new or renovated facilities. Properties portfolio of building assets is stable and the capital forecast for the facilities portfolio is 100% sustaining capital. The total spending is distributed across the following main categories over F2017 to F2026:

- Field Building Rebuilding (54%): includes the major renovation of existing facilities and the construction of new field buildings if renovation is not an effective solution.
- Building Improvements (40%): replaces end-of-life components and building systems required to maintain facilities in a safe and functional state.
- Interior Space Renovation and other (6%): increases the density of traditional office layouts thereby decreasing BC Hydro's overall space needs, allowing for lease consolidation and generating cost savings.

The forecast of Properties capital expenditures will result in a general shift to improved conditions in all asset classes. However, buildings and individual component assets (roofs, HVAC systems, etc.) deteriorate over time and many of the assets currently in satisfactory condition will require attention / replacement over time as they age and fail. This illustrates the need to budget for investment in building assets on an ongoing basis.

Key Changes from the January 2015 Update

The Properties capital expenditure forecast for the F2017 to F2026 period is $484 million, which is approximately 17% lower than the January 2015 Update total of $576M. The most significant changes are cancellations, delays, and scope reductions in Field Building Rebuilding projects at support facilities with lower risk scores, made in consultation with key stakeholders. The forecast in later years of the July 2016 Update is based on an assumed rate of asset deterioration and will need to be revisited periodically to ensure that the correct level of reinvestment (i.e. higher or lower than anticipated) is maintained.

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Prioritization

As with the January 2015 Update, the business units used the corporate risk framework to assess and rank capital investments and applied this framework in the development of the July 2016 Update. The framework has been developed jointly by the business units to provide a standardized approach across all capital investments.

Investments in the July 2016 Update were divided into three categories:

- Mandatory investments driven by legal and regulatory requirements.
- Committed investments not to be postponed. This category includes projects that were in the implementation phase prior to F2017.
- Investments to be prioritized (including projects that were be in the Identification or Definition phase prior to F2017, and could be re-prioritized without significant economic losses). Those projects that result from the Integrated Resource Plan have not been assessed, but rather noted as an Integrated Resource Plan resource.

Investments to be prioritized were then assessed based on the primary driver of the proposed project. Per the framework:

- Capital projects that are primarily to mitigate risk are assessed using a methodology that is aligned with the BC Hydro Corporate Risk Matrix (Attachment #3),
- Capital projects that are primarily to create value are assessed using a net value per dollar invested metric. The value assessments are used mainly for some capital expenditures in Technology and a small number of Generation and Properties projects.

The analysis resulted in two independent lists that were used for discussion purposes to support the capital planning process across BC Hydro. Each element of the risk and value framework is described more fully below.

As part of the annual planning process, representatives from the different business units met to review the proposed investments in their respective capital investment portfolios to ensure the framework had been applied consistently. It is not always possible to assess every proposed capital project for prioritization per the framework and best judgement must be applied. In a small number of cases, the business units also need to discuss the characteristics of those investments to ensure assessment consistency.

The assessment methodology used in the framework is designed primarily for investments that are well defined, typically those in the near term. It is often difficult to sufficiently identify Technology projects more than 3-5 years into the future so the framework has the most value in preparing near term capital expenditure forecasts such as those impacting BC Hydro's annual 5-Year Forecast, Service Plan and revenue requirement applications.

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Prioritization Framework - Risk Dimension:

Each risk driven investment was assessed according to the framework. This involved the following steps:

- Business Groups independently assigning each investment a risk score associated with postponing the investment by three years from the current timing (delay beyond three years would result in higher risk and higher scores in most instances)
- Comparing similar investments between Business Groups (e.g. roof replacements) to ensure consistent application of the Framework
- Comparing investments with the same risk score between Business Groups to ensure comparability
- Verifying and challenging the proposed investments, including the timing of the proposed investment

Prioritization Framework - Value Dimension

The framework considers the financial value of projects which is assessed by Net present Value divided by the upfront capital investment.

The results indicate that the timing of the risk mitigation projects included in the forecast generally carry significant risks with limited opportunity to postpone expenditures past the 10 year planning period.

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Attachment #1: Capital Expenditures, Capital Additions– F2015 to F2026

Current 10 Year Capital Expenditure Forecast

Consolidated by Asset Owner

	Actuals		Forecast										F17-F26	F17-F26
ESTIMATED CAPITAL EXPENDITURES *	F15	F16	F17	F18	F19	F20	F21	F22	F23	F24	F25	F26	10 Yr Total	10 Yr Avg.
Sustaining														
Generation	414	424	522	527	418	478	400	416	525	538	544	511	$ 4,879	$ 488
Transmission	187	235	256	326	374	348	289	245	288	348	381	442	$ 3,297	$ 330
Distribution	157	230	206	178	203	228	228	243	230	234	186	168	$ 2,104	$ 210
Support Services - Technology	70	77	81	92	76	69	64	65	60	55	63	61	$ 687	$ 69
Support Services - Properties	84	79	96	75	88	70	19	22	28	31	34	22	$ 484	$ 48
Support Services - Other & Powerex/Powertech[1]	92	100	46	46	41	38	43	43	45	45	50	60	$ 457	$ 46
Subtotal - Sustaining	1,004	1,146	$ 1,207	$ 1,245	$ 1,200	$ 1,233	$ 1,042	$ 1,033	$ 1,176	$ 1,252	$ 1,257	$ 1,263	$ 11,907	$ 1,191
Growth														
Generation	108	61	20	2	1	2	7	29	120	147	141	79	$ 549	$ 55
Generation - Site C Clean Energy	25	489	743	717	829	1,258	1,136	1,020	833	529	39	0	$ 7,103	$ 710
Transmission	824	382	417	222	193	266	251	230	184	277	249	119	$ 2,408	$ 241
Distribution	207	225	225	233	209	200	206	200	211	223	330	386	$ 2,423	$ 242
Support Services (Powertech)	3	2	2	2	2	2	2	3	3	3	4	4	$ 28	$ 3
Subtotal - Growth	1,166	1,160	$ 1,406	$ 1,177	$ 1,234	$ 1,729	$ 1,603	$ 1,480	$ 1,352	$ 1,179	$ 763	$ 588	$ 12,511	$ 1,251
Total before Contribution In Aid (CIA)	2,170	2,306	2,613	2,421	2,434	2,961	2,646	2,513	2,527	2,431	2,020	1,852	$ 24,418	$ 2,442
Transmission - Sustaining	(4)	(4)	(3)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	$ (38)	$ (4)
Transmission - Growth	(240)	(15)	(6)	(18)	(23)	(30)	(8)	-	-	-	-	-	$ (85)	$ (8)
Distribution - Sustaining	(1)	(3)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	$ (11)	$ (1)
Distribution - Growth	(89)	(111)	(76)	(77)	(79)	(81)	(84)	(87)	(89)	(91)	(94)	(97)	$ (855)	$ (85)
CIA Total	(334)	(134)	(86)	(100)	(106)	(116)	(96)	(91)	(94)	(97)	(99)	(102)	$ (989)	$ (99)
Total ($M)	**1,836**	**2,172**	**$ 2,527**	**$ 2,321**	**$ 2,328**	**$ 2,845**	**$ 2,549**	**$ 2,422**	**$ 2,433**	**$ 2,334**	**$ 1,920**	**$ 1,749**	**$ 23,429**	**$ 2,343**

	Actuals		Forecast										F17-F26	F17-F26
ESTIMATED CAPITAL ADDITIONS *	F15	F16	F17	F18	F19	F20	F21	F22	F23	F24	F25	F26	10 Yr Total	10 Yr Avg.
Generation	473	524	505	380	1,328	542	471	257	200	498	1,156	924	$ 6,261	$ 626
Generation - Site C Clean Energy	-	-	-	-	-	-	165	24	284	6,828	315	-	$ 7,617	$ 762
Transmission	1,128	1,537	647	448	459	491	477	761	505	337	1,037	650	$ 5,812	$ 581
Distribution	356	386	394	417	426	430	432	449	444	457	485	535	$ 4,471	$ 447
Support Services - Technology	56	73	79	90	110	67	69	65	60	55	63	61	$ 719	$ 72
Support Services - Properties	84	76	68	118	25	167	19	19	19	19	55	25	$ 534	$ 53
Support Services - Other & Powerex/Powertech[1]	67	193	54	45	49	42	43	45	47	48	51	53	$ 477	$ 48
Total before CIA	2,164	2,788	$ 1,747	$ 1,499	$ 2,397	$ 1,738	$ 1,676	$ 1,621	$ 1,560	$ 8,243	$ 3,163	$ 2,247	$ 25,891	$ 2,589
CIA	(334)	(111)	(90)	(88)	(84)	(86)	(164)	(91)	(94)	(96)	(99)	(102)	$ (995)	$ (100)
Total ($M)	**1,830**	**2,678**	**$ 1,657**	**$ 1,411**	**$ 2,313**	**$ 1,652**	**$ 1,512**	**$ 1,529**	**$ 1,466**	**$ 8,146**	**$ 3,063**	**$ 2,145**	**$ 24,896**	**$ 2,490**

* 'Capital Expenditures' are recorded when the costs are incurred. 'Capital Additions' refer to when the related asset is placed into service. Certain costs impacting BC Hydro's revenue requirements, such as amortization, return-on-equity, and finance charges, are not recorded until the related asset is placed into service.

[1] For ease of presentation, the Smart Meter Initiative (completed in F2016) has been captured within the Support Services Asset Group

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Board briefing - BC Hydro 10 Year Capital Forecast Update (July 2016)

Current 10 Year Capital Expenditure Forecast

Consolidated by Business Function

ESTIMATED CAPITAL EXPENDITURES *	Actuals F15	Actuals F16	Forecast F17	F18	F19	F20	F21	F22	F23	F24	F25	F26	F17-F26 10 Yr Total	F17-F26 10 Yr Avg.
Sustaining														
Generation	418	437	530	534	424	485	404	419	529	544	550	515	4,935	494
Transmission	194	235	256	326	374	348	289	245	288	348	381	442	3,297	330
Distribution	139	193	185	160	188	209	212	226	218	220	164	149	1,932	193
Support Services	254	281	236	224	214	190	138	142	141	139	162	157	1,743	174
Subtotal - Sustaining	1,004	1,146	1,207	1,245	1,200	1,233	1,042	1,033	1,176	1,252	1,257	1,263	11,907	1,191
Growth														
Generation	108	61	20	2	1	2	7	29	120	147	141	79	549	55
Generation - Site C Clean Energy	25	489	743	717	829	1,258	1,136	1,020	833	529	39	-	7,103	710
Transmission	822	383	417	222	193	266	251	230	184	277	249	119	2,408	241
Distribution	207	225	225	233	209	200	206	200	211	223	330	386	2,423	242
Support Services	3	2	2	2	2	2	2	3	3	3	4	4	28	3
Subtotal - Growth	1,166	1,160	1,406	1,177	1,234	1,729	1,603	1,480	1,352	1,179	763	588	12,511	1,251
Total before Contribution In Aid (CIA)	2,170	2,306	2,613	2,421	2,434	2,961	2,646	2,513	2,527	2,431	2,020	1,852	24,418	2,442
Generation - Sustaining	0	(0)	-	-	-	-	-	-	-	-	-	-	-	-
Generation - Growth	(1)	(1)	-	-	-	-	-	-	-	-	-	-	-	-
Transmission - Sustaining	(4)	(4)	(3)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(38)	(4)
Transmission - Growth	(240)	(15)	(6)	(18)	(23)	(30)	(8)	-	-	-	-	-	(85)	(8)
Distribution - Sustaining	(1)	(2)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(11)	(1)
Distribution - Growth	(88)	(111)	(76)	(77)	(79)	(81)	(84)	(87)	(89)	(91)	(94)	(97)	(855)	(85)
CIA Total	(334)	(134)	(86)	(100)	(106)	(116)	(96)	(91)	(94)	(97)	(99)	(102)	(989)	(99)
Total ($M)	**1,836**	**2,172**	**2,527**	**2,321**	**2,328**	**2,845**	**2,549**	**2,422**	**2,433**	**2,334**	**1,920**	**1,749**	**23,429**	**2,343**

ESTIMATED CAPITAL ADDITIONS *	Actuals F15	Actuals F16	Forecast F17	F18	F19	F20	F21	F22	F23	F24	F25	F26	F17-F26 10 Yr Total	F17-F26 10 Yr Avg.
Generation	483	535	513	387	1,332	545	482	260	204	504	1,162	929	6,319	632
Generation - Site C Clean Energy	-	-	-	-	-	-	165	24	284	6,828	315	-	7,617	762
Transmission	1,128	1,506	647	448	459	491	477	761	505	337	1,037	650	5,812	581
Distribution	351	412	372	399	413	415	409	433	431	443	465	516	4,297	430
Support Services	202	336	215	265	193	287	143	142	135	131	183	152	1,845	185
Total before CIA	2,164	2,788	1,747	1,499	2,397	1,738	1,676	1,621	1,560	8,243	3,163	2,247	25,891	2,589
CIA	(334)	(111)	(90)	(88)	(84)	(86)	(164)	(91)	(94)	(96)	(99)	(102)	(995)	(100)
Total ($M)	**1,830**	**2,678**	**1,657**	**1,411**	**2,313**	**1,652**	**1,512**	**1,529**	**1,466**	**8,146**	**3,063**	**2,145**	**24,896**	**2,490**

* 'Capital Expenditures' are recorded when the costs are incurred. 'Capital Additions' refer to when the related asset is placed into service. Certain costs impacting BC Hydro's revenue requirements, such as amortization, return-on-equity, and finance charges, are not recorded until the related asset is placed into service.

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Attachment #2 - Capital Expenditures for Projects Greater than $50M – F2017 to F2026

Projects > $50M with Capital Expenditures Forecasted during F2017 - F2026 ($ millions)

Asset Owner	Project	Type	Phase	Forecast ISD	Authorized Amount / Engineering Estimate
Generation	Cheakamus Units 1 and 2 Generator Replacement	Sustaining	Implementation	F2020	$73
Generation	John Hart Generating Station Replacement	Sustaining	Implementation	F2019	$1,093
Generation	Ruskin Dam Safety and Powerhouse Upgrade	Sustaining	Implementation	F2018	$748
Generation	Site C Clean Energy	Growth	Implementation	F2025	$8,335
Generation	Bridge River 2 Upgrade Units 5 and 6	Sustaining	Definition	F2019	$83 - $53
Generation	G.M. Shrum G1 to 10 Control System Upgrade	Sustaining	Definition	F2022	$77 - $58
Generation	Revelstoke Unit 6 Installation	Growth	Definition	F2026	$591 - $328
Generation	W.A.C. Bennett Dam Rip-Rap Upgrade	Sustaining	Definition	F2020	$170 - $109
Generation	Bridge River 2 Upgrade Units 7 and 8	Sustaining	Identification	TBD	TBD
Generation	Clowhom Rehabilitate Generating Station	Sustaining	Identification	TBD	TBD
Generation	John Hart Dam Seismic Upgrade	Sustaining	Identification	TBD	TBD
Generation	Ladore Spillway Seismic Upgrade	Sustaining	Identification	TBD	TBD
Generation	Strathcona Upgrade Dam Spillway	Sustaining	Identification	TBD	TBD
Generation	Strathcona Upgrade Discharge	Sustaining	Identification	TBD	TBD
Generation	G.M. Shrum Unit 1 to 5 Capacity Increase	Growth	Future	TBD	TBD
Generation	G.M. Shrum Units 9 and 10 Turbine Overhaul	Sustaining	Future	TBD	TBD
Generation	Kootenay Canal Refurbish Units 1 to 4 Generators	Sustaining	Future	TBD	TBD
Generation	La Joie Dam Improvements	Sustaining	Future	TBD	TBD
Generation	Mica Discharge Facilities Seismic and Reliability Upgrades	Sustaining	Future	TBD	TBD
Generation	Mica Overhaul Unit 1 and 2 Turbines	Sustaining	Future	TBD	TBD
Generation	Mica Overhaul Unit 3 and 4 Turbines	Sustaining	Future	TBD	TBD
Generation	Mica Replace Units 1 to 4 Circuit Breakers and Isobus	Sustaining	Future	TBD	TBD
Generation	Mica Replace Units 1 to 4 Generator Transformers	Sustaining	Future	TBD	TBD
Generation	Peace Canyon Dam Seismic Upgrade	Sustaining	Future	TBD	TBD
Generation	Revelstoke Addition of 3rd Gas Insulated Switchgear Bus	Growth	Future	TBD	TBD
Generation	Revelstoke Replace Units 1 to 4 Transformers	Sustaining	Future	TBD	TBD
Generation	Revelstoke Replace Units 3 and 4 Stators	Sustaining	Future	TBD	TBD
Generation	Seven Mile Overhaul Units 1 to 3 Turbines	Sustaining	Future	TBD	TBD
Generation	Strathcona Dam Improvements (New Powerhouse)	Sustaining	Future	TBD	TBD
Generation	Terzaghi Improve Lower Level Outlet Gate Reliability and Ground Densification	Sustaining	Future	TBD	TBD
Transmission and Distribution	Big Bend Substation	Growth	Implementation	F2018	$67
Transmission and Distribution	Horne Payne Substation Upgrade	Growth	Implementation	F2019	$93
Transmission and Distribution	Fort St. John and Taylor Electric Supply	Growth	Implementation	F2020	$53
Transmission and Distribution	Northwest Substation Upgrades	Growth	Definition	F2021	$113 -$64
Transmission and Distribution	Terrace to Kitimat Transmission	Sustaining	Definition	F2020	$177 - $100
Transmission and Distribution	Metro North Transmission	Growth	Identification	TBD	TBD
Transmission and Distribution	West Kelowna Transmission Project	Growth	Identification	TBD	TBD
Transmission and Distribution	Peace Region Electric Supply	Growth	Identification	TBD	TBD
Transmission and Distribution	Mainwaring Substation Upgrade	Sustaining	Identification	TBD	TBD
Transmission and Distribution	Capilano Substation 25Kv Conversion	Growth	Identification	TBD	TBD
Transmission and Distribution	Downtown Vancouver Electricity Supply: Property Purchases	Growth	Identification	TBD	TBD
Transmission and Distribution	Newell Station Upgrade	Sustaining	Future	TBD	TBD
Transmission and Distribution	West End Substation Construction	Growth	Future	TBD	TBD
Transmission and Distribution	Peace Region to Kelly Lake 500kV Transmission Reinforcement	Growth	Future	TBD	TBD
Transmission and Distribution	Lougheed Substation Upgrade	Growth	Future	TBD	TBD
Transmission and Distribution	Horne Payne Station Upgrade	Sustaining	Future	TBD	TBD
Transmission and Distribution	Nicola to Vaseux Lake Connection	Growth	Future	TBD	TBD
Transmission and Distribution	New Murrin Substation Construction	Growth	Future	TBD	TBD
Technology	Supply Chain Applications	Sustaining	Definition	F2019	$71 - $58

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Attachment #3
BC Hydro Corporate Risk Matrix

BC Hydro CAPITAL ALLOCATION Risk Matrix

FREQUENCY (YEARLY)	FREQUENCY OF CONSEQUENCE												
f ≥ 100	At least 100 times every year	L9	10		11		12		13		14	15	16
10 ≤ f < 100	At least 10 times every year	L8	9		10		11		12		13	14	15
1 ≤ f < 10	At least once every year	L7	8		9		10		11		12	13	14
1/3 ≤ f < 1	At least once every 3 years	L6.5	7.5	8.0	8.5	9.0	9.5	10.0	10.5	11.0	11	12	13
1/10 ≤ f < 1/3	At least once every 10 years	L6	7.0	7.5	8.0	8.5	9.0	9.5	10.0	10.5			
1/30 ≤ f < 1/10	At least once every 30 years	L5.5	6.5	7.0	7.5	8.0	8.5	9.0	9.5	10.0	10	11	12
1/100 ≤ f < 1/30	At least once every 100 years	L5	6.0	6.5	7.0	7.5	8.0	8.5	9.0	9.5			
1/300 ≤ f < 1/100	At least once every 300 years	L4.5	5.5	6.0	6.5	7.0	7.5	8.0	8.5	9.0	9	10	11
1/1K ≤ f < 1/300	At least once every 1,000 years	L4	5.0	5.5	6.0	6.5	7.0	7.5	8.0	8.5			
1/3K ≤ f < 1/1K	At least once every 3,000 years	L3.5	4.5	5.0	5.5	6.0	6.5	7.0	7.5	8.0	8	9	10
1/10K ≤ f < 1/3K	At least once every 10,000 years	L3	4.0	4.5	5.0	5.5	6.0	6.5	7.0	7.5			
1/100K ≤ f < 1/10K	At least once every 100,000 years	L2	3		4		5		6		7	8	9
1/1M ≤ f < 1/100K	At least once every 1,000,000 years	L1	2		3		4		5		6	7	8

CONSEQUENCE TYPE		CONSEQUENCE SEVERITY										
		S1	S1.5	S2	S2.5	S3	S3.5	S4	S4.5	S5	S6	S7
Safety	Worker	First Aid		Treatment by Medical Professional		Temporary Disability		Permanent Disability		Fatality	Multiple Fatalities	
Safety	Public	Near Miss		First Aid		Treatment by Medical Professional		Temporary Disability		Permanent Disability	Fatality	Multiple Fatalities
Environmental *		Low impact		Moderate impact		Moderate to High impact		High impact		Very high impact	Extreme impact	
Financial Loss		$10K to $30K	$30K to $100K	$100K to $300K	$300K to $1M	$1M to $3M	$3M to $10M	$10M to $30M	$30M to $100M	$100M to $1B	$1B to $10B	> $10B
Reputational *		Limited complaints to company or shareholder		Negative local profile		Small but vocal minority of customers critical		Many customers critical		Loss of trust- strategic change imposed by regulator and/or shareholder	Loss of consent to operate	
Reliability	Supply	N/A		N/A		Require voluntary load reduction		Localized load shedding		Significant load shedding required	BC load shedding spreads to WECC	
Reliability	Customer (hours lost per event)	< 1.5K	1.5K to 5K	5K to 15K	15K to 50K	50K to 150K	150K to 500K	500K to 1.5M	1.5M to 5M	5M to 50M	50M to 500M	> 500M

Risk Zone	Risk Communication Guidelines
3) Executive	Detailed analysis and discussion within business group at EVP or SVP level. Input from Executive Team generally should be sought.
2) Senior Managers	Analysis and discussion within business unit, with decision making at Senior Manager level. Consider seeking input from EVP or SVP.
1) Managers	Risk generally analysed and discussed within business group, with decision making at Manager level.

Purpose of the Risk Matrix

1. To provide a standard representation of the results of risk analyses for use in the evaluation and communication of risks.

2. As a risk governance tool. The Risk Zone relates to the level of management discussion to aid in decision-making.

3. Not used to describe risk tolerance.

4. A comparison of differing risks may also be conducted based on the Risk Levels.

To use the Risk Matrix

1. Select the Consequence Type.

2. Select the highest appropriate Consequence Severity.

3. Select the Frequency level of the Consequence Type and Severity.

4. Plot the Consequence severity and Frequency level pair to determine the Risk Level and associated Risk Zone.

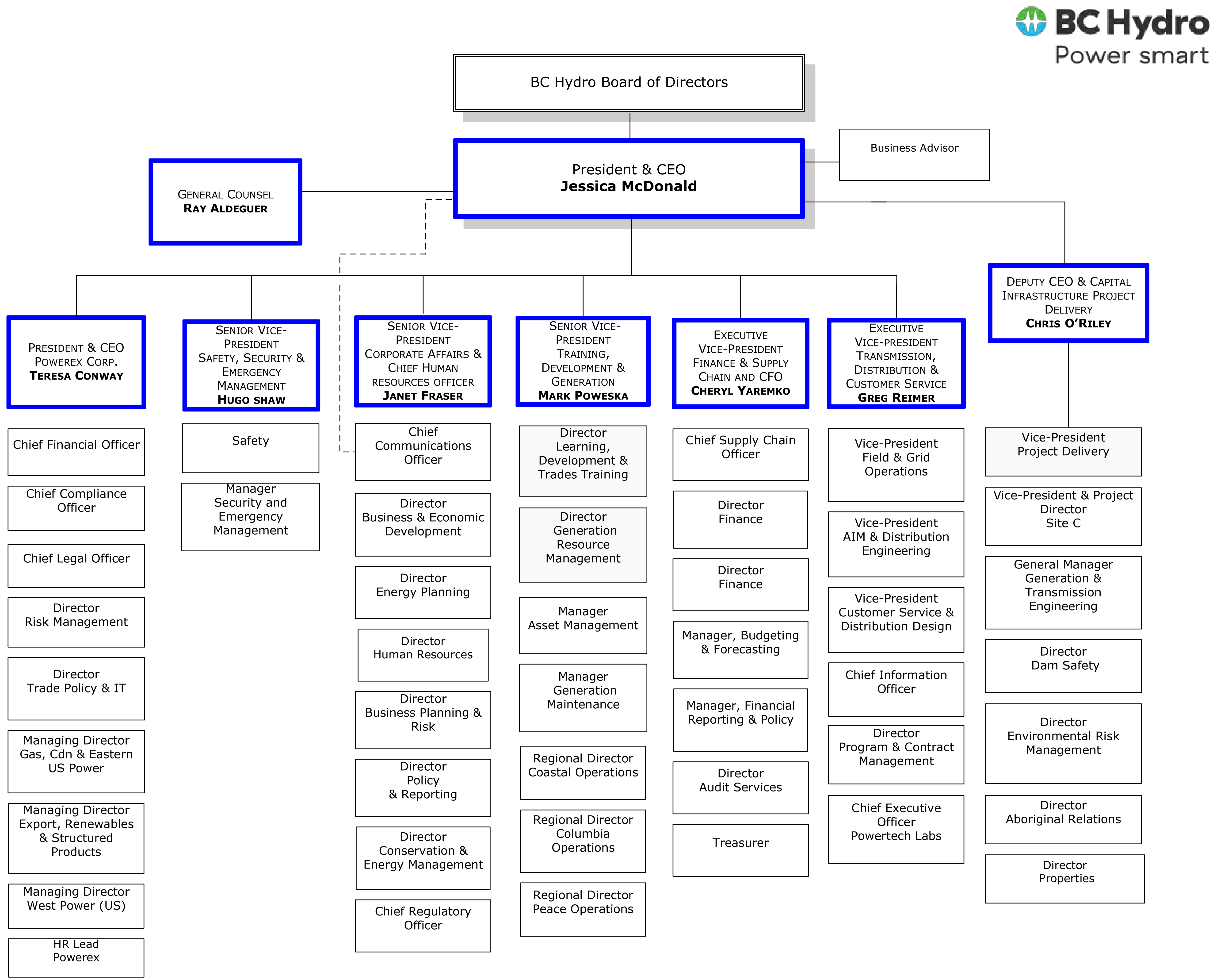
5. Based on the Risk Zone, review Risk Communication Guidelines to determine action.

NOTE: The rigour of analysis in analyzing consequence and frequency should be commensurate with the Risk Zone. This may be an iterative process.

Fiscal 2017 to Fiscal 2019
Revenue Requirements Application

Appendix H

BC Hydro Organizational Chart



January 29, 2016

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Fiscal 2017 to Fiscal 2019
Revenue Requirements Application

Appendix I

Capital Expenditures
Greater than $5 million

Alphabetical Cross Index for Appendix I and J		
Project Name	Reference	
	Appendix I (Line Number)	Appendix J (Page Number)
Hydroelectric		
Growth		
Revelstoke Install Unit 6	1	Page 1
Redevelopment		
John Hart Generating Station Replacement	2	Page 2
Ruskin Dam Safety and Powerhouse Upgrade	3	Page 4
Clowhom Rehabilitate Generating Station	4	Page 7
Dam Safety		
W.A.C. Bennett Dam Spillway Chute Rehabilitation	6	Page 9
Peace Canyon Flood Discharge Gates Reliability Improvement	8	Page 10
W.A.C. Bennett Dam Rip-Rap Upgrade	9	Page 11
W.A.C. Bennett Dam Spillway Gate Upgrade	10	Page 12
John Hart Dam Seismic Upgrade	13	Page 13
Ladore Spillway Seismic Upgrade	14	Page 15
Puntledge Flow Control Improvements	15	Page 16
Strathcona Upgrade Discharge	17	Page 17
W.A.C. Bennett Dam Seal Low Level Outlets	24	Page 18
Bridge River 1 Replace Transformers T1 and T2	25	Page 19
Sustaining		
Cheakamus Units 1 and 2 Generator Replacement	28	Page 20
Bridge River 2 Upgrade Units 5 and 6	34	Page 22
G.M. Shrum G1-10 Control System Upgrade	35	Page 24
Lake Buntzen 1 Coquitlam Tunnel Gates Refurbishment	39	Page 26
Bridge River 1 Upgrade Unit 4 Generator and Governor	43	Page 28
Bridge River 2 Upgrade Units 7 and 8	44	Page 29
Cheakamus Recoat Units 1 and 2 Penstocks (Interior and Exterior)	45	Page 30
Mica Modernize Controls	52	Page 31
Mica Upgrade Powerhouse Cranes	57	Page 32
Puntledge Recoat Interior and Exterior of Steel Penstock	59	Page 33
Mica Replace Units 1 to 4 Generator Transformers	67	Page 34
Seven Mile Overhaul Units 1 to 3 Turbines	69	Page 35

Alphabetical Cross Index for Appendix I and J		
Project Name	**Reference**	
	Appendix I (Line Number)	**Appendix J (Page Number)**
Mainwaring Substation Upgrade	43	Page 69
Esquimalt Feeder Section Replacement	44	Page 70
5L63 Telkwa Relocations	45	Page 71
Barnard 50/60 Feeder Section Replacement	46	Page 72
NERC CIP V5 Compliance at Medium Impact T&D Stations	47	Page 73
Newell Substation Upgrade	49	Page 74
Business-Driven Expenditures		
Sustaining		
Supply Chain Applications	2	Page 75
Properties		
Sustaining		
Vernon – Field Building	5	Page 76
Victoria - Field Building	6	Page 78
Construction Services/Lower Mainland Transmission Building	9	Page 80
Material Classification Facility	11	Page 82
Chilliwack – Field Building	15	Page 84
Site C Clean Energy Project	22	Page 86

Appendix I - Generation
Projects and Programs greater than $5 million with Capital Expenditures in the Test Period and/or Capital Additions in the Test Period (F17, F18, F19) as at March 31, 2016 (1), (2)
$ Million

A	B	C	D	E	F	H	I	J	K	L	M	N	O	P	Q	R	S
#	Name of Project	Growth or Sustaining Expenditure	Current Development Stage (3)	Current Forecast ISD (4)	Current Start Date of Construction (5)	Definition Approval Date (6)	Implementation Approval $ (7)	Implementation Approval ISD (10)	Current Pre-Implementation Cost Estimate (8)	Current Authorized Amount (9)	Capital Addition Actuals Prior Years	Capital Addition Forecast F17	Capital Addition Forecast F18	Capital Addition Forecast F19	Capital Addition Forecast >F19	Total Capital Additions (sum of columns M to Q)	Appendix J Reference
HYDROELECTRIC																	
1	Revelstoke Install Unit 6	4 - Growth	3 - Definition	F2026	F2022	F2014			591 to 328		-	-	-	-	437.7	437.7	Page 1
2	John Hart Generating Station Replacement	3 - Redevelopment	4 - Implementation	F2019	F2014	F2008	1,092.9	F2019		1,092.9	1.0	-	-	955.5	63.4	1,019.9	Page 2
3	Ruskin Dam Safety and Powerhouse Upgrade	3 - Redevelopment	4 - Implementation	F2018	F2011	F2009	846.6	F2018		747.7	126.2	304.0	184.4	-	-	614.6	Page 4
4	Clowhom Rehabilitate Generating Station	3 - Redevelopment	2 - Identification	TBD		TBD			TBD		-	-	-	-	90.9	90.9	Page 7
5	Jordan River Mitigate Diversion Dam Seismic Risks	2 - Dam Safety	4 - Implementation	F2017	F2015	N/A	18.4	F2017		18.4	1.0	11.7	0.0	-	-	12.8	
6	W.A.C. Bennett Dam Spillway Chute Rehabilitation	2 - Dam Safety	4 - Implementation	F2017	F2014	F2013	27.2	F2016		27.2	6.3	14.9	1.1	-	-	22.4	Page 9
7	Bridge River 1 Install Penstock Leak Detection and Protection	2 - Dam Safety	3 - Definition	F2018	Various	F2016			10.0 to 6.7		0.0	6.0	0.1	-	-	6.2	
8	Peace Canyon Flood Discharge Gates Reliability Improvement	2 - Dam Safety	3 - Definition	F2020	Jan-2017	F2013			42.5 to 21.7		-	-	-	13.0	13.0	26.0	Page 10
9	W.A.C. Bennett Dam Rip-Rap Upgrade	2 - Dam Safety	3 - Definition	F2020	Jun-2016	F2015			170.4 to 108.7		-	-	49.6	49.6	39.5	138.7	Page 11
10	W.A.C. Bennett Dam Spillway Gate Upgrade	2 - Dam Safety	3 - Definition	F2020	Nov-2016	F2013			35.9 to 20.3		-	-	-	11.8	17.7	29.5	Page 12
11	Alouette Improve Headworks & Surge Tower Seismic Stability	2 - Dam Safety	2 - Identification	TBD	TBD	TBD			TBD		-	-	-	-	10.0	10.0	
12	Bridge River 1 Improve Slope Drainage	2 - Dam Safety	2 - Identification	TBD	TBD	F2016			TBD		-	-	14.3	-	-	14.3	
13	John Hart Dam Seismic Upgrade	2 - Dam Safety	2 - Identification	TBD	TBD	TBD			TBD		-	-	-	-	408.2	408.2	Page 13
14	Ladore Spillway Seismic Upgrade	2 - Dam Safety	2 - Identification	TBD	TBD	TBD			TBD		-	-	-	-	52.9	52.9	Page 15
15	Puntledge Flow Control Improvements	2 - Dam Safety	2 - Identification	TBD	TBD	TBD			TBD		-	-	-	-	28.8	28.8	Page 16
16	Revelstoke Improve Left Bank Slope Stability	2 - Dam Safety	2 - Identification	TBD	TBD	TBD			TBD		-	-	-	5.9	-	5.9	
17	Strathcona Upgrade Discharge	2 - Dam Safety	2 - Identification	TBD	TBD	TBD			TBD		-	-	-	-	220.2	220.2	Page 17
18	Wahleach Replace Tailrace Culvert	2 - Dam Safety	2 - Identification	TBD	TBD	TBD			TBD		-	-	-	-	5.4	5.4	
19	Duncan Dam Replace Spillway Gates	2 - Dam Safety	1 - Future	TBD	TBD	TBD			TBD		-	-	-	-	19.4	19.4	
20	Mica Rehabilitate Vertical Movement Gauges	2 - Dam Safety	1 - Future	TBD	TBD	TBD			TBD		-	-	-	-	6.7	6.7	
21	Peace Canyon Install Piezometers and Drains in Concrete Dam	2 - Dam Safety	1 - Future	TBD	TBD	TBD			TBD		-	-	-	-	6.0	6.0	
22	Revelstoke Replace Downie Slide Instrumentation	2 - Dam Safety	1 - Future	TBD	TBD	TBD			TBD		-	-	-	-	7.4	7.4	
23	W.A.C. Bennett Dam Recommission / Seal Spillway Sluice Gates	2 - Dam Safety	1 - Future	TBD	TBD	TBD			TBD		-	-	-	-	12.4	12.4	
24	W.A.C. Bennett Dam Seal Low Level Outlets	2 - Dam Safety	1 - Future	TBD	TBD	TBD			TBD		-	-	-	-	24.1	24.1	Page 18
25	Bridge River 1 Replace Transformers T1 and T2	1 - Sustaining	4 - Implementation	F2018	F2016	F2014	45.1	F2018		45.1	-	-	33.2	4.3	0.0	37.6	Page 19
26	Bridge River 1 Replace Unit Circuit Breakers	1 - Sustaining	4 - Implementation	F2018	F2016	F2015	17.1	F2018		17.1	-	-	13.2	0.5	-	13.6	
27	Cheakamus Replace Units 1 and 2 Turbine Inlet Valves	1 - Sustaining	4 - Implementation	F2020	F2015	F2014	10.7	F2020		10.7	-	-	-	-	8.3	8.3	
28	Cheakamus Units 1 and 2 Generator Replacement	1 - Sustaining	4 - Implementation	F2020	F2015	F2013	73.4	F2020		73.4	-	-	-	34.2	24.6	58.8	Page 20
29	Cheakamus Upgrrade Fire Protection	1 - Sustaining	4 - Implementation	F2017	F2015	F2014	7.3	F2016		7.3	0.2	7.1	-	-	-	7.3	
30	G.M. Shrum Town Of Peace River Groundwater Management	1 - Sustaining	4 - Implementation	F2017	F2015	F2014	6.5	F2016		6.5	-	5.7	-	-	-	5.7	
31	G.M. Shrum Transformer Replacement (Phase 3)	1 - Sustaining	4 - Implementation	F2018	F2013	F2013	13.1	F2016		13.1	7.3	-	3.2	0.6	-	11.1	
32	Puntledge Improve Water Level Gauges & Public Safety Warning System	1 - Sustaining	4 - Implementation	F2017	F2015	F2015	9.0	F2017		9.0	-	7.0	0.4	-	-	7.4	
33	Revelstoke Upgrade Powerhouse Crane	1 - Sustaining	4 - Implementation	F2017	F2014	F2014	9.0	F2015		9.0	-	6.5	-	-	-	6.5	
34	Bridge River 2 Upgrade Units 5 and 6	1 - Sustaining	3 - Definition	F2019	F2018	F2016			83.3 to 52.5		-	-	-	52.2	4.5	56.7	Page 22
35	G.M. Shrum G1 to 10 Control System Upgrade	1 - Sustaining	3 - Definition	F2022	Various	F2016			77.2 to 58.4		3.2	4.1	10.1	13.9	32.5	63.9	Page 24
36	G.M. Shrum Upgrade HVAC System	1 - Sustaining	3 - Definition	F2020	F2018	F2016			19.9 to 10.9		-	-	-	-	14.9	14.9	
37	Kootenay Canal Upgrade Unit Protection and Install Sequence of Events Recorder	1 - Sustaining	3 - Definition	F2020	Aug-2016	F2016			11.3 to 5.8		-	-	1.6	3.1	1.6	6.3	
38	Ladore Install Powerhouse and Tailrace Crane	1 - Sustaining	3 - Definition	F2018	Jan-2017	F2016			14.1 to 8.1		-	-	8.7	-	-	8.7	
39	Lake Buntzen 1 Coquitlam Tunnel Gates Refurbishment	1 - Sustaining	3 - Definition	F2022	F2019	F2016			48.6 to 20.8		-	-	-	-	30.0	30.0	Page 26
40	Mica Upgrade 600V Circuit Breakers	1 - Sustaining	3 - Definition	F2019	F2018	F2016			14.5 to 8.8		-	-	-	9.4	-	9.4	
41	Peace Canyon Unit 1 to 4 Unit Protection Upgrade	1 - Sustaining	3 - Definition	F2020	Feb-2017	F2016			7.6 to 4.2		-	-	-	-	5.1	5.1	
42	Wahleach Reduce Fire Risk - Phase 2	1 - Sustaining	3 - Definition	F2018	May-2016	F2015			9.0 to 7.2		-	-	7.5	0.7	0.6	8.8	
43	Bridge River 1 Upgrade Unit 4 Generator and Governor	1 - Sustaining	2 - Identification	TBD	TBD	TBD			TBD		-	-	-	-	35.6	35.6	Page 28
44	Bridge River 2 Upgrade Units 7 and 8	1 - Sustaining	2 - Identification	TBD	TBD	TBD			TBD		-	-	-	-	53.7	53.7	Page 29
45	Cheakamus Recoat Units 1 and 2 Penstocks (Interior and Exterior)	1 - Sustaining	2 - Identification	TBD	TBD	TBD			TBD		-	-	-	-	32.4	32.4	Page 30
46	G.M. Shrum Recoat Draft Tube Maintenance Gates	1 - Sustaining	2 - Identification	TBD	TBD	TBD			TBD		-	-	-	-	5.1	5.1	
47	G.M. Shrum Replace / Refurbish 500KV Disconnect Switches	1 - Sustaining	2 - Identification	TBD	TBD	TBD			TBD		-	-	-	-	6.6	6.6	
48	G.M. Shrum Replace Unit 1-5 Exciter Transformers	1 - Sustaining	2 - Identification	TBD	TBD	TBD			TBD		-	-	-	-	6.9	6.9	
49	Hugh Keenleyside Replace Service Water Piping	1 - Sustaining	2 - Identification	TBD	TBD	TBD			TBD		-	-	-	5.0	-	5.0	
50	Jordan River Reduce Fire Risk - Phase 2	1 - Sustaining	2 - Identification	TBD	TBD	TBD			TBD		-	-	-	6.1	-	6.1	
51	Key Facilities 600V Breaker Replacement Program	1 - Sustaining	2 - Identification	TBD	TBD	TBD			TBD		-	-	-	5.9	8.0	13.9	
52	Mica Modernize Controls	1 - Sustaining	2 - Identification	TBD	TBD	TBD			TBD		-	-	-	-	40.5	40.5	Page 31
53	Mica Replace Fire Alarm System	1 - Sustaining	2 - Identification	TBD	TBD	TBD			TBD		-	-	-	-	13.6	13.6	
54	Mica Townsite Augment Accommodations Capacity	1 - Sustaining	2 - Identification	TBD	TBD	TBD			TBD		-	-	-	-	19.5	19.5	
55	Mica Townsite Replace Recreation Centre Roof	1 - Sustaining	2 - Identification	TBD	TBD	TBD			TBD		-	-	-	5.4	-	5.4	
56	Mica Upgrade HVAC System	1 - Sustaining	2 - Identification	TBD	TBD	TBD			TBD		-	-	-	-	7.6	7.6	
57	Mica Upgrade Powerhouse Cranes	1 - Sustaining	2 - Identification	TBD	TBD	TBD			TBD		-	-	-	-	24.6	24.6	Page 32
58	Peace Canyon Upgrade HVAC System	1 - Sustaining	2 - Identification	TBD	TBD	TBD			TBD		-	-	-	-	6.2	6.2	
59	Puntledge Recoat Interior and Exterior of Steel Penstock	1 - Sustaining	2 - Identification	TBD	TBD	TBD			TBD		-	-	-	23.0	15.5	38.5	Page 33
60	Wahleach Recoat Penstock (Interior and Exterior)	1 - Sustaining	2 - Identification	TBD	TBD	TBD			TBD		-	-	-	-	19.5	19.5	
61	Ash River Extend Life of Steel Penstock	1 - Sustaining	1 - Future	TBD	TBD	TBD			TBD		-	-	-	-	5.4	5.4	
62	Bridge River 2 Strip and Recoat Penstock 1 Interior	1 - Sustaining	1 - Future	TBD	TBD	TBD			TBD		-	-	-	15.4	1.2	16.6	
63	Hugh Keenleyside Recoat Navlock Gates	1 - Sustaining	1 - Future	TBD	TBD	TBD			TBD		-	-	-	1.4	7.9	9.3	
64	Kootenay Canal Upgrade Powerhouse Crane	1 - Sustaining	1 - Future	TBD	TBD	TBD			TBD		-	-	-	15.3	-	15.3	
65	Ladore Upgrade Protection and Control Systems	1 - Sustaining	1 - Future	TBD	TBD	TBD			TBD		-	-	-	-	7.2	7.2	
66	Mica Replace Units 1 to 4 Fire and Cooling Water Piping	1 - Sustaining	1 - Future	TBD	TBD	TBD			TBD		-	-	-	-	10.1	10.1	
67	Mica Replace Units 1 to 4 Generator Transformers	1 - Sustaining	1 - Future	TBD	TBD	TBD			TBD		-	-	-	-	61.8	61.8	Page 34
68	Revelstoke Replace Fire Alarm System	1 - Sustaining	1 - Future	TBD	TBD	TBD			TBD		-	-	-	-	10.7	10.7	
69	Seven Mile Overhaul Units 1 to 3 Turbines	1 - Sustaining	1 - Future	TBD	TBD	TBD			TBD		-	-	-	-	83.0	83.0	Page 35
70	Seven Mile Replace Fire Alarm System	1 - Sustaining	1 - Future	TBD	TBD	TBD			TBD		-	-	-	-	5.3	5.3	
71	Seven Mile Upgrade Powerhouse Crane Controls	1 - Sustaining	1 - Future	TBD	TBD	TBD			TBD		-	-	-	-	8.3	8.3	
72	Various Facilities Reduce Cutler Hammer Exciter Safety Risk Program	1 - Sustaining	1 - Future	TBD	TBD	TBD			TBD		-	-	-	3.5	3.6	7.0	
73	Various Facilities Replace Water Level Gauges	1 - Sustaining	1 - Future	TBD	TBD	TBD			TBD		-	-	-	-	8.2	8.2	
	Projects less than $5 million or In-Service	4 - Growth									848.8	26.6	0.9	0.2	185.6	1,062.2	
		3 - Redevelopment									-	-	-	-	512.5	512.5	
		2 - Dam Safety									326.6	24.7	1.8	7.1	4,022.0	4,382.2	
		1 - Sustaining									542.0	70.7	46.7	68.1	4,678.7	5,406.2	

A	B	C	D	E	F	H	I	J	K	L	M	N	O	P	Q	R	S
#	Name of Project	Growth or Sustaining Expenditure	Current Development Stage (3)	Current Forecast ISD (4)	Current Start Date of Construction (5)	Definition Approval Date (6)	Implementation Approval $ (7)	Implementation Approval ISD (10)	Current Pre-Implementation Cost Estimate (8)	Current Authorized Amount (9)	Capital Addition Actuals Prior Years	Capital Addition Forecast F17	Capital Addition Forecast F18	Capital Addition Forecast F19	Capital Addition Forecast >F19	Total Capital Additions (sum of columns M to Q)	Appendix J Reference
THERMAL																	
74	Burrard Convert Facility to Synchronous Condense Only Operation	1 - Sustaining	4 - Implementation	F2017	F2016	F2016	7.3	F2017		7.3	-	6.5	-	-	-	6.5	
75	Fort Nelson Facilities Upgrades	1 - Sustaining	3 - Definition	F2019	F2018	F2016			16.2 to 6.8		-	-	-	9.2	-	9.2	
	Project less than $5 million or In-Service	4 - Growth									-	-	-	-	3.7	3.7	
		1 - Sustaining									3.4	9.1	3.4	7.6	48.9	72.5	
DIESEL GENERATION																	
76	Project less than $5 million or In-Service	4 - Growth										1.2	-	-			
77	CLA - Station/Dam Upgrades	1 - Sustaining	1 - Future	TBD	TBD	TBD			TBD		-	-	-	-	7.4	7.4	
78	Project less than $5 million or In-Service	1 - Sustaining										7.1	6.9	4.2			
OTHER																	
79	Contribution in Aid of Construction	4 - Growth										(0.3)	-	-			
80	Portfolio Delivery Adjustment										-	-	-	-	(300.0)	(300.0)	
GENERATION TOTAL																	
81												512.8	387.2	1,332.3			

Notes:

(1) Information provided is current as of the established 'Currency Date' which is March 31, 2016, and which aligns with the information provided in BC Hydro's 10 Year Capital Forecast.
(2) Some projects in service at the end of F2016 have trailing expenditures that result in capital additions in the test period. These expenditures have been aggregated and included in the line item "Projects less than $5 million".
(3) Project/ Program dollars are generally capitalized starting in the definition phase
(4) Current Forecast ISD is the expected in-service date (as at the Currency Date) when the project goes into service.
(5) Start Date of Construction is the Implementation Approval Date. Where the Start Date of Construction date is known to be materially different than the Implementation Approval Date, both dates are provided, with the Implementation Approval Date in parenthesis.
(6) Fiscal Year project received definition approval.
(7) Implementation Approval $ refers to the 'authored' total capitalcost of the project when it was first approved by BC Hydro for implementatic

(8) Pre-Implementation phases are: Future, Identification and Definition. See Chapter 6, section 6.4.1.3, for further discussion on pre-implementation phases. Pre-implementation cost estimates are provided where an engineering estimate is available. Engineering estimates are completed during the mid-stage of identification phase for projects greater than $20 million and at definition phase for projects less than $20 million. N/A indicates that an engineering estimate is not yet available, or that project is in implementation phase.

(9) Amounts reflect only capital portion of authorized amount.

(10) Implementation Approval ISD refers to the ISD date identified when the project was first approved by BC Hydro for implementation.

Use of To Be Determined (TBD):

For projects in Future or Identification Phase, To Be Determined (TBD) is provided for the following: Current Pre-Implementation Cost Estimate, Current Forecast In-service Date (ISD) and Current Start Date of Construction, for the following reasons:

For Future phase projects, a problem or opportunity has been identified, but the required response has not yet been determined. In the Identification Phase, a number of identified alternative responses are being investigated, and each alternative can result in a very different project scope, schedule and cost. As a result, Current Pre-Implementation Cost Estimate, Current Forecast In-Service Date (ISD) and Current Start Date of Construction, are only provided for projects in the Definition phase and later phases.

Appendix I - Transmission
Projects and Programs greater than $5 million with Capital Expenditures in the Test Period and/or Capital Additions in the Test Period (F17, F18, F19) as at March 31,2016 (1), (2)
$ Million

A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S
#	Name of Project	Growth or Sustaining Expenditure	Current Development Stage (3)	Current Forecast ISD (4)	Current Start Date of Construction (5)		Definition Approval Date (6)	Implementation Approval $ (7)	Implementation Approval ISD (10)	Current Pre-Implementation Cost Estimate (8)	Current Authorized Amount (9)	Capital Addition Actuals Prior Years	Capital Addition Forecast F17	Capital Addition Forecast F18	Capital Addition Forecast F19	Capital Addition Forecast >F19	Total Capital Additions (sum of columns N to R)	Appendix J Reference
Transmission																		
	Growth Capital Expenditures																	
	Regional System Reinforcement																	
1	Courtenay Area Substation	Growth	Implementation	F2017	F2012		F2010	32.1	F2014	N/A - In Implementation	32.1	-	23.3	0.0	-	-	23.3	Page 36
2	North Peace River Area RAS Add Capacity	Growth	Implementation	F2017	F2012		F2011	18.1	F2014	N/A - In Implementation	22.0	-	22.0	-	-	-	22.0	Page 37
3	Wellington Substation	Growth	Implementation	F2017	F2011		F2010	28.9	F2014	N/A - In Implementation	28.9	-	21.8	-	-	-	21.8	Page 38
4	Taylor Capacitor Bank	Growth	Definition	F2018	May / F2017		F2015			8 - 6	-	-		6.6	-		6.6	
5	Horne Payne Substation Upgrade	Growth	Implementation	F2019	F2016		F2015	92.6	F2019	N/A - In Implementation	92.6	-	-	-	74.6	2.9	77.5	Page 40
6	Kamloops Substation	Growth	Implementation	F2019	F2016		F2014	48.9	F2019	N/A - In Implementation	48.9	-	-	-	43.8	0.3	44.1	Page 42
7	Fort St. John and Taylor Electric Supply	Growth	Implementation	F2020	F2016		Note C	53.1	F2020	N/A - In Implementation	53.1	-	-	-	-	45.8	45.8	Page 43
8	Metro North Transmission (MNT)	Growth	Identification	TBD	Note A		TBD			TBD	-	-	-	-	-	216.6	216.6	Page 44
9	West Kelowna Transmission Project	Growth	Identification	TBD	Note A		TBD			TBD	-	-	-	-	-	77.6	77.6	Page 46
10	Peace Region Electric Supply (PRES)	Growth	Identification	TBD	Note A		TBD			TBD	-	-	-	-	-	162.9	162.9	Page 47
11	Project A	Growth	Identification	TBD	Note A		TBD			TBD	-	-	130.0	-	-	-	130.0	Page 49
12	Project B	Growth	Identification	TBD	Note A		TBD			TBD	-	-	25.0	-	-		25.0	Page 50
13	South Vancouver Island Reactor Addition	Growth	Identification	TBD	Note A		TBD			TBD	-	-	-	-	8.0	-	8.0	
14	West End Substation Construction Project	Growth	Future	TBD	Note A		TBD			TBD	-	-	-	-	-	331.0	331.0	Page 51
	Bulk System Reinforcements																	
15	PEACE Region Load Shedding RAS (Note B)	Growth	Implementation	F2017	F2014		F2014	21.0	F2016	N/A - In Implementation	21.0	-	-	19.0	-	-	19.0	
16	Northwest Substation Upgrades Project (NSUP)	Growth	Definition	F2021	F2018		F2015			113 -64	-	-	-	-	-	75.3	75.3	Page 53
17	Peace Region to Kelly Lake 500kV Transmission Reinforcement	Growth	Future	TBD	TBD		TBD			TBD	-	-	-	-	-	268.0	268.0	Page 54
	Customer Requested Projects																	
18	Customer A	Growth	Definition	F2018	July / F2017		F2016			30 - 17	-	-	-	18.5	1.2	-	19.7	
19	Customer B	Growth	Definition	F2020	May / F2017		F2015			51 - 37	-	-	-	-	-	41.6	41.6	
20	Customer C	Growth	Identification	TBD	TBD		TBD			TBD	-	-	-	-	5.8	-	5.8	
21	Customer D	Growth	Future	TBD	TBD		TBD			TBD	-	-	-	-	-	9.6	9.6	
	Generation Interconnections																	
22	Merritt Green Energy Project - BIO2 IPP	Growth	Implementation	F2017	F2014		F2012	8.2	F2015	N/A - In Implementation	8.2	-	6.3	-	-	-	6.3	
23	Upper Lillooet River - CPC08 IPP	Growth	Implementation	F2017	F2012		2010	21.5	F2015	N/A - In Implementation	21.5	-	14.2	-	-	-	14.2	
24	Meikle Wind Energy Project - CPC08 IPP	Growth	Implementation	F2017	F2016		F2015	35.0	F2017	N/A - In Implementation	35.0	-	26.9	0.1	-	-	26.9	
25	Moose Lake Wind Project	Growth	Definition	F2018	Aug / F2017		F2016	-		11 - 3	-	-	-	5.3	-	-	5.3	
	Station Expansion & Modification																	
26	Fort St-John Substation Transformer Upgrade	Growth	Implementation	F2017	F2013		F2013	16.6	F2016	N/A - In Implementation	29.2	-	26.5	0.0	-	-	26.5	Page 55
27	Winsor Substation Transformer Upgrade (Note B)	Growth	Implementation	F2017	F2015		F2014	15.7	F2017	N/A - In Implementation	15.7	-	-	15.7	-	-	15.7	
28	Arnott Capacity Upgrade	Growth	Implementation	F2018	F2015		F2014	38.5	F2018	N/A - In Implementation	38.5	-	-	33.8	0.0	-	33.8	Page 56
29	Big Bend Substation (BBS)	Growth	Implementation	F2018	F2014		F2011	56.4	F2016	N/A - In Implementation	67.0	-	-	67.0	-	-	67.0	Page 57
30	Campbell River Substation Capacity Upgrade	Growth	Implementation	F2018	F2016		F2015	29.4	F2018	N/A - In Implementation	29.4	-	-	29.4	-	-	29.4	Page 58
31	Fernie - Substation Upgrade (Note B)	Growth	Definition	F2018	Apr / F2017		F2013			27 - 21	-	-	-	-	23.5	-	23.5	Page 59
32	South Surrey Area Reinforcement	Growth	Definition	F2019	May / F2017		F2015	-		35 - 28	-	-	-	-	27.4	3.3	30.7	Page 60
33	Mount Lehman Substation Upgrade	Growth	Identification	TBD	TBD		TBD			TBD	-	-	-	-	-	38.2	38.2	Page 61
34	Project C	Growth	Identification	TBD	TBD		TBD	-		TBD	-	-	-	8.4	-	-	8.4	
35	Westbank Substation Upgrade	Growth	Identification	TBD	TBD		TBD			TBD	-	-	-	-	23.0	1.0	24.0	Page 62
36	Capilano Substation 25Kv Conversion	Growth	Identification	TBD	TBD		TBD			TBD	-	-	-	-	-	52.9	52.9	Page 63
37	Clayburn Substation Upgrade	Growth	Identification	TBD	TBD		TBD			TBD	-	-	-	-	-	15.3	15.3	
38	Squamish Area Reinforcement	Growth	Identification	TBD	TBD		TBD			TBD	-	-	-	-	-	48.1	48.1	Page 64
	Add: Projects Less than $5M												96.2	27.4	6.6			
	TOTAL Gross Growth Capital Additions												**392.2**	**231.2**	**213.8**			
	Less: Contributions in Aid of Construction												(11.0)	(6.2)	(0.8)			
	Net Growth Capital Additions												**381.1**	**225.0**	**213.0**			
	Sustaining Capital Expendiutres																	
39	Horsey GIS Replacement Program	Sustaining	Implementation	F2017	F2012		F2008	24.0	F2014	N/A - In Implementation	32.4	-	30.0	0.0	-	-	30.0	Page 66
40	60L020 Segment Relocation	Sustaining	Implementation	F2019	F2015		F2014	10.4	F2017	N/A - In Implementation	10.4	-	-	-	7.9	1.3	9.2	
41	Terrace to Kitimat Transmission (TKT)	Sustaining	Definition	F2020	Jan / F2017		F2015			177 - 100	-	-	-	-	-	136.4	136.4	Page 67
42	George Massey Tunnel Transmission (GMTT) Relocation	Sustaining	Identification	TBD	TBD		TBD			TBD	-	-	-	-	-	49.3	49.3	Page 68

A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S
#	Name of Project	Growth or Sustaining Expenditure	Current Development Stage (3)	Current Forecast ISD (4)	Current Start Date of Construction (5)		Definition Approval Date (6)	Implementation Approval $ (7)	Implementation Approval ISD (10)	Current Pre-Implementation Cost Estimate (8)	Current Authorized Amount (9)	Capital Addition Actuals Prior Years	Capital Addition Forecast F17	Capital Addition Forecast F18	Capital Addition Forecast F19	Capital Addition Forecast >F19	Total Capital Additions (sum of columns N to R)	Appendix J Reference
43	Mainwaring Substation Upgrade	Sustaining	Identification	TBD	TBD		TBD			TBD	-	-	-	-	-	92.9	92.9	Page 69
44	Esquimalt Feeder Section Replacement	Sustaining	Identification	TBD	TBD		TBD			TBD	-	-	-	-	-	22.5	22.5	Page 70
45	5L63 Telkwa Relocation	Sustaining	Identification	TBD	TBD		TBD			TBD	-	-	-	-	-	23.2	23.2	Page 71
46	Barnard 50/60 Feeder Section Replacement	Sustaining	Identification	TBD	TBD		TBD			TBD	-	-	-	-	-	21.0	21.0	Page 72
47	NERC CIP V5 Compliance at Medium Impact T&D Stations	Sustaining	Identification	TBD	TBD		TBD	-		TBD	-	-	1.9	12.2	9.1	1.6	24.8	Page 73
48	Horsey (HSY) Outdoor 12kV Feeder Section Replacement	Sustaining	Future	TBD	TBD		TBD	-		TBD	-	-	0.1	2.3	6.2	1.4	9.9	
49	Newell Substation Upgrade	Sustaining	Future	TBD	TBD		TBD			TBD	-	-	-	-	-	52.9	52.9	Page 74
	Add: Projects & Programs Less than $5M												223.1	202.4	221.7			
	TOTAL Gross Sustaining Capital Additions												**255.1**	**216.9**	**245.0**			
	Less: Contributions in Aid of Construction												(2.8)	(3.5)	(3.6)			
	Net Sustaining Capital Additions												**252.4**	**213.4**	**241.4**			

Note A: Construction Start is dependent upon commitment from the customer to proceed with the project

Note B: ISA is in the fiscal year following the ISD because of a 3 month span between project in-service and finalization of the in-service additions by Finance

Note C: Definition work for the project was completed under the Site C Clean Energy Project

Notes:

(1) Information provided is current as of the established 'Currency Date' which is March 31, 2016, and which aligns with the information provided in BC Hydro's 10 Year Capital Forecast.
(2) Some projects in service at the end of F2016 have trailing expenditures that result in capital additions in the test period. These expenditures have been aggregated and included in the line item "Projects less than $5 million".
(3) Project/ Program dollars are generally capitalized starting in the definition phase.
(4) Current Forecast ISD is the expected in-service date (as at the Currency Date) when the project goes into service.
(5) Start Date of Construction is the Implementation Approval Date. Where the Start Date of Construction date is known to be materially different than the Implementation Approval Date, both dates are provided, with the Implementation Approval Date in parenthesis.
(6) Fiscal Year project received definition approval.

(7) Implementation Approval $ refers to the 'authorized' total capital cost of the project when it was first approved by BC Hydro for implementation.

(8) Pre-Implementation phases are: Future, Identification and Definition. See Chapter 6, section 6.4.1.3, for further discussion on pre-implementation phases. Pre-implementation cost estimates are provided where an engineering estimate is available. Engineering estimates are completed during the mid-stage of identification phase for projects greater than $20 million and at definition phase for projects less than $20 million. N/A indicates that an engineering estimate is not yet available, or that project is in implementation phase.

(9) Amounts reflect only capital portion of authorized amount.
(10) Implementation Approval ISD refers to the ISD date identified when the project was first approved by BC Hydro for implementation.

Use of To Be Determined (TBD):

For projects in Future or Identification Phase, To Be Determined (TBD) is provided for the following: Current Pre-Implementation Cost Estimate, Current Forecast In-service Date (ISD) and Current Start Date of Construction, for the following reasons:

For Future phase projects, a problem or opportunity has been identified, but the required response has not yet been determined. In the Identification Phase, a number of identified alternative responses are being investigated, and each alternative can result in a very different project scope, schedule and cost. As a result, Current Pre-Implementation Cost Estimate, Current Forecast In-Service Date (ISD) and Current Start Date of Construction, are only provided for projects in the Definition phase and later phases.

Appendix I - Distribution
Projects and Programs greater than $5 million with Capital Expenditures in the Test Period and/or Capital Additions in the Test Period (F17, F18, F19) as at March 31, 2016 (1), (2)
$ Million

A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S
#	Name of Project	Growth or Sustaining Expenditure	Current Development Stage (3)	Current Forecast ISD (4)	Current Start Date of Construction (5)		Definition Approval Date (6)	Implementation Approval $ (7)	Implementation Approval ISD	Current Pre-Implementation Cost Estimate (8)	Current Authorized Amount (9)	Capital Addition Actuals Prior Years	Capital Addition Forecast F17	Capital Addition Forecast F18	Capital Addition Forecast F19	Capital Addition Forecast >F19	Total Capital Additions (sum of columns N to R)	Appendix J Reference
	Growth Capital Expenditures																	
	Customer Driven																	
1	Extension #1	Growth	Future	TBD	TBD		TBD			TBD			2.8	2.7	2.7		8.3	
	Add: Projects Less than $5M												151.6	159.9	161.8			
	Total Customer Driven												**154.4**	**162.7**	**164.5**			
	System Expansion & Improvement																	
2	LOH 12F52 Voltage Conversion and Standby (LM-BBY-063) (Note A)	Growth	Definition	F2017	Nov / F2017		F2015			16 - 9	-	-	-	10.7	-	-	10.7	
3	MPT Circuit Offload from MAN to MPT (LM-MV-170) (Note A)	Growth	Definition	F2018	Apr / F2017		F2014			9 - 5	-	-	-	-	6.2	-	6.2	
4	COK Distribution Egress Reinforcement (LM-COQ-694)	Growth	Definition	F2018	Mar / F2017		F2014			12 - 7	-	-	-	7.7	-	-	7.7	
5	Voltage Conversion of ESQ1258 (VI-SVI-259)	Growth	Definition	F2018	Sep / F2017		F2015			14 - 8	-	0.7	5.6	3.3	-	-	9.5	
6	Phase KI14F65 and 4F66 Conversion (LM-MV-158)	Growth	Definition	F2018	Apr / F2017		F2012			15 - 9	-	3.0	1.1	3.7	1.2	1.2	10.3	
7	Three new MLE Feeders to offload CBN (LM-FVE-607)	Growth	Definition	F2018	F2018		F2015			17 - 10	-	-	-	8.0	1.7	1.8	11.5	
8	HPN 12F54, 72Q, 73Q, and 324 Voltage Conversion (LM-BBY-051) (Note A)	Growth	Definition	F2018	Mar / F2017		F2016			16 - 9	-	-	-	-	10.6	-	10.6	
9	12F51 & 53 HPN Voltage Conversion (LM-BBY-048)	Growth	Definition	F2019	Jul / F2017		F2015			16- 9	-	0.5	0.4	0.4	3.1	5.9	10.4	
10	CAP distribution voltage conversion for 51,52,58 (LM-NSC-124) (Note A)	Growth	Definition	F2019	Mar / F2017		F2016			8 - 5	-	-	-	-	-	5.5	5.5	
11	CBL New Feeder South Campbell River (VI-NVI-417)	Growth	Identification	TBD	TBD		TBD			TBD	-	-	-	7.8	-	-	7.8	
12	GDK Voltage conversion & transfer GDK 4kV to SPG One (LM-VAN-030)	Growth	Future	TBD	TBD		TBD			TBD	-	-	-	-	-	6.2	6.2	
13	Substation Load transfer, MAN 15 MVA to MPT (LM-VAN-033)	Growth	Future	TBD	TBD		TBD			TBD	-	-	-	-	-	7.0	7.0	
	Add: Projects & Programs Less than $5M												27.9	36.9	41.2			
	Total System Expansion & Improvement												35.0	78.5	64.0			
	Uneconomic Extension Assistance												0.4	0.5	0.5			
	TOTAL Gross Growth Capital Additions												**189.8**	**241.6**	**229.0**			
	Less: Contributions in Aid of Construction												(75.0)	(77.2)	(79.1)			
	Net Growth Capital Additions												**114.8**	**164.3**	**150.0**			
	Sustaining Capital Expendiutres																	
14	Open Loop - South End (LM-MV-230)	Sustaining	Definition	F2018	F2018		F2016			9 - 5	-	0.5	2.8	2.8	-	-	6.1	
15	Takla Landing (NI-NEW-287) (Note A)	Sustaining	Definition	F2019	F2018		F2016			21 - 12	-	-	-	-	-	13.9	13.9	
	Add: Projects & Programs Less than $5M												41.5	23.7	51.9			
	Total System Expansion & Improvement												**44.3**	**26.5**	**51.9**			
	Asset Replacement	Sustaining											**136.6**	**129.8**	**130.6**			
	Beautification	Sustaining											**1.4**	**1.4**	**1.5**			
	TOTAL Gross Sustaining Capital Additions												**182.3**	**157.7**	**184.0**			
	Less: Contributions in Aid of Construction												(1.0)	(1.1)	(1.1)			
	Net Sustaining Capital Additions												**181.2**	**156.7**	**182.9**			

Note A: ISA is in the fiscal year following the ISD because of a 3 month span between project in-service and finalization of the in-service additions by Finance

Notes:
(1) Information provided is current as of the established 'Currency Date' which is March 31, 2016, and which aligns with the information provided in BC Hydro's 10 Year Capital Forecast.
(2) Some projects in service at the end of F2016 have trailing expenditures that result in capital additions in the test period. These expenditures have been aggregated and included in the line item "Projects less than $5 million".
(3) Project/ Program dollars are generally capitalized starting in the definition phase.

(4) Current Forecast ISD is the expected in-service date (as at the Currency Date) when the project goes into service.
(5) Start Date of Construction is the Implementation Approval Date. Where the Start Date of Construction date is known to be materially different than the Implementation Approval Date, both dates are provided, with the Implementation Approval Date in parenthesis.
(6) Fiscal Year project received definition approval.

(7) Implementation Approval $ refers to the 'authorized' total capital cost of the project when it was first approved by BC Hydro for implementation.

(8) Pre-Implementation phases are: Future, Identification and Definition. See Chapter 6, section 6.4.1.3, for further discussion on pre-implementation phases. Pre-implementation cost estimates are provided where an engineering estimate is available. Engineering estimates are completed during the mid-stage of
(9) Amounts reflect only capital portion of authorized amount.
(10) Implementation Approval ISD refers to the ISD date identified when the project was first approved by BC Hydro for implementation.

Use of To Be Determined (TBD):

For projects in Future or Identification Phase, To Be Determined (TBD) is provided for the following: Current Pre-Implementation Cost Estimate, Current Forecast In-service Date (ISD) and Current Start Date of Construction, for the following reasons:

For Future phase projects, a problem or opportunity has been identified, but the required response has not yet been determined. In the Identification Phase, a number of identified alternative responses are being investigated, and each alternative can result in a very different project scope, schedule and cost. As a result, Current Pre-Implementation Cost Estimate, Current Forecast In-Service Date (ISD) and Current Start Date of Construction, are only provided for projects in the Definition phase and later phases.

Appendix I - Technology

Projects and Programs greater than $2 million with Capital Expenditures in the Test Period and/or Capital Additions in the Test Period (F17, F18, F19) as at March 31, 2016 (1), (2)

$ Million

A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S
#	Name of Project or Program	Growth or Sustaining Expenditure	Current Development Stage (3)	Current Forecast ISD (4)	Current Start Date of Construction (5)		Definition Approval Date (6)	Implementation Approval $ (7)	Implementation Approval ISD (10)	Current Pre-Implementation Cost Estimate (8)	Current Authorized Amount (9)	Capital Addition Actuals Prior Years	Capital Addition Forecast F17	Capital Addition Forecast F18	Capital Addition Forecast F19	Capital Addition Forecast >F19	Total Capital Additions (sum of columns M to Q)	Appendix J Reference
	Business-Driven Expenditures																	
1	Projects over $2 million																	
2	Supply Chain Applications	Sustaining	Definition	F2019	TBD		F2016	N/A	TBD	54.8 - 71.0	18.4	0.0	0.0	0.0	71.0	0.0	71.0	Page 75
3	Enterprise Billing Infrastructure	Sustaining	Identification	TBD	TBD		TBD	N/A	TBD	TBD	3.2	0.0	0.0	16.2	0.0	0.0	16.2	
4	Graphic Work Design Tool	Sustaining	Definition	F2018	TBD		F2015	N/A	TBD	12.9 - 23.0	5.5	0.0	0.0	15.0	0.0	0.0	15.0	
5	Mobile Radio Optimization	Sustaining	Implementation	Multiple	F2016		F2015	9.5	Multiple	N/A	9.5	0.0	2.6	1.7	1.7	1.3	7.3	
6	Fleet / Garage Management System	Sustaining	Definition	F2017	TBD		F2015	N/A	TBD	4.2 - 7.4	2.6	0.0	0.0	4.3	0.0	0.0	4.3	
7	Evolve Digital Channels	Sustaining	Future	TBD	TBD		TBD	N/A	TBD	TBD	0.0	0.0	0.0	1.0	1.0	2.0	4.0	
8	Field Access to Safety Information	Sustaining	Definition	F2017	TBD		F2016	N/A	TBD	2.5 - 4.4	1.2	0.0	2.9	0.0	0.0	0.0	2.9	
9	Commercial Management Application Refresh	Sustaining	Future	TBD	TBD		TBD	N/A	TBD	TBD	0.0	0.0	0.0	1.5	1.5	0.0	3.0	
10	Lodestar Replacement with SAP	Sustaining	Future	TBD	TBD		TBD	N/A	TBD	TBD	0.0	0.0	0.0	0.0	3.0	0.0	3.0	
11	NERC CIP v5	Sustaining	Identification	TBD	TBD		TBD	N/A	TBD	TBD	0.2	0.0	1.0	1.0	0.9	0.0	2.9	
12	MyHydro EDX	Sustaining	In Service	N/A	TBD		F2016	3.3	F2016	N/A	3.3	2.4	0.3	0.0	0.0	0.0	2.8	
13	GRM LAMP Operational Planning Platform	Sustaining	Implementation	F2017	F2015		F2014	2.0	F2017	N/A	2.0	0.0	0.0	2.8	0.0	0.0	2.8	
14	Energy Insights	Sustaining	Future	TBD	TBD		TBD	N/A	TBD	TBD	0.0	0.0	0.0	2.5	0.0	0.0	2.5	
15	Hazard Barrier Register	Sustaining	Future	TBD	TBD		TBD	N/A	TBD	TBD	0.0	0.0	0.0	0.0	0.0	2.4	2.4	
16	Customer Pay Now	Sustaining	Definition	F2017	TBD		F2016	N/A	TBD	1.8 - 3.2	0.9	0.0	2.1	0.0	0.0	0.0	2.1	
17	Outage - Automatic Notifications and Alerts	Sustaining	Future	TBD	TBD		TBD	N/A	TBD	TBD	0.0	0.0	0.0	2.0	0.0	0.0	2.0	
	Programs over $1 million CAPEX in test period																	
18	Dam Safety GIS Application Program	Sustaining	Future	N/A	N/A		N/A	N/A	N/A	N/A	0.0	0.0	0.5	0.6	0.7	3.2	4.9	
19	Construction Contract Management Upgrades	Sustaining	N/A	N/A	N/A		N/A	N/A	N/A	N/A	N/A	N/A	0.5	0.3	0.3	N/A	N/A	
20	T&D Outage Management System Improvements	Sustaining	N/A	N/A	N/A		N/A	N/A	N/A	N/A	N/A	N/A	0.6	0.2	0.4	N/A	N/A	
21	T&D AIM System Improvements	Sustaining	N/A	N/A	N/A		N/A	N/A	N/A	N/A	N/A	N/A	0.8	0.2	0.4	N/A	N/A	
22	T&D Eng & Design System Improvements	Sustaining	N/A	N/A	N/A		N/A	N/A	N/A	N/A	N/A	N/A	0.4	0.4	0.4	N/A	N/A	
23	Generation Application Minor Improvements	Sustaining	N/A	N/A	N/A		N/A	N/A	N/A	N/A	N/A	N/A	0.5	0.4	0.4	N/A	N/A	
24	Other Expenditures	Sustaining	N/A	N/A	N/A		N/A	N/A	N/A	N/A	N/A	N/A	32.0	15.0	5.2	N/A	N/A	N/A
	Foundational Expenditures																	
25	Projects over $2 million CAPEX																	
26	Mountain Top Radio Asset Refresh	Sustaining	Future	TBD	TBD		TBD	N/A	TBD	TBD	0.0	0.0	0.0	4.9	3.0	7.6	15.5	N/A
27	Data Centre Refresh	Sustaining	Future	TBD	TBD		TBD	N/A	TBD	TBD	0.0	0.0	0.0	0.7	1.6	4.0	6.4	
28	Windows 10 Upgrade	Sustaining	Future	TBD	TBD		TBD	N/A	TBD	TBD	0.0	0.0	0.0	2.5	2.0	0.0	4.5	
29	Call Centre LT Telephony and IVR Foundation	Sustaining	Future	TBD	TBD		TBD	N/A	TBD	TBD	0.0	0.0	0.0	4.0	0.0	0	4.0	
30	Enterprise Identity and Access Management	Sustaining	Implementation	F2017	F2013		F2013	2.2	F2014	N/A	3.6	0.0	3.1	0.0	0.0	0.0	3.1	
31	SAP Environment Health & Safety Upgrade	Sustaining	Definition	F2017	TBD		F2016	N/A	TBD	1.9 - 3.3	0.4	0.0	2.2	0.0	0.0	0.0	2.2	
32	MS XRM Service Desk and Infrastructure	Sustaining	Implementation	F2017	F2017		F2015	2.8	F2017	N/A	2.8	0.0	2.2	0.0	0.0	0.0	2.2	
33	Windows Server 2003 Upgrade	Sustaining	Implementation	F2017	F2017		N/A	1.7	F2016	N/A	1.7	0.0	2.2	0.0	0.0	0.0	2.2	
34	MPLS Network Commissioning	Sustaining	Implementation	Multiple	F2016		N/A	0.7	F2016	N/A	0.7	0.0	2.0	0.0	0.0	0.0	2.0	
35	Programs over $1 million CAPEX in test period																	
36	SMI Field Area Network Sustainment	Sustaining	Future		N/A			N/A	N/A	N/A	0.0	0.0	4.2	4.5	4.5	N/A	N/A	
37	VHF Radio Asset Sustainment	Sustaining	N/A	N/A	N/A		N/A	N/A	N/A	N/A	N/A	N/A	2.0	0.0	0.0	N/A	N/A	
38	Microsoft Enterprise License True-up	Sustaining	N/A	N/A	N/A		N/A	N/A	N/A	N/A	N/A	N/A	0.9	0.9	1.2	N/A	N/A	
39	BCH Desktop Application Software Licenses	Sustaining	N/A	N/A	N/A		N/A	N/A	N/A	N/A	N/A	N/A	0.4	0.4	0.4	N/A	N/A	
40	SAP Enhancement Pack Upgrades	Sustaining	N/A	N/A	N/A		N/A	N/A	N/A	N/A	N/A	N/A	1.7	0.6	0.8	N/A	N/A	
41	Microsoft End-User Devices License	Sustaining	N/A	N/A	N/A		N/A	N/A	N/A	N/A	N/A	0.0	3.6	3.8	3.6	N/A	N/A	
42	T&D Field Mobility Equipment	Sustaining	N/A	N/A	N/A		N/A	N/A	N/A	N/A	N/A	N/A	0.6	1.3	0.8	N/A	N/A	
43	T&D Field Mobility Equipment Refresh	Sustaining	N/A	N/A	N/A		N/A	N/A	N/A	N/A	N/A	N/A	0.0	1.2	0.8	N/A	N/A	
44	PC Refresh	Sustaining	N/A	N/A	N/A		N/A	N/A	N/A	N/A	N/A	N/A	4.0	3.0	3.0	N/A	N/A	
45	Operations PC Provisioning	Sustaining	N/A	N/A	N/A		N/A	N/A	N/A	N/A	N/A	N/A	1.0	1.0	1.0	N/A	N/A	
46	Storage Capacity Growth	Sustaining	N/A	N/A	N/A		N/A	N/A	N/A	N/A	N/A	N/A	1.1	2.0	2.0	N/A	N/A	
47	Server Sustainment	Sustaining	N/A	N/A	N/A		N/A	N/A	N/A	N/A	N/A	N/A	1.6	0.7	0.4	N/A	N/A	
48	SMI Infrastructure Renewal	Sustaining	N/A	N/A	N/A		N/A	N/A	N/A	N/A	N/A	N/A	0.5	0.5	0.5	N/A	N/A	
49	VoIP System Refresh	Sustaining	N/A	N/A	N/A		N/A	N/A	N/A	N/A	N/A	N/A	0.4	0.4	0.4	N/A	N/A	
50	MPLS Sustainment	Sustaining	N/A	N/A	N/A		N/A	N/A	N/A	N/A	N/A	N/A	0.0	1.0	1.0	N/A	N/A	
51	Other Expenditures	Sustaining	N/A	N/A	N/A		N/A	N/A	N/A	N/A	N/A	N/A	18.9	1.7	8.2	N/A	N/A	N/A
52	Subtotal												96.7	100.0	122.2			
53	Portfolio Adjustment												(17.6)	(9.9)	(12.2)			
54	Physical Security												2.5	1.0	2.6			
55	Total												**81.6**	**91.1**	**112.6**			

Notes:

(1) Information provided is current as of the established 'Currency Date' which is March 31, 2016, and which aligns with the information provided in BC Hydro's 10 Year Capital Forecast. Two key changes were made after the Currenct Date: (1) Customer Strategy scope reduction, and (2) Additional capital investment needed in F17-F19 for SMI network expansion, Web system reliability, and cybersecurity.

(2) Some projects in service at the end of F2016 have trailing expenditures that result in capital additions in the test period. These expenditures have been aggregated and included in the line item "Projects less than $5 million".

(3) Generally, Project/ Program dollars are capitalized starting in the definition phase. Some projects are capitalized at the end of the IDN phase due to 'work-ahead funding'. The 'Work-ahead funding' concept is specific only to Technology and is essentially capital funding to bridge the project team to the next phase (DEF or IMP) and enable them to begin the next phase of work. Without this funding, the irregular timing of funding approvals would result in work stoppages and the likely loss of project staff.

(4) Current Forecast ISD is the expected in-service as at the Currency Date.

(5) The Current Start Date of Construction is the Implementation Approval Date as at the Currency Date. Where the Start Date of Construction is known to be materially different than the Implementation Approval Date, both dates are provided, with the Implementation Approval Date in parenthesis.

(6) Fiscal Year project received definition approval.

(7) Implementation Approval $ refers to the 'authorized' total cost of the project when it was first approved by BC Hydro for implementation.

(8) Pre-Implementation phases are: Future, Identification and Definition. See Chapter 6, section 6.4.1.3, for further discussion on pre-implementation phases. Pre-implementation cost estimates are provided where an engineering estimate is available. Engineering estimates are completed during the mid-stage of identification phase for projects greater than $20 million and at definition phase for projects less than $20 million. N/A indicates that an engineering estimate is not yet available, or that project is in implementation phase.

(9) Current Authorized Amount is the total authorized capital as at the Currency Date

(10) Implementation Approval ISD is the in service date identified when the project was first approved for implementation

Note on the Use of To Be Determined (TBD) for certain information:

For projects in Future or Identification Phase, To Be Determined (TBD) is provided for the following: Current Pre-Implementation Cost Estimate, Current Forecast In-service Date (ISD) and Current Start Date of Construction, for the following reasons:

For Future phase projects, a problem or opportunity has been identified, but the required response has not yet been determined. In the Identification Phase, a number of identified alternative responses are being investigated, and each alternative can result in a very different project scope, schedule and cost. As a result, Current Pre-Implementation Cost Estimate, Current Forecast In-Service Date (ISD) and Current Start Date of Construction, are only provided for projects in the Definition phase and later phases.

Appendix I - Other
Projects and Programs greater than $5 million with Capital Expenditures in the Test Period and/or with Capital Additions in the Test Period (F17, F18, F19) as at March 31, 2016 (1), (2)
$ Million

A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S
#	Name of Project	Growth or Sustaining Expenditure	Current Development Stage (3)	Current Forecast ISD (4)	Current Start Date of Construction (5)		Definition Approval Date (6)	Implementation Approval $ (7)	Implementation Approval ISD (10)	Current Pre-Implementation Cost Estimate (8)	Current Authorized Amount (9)	Capital Addition Actuals Prior Years	Capital Addition Forecast F17	Capital Addition Forecast F18	Capital Addition Forecast F19	Capital Addition Forecast >F19	Total Capital Additions (sum of columns M to Q)	Appendix J Reference
Properties																		
1	Edmonds Podium C02 Interior Renovations	Sustaining	Implementation	F2017	F2016		F2016	5.4	F2017	N/A	5.4		5.4				5.4	
2	Hamilton Contact Centre	Sustaining	Implementation	F2017	F2016		F2016	10.0	F2016	N/A	10.0		10.0				10.0	
3	Dunsmuir D01 Renovation	Sustaining	Implementation	F2017	June/F2017		F2016	6.1	F2017	N/A	6.1		6.1				6.1	
4	Edmonds Podium C03 Interior Renovations	Sustaining	Definition	F2018	Feb/F2017		F2016	N/A	TBD	TBD	0.4			7.0			7.0	
5	Vernon Field Building	Sustaining	Implementation	F2018	F2015		F2013	46.3	F2017	N/A	46.3			46.3			46.3	Page 76
6	Victoria Field Building	Sustaining	Implementation	F2018	F2016		F2014	41.6	F2018	N/A	41.6			41.6			41.6	Page 78
7	Long Beach Field Building	Sustaining	Definition	F2019	F2018		F2016	N/A	TBD	TBD	1.7				6.3		6.3	
8	Dawson Creek Field Building	Sustaining	Definition	F2020	F2018		F2016	N/A	TBD	TBD	2.9					13.7	13.7	
9	Construction Services/Lower Mainland Transmission Building	Sustaining	Definition	F2020	F2018		F2016	N/A	TBD	TBD	3.8					36.5	36.5	Page 80
10	Edmonds Podium C01 Interior Renovations	Sustaining	Future	TBD	TBD		TBD	N/A	TBD	TBD	0.0			5.4			5.4	
11	Material Classification Facility	Sustaining	Identification	TBD	TBD		TBD	N/A	TBD	TBD	0.0					40.5	40.5	Page 82
12	Materials Management Facility	Sustaining	Identification	TBD	TBD		TBD	N/A	TBD	TBD	0.0					10.0	10.0	
13	Fleet Facility	Sustaining	Identification	TBD	TBD		TBD	N/A	TBD	TBD	0.0					10.0	10.0	
14	Pemberton Field Building	Sustaining	Identification	TBD	TBD		TBD	N/A	TBD	TBD	0.0					8.2	8.2	
15	Chilliwack Field Building	Sustaining	Identification	TBD	TBD		TBD	N/A	TBD	TBD	0.0					29.3	29.3	Page 84
16	Projects Less than $5 Million	Sustaining	Multiple	Multiple	Multiple		Multiple	Multiple	Multiple	Multiple	Multiple		46.8	17.8	19.2		83.8	
17	Total												**68.3**	**118.1**	**25.5**			
Other Capital																		
18	Fleet/Vehicles/Materials Management	Sustaining											40.3	32.4	30.2		102.9	
19	T&D Other Capital	Sustaining											12.5	11.1	8.9		32.5	
20	Other General Capital	Sustaining											6.4	2.6	6.6			
21	Total												**59.2**	**46.1**	**45.7**			
Site C Clean Energy Project																		
22	Site C Clean Energy Project	Growth	Implementation	F2024 (Unit 1)	F2016		F2015	8335.0	F2024 (Unit 1)	N/A	8,335.0					8,335.0	8,335.0	Page 86

Notes:

(1) Information provided is current as of the established 'Currency Date' which is March 31, 2016, and which aligns with the information provided in BC Hydro's 10 Year Capital Forecast.

(2) Some projects in service at the end of F2016 have trailing expenditures that result in capital additions in the test period. These expenditures have been aggregated and included in the line item "Projects less than $5 million".

(3) Project/ Program dollars are generally capitalized starting in the definition phase.

(4) Current Forecast ISD is the expected in-service date (as at the Currency Date) when the project goes into service.

(5) Start Date of Construction is the Implementation Approval Date. Where the Start Date of Construction date is known to be materially different than the Implementation Approval Date, both dates are provided, with the Implementation Approval Date in parenthesis.

(6) Fiscal Year project received definition approval.

(7) Implementation Approval $ refers to the 'authorized' total capital cost of the project when it was first approved by BC Hydro for implementation.

(8) Pre-Implementation phases are: Future, Identification and Definition. See Chapter 6, section 6.4.1.3, for further discussion on pre-implementation phases. Pre-implementation cost estimates are provided where an engineering estimate is available. Engineering estimates are completed during the mid-stage of identification phase for projects greater than $20 million and at definition phase for projects less than $20 million. N/A indicates that an engineering estimate is not yet available, or that project is in implementation phase.

(9) Amounts reflect only capital portion of authorized amount.

(10) Implementation Approval ISD refers to the ISD date identified when the project was first approved by BC Hydro for implementation.

Use of To Be Determined (TBD):

For projects in Future or Identification Phase, To Be Determined (TBD) is provided for the following: Current Pre-Implementation Cost Estimate, Current Forecast In-service Date (ISD) and Current Start Date of Construction, for the following reasons:

For Future phase projects, a problem or opportunity has been identified, but the required response has not yet been determined. In the Identification Phase, a number of identified alternative responses are being investigated, and each alternative can result in a very different project scope, schedule and cost. As a result, Current Pre-Implementation Cost Estimate, Current Forecast In-Service Date (ISD) and Current Start Date of Construction, are only provided for Properties projects beyond the Definition phase.

Fiscal 2017 to Fiscal 2019
Revenue Requirements Application

Supplemental Appendix I–A

Capital Expenditures
Fiscal 2017 – Fiscal 2019

[SUPPLEMENTAL – September 23, 2016]

Supplemental Appendix I-A
Generation Projects and Programs greater than $5 million with Capital Expenditures in the Test Period and/or Capital Additions in the Test Period (F17, F18, F19) as at March 31, 2016 (1), (2)
$ Million

A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T	U	V
																			Supplementary Information		
#	Name of Project	Growth or Sustaining Expenditure	Current Development Stage (3)	Current Forecast ISD (4)	Current Start Date of Construction (5)		Definition Approval Date (6)	Implementation Approval $ (7)	Implementation Approval ISD (10)	Current Pre-Implementation Cost Estimate (8)	Current Authorized Amount (9)	Capital Addition Actuals Prior Years	Capital Addition Forecast F17	Capital Addition Forecast F18	Capital Addition Forecast F19	Capital Addition Forecast >F19	Total Capital Additions (sum of columns M to Q)	Appendix J Reference	Capital Expenditure Forecast F17	Capital Expenditure Forecast F18	Capital Expenditure Forecast F19
HYDROELECTRIC																			(Note - columns T,U,V only provided for projects with >$20 million total forecast capital cost, per Column R)		
1	Revelstoke Install Unit 6	4 - Growth	3 - Definition	F2026	F2022		F2014			591 to 328		-	-	-	-	437.7	437.7	Page 1	2.0	1.5	0.5
2	John Hart Generating Station Replacement	3 - Redevelopment	4 - Implementation	F2019	F2014		F2008	1,092.9	F2019		1,092.9	1.0	-	-	955.5	63.4	1,019.9	Page 2	202.3	197.3	120.8
3	Ruskin Dam Safety and Powerhouse Upgrade	3 - Redevelopment	4 - Implementation	F2018	F2011		F2009	846.6	F2018		747.7	126.2	304.0	184.4	-	-	614.6	Page 4	132.7	78.5	0.0
4	Clowhom Rehabilitate Generating Station	3 - Redevelopment	2 - Identification	TBD			TBD			TBD		-	-	-	-	90.9	90.9	Page 7	0.3	1.1	1.2
5	Jordan River Mitigate Diversion Dam Seismic Risks	2 - Dam Safety	4 - Implementation	F2017	F2015		N/A	18.4	F2017		18.4	1.0	11.7	0.0	-	-	12.8				
6	W.A.C. Bennett Dam Spillway Chute Rehabilitation	2 - Dam Safety	4 - Implementation	F2017	F2014		F2013	27.2	F2016		27.2	6.3	14.9	1.1	-	-	22.4	Page 9	11.3	1.1	0.0
7	Bridge River 1 Install Penstock Leak Detection and Protection	2 - Dam Safety	3 - Definition	F2018	Various		F2016			10.0 to 6.7		0.0	6.0	0.1	-	-	6.2				
8	Peace Canyon Flood Discharge Gates Reliability Improvement	2 - Dam Safety	3 - Definition	F2020	Jan-2017		F2013			42.5 to 21.7		-	-	-	13.0	13.0	26.0	Page 10	2.0	5.7	7.9
9	W.A.C. Bennett Dam Rip-Rap Upgrade	2 - Dam Safety	3 - Definition	F2020	Jun-2016		F2015			170.4 to 108.7		-	-	49.6	49.6	39.5	138.7	Page 11	15.4	42.8	40.6
10	W.A.C. Bennett Dam Spillway Gate Upgrade	2 - Dam Safety	3 - Definition	F2020	Nov-2016		F2013			35.9 to 20.3		-	-	-	11.8	17.7	29.5	Page 12	1.7	7.0	8.0
11	Alouette Improve Headworks & Surge Tower Seismic Stability	2 - Dam Safety	2 - Identification	TBD	TBD		TBD			TBD		-	-	-	-	10.0	10.0				
12	Bridge River 1 Improve Slope Drainage	2 - Dam Safety	2 - Identification	TBD	TBD		F2016			TBD		-	-	14.3	-	-	14.3				
13	John Hart Dam Seismic Upgrade	2 - Dam Safety	2 - Identification	TBD	TBD		TBD			TBD		-	-	-	-	408.2	408.2	Page 13	3.9	9.0	11.1
14	Ladore Spillway Seismic Upgrade	2 - Dam Safety	2 - Identification	TBD	TBD		TBD			TBD		-	-	-	-	52.9	52.9	Page 15	0.3	2.5	10.4
15	Puntledge Flow Control Improvements	2 - Dam Safety	2 - Identification	TBD	TBD		TBD			TBD		-	-	-	-	28.8	28.8	Page 16	0.2	0.4	8.5
16	Revelstoke Improve Left Bank Slope Stability	2 - Dam Safety	2 - Identification	TBD	TBD		TBD			TBD		-	-	-	5.9	-	5.9				
17	Strathcona Upgrade Discharge	2 - Dam Safety	2 - Identification	TBD	TBD		TBD			TBD		-	-	-	-	220.2	220.2	Page 17	0.0	1.5	4.5
18	Wahleach Replace Tailrace Culvert	2 - Dam Safety	2 - Identification	TBD	TBD		TBD			TBD		-	-	-	-	5.4	5.4				
19	Duncan Dam Replace Spillway Gates	2 - Dam Safety	1 - Future	TBD	TBD		TBD			TBD		-	-	-	-	19.4	19.4				
20	Mica Rehabilitate Vertical Movement Gauges	2 - Dam Safety	1 - Future	TBD	TBD		TBD			TBD		-	-	-	-	6.7	6.7				
21	Peace Canyon Install Piezometers and Drains in Concrete Dam	2 - Dam Safety	1 - Future	TBD	TBD		TBD			TBD		-	-	-	-	6.0	6.0				
22	Revelstoke Replace Downie Slide Instrumentation	2 - Dam Safety	1 - Future	TBD	TBD		TBD			TBD		-	-	-	-	7.4	7.4				
23	W.A.C. Bennett Dam Recommission / Seal Spillway Sluice Gates	2 - Dam Safety	1 - Future	TBD	TBD		TBD			TBD		-	-	-	-	12.4	12.4				
24	W.A.C. Bennett Dam Seal Low Level Outlets	2 - Dam Safety	1 - Future	TBD	TBD		TBD			TBD		-	-	-	-	24.1	24.1	Page 18	0.0	0.0	5.8
25	Bridge River 1 Replace Transformers T1 and T2	1 - Sustaining	4 - Implementation	F2018	F2016		F2014	45.1	F2018		45.1	-	-	33.2	4.3	0.0	37.6	Page 19	15.3	10.7	4.3
26	Bridge River 1 Replace Unit Circuit Breakers	1 - Sustaining	4 - Implementation	F2018	F2016		F2015	17.1	F2018		17.1	-	-	13.2	0.5	-	13.6				
27	Cheakamus Replace Units 1 and 2 Turbine Inlet Valves	1 - Sustaining	4 - Implementation	F2020	F2015		F2014	10.7	F2020		10.7	-	-	-	-	8.3	8.3				
28	Cheakamus Units 1 and 2 Generator Replacement	1 - Sustaining	4 - Implementation	F2020	F2015		F2013	73.4	F2020		73.4	-	-	-	34.2	24.6	58.8	Page 20	11.3	18.0	13.0
29	Cheakamus Upgrade Fire Protection	1 - Sustaining	4 - Implementation	F2017	F2015		F2014	7.3	F2016		7.3	0.2	7.1	-	-	-	7.3				
30	G.M. Shrum Town Of Peace River Groundwater Management	1 - Sustaining	4 - Implementation	F2017	F2015		F2014	6.5	F2016		6.5	-	5.7	-	-	-	5.7				
31	G.M. Shrum Transformer Replacement (Phase 3)	1 - Sustaining	4 - Implementation	F2018	F2013		F2013	13.1	F2016		13.1	7.3	-	3.2	0.6	-	11.1				
32	Puntledge Improve Water Level Gauges & Public Safety Warning System	1 - Sustaining	4 - Implementation	F2017	F2015		F2015	9.0	F2017		9.0	-	7.0	0.4	-	-	7.4				
33	Revelstoke Upgrade Powerhouse Crane	1 - Sustaining	4 - Implementation	F2017	F2014		F2014	9.0	F2015		9.0	-	6.5	-	-	-	6.5				
34	Bridge River 2 Upgrade Units 5 and 6	1 - Sustaining	3 - Definition	F2019	F2018		F2016			83.3 to 52.5		-	-	-	52.2	4.5	56.7	Page 22	4.6	29.9	15.8
35	G.M. Shrum G1 to 10 Control System Upgrade	1 - Sustaining	3 - Definition	F2022	Various		F2016			77.2 to 58.4		3.2	4.1	10.1	13.9	32.5	63.9	Page 24	11.4	11.9	8.9
36	G.M. Shrum Upgrade HVAC System	1 - Sustaining	3 - Definition	F2020	F2018		F2016			19.9 to 10.9		-	-	-	-	14.9	14.9				
37	Kootenay Canal Upgrade Unit Protection and Install Sequence of Events Rec	1 - Sustaining	3 - Definition	F2020	Aug-2016		F2016			11.3 to 5.8		-	-	1.6	3.1	1.6	6.3				
38	Ladore Install Powerhouse and Tailrace Crane	1 - Sustaining	3 - Definition	F2018	Jan-2017		F2016			14.1 to 8.1		-	-	8.7	-	-	8.7				
39	Lake Buntzen 1 Coquitlam Tunnel Gates Refurbishment	1 - Sustaining	3 - Definition	F2022	F2019		F2016			48.6 to 20.8		-	-	-	-	30.0	30.0	Page 26	1.1	3.7	3.6
40	Mica Upgrade 600V Circuit Breakers	1 - Sustaining	3 - Definition	F2019	F2018		F2016			14.5 to 8.8		-	-	-	9.4	-	9.4				
41	Peace Canyon Unit 1 to 4 Unit Protection Upgrade	1 - Sustaining	3 - Definition	F2020	Feb-2017		F2016			7.6 to 4.2		-	-	-	-	5.1	5.1				
42	Wahleach Reduce Fire Risk - Phase 2	1 - Sustaining	3 - Definition	F2018	May-2016		F2015			9.0 to 7.2		-	-	7.5	0.7	0.6	8.8				
43	Bridge River 1 Upgrade Unit 4 Generator and Governor	1 - Sustaining	2 - Identification	TBD	TBD		TBD			TBD		-	-	-	-	35.6	35.6	Page 28	0.1	0.8	0.8
44	Bridge River 2 Upgrade Units 7 and 8	1 - Sustaining	2 - Identification	TBD	TBD		TBD			TBD		-	-	-	-	53.7	53.7	Page 29	0.0	0.9	6.4
45	Cheakamus Recoat Units 1 and 2 Penstocks (Interior and Exterior)	1 - Sustaining	2 - Identification	TBD	TBD		TBD			TBD		-	-	-	-	32.4	32.4	Page 30	0.4	0.3	6.9
46	G.M. Shrum Recoat Draft Tube Maintenance Gates	1 - Sustaining	2 - Identification	TBD	TBD		TBD			TBD		-	-	-	-	5.1	5.1				
47	G.M. Shrum Replace / Refurbish 500KV Disconnect Switches	1 - Sustaining	2 - Identification	TBD	TBD		TBD			TBD		-	-	-	-	6.6	6.6				
48	G.M. Shrum Replace Unit 1-5 Exciter Transformers	1 - Sustaining	2 - Identification	TBD	TBD		TBD			TBD		-	-	-	-	6.9	6.9				
49	Hugh Keenleyside Replace Service Water Piping	1 - Sustaining	2 - Identification	TBD	TBD		TBD			TBD		-	-	-	5.0	-	5.0				
50	Jordan River Reduce Fire Risk - Phase 2	1 - Sustaining	2 - Identification	TBD	TBD		TBD			TBD		-	-	-	6.1	-	6.1				
51	Key Facilities 600V Breaker Replacement Program	1 - Sustaining	2 - Identification	TBD	TBD		TBD			TBD		-	-	-	5.9	8.0	13.9				
52	Mica Modernize Controls	1 - Sustaining	2 - Identification	TBD	TBD		TBD			TBD		-	-	-	-	40.5	40.5	Page 31	0.0	0.9	3.2
53	Mica Replace Fire Alarm System	1 - Sustaining	2 - Identification	TBD	TBD		TBD			TBD		-	-	-	-	13.6	13.6				
54	Mica Townsite Augment Accommodations Capacity	1 - Sustaining	2 - Identification	TBD	TBD		TBD			TBD		-	-	-	-	19.5	19.5				
55	Mica Townsite Replace Recreation Centre Roof	1 - Sustaining	2 - Identification	TBD	TBD		TBD			TBD		-	-	-	5.4	-	5.4				
56	Mica Upgrade HVAC System	1 - Sustaining	2 - Identification	TBD	TBD		TBD			TBD		-	-	-	-	7.6	7.6				
57	Mica Upgrade Powerhouse Cranes	1 - Sustaining	2 - Identification	TBD	TBD		TBD			TBD		-	-	-	-	24.6	24.6	Page 32	9.8	2.0	5.9
58	Peace Canyon Upgrade HVAC System	1 - Sustaining	2 - Identification	TBD	TBD		TBD			TBD		-	-	-	-	6.2	6.2				
59	Puntledge Recoat Interior and Exterior of Steel Penstock	1 - Sustaining	2 - Identification	TBD	TBD		TBD			TBD		-	-	-	23.0	15.5	38.5	Page 33	0.4	0.6	22.0
60	Wahleach Recoat Penstock (Interior and Exterior)	1 - Sustaining	2 - Identification	TBD	TBD		TBD			TBD		-	-	-	-	19.5	19.5				
61	Ash River Extend Life of Steel Penstock	1 - Sustaining	1 - Future	TBD	TBD		TBD			TBD		-	-	-	-	5.4	5.4				
62	Bridge River 2 Strip and Recoat Penstock 1 Interior	1 - Sustaining	1 - Future	TBD	TBD		TBD			TBD		-	-	-	15.4	1.2	16.6				
63	Hugh Keenleyside Recoat Navlock Gates	1 - Sustaining	1 - Future	TBD	TBD		TBD			TBD		-	-	-	1.4	7.9	9.3				
64	Kootenay Canal Upgrade Powerhouse Crane	1 - Sustaining	1 - Future	TBD	TBD		TBD			TBD		-	-	-	15.3	-	15.3				
65	Ladore Upgrade Protection and Control Systems	1 - Sustaining	1 - Future	TBD	TBD		TBD			TBD		-	-	-	-	7.2	7.2				
66	Mica Replace Units 1 to 4 Fire and Cooling Water Piping	1 - Sustaining	1 - Future	TBD	TBD		TBD			TBD		-	-	-	-	10.1	10.1				
67	Mica Replace Units 1 to 4 Generator Transformers	1 - Sustaining	1 - Future	TBD	TBD		TBD			TBD		-	-	-	-	61.8	61.8	Page 34	0.0	0.6	1.2
68	Revelstoke Replace Fire Alarm System	1 - Sustaining	1 - Future	TBD	TBD		TBD			TBD		-	-	-	-	10.7	10.7				
69	Seven Mile Overhaul Units 1 to 3 Turbines	1 - Sustaining	1 - Future	TBD	TBD		TBD			TBD		-	-	-	-	83.0	83.0	Page 35	0.0	0.0	0.9
70	Seven Mile Replace Fire Alarm System	1 - Sustaining	1 - Future	TBD	TBD		TBD			TBD		-	-	-	-	5.3	5.3				
71	Seven Mile Upgrade Powerhouse Crane Controls	1 - Sustaining	1 - Future	TBD	TBD		TBD			TBD		-	-	-	-	8.3	8.3				
72	Various Facilities Reduce Cutler Hammer Exciter Safety Risk Program	1 - Sustaining	1 - Future	TBD	TBD		TBD			TBD		-	-	-	3.5	3.6	7.0				
73	Various Facilities Replace Water Level Gauges	1 - Sustaining	1 - Future	TBD	TBD		TBD			TBD		-	-	-	-	8.2	8.2				
	Projects less than $5 million or In-Service	4 - Growth										848.8	26.6	0.9	0.2	185.6	1,062.2				
		3 - Redevelopment										-	-	-	-	512.5	512.5				
		2 - Dam Safety										326.6	24.7	1.8	7.1	4,022.0	4,382.2				

#	Name of Project	Growth or Sustaining Expenditure	Current Development Stage (3)	Current Forecast ISD (4)	Current Start Date of Construction (5)		Definition Approval Date (6)	Implementation Approval $ (7)	Implementation Approval ISD (10)	Current Pre-Implementation Cost Estimate (8)	Current Authorized Amount (9)	Capital Addition Actuals Prior Years	Capital Addition Forecast F17	Capital Addition Forecast F18	Capital Addition Forecast F19	Capital Addition Forecast >F19	Total Capital Additions (sum of columns M to Q)	Appendix J Reference	Capital Expenditure Forecast F17	Capital Expenditure Forecast F18	Capital Expenditure Forecast F19
HYDROELECTRIC																			(Note - columns T,U,V only provided for projects with >$20 million total forecast capital cost, per Column R)		
		1 - Sustaining										542.0	70.7	46.7	68.1	4,678.7	5,406.2				
THERMAL																					
74	Burrard Convert Facility to Synchronous Condense Only Operation	1 - Sustaining	4 - Implementation	F2017	F2016		F2016	7.3	F2017		7.3	-	6.5	-	-	-	6.5				
75	Fort Nelson Facilities Upgrades	1 - Sustaining	3 - Definition	F2019	F2018		F2016			16.2 to 6.8		-	-	-	9.2	-	9.2				
	Project less than $5 million or In-Service	4 - Growth										-	-	-	-	3.7	3.7				
		1 - Sustaining										3.4	9.1	3.4	7.6	48.9	72.5				
DIESEL GENERATION																					
76	Project less than $5 million or In-Service	4 - Growth											1.2	-	-						
77	CLA - Station/Dam Upgrades	1 - Sustaining	1 - Future	TBD	TBD		TBD			TBD		-	-	-	-	7.4	7.4				
78	Project less than $5 million or In-Service	1 - Sustaining											7.1	6.9	4.2						
OTHER																					
79	Contribution in Aid of Construction	4 - Growth											(0.3)	-	-						
80	Portfolio Delivery Adjustment											-	-	-	-	(300.0)	(300.0)				
GENERATION TOTAL																					
81													512.8	387.2	1,332.3						

Notes:

(1) Information provided is current as of the established 'Currency Date' which is March 31, 2016, and which aligns with the information provided in BC Hydro's 10 Year Capital Forecast.
(2) Some projects in service at the end of F2016 have trailing expenditures that result in capital additions in the test period. These expenditures have been aggregated and included in the line item "Projects less than $5 million".
(3) Project/ Program dollars are generally capitalized starting in the definition phase.
(4) Current Forecast ISD is the expected in-service date (as at the Currency Date) when the project goes into service.
(5) Start Date of Construction is the Implementation Approval Date. Where the Start Date of Construction date is known to be materially different than the Implementation Approval Date, both dates are provided, with the Implementation Approval Date in parenthesis.
(6) Fiscal Year project received definition approval.
(7) Implementation Approval $ refers to the 'authoriz ed' total capital cost of the project when it was first approved by BC Hydro for implementation.
(8) Pre-Implementation phases are: Future, Identification and Definition. See Chapter 6, section 6.4.1.3, for further discussion on pre-implementation phases. Pre-implementation cost estimates are provided where an engineering estimate is available. Engineering estimates are completed during the mid-stage of identification phase for projects greater than $20 million and at definition

(9) Amounts reflect only capital portion of authorized amount.
(10) Implementation Approval ISD refers to the ISD date identified when the project was first approved by BC Hydro for implementation.

Use of To Be Determined (TBD):

For projects in Future or Identification Phase, To Be Determined (TBD) is provided for the following: Current Pre-Implementation Cost Estimate, Current Forecast In-service Date (ISD) and Current Start Date of Construction, for the following reasons:
For Future phase projects, a problem or opportunity has been identified, but the required response has not yet been determined. In the Identification Phase, a number of identified alternative responses are being investigated, and each alternative can result in a very different project scope, schedule and cost. As a result, Current Pre-Implementation Cost Estimate, Current Forecast In-Service Date (ISD) and Current Start Date of Construction, are only provided for projects in the Definition phase and later phases.

Supplemental Appendix I-A
Transmission Projects and Programs greater than $5 million with Capital Expenditures in the Test Period and/or Capital Additions in the Test Period (F17, F18, F19) as at March 31,2016 (1), (2)
$ Million

																			Supplementary Information		
A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T	U	V
#	Name of Project	Growth or Sustaining Expenditure	Current Development Stage (3)	Current Forecast ISD (4)	Current Start Date of Construction (5)		Definition Approval Date (6)	Implementation Approval $ (7)	Implementation Approval ISD (10)	Current Pre-Implementation Cost Estimate (8)	Current Authorized Amount (9)	Capital Addition Actuals Prior Years	Capital Addition Forecast F17	Capital Addition Forecast F18	Capital Addition Forecast F19	Capital Addition Forecast >F19	Total Capital Additions (sum of columns M to Q)	Appendix J Reference	Capital Expenditure Forecast F17	Capital Expenditure Forecast F18	Capital Expenditure Forecast F19
Transmission																			(Note - columns T,U,V only provided for projects with >$20 million total forecast capital cost, per Column R)		
	Growth Capital Expenditures																				
	Regional System Reinforcement																				
1	Courtenay Area Substation	Growth	Implementation	F2017	F2012		F2010	32.1	F2014	N/A - In Implementation	32.1	-	23.3	0.0	-	-	23.3	Page 36	1.6	0.0	0.0
2	North Peace River Area RAS Add Capacity	Growth	Implementation	F2017	F2012		F2011	18.1	F2014	N/A - In Implementation	22.0	-	22.0	-	-	-	22.0	Page 37	2.5	0.0	0.0
3	Wellington Substation	Growth	Implementation	F2017	F2011		F2010	28.9	F2014	N/A - In Implementation	28.9	-	21.8	-	-	-	21.8	Page 38	0.8	0.0	0.0
4	Taylor Capacitor Bank	Growth	Definition	F2018	May / F2017		F2015			8 - 6	-	-	-	6.6	-	-	6.6				
5	Horne Payne Substation Upgrade	Growth	Implementation	F2019	F2016		F2015	92.6	F2019	N/A - In Implementation	92.6	-	-	-	74.6	2.9	77.5	Page 40	18.6	29.0	21.9
6	Kamloops Substation	Growth	Implementation	F2019	F2016		F2014	48.9	F2019	N/A - In Implementation	48.9	-	-	-	43.8	0.3	44.1	Page 42	11.4	16.9	9.7
7	Fort St. John and Taylor Electric Supply	Growth	Implementation	F2020	F2016		Note C	53.1	F2020	N/A - In Implementation	53.1	-	-	-	-	45.8	45.8	Page 43	2.2	22.2	15.1
8	Metro North Transmission (MNT) **(Note D)**	Growth	Identification	TBD	TBD		TBD			TBD	-	-	-	-	-	216.6	216.6	Page 44	2.5	4.2	9.9
9	West Kelowna Transmission Project **(Note D)**	Growth	Identification	TBD	TBD		TBD			TBD	-	-	-	-	-	77.6	77.6	Page 46	1.1	3.6	12.6
10	Peace Region Electric Supply (PRES) **(Note D)**	Growth	Identification	TBD	TBD		TBD			TBD	-	-	-	-	-	162.9	162.9	Page 47	1.5	2.0	6.0
11	Project A **(Note D)**	Growth	Identification	TBD	TBD		TBD			TBD	-	-	130.0	-	-	-	130.0	Page 49	130.0	0.0	0.0
12	Project B **(Note D)**	Growth	Identification	TBD	TBD		TBD			TBD	-	-	25.0	-	-	-	25.0	Page 50	25.0	0.0	0.0
13	South Vancouver Island Reactor Addition **(Note D)**	Growth	Identification	TBD	TBD		TBD			TBD	-	-	-	-	8.0	-	8.0				
14	West End Substation Construction Project **(Note D)**	Growth	Future	TBD	TBD		TBD			TBD	-	-	-	-	-	331.0	331.0	Page 51	0.0	1.0	3.0
	Bulk System Reinforcements																				
15	PEACE Region Load Shedding RAS (Note B)	Growth	Implementation	F2017	F2014		F2014	21.0	F2016	N/A - In Implementation	21.0	-	-	19.0	-	-	19.0				
16	Northwest Substation Upgrades Project (NSUP)	Growth	Definition	F2021	F2018		F2015			113 -64	-	-	-	-	-	75.3	75.3	Page 53	0.0	15.1	22.6
17	Peace Region to Kelly Lake 500kV Transmission Reinforcement	Growth	Future	TBD	TBD		TBD			TBD	-	-	-	-	-	268.0	268.0	Page 54	0.0	0.0	1.0
	Customer Requested Projects																				
18	Customer A	Growth	Definition	F2018	July / F2017		F2016			30 - 17	-	-	-	18.5	1.2	-	19.7				
19	Customer B	Growth	Definition	F2020	May / F2017		F2015			51 - 37	-	-	-	-	-	41.6	41.6		3.0	14.0	17.6
20	Customer C	Growth	Identification	TBD	TBD		TBD			TBD	-	-	-	-	5.8	-	5.8				
21	Customer D	Growth	Future	TBD	TBD		TBD			TBD	-	-	-	-	-	9.6	9.6				
	Generation Interconnections																				
22	Merritt Green Energy Project - BIO2 IPP	Growth	Implementation	F2017	F2014		F2012	8.2	F2015	N/A - In Implementation	8.2	-	6.3	-	-	-	6.3				
23	Upper Lillooet River - CPC08 IPP	Growth	Implementation	F2017	F2012		2010	21.5	F2015	N/A - In Implementation	21.5	-	14.2	-	-	-	14.2				
24	Meikle Wind Energy Project - CPC08 IPP	Growth	Implementation	F2017	F2016		F2015	35.0	F2017	N/A - In Implementation	35.0	-	26.9	0.1	-	-	26.9		11.9	0.1	0.0
25	Moose Lake Wind Project	Growth	Definition	F2018	Aug / F2017		F2016	-		11 - 3	-	-	-	5.3	-	-	5.3				
	Station Expansion & Modification																				
26	Fort St-John Substation Transformer Upgrade	Growth	Implementation	F2017	F2013		F2013	16.6	F2016	N/A - In Implementation	29.2	-	26.5	0.0	-	-	26.5	Page 55	6.9	0.0	0.0
27	Winsor Substation Transformer Upgrade (Note B)	Growth	Implementation	F2017	F2015		F2014	15.7	F2017	N/A - In Implementation	15.7	-	-	15.7	-	-	15.7				
28	Arnott Capacity Upgrade	Growth	Implementation	F2018	F2015		F2014	38.5	F2018	N/A - In Implementation	38.5	-	-	33.8	0.0	-	33.8	Page 56	6.9	3.4	0.0
29	Big Bend Substation (BBS)	Growth	Implementation	F2018	F2014		F2011	56.4	F2016	N/A - In Implementation	67.0	-	-	67.0	-	-	67.0	Page 57	24.2	3.0	0.0
30	Campbell River Substation Capacity Upgrade	Growth	Implementation	F2018	F2016		F2015	29.4	F2018	N/A - In Implementation	29.4	-	-	29.4	-	-	29.4	Page 58	14.8	11.1	0.0
31	Fernie - Substation Upgrade (Note B)	Growth	Definition	F2018	Apr / F2017		F2013			27 - 21	-	-	-	-	23.5	-	23.5	Page 59	4.9	16.1	0.7
32	South Surrey Area Reinforcement	Growth	Definition	F2019	May / F2017		F2015	-		35 - 28	-	-	-	-	27.4	3.3	30.7	Page 60	5.5	14.5	6.5
33	Mount Lehman Substation Upgrade	Growth	Identification	TBD	TBD		TBD			TBD	-	-	-	-	-	38.2	38.2	Page 61	1.3	2.3	15.5
34	Project C	Growth	Identification	TBD	TBD		TBD	-		TBD	-	-	-	8.4	-	-	8.4				
35	Westbank Substation Upgrade	Growth	Identification	TBD	TBD		TBD			TBD	-	-	-	-	23.0	1.0	24.0	Page 62	0.5	10.0	12.5
36	Capilano Substation 25Kv Conversion	Growth	Identification	TBD	TBD		TBD			TBD	-	-	-	-	-	52.9	52.9	Page 63	3.5	7.1	10.6
37	Clayburn Substation Upgrade	Growth	Identification	TBD	TBD		TBD			TBD	-	-	-	-	-	15.3	15.3				
38	Squamish Area Reinforcement	Growth	Identification	TBD	TBD		TBD			TBD	-	-	-	-	-	48.1	48.1	Page 64	0.3	1.3	7.1
	Add: Projects Less than $5M												96.2	27.4	6.6						
	TOTAL Gross Growth Capital Additions												392.2	231.2	213.8						
	Less: Contributions in Aid of Construction												(11.0)	(6.2)	(0.8)						
	Net Growth Capital Additions												**381.1**	**225.0**	**213.0**						
	Sustaining Capital Expendiutres																				
39	Horsey GIS Replacement Program	Sustaining	Implementation	F2017	F2012		F2008	24.0	F2014	N/A - In Implementation	32.4	-	30.0	0.0	-	-	30.0	Page 66	4.9	0.0	0.0
40	60L020 Segment Relocation	Sustaining	Implementation	F2019	F2015		F2014	10.4	F2017	N/A - In Implementation	10.4	-	-	-	7.9	1.3	9.2				

A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T	U	V
#	Name of Project	Growth or Sustaining Expenditure	Current Development Stage (3)	Current Forecast ISD (4)	Current Start Date of Construction (5)		Definition Approval Date (6)	Implementation Approval $ (7)	Implementation Approval ISD (10)	Current Pre-Implementation Cost Estimate (8)	Current Authorized Amount (9)	Capital Addition Actuals Prior Years	Capital Addition Forecast F17	Capital Addition Forecast F18	Capital Addition Forecast F19	Capital Addition Forecast >F19	Total Capital Additions (sum of columns M to Q)	Appendix J Reference	Capital Expenditure Forecast F17	Capital Expenditure Forecast F18	Capital Expenditure Forecast F19
41	Terrace to Kitimat Transmission (TKT)	Sustaining	Definition	F2020	Jan / F2017		F2015			177 - 100	-	-	-	-	-	136.4	136.4	Page 67	12.8	30.7	30.7
42	George Massey Tunnel Transmission (GMTT) Relocation	Sustaining	Identification	TBD	TBD		TBD			TBD	-	-	-	-	-	49.3	49.3	Page 68	6.1	26.2	11.6
43	Mainwaring Substation Upgrade	Sustaining	Identification	TBD	TBD		TBD			TBD	-	-	-	-	-	92.9	92.9	Page 69	1.4	31.3	40.8
44	Esquimalt Feeder Section Replacement	Sustaining	Identification	TBD	TBD		TBD			TBD	-	-	-	-	-	22.5	22.5	Page 70	0.1	2.4	9.5
45	5L63 Telkwa Relocation	Sustaining	Identification	TBD	TBD		TBD			TBD	-	-	-	-	-	23.2	23.2	Page 71	0.6	2.7	9.0
46	Barnard 50/60 Feeder Section Replacement	Sustaining	Identification	TBD	TBD		TBD			TBD	-	-	-	-	-	21.0	21.0	Page 72	0.8	5.2	12.0
47	NERC CIP V5 Compliance at Medium Impact T&D Stations	Sustaining	Identification	TBD	TBD		TBD	-		TBD	-	-	1.9	12.2	9.1	1.6	24.8	Page 73	2.4	14.7	7.7
48	Horsey (HSY) Outdoor 12kV Feeder Section Replacement	Sustaining	Future	TBD	TBD		TBD	-		TBD	-	-	0.1	2.3	6.2	1.4	9.9				
49	Newell Substation Upgrade	Sustaining	Future	TBD	TBD		TBD			TBD	-	-	-	-	-	52.9	52.9	Page 74	1.2	9.5	16.3
	Add: Projects & Programs Less than $5M												223.1	202.4	221.7						
	TOTAL Gross Sustaining Capital Additions												255.1	216.9	245.0						
	Less: Contributions in Aid of Construction												(2.8)	(3.5)	(3.6)						
	Net Sustaining Capital Additions												**252.4**	**213.4**	**241.4**						

Note A: Construction Start is dependent upon commitment from the customer to proceed with the project

Note B: ISA is in the fiscal year following the ISD because of a 3 month span between project in-service and finalization of the in-service additions by Finance

Note C: Definition work for the project was completed under the Site C Clean Energy Project

Note D: These projects were included in Appendix I with a Note A reference in column F and have been corrected to TBD as these projects are not dependant on customer commitments

Notes:

(1) Information provided is current as of the established 'Currency Date' which is March 31, 2016, and which aligns with the information provided in BC Hydro's 10 Year Capital Forecast.
(2) Some projects in service at the end of F2016 have trailing expenditures that result in capital additions in the test period. These expenditures have been aggregated and included in the line item "Projects less than $5 million".
(3) Project/ Program dollars are generally capitalized starting in the definition phase.
(4) Current Forecast ISD is the expected in-service date (as at the Currency Date) when the project goes into service.
(5) Start Date of Construction is the Implementation Approval Date. Where the Start Date of Construction date is known to be materially different than the Implementation Approval Date, both dates are provided, with the Implementation Approval Date in parenthesis.
(6) Fiscal Year project received definition approval.

(7) Implementation Approval $ refers to the 'authorized' total capital cost of the project when it was first approved by BC Hydro for implementation.

(8) Pre-Implementation phases are: Future, Identification and Definition. See Chapter 6, section 6.4.1.3, for further discussion on pre-implementation phases. Pre-implementation cost estimates are provided where an engineering estimate is available. Engineering estimates are completed during the mid-stage of identification phase for projects greater than $20 million and at definition phase for projects less than $20 million. N/A indicates that an engineering estimate is not yet available, or that project is in implementation phase.

(9) Amounts reflect only capital portion of authorized amount.
(10) Implementation Approval ISD refers to the ISD date identified when the project was first approved by BC Hydro for implementation.

<u>Use of To Be Determined (TBD):</u>

For projects in Future or Identification Phase, To Be Determined (TBD) is provided for the following: Current Pre-Implementation Cost Estimate, Current Forecast In-service Date (ISD) and Current Start Date of Construction, for the following reasons:

For Future phase projects, a problem or opportunity has been identified, but the required response has not yet been determined. In the Identification Phase, a number of identified alternative responses are being investigated, and each alternative can result in a very different project scope, schedule and cost. As a result, Current Pre-Implementation Cost Estimate, Current Forecast In-Service Date (ISD) and Current Start Date of Construction, are only provided for projects in the Definition phase and later phases.

Supplemental Appendix I-A
Technology Projects and Programs greater than $2 million with Capital Expenditures in the Test Period and/or Capital Additions in the Test Period (F17, F18, F19) as at March 31, 2016 (1), (2)
$ Million

																			Supplmentary Information		
A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T	U	V
#	Name of Project or Program	Growth or Sustaining Expenditure	Current Development Stage (3)	Current Forecast ISD (4)	Current Start Date of Construction (5)		Definition Approval Date (6)	Implementation Approval $ (7)	Implementation Approval ISD (10)	Current Pre-Implementation Cost Estimate (8)	Current Authorized Amount (9)	Capital Addition Actuals Prior Years	Capital Addition Forecast F17	Capital Addition Forecast F18	Capital Addition Forecast F19	Capital Addition Forecast >F19	Total Capital Additions (sum of columns M to Q)	Appendix J Reference	Capital Expenditure Forecast F17	Capital Expenditure Forecast F18	Capital Expenditure Forecast F19
	Business-Driven Expenditures																		(Note - columns T,U,V only provided for projects with >$5 million total forecast capital cost, per Column R)		
1	Projects over $2 million																				
2	Supply Chain Applications **(Note 11)**	Sustaining	Definition	F2019	TBD		F2016	N/A	TBD	**58.4 - 71.0**	18.4	0.0	0.0	0.0	71.0	0.0	71.0	Page 75	0.0	38.0	23.1
3	Enterprise Billing Infrastructure	Sustaining	Identification	TBD	TBD		TBD	N/A	TBD	TBD	3.2	0.0	0.0	16.2	0.0	0.0	16.2		8.8	2.1	0.0
4	Graphic Work Design Tool	Sustaining	Definition	F2018	TBD		F2015	N/A	TBD	12.9 - 23.0	5.5	0.0	0.0	15.0	0.0	0.0	15.0		6.2	4.3	0.0
5	Mobile Radio Optimization	Sustaining	Implementation	Multiple	F2016		F2015	9.5	Multiple	N/A	9.5	0.0	2.6	1.7	1.7	1.3	7.3		1.2	1.7	1.7
6	Fleet / Garage Management System	Sustaining	Definition	F2017	TBD		F2015	N/A	TBD	4.2 - 7.4	2.6	0.0	0.0	4.3	0.0	0.0	4.3				
7	Evolve Digital Channels	Sustaining	Future	TBD	TBD		TBD	N/A	TBD	TBD	0.0	0.0	0.0	1.0	1.0	2.0	4.0				
8	Field Access to Safety Information	Sustaining	Definition	F2017	TBD		F2016	N/A	TBD	2.5 - 4.4	1.2	0.0	2.9	0.0	0.0	0.0	2.9				
9	Commercial Management Application Refresh	Sustaining	Future	TBD	TBD		TBD	N/A	TBD	TBD	0.0	0.0	0.0	1.5	1.5	0.0	3.0				
10	Lodestar Replacement with SAP	Sustaining	Future	TBD	TBD		TBD	N/A	TBD	TBD	0.0	0.0	0.0	0.0	3.0	0.0	3.0				
11	NERC CIP v5	Sustaining	Identification	TBD	TBD		TBD	N/A	TBD	TBD	0.2	0.0	1.0	1.0	0.9	0.0	2.9				
12	MyHydro EDX	Sustaining	In Service	N/A	TBD		F2016	3.3	F2016	N/A	3.3	2.4	0.3	0.0	0.0	0.0	2.8				
13	GRM LAMP Operational Planning Platform	Sustaining	Implementation	F2017	F2015		F2014	2.0	F2017	N/A	2.0	0.0	0.0	2.8	0.0	0.0	2.8				
14	Energy Insights	Sustaining	Future	TBD	TBD		TBD	N/A	TBD	TBD	0.0	0.0	0.0	2.5	0.0	0.0	2.5				
15	Hazard Barrier Register	Sustaining	Future	TBD	TBD		TBD	N/A	TBD	TBD	0.0	0.0	0.0	0.0	0.0	2.4	2.4				
16	Customer Pay Now	Sustaining	Definition	F2017	TBD		F2016	N/A	TBD	1.8 - 3.2	0.9	0.0	2.1	0.0	0.0	0.0	2.1				
17	Outage - Automatic Notifications and Alerts	Sustaining	Future	TBD	TBD		TBD	N/A	TBD	TBD	0.0	0.0	0.0	2.0	0.0	0.0	2.0				
	Programs over $1 million CAPEX in test period																				
18	Dam Safety GIS Application Program	Sustaining	Future	N/A	N/A		N/A	N/A	N/A	N/A	0.0	0.0	0.5	0.6	0.7	3.2	4.9				
19	Construction Contract Management Upgrades	Sustaining	N/A	N/A	N/A		N/A	N/A	N/A	N/A	N/A	N/A	0.5	0.3	0.3	N/A	N/A				
20	T&D Outage Management System Improvements	Sustaining	N/A	N/A	N/A		N/A	N/A	N/A	N/A	N/A	N/A	0.6	0.2	0.4	N/A	N/A				
21	T&D AIM System Improvements	Sustaining	N/A	N/A	N/A		N/A	N/A	N/A	N/A	N/A	N/A	0.8	0.2	0.4	N/A	N/A				
22	T&D Eng & Design System Improvements	Sustaining	N/A	N/A	N/A		N/A	N/A	N/A	N/A	N/A	N/A	0.4	0.4	0.4	N/A	N/A				
23	Generation Application Minor Improvements	Sustaining	N/A	N/A	N/A		N/A	N/A	N/A	N/A	N/A	N/A	0.5	0.4	0.4	N/A	N/A				
24	Other Expenditures	Sustaining	N/A	N/A	N/A		N/A	N/A	N/A	N/A	N/A	N/A	32.0	15.0	5.2	N/A	N/A	N/A			
	Foundational Expenditures																				
25	Projects over $2 million CAPEX																				
26	Mountain Top Radio Asset Refresh	Sustaining	Future	TBD	TBD		TBD	N/A	TBD	TBD	0.0	0.0	0.0	4.9	3.0	7.6	15.5	N/A	0.4	4.5	3.0
27	Data Centre Refresh	Sustaining	Future	TBD	TBD		TBD	N/A	TBD	TBD	0.0	0.0	0.0	0.7	1.6	4.0	6.4		0.0	0.7	1.6
28	Windows 10 Upgrade	Sustaining	Future	TBD	TBD		TBD	N/A	TBD	TBD	0.0	0.0	0.0	2.5	2.0	0.0	4.5				
29	Call Centre LT Telephony and IVR Foundation	Sustaining	Future	TBD	TBD		TBD	N/A	TBD	TBD	0.0	0.0	0.0	4.0	0.0	0	4.0				
30	Enterprise Identity and Access Management	Sustaining	Implementation	F2017	F2013		F2013	2.2	F2014	N/A	3.6	0.0	3.1	0.0	0.0	0.0	3.1				
31	SAP Environment Health & Safety Upgrade	Sustaining	Definition	F2017	TBD		F2016	N/A	TBD	1.9 - 3.3	0.4	0.0	2.2	0.0	0.0	0.0	2.2				
32	MS XRM Service Desk and Infrastructure	Sustaining	Implementation	F2017	F2017		F2015	2.8	F2017	N/A	2.8	0.0	2.2	0.0	0.0	0.0	2.2				
33	Windows Server 2003 Upgrade	Sustaining	Implementation	F2017	F2017		N/A	1.7	F2016	N/A	1.7	0.0	2.2	0.0	0.0	0.0	2.2				
34	MPLS Network Commissioning	Sustaining	Implementation	Multiple	F2016		N/A	0.7	F2016	N/A	0.7	0.0	2.0	0.0	0.0	0.0	2.0				
35	Programs over $1 million CAPEX in test period																				
36	SMI Field Area Network Sustainment	Sustaining	Future		N/A			N/A	N/A	N/A	0.0	0.0	4.2	4.5	4.5	N/A	N/A				
37	VHF Radio Asset Sustainment	Sustaining	N/A	N/A	N/A		N/A	N/A	N/A	N/A	N/A	N/A	2.0	0.0	0.0	N/A	N/A				
38	Microsoft Enterprise License True-up	Sustaining	N/A	N/A	N/A		N/A	N/A	N/A	N/A	N/A	N/A	0.9	0.9	1.2	N/A	N/A				
39	BCH Desktop Application Software Licenses	Sustaining	N/A	N/A	N/A		N/A	N/A	N/A	N/A	N/A	N/A	0.4	0.4	0.4	N/A	N/A				
40	SAP Enhancement Pack Upgrades	Sustaining	N/A	N/A	N/A		N/A	N/A	N/A	N/A	N/A	N/A	1.7	0.6	0.8	N/A	N/A				
41	Microsoft End-User Devices License	Sustaining	N/A	N/A	N/A		N/A	N/A	N/A	N/A	N/A	0.0	3.6	3.8	3.6	N/A	N/A				
42	T&D Field Mobility Equipment	Sustaining	N/A	N/A	N/A		N/A	N/A	N/A	N/A	N/A	N/A	0.6	1.3	0.8	N/A	N/A				
43	T&D Field Mobility Equipment Refresh	Sustaining	N/A	N/A	N/A		N/A	N/A	N/A	N/A	N/A	N/A	0.0	1.2	0.8	N/A	N/A				
44	PC Refresh	Sustaining	N/A	N/A	N/A		N/A	N/A	N/A	N/A	N/A	N/A	4.0	3.0	3.0	N/A	N/A				
45	Operations PC Provisioning	Sustaining	N/A	N/A	N/A		N/A	N/A	N/A	N/A	N/A	N/A	1.0	1.0	1.0	N/A	N/A				
46	Storage Capacity Growth	Sustaining	N/A	N/A	N/A		N/A	N/A	N/A	N/A	N/A	N/A	1.1	2.0	2.0	N/A	N/A				
47	Server Sustainment	Sustaining	N/A	N/A	N/A		N/A	N/A	N/A	N/A	N/A	N/A	1.6	0.7	0.4	N/A	N/A				
48	SMI Infrastructure Renewal	Sustaining	N/A	N/A	N/A		N/A	N/A	N/A	N/A	N/A	N/A	0.5	0.5	0.5	N/A	N/A				
49	VoIP System Refresh	Sustaining	N/A	N/A	N/A		N/A	N/A	N/A	N/A	N/A	N/A	0.4	0.4	0.4	N/A	N/A				
50	MPLS Sustainment	Sustaining	N/A	N/A	N/A		N/A	N/A	N/A	N/A	N/A	N/A	0.0	1.0	1.0	N/A	N/A				
51	Other Expenditures	Sustaining	N/A	N/A	N/A		N/A	N/A	N/A	N/A	N/A	N/A	18.9	1.7	8.2	N/A	N/A	N/A			
52	Subtotal												96.7	100.0	122.2						
53	Portfolio Adjustment												(17.6)	(9.9)	(12.2)						
54	Physical Security												2.5	1.0	2.6						
55	Total												**81.6**	**91.1**	**112.6**						

Notes:

(1) Information provided is current as of the established 'Currency Date' which is March 31, 2016, and which aligns with the information provided in BC Hydro's 10 Year Capital Forecast. Two key changes were made after the Currenct Date: (1) Customer Strategy scope reduction, and (2) Additional capital investment needed in F17-F19 for SMI network expansion, Web system reliability, and cybersecurity.

(2) Some projects in service at the end of F2016 have trailing expenditures that result in capital additions in the test period. These expenditures have been aggregated and included in the line item "Projects less than $5 million".

(3) Generally, Project/ Program dollars are capitalized starting in the definition phase . Some projects are capitalized at the end of the IDN phase due to 'work-ahead funding'. The 'Work-ahead funding' concept is specific only to Technology and is essentially capital funding to bridge the project team to the next phase (DEF or IMP) and enable them to begin the next phase of work. Without this funding, the irregular timing of funding approvals would result in work stoppages and the likely loss of project staff.

(4) Current Forecast ISD is the expected in-service as at the Currency Date.

(5) The Current Start Date of Construction is the Implementation Approval Date as at the Currency Date. Where the Start Date of Construction is known to be materially different than the Implementation Approval Date, both dates are provided, with the Implementation Approval Date in parenthesis.

(6) Fiscal Year project received definition approval.

(7) Implementation Approval $ refers to the 'authoriz ed' total cost of the project when it was first approved by BC Hydro for implementation.

(8) Pre-Implementation phases are: Future, Identification and Definition. See Chapter 6, section 6.4.1.3, for further discussion on pre-implementation phases. Pre-implementation cost estimates are provided where an engineering estimate is available. Engineering estimates are completed during the mid-stage of identification phase for projects greater than $20 million and at definition phase for projects less than $20 million. N/A indicates that an engineering estimate is not yet available, or that project is in implementation phase.

(9) Current Authorized Amount is the total authorized capital as at the Currency Date

(10) Implementation Approval ISD is the in service date identified when the project was first approved for implementation

(11) The current pre-implementation cost estimate provided in Appendix I included a transposition error which is corrected in Supplemental Appendix I-A and is consistent with the range provided in Appendix J for this project.

Note on the Use of To Be Determined (TBD) for certain information:

For projects in Future or Identification Phase, To Be Determined (TBD) is provided for the following: Current Pre-Implementation Cost Estimate, Current Forecast In-service Date (ISD) and Current Start Date of Construction, for the following reasons:

For Future phase projects, a problem or opportunity has been identified, but the required response has not yet been determined. In the Identification Phase, a number of identified alternative responses are being investigated, and each alternative can result in a very different project scope, schedule and cost. As a result, Current Pre-Implementation Cost Estimate, Current Forecast In-Service Date (ISD) and Current Start Date of Construction, are only provided for projects in the Definition phase and later phases.

Supplemental Appendix I-A
Other Capital Projects and Programs greater than $5 million with Capital Expenditures in the Test Period and/or with Capital Additions in the Test Period (F17, F18, F19) as at March 31, 2016 (1), (2)
$ Million

																			Supplementary Information		
A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T	U	V
#	Name of Project	Growth or Sustaining Expenditure	Current Development Stage (3)	Current Forecast ISD (4)	Current Start Date of Construction (5)		Definition Approval Date (6)	Implementation Approval $ (7)	Implementation Approval ISD (10)	Current Pre-Implementation Cost Estimate (8)	Current Authorized Amount (9)	Capital Addition Actuals Prior Years	Capital Addition Forecast F17	Capital Addition Forecast F18	Capital Addition Forecast F19	Capital Addition Forecast >F19	Total Capital Additions (sum of columns M to Q)	Appendix J Reference	Capital Expenditure Forecast F17	Capital Expenditure Forecast F18	Capital Expenditure Forecast F19
Properties																			(Note - columns T,U,V only provided for projects with >$20 million total forecast capital cost, per Column R)		
1	Edmonds Podium C02 Interior Renovations	Sustaining	Implementation	F2017	F2016		F2016	5.4	F2017	N/A	5.4		5.4				5.4				
2	Hamilton Contact Centre	Sustaining	Implementation	F2017	F2016		F2016	10.0	F2016	N/A	10.0		10.0				10.0				
3	Dunsmuir D01 Renovation	Sustaining	Implementation	F2017	June/F2017		F2016	6.1	F2017	N/A	6.1		6.1				6.1				
4	Edmonds Podium C03 Interior Renovations	Sustaining	Definition	F2018	Feb/F2017		F2016	N/A	TBD	TBD	0.4			7.0			7.0				
5	Vernon Field Building	Sustaining	Implementation	F2018	F2015		F2013	46.3	F2017	N/A	46.3			46.3			46.3	Page 76	20.5	6.5	0.0
6	Victoria Field Building	Sustaining	Implementation	F2018	F2016		F2014	41.6	F2018	N/A	41.6			41.6			41.6	Page 78	19.2	15.5	0.4
7	Long Beach Field Building	Sustaining	Definition	F2019	F2018		F2016	N/A	TBD	TBD	1.7				6.3		6.3				
8	Dawson Creek Field Building	Sustaining	Definition	F2020	F2018		F2016	N/A	TBD	TBD	2.9					13.7	13.7				
9	Construction Services/Lower Mainland Transmission Building	Sustaining	Definition	F2020	F2018		F2016	N/A	TBD	TBD	3.8					36.5	36.5	Page 80	1.4	7.1	15.2
10	Edmonds Podium C01 Interior Renovations	Sustaining	Future	TBD	TBD		TBD	N/A	TBD	TBD	0.0			5.4			5.4				
11	Material Classification Facility	Sustaining	Identification	TBD	TBD		TBD	N/A	TBD	TBD	0.0					40.5	40.5	Page 82	1.6	6.9	15.8
12	Materials Management Facility	Sustaining	Identification	TBD	TBD		TBD	N/A	TBD	TBD	0.0					10.0	10.0				
13	Fleet Facility	Sustaining	Identification	TBD	TBD		TBD	N/A	TBD	TBD	0.0					10.0	10.0				
14	Pemberton Field Building	Sustaining	Identification	TBD	TBD		TBD	N/A	TBD	TBD	0.0					8.2	8.2				
15	Chilliwack Field Building	Sustaining	Identification	TBD	TBD		TBD	N/A	TBD	TBD	0.0					29.3	29.3	Page 84	4.7	2.4	10.2
16	Projects Less than $5 Million	Sustaining	Multiple	Multiple	Multiple		Multiple	Multiple	Multiple	Multiple	Multiple		46.8	17.8	19.2		83.8				
17	Total												**68.3**	**118.1**	**25.5**						
Other Capital																					
18	Fleet/Vehicles/Materials Management	Sustaining											40.3	32.4	30.2		102.9				
19	T&D Other Capital	Sustaining											12.5	11.1	8.9		32.5				
20	Other General Capital	Sustaining											6.4	2.6	6.6						
21	Total												**59.2**	**46.1**	**45.7**						
Site C Clean Energy Project																					
22	Site C Clean Energy Project	Growth	Implementation	F2024 (Unit 1)	F2016		F2015	8335.0	F2024 (Unit 1)	N/A	8,335.0					8,335.0	8,335.0	Page 86	743.0	717.0	829.0

Notes:
(1) Information provided is current as of the established 'Currency Date' which is March 31, 2016, and which aligns with the information provided in BC Hydro's 10 Year Capital Forecast.
(2) Some projects in service at the end of F2016 have trailing expenditures that result in capital additions in the test period. These expenditures have been aggregated and included in the line item "Projects less than $5 million".
(3) Project/ Program dollars are generally capitalized starting in the definition phase .
(4) Current Forecast ISD is the expected in-service date (as at the Currency Date) when the project goes into service.
(5) Start Date of Construction is the Implementation Approval Date. Where the Start Date of Construction date is known to be materially different than the Implementation Approval Date, both dates are provided, with the Implementation Approval Date in parenthesis.
(6) Fiscal Year project received definition approval.
(7) Implementation Approval $ refers to the 'authoriz ed' total capital cost of the project when it was first approved by BC Hydro for implementation.
(8) Pre-Implementation phases are: Future, Identification and Definition. See Chapter 6, section 6.4.1.3, for further discussion on pre-implementation phases. Pre-implementation cost estimates are provided where an engineering estimate is available. Engineering estimates are completed during the mid-stage of identification phase for projects greater than $20 million and at definition phase for projects less than $20 million. N/A indicates that an engineering estimate is not yet available, or that project is in implementation phase.
(9) Amounts reflect only capital portion of authorized amount.
(10) Implementation Approval ISD refers to the ISD date identified when the project was first approved by BC Hydro for implementation.

Use of To Be Determined (TBD):

For projects in Future or Identification Phase, To Be Determined (TBD) is provided for the following: Current Pre-Implementation Cost Estimate, Current Forecast In-service Date (ISD) and Current Start Date of Construction, for the following reasons:

For Future phase projects, a problem or opportunity has been identified, but the required response has not yet been determined. In the Identification Phase, a number of identified alternative responses are being investigated, and each alternative can result in a very different project scope, schedule and cost. As a result, Current Pre-Implementation Cost Estimate, Current Forecast In-Service Date (ISD) and Current Start Date of Construction, are only provided for Properties projects beyond the Definition phase.

Fiscal 2017 to Fiscal 2019
Revenue Requirements Application

Supplemental Appendix I–B

Capital Additions
Fiscal 2015 – Fiscal 2016

[SUPPLEMENTAL – September 23, 2016]

Supplemental Appendix I-B
Generation Capital Additions
Projects Greater than $20 million in Service F15-F16
$ Million

A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
#	Name of Project	Growth or Sustaining Expenditure	Exempt from BCUC review per section 11 of Direction 7. (Y = Yes, N=No) (9)	In-Service Date (ISD) per SAP (3)	Start Date of Construction (4)	Definition Approval Date (5)	Implementation Approval $ (6)	Implementation Approval ISD (7)	Authorized Amount as at March 31, 2016 (8)	Capital Additions Prior to F15	Capital Additions F15	Capital Additions F16	Forecast Capital Additions >F16 (2)	Total Capital Additions (sum of columns K to N)
HYDROELECTRIC														
1	G.M. Shrum Units 1 to 5 Turbine Replacement	Sustaining	N	F2016 (Oct 2015)	F2009	F2007	312.5	F2017	272.4	60.2	51.3	57.8	14.9	184.2
2	Upper Columbia Capacity Additions at Mica Units 5 and 6	Growth	Y	F2016 (Dec 2015)	F2011	F2009	799.7	F2016	714.2	27.6	292.1	244.1	28.8	592.6
3	Hugh Keenleyside Spillway Gate Reliability Upgrade	Sustaining	N	F2016 (Dec 2015)	F2011	F2008	101.2	F2014	123.3	34.4	10.5	59.6	8.0	112.5
4	G.M. Shrum Units 1 to 4 Generator Rotor Pole Replacement	Sustaining	N	F2016 (Oct 2015)	F2011	F2010	23.9	F2016	43.5	11.1	8.5	12.5	0.3	32.5
5	Mica SF6 Gas Insulated Switchgear (GIS) Replacement	Sustaining	N	F2015 (Aug 2014)	F2010	F2009	199.2	F2013	199.2	155.4	14.1	12.0	5.4	186.8

Notes:

(1) Information provided is current as of the established 'Currency Date' which is March 31, 2016, and which aligns with the information provided in BC Hydro's 10 Year Capital Forecast.
(2) Some projects in service at the end of F2016 have trailing expenditures that result in capital additions after F2016.
(3) ISD is the in-service date per SAP financial system when the project goes into service, including month and fiscal year.
(4) Start Date of Construction is the Implementation Approval Date. Where the Start Date of Construction date is known to be materially different than the Implementation Approval Date, both dates are provided, with the Implementation Approval Date in parenthesis.
(5) Definition Approval Date is the Fiscal Year project received definition approval.
(6) Implementation Approval $ refers to the 'authorized' total capital cost of the project when it was first approved by BC Hydro for implementation.
(7) Implementation Approval ISD refers to the ISD date identified when the project was first approved by BC Hydro for implementation.
(8) Currency date is March 31, 2016, consistent with Application.

(9) Based on the meaning of "extension" used in BC Hydro's existing Capital Filing Guidelines, indicates if the project is an extension and is therefore considered to be exempt from BCUC review pursuant to section 11 of Direction 7.

Supplemental Appendix I-B
Transmission Capital Additions
Projects Greater than $20 million in Service F15-F16
$ Million

A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q
#	Name of Project	Growth or Sustaining Expenditure	Exempt from BCUC review per section 11 of Direction 7. (Y = Yes, N=No) (9)	In-Service Date (ISD) per SAP (3)	Start Date of Construction (4)	Definition Approval Date (5)	Implementation Approval $ (6)	Implementation Approval ISD (7)	Authorized Amount as at March 31, 2016 (8)	Capital Additions Prior to F15	Capital Additions F15	Capital Additions F16	Forecast Capital Additions >F16 (2)	Total Capital Additions (sum of columns K to N)	Total Contribution in Aid	Net Capital Additions (columns O + P)
Growth																
1	Interior to Lower Mainland Project (ILM)	4 - Growth	Yes	F2016 (Dec 2015)	F2011	F2006	725.0	F2015	743.3	0.0	6.6	698.9	34.8	740.4	(1.7)	738.7
2	Dawson Creek / Chetwynd Area Transmission (DCAT)	4 - Growth	Yes	F2016 (Nov 2015)	F2014	F2010	296.4	F2016	296.2	0.0	0.0	280.9	14.7	295.6		
3	Merritt Area Transmission Project (MAT)	4 - Growth	Yes	F2016 (Nov 2015)	F2013	F2011	64.5	F2015	64.8	0.0	0.0	55.4	4.4	59.8		
4	Surrey Area Substation (SAS) Project (formerly Fraser Valley West)	4 - Growth	Yes	F2016 (March 2016)	F2013	F2012	94.4	F2016	94.4	0.0	0.0	76.8	3.0	79.8		
5	Long Beach Area Transmission (LBAR)	4 - Growth	Yes	F2016 (Oct 2015)	F2014	F2012	55.8	F2016	55.8	0.0	0.0	36.1	2.0	38.0		
6	CUSTOMER E	4 - Growth	Yes	F2016 (July 2015)	F2014	F2013	35.9	F2016	35.9	0.0	0.0	32.9	0.5	33.3	(18.5)	14.8
7	Silverdale Substation	4 - Growth	Yes	F2016 (Oct 2015)	F2012	F2011	45.1	F2015	49.5	0.0	0.0	47.7	1.6	49.3		
8	2L142 GTP-HSY 230 Kv Cable	4 - Growth	No	F2016 (March 2016)	F2014	F2014	46.7	F2016	46.7	0.0	0.0	33.3	4.8	38.1		
9	Meridian Transformer Addition	4 - Growth	No	F2016 (Nov 2015)	F2011	F2011	28.7	F2014	28.7	0.0	13.8	4.8	1.9	20.5		
10	Northwest Transmission Line (NTL) (Note 10)	4 - Growth	Yes	F2015 (July 2014)	F2012	F2010	561.0	F2014	746.0	0.0	563.1	(1.6)	12.3	573.8	(256.4)	317.4
11	Kidd 1 - Substation Redevelopment	4 - Growth	Yes	F2015 (Sept 2014)	F2009	F2008	19.4	F2011	36.3	0.0	33.9	0.0	0.0	33.9		
12	Burnaby - New Westminster Transmission Project	4 - Growth	Yes	F2015 (Nov 2014)	F2012	F2009	36.6	F2013	36.6	0.0	29.4	2.1	0.3	31.8	(0.3)	31.5
13	Kidd 2 Substation (Richmond Area Reinforcement)	4 - Growth	Yes	F2015 (Dec 2014)	F2011	F2010	29.7	F2013	37.9	0.0	34.4	0.8	0.0	35.2		
14	Iskut Extension (Note 4)	4 - Growth	Yes	F2015 (Dec 2014)	F2014 (F2013)	F2013	179.1	F2016	179.1	0.0	164.0	3.7	5.5	173.2	(58.7)	114.5
15	Coquitlam Area Reinforcement (formerly Como Lake Xfr Addn.)	4 - Growth	Yes	F2015 (Jan 2015)	F2012	F2012	21.5	F2015	21.5	0.0	19.4	0.2	1.8	21.5		

Notes:

(1) Information provided is current as of the established 'Currency Date' which is March 31, 2016, and which aligns with the information provided in BC Hydro's 10 Year Capital Forecast.
(2) Some projects in service at the end of F2016 have trailing expenditures that result in capital additions after F2016. These expenditures have been included in Column N.
(3) ISD is the in-service date per SAP financial system when the project goes into service, including month and fiscal year.
(4) Start Date of Construction is the Implementation Approval Date. Where the Start Date of Construction date is known to be materially different than the Implementation Approval Date, both dates are provided, with the Implementation Approval Date in parenthesis.
(5) Definition Approval Date is the Fiscal Year project received definition approval.
(6) Implementation Approval $ refers to the 'authorized' total capital cost of the project when it was first approved by BC Hydro for implementation. Amounts shown are before Contribution in Aid.
(7) Implementation Approval ISD refers to the ISD date identified when the project was first approved by BC Hydro for implementation.
(8) Currency date is March 31, 2016, consistent with Application. Amounts shown are before Contribution in Aid.
(9) Based on the meaning of "extension" used in BC Hydro's existing Capital Filing Guidelines, indicates if the project is an extension and is therefore considered to be exempt from BCUC review pursuant to section 11 of Direction 7.
(10) Northwest Transmission line (NTL): Amounts shown in columns H and J are before Federal Government Green Infrastructure Fund reimbursement of eligible costs of $130 million. Amounts shown in columns L to O are net of the reimbursement.

Supplemental Appendix I-B
Technology Capital Additions
Projects Greater than $5 million in Service F15-F16
$ Million

A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
#	Name of Project	Growth or Sustaining Expenditure	Exempt from BCUC review per section 11 of Direction 7. (Y = Yes, N=No) (9)	In-Service Date (ISD) per SAP (3)	Start Date of Construction (4)	Definition Approval Date (5)	Implementation Approval $ (6)	Implementation Approval ISD (7)	Authorized Amount as at March 31, 2016 (8)	Capital Additions Prior to F15	Capital Additions F15	Capital Additions F16	Forecast Capital Additions >F16 (2)	Total Capital Additions (sum of columns K to N)
	Business-Driven Expenditures													
1	Supply Chain Solutions - SharePoint	Sustaining	N	F2015 (Dec 2014)	F2014	F2014	7.3	F2015	7.9	0.0	7.9	0.0	0.0	7.9
2	Distribution Work Scheduling	Sustaining	N	F2016 (June 2015)	F2014	F2014	8.5	F2015	11.5	0.0	9.4	2.1	0.0	11.4
3	Supply Chain Solutions - SAP	Sustaining	N	F2015 (Sept 2014)	F2014	F2014	6.7	F2015	7.0	0.0	6.9	0.0	0.0	6.9

Notes:

(1) Information provided is current as of the established 'Currency Date' which is March 31, 2016, and which aligns with the information provided in BC Hydro's 10 Year Capital Forecast.
(2) Some projects in service at the end of F2016 have trailing expenditures that result in capital additions after F2016. These expenditures have been included in Column N.
(3) ISD is the in-service date per SAP financial system when the project goes into service, including month and fiscal year.
(4) Start Date of Construction is the Implementation Approval Date. Where the Start Date of Construction date is known to be materially different than the Implementation Approval Date, both dates are provided, with the Implementation Approval Date in parenthesis.
(5) Definition Approval Date is the Fiscal Year project received definition approval.
(6) Implementation Approval $ refers to the 'authorized' total capital cost of the project when it was first approved by BC Hydro for implementation.
(7) Implementation Approval ISD refers to the ISD date identified when the project was first approved by BC Hydro for implementation.
(8) Currency date is March 31, 2016, consistent with Application.
(9) Based on the meaning of "extension" used in BC Hydro's existing Capital Filing Guidelines, indicates if the project is an extension and is therefore considered to be exempt from BCUC review pursuant to section 11 of Direction 7.

Supplemental Appendix I-B
Other Capital Additions
Projects Greater than $20 million in Service F15-F16
$ Million

A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
#	Name of Project	Growth or Sustaining Expenditure	Exempt from BCUC review per section 11 of Direction 7. (Y = Yes, N=No) (9)	In-Service Date (ISD) per SAP (3)	Start Date of Construction (4)	Definition Approval Date (5)	Implementation Approval $ (6)	Implementation Approval ISD (7)	Authorized Amount as at March 31, 2016 (8)	Capital Additions Prior to F15	Capital Additions F15	Capital Additions F16	Forecast Capital Additions >F16 (2)	Total Capital Additions (sum of columns K to N)
Properties														
1	Nanaimo District Office	1 - Sustaining	N	F2016 (Nov 2015)	F2014	F2013	48.6	F2016	48.6	0.0	0.0	37.6	11.0	48.6
2	Campbell River District Office	1 - Sustaining	N	F2015 (Jan 2015)	F2014	F2011	24.0	F2015	24.0	0.0	20.8	0.6	0.0	21.4
Other Capital														
1	Smart Metering and Infrastucture Program (Note 10)	1 - Sustaining	N	F2016 (Mar 2016)	F2011	F2009	781.6	F2014	781.6	509.6	31.5	155.5	0.0	696.6

Notes:

(1) Information provided is current as of the established 'Currency Date' which is March 31, 2016, and which aligns with the information provided in BC Hydro's 10 Year Capital Forecast.
(2) Some projects in service at the end of F2016 have trailing expenditures that result in capital additions after F2016. These expenditures have been included in Column N.
(3) ISD is the in-service date per SAP financial system when the project goes into service, including month and fiscal year.
(4) Start Date of Construction is the Implementation Approval Date. Where the Start Date of Construction date is known to be materially different than the Implementation Approval Date, both dates are provided, with the Implementation Approval Date in parenthesis.
(5) Definition Approval Date is the Fiscal Year project received definition approval.
(6) Implementation Approval $ refers to the 'authorized' total capital cost of the project when it was first approved by BC Hydro for implementation.
(7) Implementation Approval ISD refers to the ISD date identified when the project was first approved by BC Hydro for implementation.
(8) Currency date is March 31, 2016, consistent with Application.

(9) Based on the meaning of "extension" used in BC Hydro's existing Capital Filing Guidelines, indicates if the project is an extension and is therefore considered to be exempt from BCUC review pursuant to section 11 of Direction 7. The Smart Metering and Infrastructure Program is not exempt pursuant to section 11, Direction 7, however it is required pursuant to the *Clean Energy Act*.
(10) The Total Authorized Amount of the Smart Metering and Infrastructure Program was $930.0 million consisting of $781.6 million of capital expenditures and $148.4 million of non-capital expenditures.

Fiscal 2017 to Fiscal 2019
Revenue Requirements Application

Appendix J

Capital Expenditures
Greater than $20 million

PUBLIC

Alphabetical Cross Index for Appendix I and J		
Project Name	Reference	
	Appendix I (Line Number)	Appendix J (Page Number)
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Redevelopment		
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Ruskin Dam Safety and Powerhouse Upgrade	3	Page 4
Clowhom Rehabilitate Generating Station	4	Page 7
Dam Safety		
W.A.C. Bennett Dam Spillway Chute Rehabilitation	6	Page 9
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Bridge River 1 Replace Transformers T1 and T2	25	Page 19
Sustaining		
Cheakamus Units 1 and 2 Generator Replacement	28	Page 20
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G.M. Shrum G1-10 Control System Upgrade	35	Page 24
Lake Buntzen 1 Coquitlam Tunnel Gates Refurbishment	39	Page 26
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Bridge River 2 Upgrade Units 7 and 8	44	Page 29
Cheakamus Recoat Units 1 and 2 Penstocks (Interior and Exterior)	45	Page 30
Mica Modernize Controls	52	Page 31
Mica Upgrade Powerhouse Cranes	57	Page 32
Puntledge Recoat Interior and Exterior of Steel Penstock	59	Page 33
Mica Replace Units 1 to 4 Generator Transformers	67	Page 34
Seven Mile Overhaul Units 1 to 3 Turbines	69	Page 35

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Growth		
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North Peace River Area RAS Add Capacity	2	Page 37
Wellington Substation (formerly Nanaimo Area Substation)	3	Page 38
Horne Payne Substation Upgrade	5	Page 40
Kamloops Substation	6	Page 42
Fort St. John and Taylor Electric Supply	7	Page 43
Metro North Transmission (MNT) (formerly Metro North System Supply Reinforcement)	8	Page 44
West Kelowna Transmission Project	9	Page 46
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Project A	11	Page 49
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West End Substation Construction Project (formerly Downtown Vancouver Redevelopment)	14	Page 51
Northwest Substations Upgrades Project (NSUP)	16	Page 53
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South Surrey Area Reinforcement	32	Page 60
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Sustaining		
Horsey GIS Replacement Program	39	Page 66
Terrace to Kitimat Transmission (TKT)2L99	41	Page 67
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5L63 Telkwa Relocations	45	Page 71
Barnard 50/60 Feeder Section Replacement	46	Page 72
NERC CIP V5 Compliance at Medium Impact T&D Stations	47	Page 73
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Business-Driven Expenditures		
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Supply Chain Applications	2	Page 75
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Construction Services/Lower Mainland Transmission Building	9	Page 80
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Site C Clean Energy Project	22	Page 86

Project Name: Revelstoke Install Unit 6	
Forecast Capital Cost: $591 million to $328 million	**In-Service Date:** Fiscal 2026
Development Phase: Definition	**Filing Reference:** 2008 LTAP: • Appendix F1 Resource Options Database (**RODAT)** Sheets F11 RRA: • BCUC IRs 1.5.1, 1.5.1.1 – 1.5.1.3, 1.217.1 Attachment 6, 1.285.6, 1.331.1 Attachments 1 and 2, 2.515.1, 2.545.5 Attachment 1, 2.599.3, 3.669.1; • IPPBC IR 1.1.6 Attachment 4 Amended F12-F14 RRA • Amended Appendix I, line 136; Amended Appendix J, page 72

Description:

The scope of the Revelstoke Unit 6 project is to install a 500 MW unit in the existing empty Unit 6 bay. In addition, there is a transmission requirement for an additional series capacitor station on the transmission line from Vaseux to Nicola and some enhancements within existing substations.

Key Drivers:

- Reliability of Supply

Issues Being Addressed:

Revelstoke Generating Station is BC Hydro's third largest generating facility. The facility was originally constructed in the 1980s with four hydroelectric generating units and with empty bays for two additional units. Revelstoke Unit 5 was approved by the British Columbia Utilities Commission in May 2007 and was placed into commercial service in fiscal 2011. There is one remaining empty bay where a sixth unit could be installed to meet the requirement for additional capacity in the BC Hydro system. Revelstoke Unit 6 is the least cost alternative for adding this additional capacity.

Discussion of Alternatives:

BC Hydro's approved 2013 Integrated Resource Plan identifies Revelstoke Unit 6 as a contingency resource and recommends advancing Revelstoke Unit 6 through Definition phase to preserve a fiscal 2021 earliest in-service date.

More recent work on the load resource balance suggests that Revelstoke Unit 6 could be needed for an earliest in service date of fiscal 2022. In addition, the project would be needed on an expected basis in fiscal 2026; this timing is driven by long term maintenance outages planned for Mica Units 1-4.

Additional Information:

Section 7 of British Columbia's *Clean Energy Act* exempts BC Hydro from sections 45 to 47 and 71 of the *Utilities Commission Act* with respect to various projects including the Revelstoke Unit 6.

The Forecast Capital Cost does not include any associated transmission-related costs.

<table>
<tr><td colspan="2">Project Name: John Hart Generating Station Replacement</td></tr>
<tr><td>Forecast Capital Cost:
$1,092.9 million</td><td>In-Service Dates:
Units 1 to 3: Fiscal 2019
Bypass: Fiscal 2019</td></tr>
<tr><td>Development Phase:
Implementation</td><td>Filing Reference:

2006 IEP – LTAP:
• BCOAPO IR 1.28.1
• TGI IR 2.2.1 Attachment 4

F07/F08 RRA:
• Application, Appendix J
• BCUC IRs 1.5.1 Attachments 1 and 5, 1.83.2
• BCOAPO IR 1.27.2
• IPPBC IRs 1.27.1 and 1.29.1

F09/F10 RRA:
• Application: Appendix I, page 1 and Appendix J, page 28
• BCUC IR 1.5.1, 2.341.1, 2.343.1
• BCOAPO IRs 1.14.1, 2.1.0

F11 RRA:
• Application: Appendix I, page 2, Appendix J, page 32
• BCUC IRs 1.109.2, 1.116.2, 1.199.3, 1.230.2 Attachment 1, 1.257.1, 1.261.1 Attachment 2, 1.265.1 Attachment 1, 1.269.1 Confidential Attachment 1, 1.285.6, 1.331.1 Attachment 1, 1.331.1 Attachment 2, 3.630.1, 3.631.1, 2.398.2, 2.398.4, 2.398.5, 2.401.1 Attachment 1, 2.406.4, 2.459.1, 2.460.1, 2.496.3 Attachment 1, 2.545.5 Attachment 1, 2.2.9 Confidential
• JIESC IR 1.12.4 Confidential Attachment 1, 1.12.4 Attachment 1

John Hart Generating Station Replacement Project CPCN Application – Decision and Order No. C-2-13

Amended F12-F14 RRA:
• Application: Pages 6-36, 6-37, 6-38; Amended Appendix I, page 12, Amended Appendix J, page 29
• BCUC IRs 1.187.3,.1.197.6, 1.204.1 Attachment 1,1.219 Series,1.220.1, 2.127.1 Series

BC Hydro’s F2014 Annual Report to the BCUC:
• Attachment to Section 8 – Part 2
Appendix I, line 88
Appendix J, page 19</td></tr>
</table>

Description:

The purpose of the project is to replace the existing John Hart Generating Station. The existing six unit, 121 MW generating station, located on Vancouver Island near the community of Campbell River, has been in operation since 1947. The age and condition of the John Hart facility indicate the need for significant capital investment in the powerhouse and penstocks to ensure reliable generation from the facility in the long term and to mitigate seismic and environmental risks.

The John Hart Replacement Project includes: replacement of the existing powerhouse with a new three-unit 132.2 MW powerhouse with integrated flow bypass capability. The new facility will provide an additional 11.2 MW dependable capacity (from 121 MW to 132.2 MW) and approximately 10 per cent additional Resource Smart energy from the same amount of water.

Key Drivers:

- Reliability of Supply
- Environmental
- Safety

Issues Being Addressed:

- **Risk of Failures during a Major Earthquake:** The Powerhouse structure does not meet current seismic standards. The wood stave penstocks are located on seismically unstable ground. The soils underlying the penstocks would deform and settle significantly during a major seismic event. The existing steel penstocks are also in need of seismic upgrades. The potential consequences of failure could include injury to employees or the public, environmental damage, disruption of the domestic water supply to the City of Campbell River, and disruption (potentially long term) to plant operations;
- **Risk of Flow Disruption:** There is an ongoing risk of flow disruption in the Campbell River caused by forced outages of the John Hart generating units as presently there is no adequate flow bypass facility. The potential consequences of flow disruption are impacts to fish and fish habitat; and
- **Reliability of Generating Facilities:** The deteriorating condition of the generating facilities increase the probability of forced outages with their attendant potential environmental, safety, and financial impacts (including repair and lost generation).

Discussion of Alternatives

Please refer to the Certificate of Public Convenience and Necessity Application for alternatives considered.

Additional Information:

On February 8, 2013, the British Columbia Utilities Commission granted a Certificate of Public Convenience and Necessity for this Project (Commission Order No. C-2-13).

<table>
<tr><td colspan="2">Project Name: Ruskin Dam Safety and Powerhouse Upgrade</td></tr>
<tr><td>Forecast Capital Cost:
$747.7 million</td><td>In-Service Date:
Various:
Spillway Gates 1 and 2 — F2016
Spillway Gates 3 and 4 — F2017
Spillway Gate 5 — F2018
Turbine Generator U3 — F2017
Turbine Generator U2 — F2017
Turbine Generator U1 — F2018
Switchyard — F2018</td></tr>
<tr><td>Development Phase:
Implementation</td><td>Filing Reference:

2006 IEP – LTAP:
• BCUC IR 3.28.1

F07/F08 RRA:
• Application: Appendix K
• BCUC IRs 1.5.1, 2.341.1 Attachment 1, 2.344.0
• BCOAPO IR 2.1.0 Attachment 2

F09/F10 RRA:
• Application: Appendix I, page 1; Appendix J, page 45
• BCUC IR 2.161.3

F11 RRA:
• Application: Appendix I, page 2; Appendix J, page 17.
• BCUC IRs 1.31.5 Confidential Attachment 1, 1.145.1, 1.257.1, 1.261.1 Attachment 1, 5 and 10, 1.265.1 Attachment 1, 1.269.1 Confidential Attachment 1, 1.285.6, 1.331.1 Attachment 1, 1.331.1 Attachment 2, 3.630.1, 3.631.1, 2.401.1 Attachment 1, 2.406.4 , 2.460.1, 2.545.5 Attachment 1

Ruskin Dam and Powerhouse Upgrade Project CPCN Application; BCUC Decision & Order No. C-5-12

Amended F12-F14 RRA:
• Application: Page 6-36, 6-37, 6-42, Amended Appendix I, page 12, Amended Appendix J, page 31
• BCUC IR 1.204.1 Attachment 1, 1.126.1, 1.219 Series
• BCOAPO IR 1.43 Series, 1.190.4.1, 1.197.6, 1.205.1, 1.209.1
• COPE 1.41.1 Attachment 1

BC Hydro’s F2014 Annual Report to the BCUC:
• Attachment to Section 8 – Part 2 Appendix I, line 74, Appendix J, page 28</td></tr>
</table>

Description:

The Project includes the replacement of parts of the seismically deficient Ruskin Dam and the rehabilitation/replacement of the 105 MW Ruskin Powerhouse, including generating equipment brought into service between 1930 and 1950, and associated substation.

Key Drivers:

- Safety
- Reliability of Supply
- Environmental

Issues Being Addressed:

The Ruskin Dam and Generating Station (Powerhouse and Unit 1) were originally commissioned in 1930. The second and third generating units were installed in 1938 and 1950, respectively, and no substantial upgrades or modifications to the Ruskin Powerhouse have been made since the third generating unit was added in 1950.

Dam Safety Improvement

The concrete dam and right abutment have been assessed as having a low seismic withstand capability relative to other BC Hydro facilities and current seismic standards. The right abutment has been observed to have excessive seepage, raising the risk of piping failure and uncontrolled release of the reservoir.

The primary issues being addressed are the unacceptable risks associated with the condition of the seismic stability of the dam, spillway operational reliability, as well as the static and seismic deficiencies in the right abutment.

The Dam upgrade includes:

1) Replacement of the spillway piers and spillway gates; anchoring of the concrete; rehabilitation of the spillway surface; replacement of the roadway crossing the top of the dam;
2) Construction of a new seepage cut-off wall and reinforcing sections of the Right Abutment; and
3) Reducing the slope and installing a filter blanket and monitoring instrumentation at the Left Abutment.

Items 2) and 3) above have now been completed.

Generating Station Redevelopment

Most of the major generating station equipment is in Poor or Unsatisfactory condition and requires significant capital investment to support safe and reliable operation; the powerhouse does not meet current seismic standards. In addition, unit or station failures can interrupt the flow of water downstream into the lower Stave River, which may endanger fish habitat below the dam. Use of the spillway can also increase the total gas pressure in the lower Stave River beyond acceptable limits. Improved unit reliability will reduce both de-watering and total gas pressure risks to the lower Stave River.

The Powerhouse rehabilitation/replacement includes:

1) Seismic upgrades to the Powerhouse superstructure and substructure; rehabilitation/replacement of the three generating units, electrical and mechanical equipment, and ancillary systems; rehabilitation of water conveyance components (draft tubes, penstocks and intakes); replacement of step-up transformers; re-sloping of the left abutment, and
2) Upgrade and relocation of the switchyard from the roof of the existing Powerhouse to an area above the Powerhouse.

The Ruskin Dam and Powerhouse Project, currently in Implementation Phase, was initiated to address these concerns, and is expected to be put into service in stages over fiscal 2014 to fiscal 2018.

Discussion of Alternatives:

In addition to the Project, several other alternatives were considered:

i. **Permanently De-Rate Two Generating Units, Remove the Third Generating Unit:** The spillway gates would be removed and small automated crest gates installed on the Dam crest to provide enough spill capability to ensure that a plant trip does not dewater the lower Stave River. The reservoir elevation would be maintained at approximately 37 m. At this reservoir elevation Unit 3 is inoperable. Unit 3 and ancillary equipment would be removed while the other two units and their ancillary equipment would be replaced in the same way as contemplated in the Project. These two remaining generating units would provide less energy and capacity than they are presently rated due to the reduced available head;

ii. **Abandon with Overflow:** The spillway gates would be removed and flashboards installed on the crest of the five interior spillway bays. As for Alternative i, this reduces the consequence of a failure of the spillway piers. The Powerhouse would be removed down to the generator floor and new discharge valves would be installed in a newly-constructed valve-house. These valves would be sized to allow the Unit 1 and Unit 2 penstocks to pass the normal flow of approximately 100 m3/s into the Unit 1 and Unit 2 draft tubes. The Unit 3 penstock would be filled with gravel and capped with concrete at both ends, as would the U3 draft tube;

iii. **Abandon and Dam Removal:** The Dam would be removed and the Hayward Lake Reservoir would be returned, to the extent practicable, to its original condition. The Powerhouse would be removed to the generator floor, and all three penstocks would be filled with gravel and capped with concrete at both ends, as would all three draft tubes. This alternative would require dewatering Hayward Lake Reservoir prior to removal of the Dam;

iv. **Abandon without Dam Removal:** This alternative is similar to Alternative iii; rather than removing the Dam, a large opening would be cut through the base of the Dam to allow water passage; and

v. **Permanently De-Rate all Generating Units and perform Intake Modifications:** As in Alternative i, the spillway gates would be removed and small automated crest gates installed on the Dam crest. As for Alternatives i and ii, this reduces the consequence of a failure of the spillway piers. The reservoir elevation would be maintained at approximately 37 m. To continue the use of Unit 3, the intake would be modified so that the intake is lowered to the same elevation as the other two units. The Powerhouse rehabilitation would be substantially similar to that contemplated in the Project, leaving the facility with three operating units but with a reduced hydraulic head.

Evaluation of these alternatives was extensively set out in the Ruskin Certificate of Public Convenience and Necessity application, page 3-17 to 3-49.

BC Hydro concluded that while the Project has the highest capital cost as compared to the other alternatives, it is the most cost-effective as it provides the greatest energy and capacity. The value of the energy and capacity of the Project compensates for the increased capital cost: the Project has the highest NPV compared to the alternatives and provides the lowest UEC. Both the Project and the de-rating alternatives are competitive with IPP energy purchases as measured by the Clean Power Call results.

Additional Information:

BC Hydro submitted an Application for a Certificate of Public Convenience and Necessity for the Ruskin Dam and Powerhouse Upgrade Project on February 22, 2011, and the Commission granted the requested Certificate of Public Convenience and Necessity by Order No. C-5-12 on March 30, 2012. In their Order the Commission excluded Overhead on Implementation Phase costs, deferring consideration of that cost element to future Revenue Requirements Application hearings, which BC Hydro had argued was the appropriate venue. Accordingly, BC Hydro excludes Overheads in its ongoing Project progress reporting. Overheads are included in the costs for the project shown in Appendices I and J.

Project Name: Clowhom Rehabilitate Generating Station	
Forecast Capital Cost: To be determined	**In-Service Date:** To be determined
Development Phase: Identification	**Filing Reference:** BC Hydro's 2014 Annual Report to the BCUC • Attachment to Section 8 – Part 2 Appendix I, lines 122 and 123 Appendix J, pages 7 and 8
Description: The purpose of this project is to rehabilitate the Clowhom Generating Station to enable it to provide reliable, dependable energy and capacity.	
Key Drivers: • Reliability of Supply	
Issues Being Addressed: Clowhom is a 30 MW generating station commissioned in 1958. Clowhom is classified as a Strategic Facility as it is critical to ensuring reliable supply for the Sunshine Coast area when certain transmission lines are out of service. In addition, Clowhom has "black-start" capability, enabling the generating station to be returned to service without relying on an external power source such as during a major transmission outage. This enables restoration of area load. There have been no substantive upgrades or modifications at Clowhom since the generating station was commissioned, other than the installation of a replacement unit transformer in fiscal 2010 and the removal of dwellings in the downstream inundation zone in fiscal 2014 that allowed the dam consequence classification to be reduced from 'High' to 'Significant'. The turbine and generator are each rated Unsatisfactory according to BC Hydro's Equipment Health Rating methodology; the governor and exciter are rated Poor. In May 2010, 16 cracks were discovered in the runner blades. The worst cracks were repaired, and the unit was returned to service for four months until the unit could be scheduled out of service for an extended period to repair all cracks. In September 2010, 15 cracks were found in the runner; five new cracks and one crack in a blade that had been repaired in May. Since then, the runner blades have continued to crack, despite operating restrictions to reduce the number of starts/stops, thereby reducing the pressure cycles experienced by the runner. In 2012, the generator condition was downgraded from Poor to Unsatisfactory due to the condition of the stator winding insulation. Generators of this vintage and insulation type are known to suffer from instability of the insulation at an age of 40 to 50 years. The solid polyester resin essentially dissolves, reducing the effectiveness of the insulation. Operating restrictions have been imposed to limit generator output until the generator is replaced. Due to these issues and others, the total forced outage time increased from 79.8 hours in fiscal 2011 to 788.5 hours in fiscal 2015.	
Discussion of Alternatives: This project will include replacing the generator and turbine, and upgrades to the AC/DC station service (which is undersized) and the main powerhouse crane (a recent inspection has shown the crane to be in unsatisfactory condition). During the Identification Phase it will be determined if the exciter and governor should also be replaced; the analysis of which will include a detailed condition assessment. Access to Clowhom is by sea or air only. There is no accommodation at or near Clowhom that could accommodate the number of workers required to undertake this work and the project will consider the cost of accommodation, logistics and mobilizing-demobilizing for various alternatives. . During the Project Identification Phase, the economic benefit of upgrading the capacity of Clowhom will also be studied.	

Additional Information:

In BC Hydro's F2014 Annual Report to the British Columbia Utilities Commission, Attachment to Section 8 – Part 2; Appendix I, Hydroelectric Generation, lines 121 to 123 and Appendix J, pages 7 and 8; this work is listed as three separate projects: Clowhom Replace AC/DC Station Service, Clowhom Replace Generator, and Clowhom Replace Turbine. The work has now been combined into this single project.

Project Name: W.A.C. Bennett Dam Spillway Chute Rehabilitation	
Forecast Capital Cost: $27.2 million	**In-Service Date:** Fiscal 2017
Development Phase: Implementation	**Filing Reference:** F11 RRA: • Application: Appendix I, page 3, Appendix J, page 58 • BCUC IR 2.406.3 Amended F12-F14 RRA: • Application: page 6-19, 6-41, Amended Appendix I, page 12, Amended Appendix J, page 47 • BCUC IR 1.204.1 Attachment 1 BC Hydro's F2014 Annual Report to the BCUC: • Attachment to Section 8 – Part 2 Appendix I, line 90 Appendix J, page 35
Description: The purpose of this project is to remove and replace the concrete surface of the lower, high-velocity portion of the spillway chute, which has been damaged by rock fall, freeze-thaw cycles, and concrete cracking.	
Key Drivers: • Safety	
Issues Being Addressed: The spillway is in unacceptable condition and a prolonged use of the spillway or heavy spill could result in severe damage to the spillway. This represents a high dam safety risk at an extreme consequence facility.	
Discussion of Alternatives: Response options considered ranged from localized crack repair, to surface removal and replacement over varying lengths of the spillway, to a complete spillway rebuild. The selected alternative of surface removal and replacement was considered to be the minimum action that will adequately resolve the existing damage to the spillway. The extent of the repairs was determined in consultation with an external international expert on spillways.	
Additional Information: The Project will be implemented over two or more summer construction seasons. The first work season was in the summer of 2014, but work planned for the summer of 2015 was deferred due to high reservoir conditions and the possibility that the spillway might be required for discharge. Work for the summer of 2016 has started.	

Project Name: Peace Canyon Flood Discharge Gates Reliability Improvement	
Forecast Capital Cost: $42.5 million to $21.7 million	**In-Service Date:** Fiscal 2020
Development Phase: Definition	**Filing Reference:**
Description: This project will improve the reliability of the discharge gate systems at the Peace Canyon facility to ensure they are able to operate as needed to provide safe passage of floods and/or support reservoir drawdown.	
Key Drivers: • Safety	
Issues Being Addressed: The Peace Canyon Dam is located 6 km upstream of Hudson's Hope. The concrete dam is 61 m high and has six spillway bays with radial gates. A 21 m high earthfill saddle dam is located on the right abutment. Upgrades to the electrical, mechanical and protection and control equipment are required to ensure the reliability of the Water Discharge System to pass flows without endangering the dams and/or the public.	
Discussion of Alternatives: Design options to improve reliability are being developed using informed assessments and cost estimates, to guide decisions towards upgrades that provide a comparatively large increase in performance versus cost to achieve an acceptable balance between safety improvements and the investment made.	
Additional Information Safety by Design, failure mode, and reliability analysis completed during Preliminary Design, plus lessons learned from other ongoing spillway gates projects, has resulted in recommendations from the designers to broaden the project scope beyond what was identified at the end of Feasibility Design. This has resulted in a longer design and longer construction schedule resulting in an extension to the overall schedule of approximately two years.	

Project Name: W.A.C. Bennett Dam Rip-Rap Upgrade	
Forecast Capital Cost: $170.4 million to $108.7 million	**In-Service Date:** Fiscal 2020
Development Phase: Definition	**Filing Reference:** Amended F12-F14 RRA: • Application: Amended Appendix I, page 12, Amended Appendix J, page 46 • BCUC IR 1.215.1 BC Hydro Annual Report to the BCUC: • Attachment to Section 8 – Part 2 Appendix I, line 104 Appendix J, page 34 W.A.C. Bennett Riprap Upgrade Project Application; BCUC Decision and Order No. G-78-16 was issued May 27, 2016, subsequent to the planning date for the F17-F19 RRA.

Description:

The purpose of the project is to address inadequate erosion protection on the upstream face of the W.A.C. Bennett Dam.

Key Drivers:

- Safety
- Reliability of Supply

Issues Being Addressed:

The W.A.C. Bennett Dam impounds the Peace River to form Williston Reservoir, which holds up to 74 km^3 of water at full pool. The dam provides storage for the G.M. Shrum generating station.

The primary driver of the project is the safety of the W.A.C. Bennett Dam itself as well as safety of the public, property and environment downstream and reliability of supply.

The outer layer of the dam is comprised of large stone pieces (rip-rap) that protect the internal zones of the dam, including the impervious core, from weathering and erosion. Since the dam's original construction in the 1960s, wind generated waves, ice loading and freeze-thaw actions have damaged the existing rip-rap. Investigations have concluded that erosion of the underlying dam fill is occurring as a result and the protective rip-rap and its underlying bedding layer on the dam face should be replaced on the upper portion of the dam face.

Discussion of Alternatives:

Replacing and upgrading the damaged rip-rap was recommended for further evaluation in Definition phase. There are no other viable alternatives for the project.

Additional Information:

If no intervention is taken, the erosion would ultimately reach the core of the dam, eventually leading to overtopping and uncontrolled release of the reservoir. In practice, BC Hydro would not allow such a sequence of events which could lead to dam failure.

The current consequences of erosion are limited to the localized instability and shallow sliding seen on the upstream face of the dam. The longer the rip-rap is left in a damaged state that does not protect the underlying fill, the greater the chance of significant damage in a high wind event. Should localized failure of the upstream face of the dam occur, BC Hydro would be in a reactive response position, which would likely include emergency reservoir drawdown.

Project Name: W.A.C. Bennett Dam Spillway Gate Upgrade	
Forecast Capital Cost: $35.9 million to $20.3 million (see Additional Information below)	**In-Service Date:** Fiscal 2020
Development Phase: Definition	**Filing Reference:** Amended F12-F14 RRA: • Amended Appendix I, line 76; Amended Appendix J, page 40
Description: This project is to assess the condition and design of the existing electrical, mechanical and protection and control equipment of the flood discharge system, develop design options to enhance reliability and implement the preferred option that provides an acceptable balance between reliability improvements and the investment made.	
Key Drivers: • Safety	
Issues Being Addressed: Upgrades to the electrical, mechanical and protection and control equipment are required to ensure the reliability of the Water Discharge System to pass flows without endangering the dam.	
Discussion of Alternatives: Design options to improve reliability are being developed using informed assessments and cost estimates, to guide decisions towards upgrades that provide a comparatively large increase in performance versus cost to achieve an acceptable balance between safety improvements and the investment made.	
Additional Information: In BC Hydro’s Fiscal 2012-Fiscal 2014 Amended Revenue Requirements Application, this project was named G.M. Shrum Spillway Gate Upgrade Project (Stage 1). The forecast capital cost of $35.9 million to $20.3 million was prepared by Project Delivery. This forecast is based on Engineering’s 2012 feasibility level cost estimate with additions for costs associated with new scope due to site inspections that uncovered poorer conditions than were anticipated. The Engineering Cost Estimate will be formally updated at the conclusion of the Definition Phase.	

<table>
<tr><td colspan="2">Project Name: John Hart Dam Seismic Upgrade</td></tr>
<tr><td>Forecast Capital Cost:
To be determined</td><td>In-Service Date:
To be determined</td></tr>
<tr><td>Development Phase:
Identification</td><td>Filing Reference:
Amended F12-F14 RRA:
• Application: Amended Appendix I, Page 13, Amended Appendix J, page 57
• BCUC IR 1.205.1 Attachment 1, 1.219.10 Attachment 1, 2.127.1
BC Hydro's F2014 Annual Report to BCUC:
• Attachment to Section 8 – Part 2
Appendix I, line 98
Appendix J, page 18</td></tr>
<tr><td colspan="2">Description:
The John Hart Dam requires upgrading to reliably withstand severe earthquake loading. This project will design and construct the following:
• Upgrades to the Middle Earthfill dam and Power Intake Dam;
• Upgrades to the North Earthfill dam;
• Upgrades to the concrete dam, including incorporation of a free overflow spillway; and
• Upgrades to the spillway gates system.</td></tr>
<tr><td colspan="2">Key Drivers:
• Safety</td></tr>
<tr><td colspan="2">Issues Being Addressed:
The John Hart Dam is the most downstream of three dams; Strathcona, Ladore and John Hart forming the Campbell River generation system. The John Hart Dam is comprised of: a concrete gravity dam with a three bay gated spillway; the north and middle earthfill dams; and a Power Intake Dam/structure with six gated bays, connected to three woodstave penstocks.

The John Hart Dam is classified as an Extreme consequence dam and therefore the expected seismic performance under the 2007 Canadian Dam Association Guidelines is for no uncontrolled release (withstand) for the Maximum Design Earthquake ground motion (Maximum Design Earthquake, equivalent to 1/10,000-annual probability of exceedance).

A seismic performance investigation was carried out for the updated seismic hazard. The withstand of the various component dams and spillway gate system is significantly less than the Maximum Design Earthquake, and damage from a seismic event could lead to uncontrolled release of the reservoir. Therefore, seismic upgrades to the dams and spillway gates system are required. There is also a potential for overtopping of the facility due to a flow imbalance situation with the upstream Ladore plant. A free overflow spillway will be constructed to address this concern.</td></tr>
</table>

Discussion of Alternatives:

The following broad alternatives were considered for the John Hart Dam:

1) Leave the Dam in its current state;
2) Decommission the Dam;
3) Permanently lower the reservoir to reduce loading on the Dam; and
4) Improve the condition of the Dam.

Upon assessment of these alternatives, it was concluded that only Option 4 represents an adequate response to the current condition of the Dam. Subsequently, BC Hydro has examined technical alternatives for each of the structures comprising the overall John Hart Dam, as follows.

- Middle Earthfill Dam: new dam in the reservoir; ground treatment; ground treatment combined with a new downstream dam; and a seepage cutoff structure combined with an upstream berm and downstream reinforcement where required;
- North Earthfill Dam: ground treatment with vibro-compaction of upstream loose fill; and a seepage cutoff structure with or without densification of upstream soil (a need for densification depends on the type of the cutoff structure); and
- Concrete Dam: roadway deck upgrade, reinforcing of the upper portions of the dam with anchors, building a passive spillway.

Based on performance, constructability, and cost considerations, BC Hydro has identified a leading alternative consisting of:

- A seepage cutoff structure combined with an upstream berm and downstream reinforcement where required at the Middle Earthfill Dam,
- A seepage cutoff structure (with soil densification if required) at the North Earthfill Dam, and
- Roadway deck upgrade, anchoring and passive spillway construction at the Concrete Dam.

No leading alternative has yet been identified for spillway gate system upgrades but refurbishment and full replacement are being evaluated.

Additional Information:

The John Hart Generating Station Replacement Project includes a new intake and a new power tunnel, and will also decommission the existing intakes and penstocks. The upgraded intake and power tunnel will allow reservoir drawdown for construction of the dam upgrades within this Project.

Project Name: Ladore Spillway Seismic Upgrade	
Forecast Capital Cost: To be determined	**In-Service Date:** To be determined
Development Phase: Identification	**Filing Reference:** Amended F12-F14 RRA: • Amended Appendix I, line 118; Amended Appendix, page 62 BC Hydro's F2014 Annual Report to the BCUC: • Attachment to Section 8 – Part 2 Appendix I, line 118 Appendix J, page 22

Description:

The purpose of the project is to design and construct upgrades to ensure that:

- The spillway and water conveyance system act as an integral water barrier to retain the Ladore Reservoir;
- The spillway can release water in a controlled manner after a seismic event up to maximum design earthquake; and
- Electromechanical systems that operate the spillway have an acceptable level of reliability.

Key Drivers:

- Safety

Issues Being Addressed:

The Ladore Dam is the central dam in the Campbell River System. It is a concrete gravity dam founded on bedrock, and includes a three bay spillway with vertical lift gates. The dam retains the Lower Campbell Reservoir.

The Ladore Dam is classified as an Extreme consequence dam and therefore the expected seismic performance by the 2007 Canadian Dam Association Guidelines is for no uncontrolled release (withstand) for the Maximum Design Earthquake ground motion (Maximum Design Earthquake, equivalent to 1 in 10,000 annual exceedance probability).

A Dam Safety Investigation is in progress to evaluate the seismic performance of the dam, including the spillway, for the updated seismic hazard. Preliminary results indicate that the withstand of the spillway gates and hoist structure is less than the Maximum Design Earthquake and damage could lead to an uncontrolled release of the reservoir. The John Hart reservoir and dam are located just downstream of the Ladore dam. Failure of the Ladore gates could lead to a flow imbalance at John Hart; with potential for overtopping of the John Hart Dam. Therefore, upgrades to the Ladore spillway are required. Work is ongoing to evaluate the seismic performance of the dam.

Discussion of Alternatives:

The Do Nothing alternative is unacceptable as it does not address the dam safety issues.

Assessment of alternatives will be based on an acceptable balance between safety improvements and the investment made.

Additional Information:

In BC Hydro's Fiscal 2012-Fiscal 2014 Amended Revenue Requirements Application, this project was named Ladore Spillway Gate Upgrade (Stage 2).

Project Name: Puntledge Flow Control Improvements	
Forecast Capital Cost: To be determined	**In-Service Date:** To be determined
Development Phase: Identification	**Filing Reference:** BC Hydro's F2014 Annual Report to the BCUC • Attachment to Section 8 – Part 2 Appendix I, line 109 Appendix J, page 9
Description: This project is to minimize the risk of sudden changes in water levels in the Puntledge River, between the Comox Dam and the Puntledge generating station.	
Key Drivers: • Safety	
Issues Being Addressed: The potential for water levels to rise rapidly in the heavily used recreational area of the Puntledge River creates a serious public safety risk. Rapid changes in water levels could result from a number of factors, including mis-operation of the Comox Dam sluice gates, a failure of the Puntledge Generating Station water passage, or failures that force the generating unit out of service.	
Discussion of Alternatives: To be determined	
Additional Information:	

Project Name: Strathcona Upgrade Discharge	
Forecast Capital Cost: To be determined	**In-Service Date:** To be determined
Development Phase: Identification	**Filing Reference:** New

Description:

This project will construct a new Low Level Outlet to allow for effective drawdown the Upper Campbell Reservoir in a post-seismic situation. The drawdown will protect a seriously damaged Strathcona Dam from failure, and help to ensure there is no uncontrolled release of water from the reservoir which could cause multiple public fatalities.

Key Drivers:

- Safety

Issues Being Addressed:

The Strathcona Dam is known to be seismically deficient, and this project is one of the first steps in resolving this major deficiency. The seismic withstand of the current intake and water passage is about 1:800, and cannot be relied upon to assist in reservoir drawdown. Failure would directly impact the post-seismic stability of the dam (which, under Canadian Dam Association's Dam Safety Guidelines, should have a 1:10,000 withstand due to its Extreme Consequence classification).

The provision of a new Low level Outlet, with a new inlet founded on a rock abutment rather than in the earth dam itself, will not only provide emergency deep drawdown of the reservoir, but will allow for future decommissioning of the current intake and water passage, which will provide further protection to the dam.

In addition to developing a new Low Level Outlet, including sizing of the new discharge, the project will establish how the resulting flow will be safely discharged through the Campbell River system. Also, any interim upgrade requirements for the existing outlet (currently out-of-service, and to be eventually decommissioned) will be evaluated.

The eventual re-location of the powerhouse to a safer location, rather than at the toe of the embankment dam, is required in order to proceed with future dam seismic upgrades. Although powerhouse relocation is not part of this project, planning on where to construct a new power tunnel and a new powerhouse is included in the scope, to ensure that the layout will be compatible with the potential footprint for the future upgrade to the embankment dam in the final step of the seismic upgrades.

Discussion of Alternatives:

Retention of the seismic risk associated with Strathcona is considered to be unacceptable, and upgrading this site to a level of acceptable engineering and dam safety practice is necessary.

Conceptual alternatives have been considered to date. These comprise a new Low Level Outlet on either the right or left abutment. However, these concepts are very high level, and additional investigations to confirm bedrock elevations and rock conditions will dictate the feasibility of these options, as well as layout considerations for future powerhouse relocation.

Additional Information:

This project is one of a series of seismic upgrade projects at Strathcona. The full risk reduction strategy is to construct a new low-level outlet (this project), upgrade the spillway, decommission the existing intake tower and power conduit beneath the embankment, relocate the powerhouse and finally, to rebuild the embankment dam. The work will be carried out in a staged manner over two or perhaps three decades.

Project Name: W.A.C. Bennett Dam Seal Low Level Outlets	
Forecast Capital Cost: To be determined	**In-Service Date:** To be determined
Development Phase: Future	**Filing Reference** • New
Description: The purpose of this project is to safely seal the low-level outlet facilities beneath the embankment dam.	
Key Drivers: • Safety	
Issues Being Addressed: Three low level outlets are located beneath the embankment dam, in rock, in the diversion tunnels that were used to divert the river during dam construction. The inlets to the tunnels are located at a depth of about 150 m in the reservoir. The low level outlets were designed as temporary discharge devices for use during first filling and were not intended for use as discharge devices at normal reservoir operating levels. The low level outlets are currently out of service and regular testing or inspections are not carried out due to the high head against the gates and valves. The condition of the outlets equipment, almost 50 years old, is deteriorating making them a potential hazard. An uncontrolled release of water due to structural failure of the low level outlets would eventually result in damage to the dam if the flow was not shutoff. Such a release would be very difficult to stop given the high head and depth of the outlets.	
Discussion of Alternatives: i. **Do-nothing:** This has been the status quo and is no longer considered acceptable for the reasons described above; ii. **Refurbishment:** Refurbishment of the outlets, while technically feasible, would present significant technical and safety challenges to implement. No future operating scenario has been identified that warrants refurbishment of the low level outlets for flow release, as currently designed; and iii. **Seal the Outlets:** For the reasons described above, this alternative is being considered to remove the risks associated with the low level outlets.	
Additional Information:	

<table>
<tr><td colspan="2">Project Name: Bridge River 1 Replace Transformers T1 and T2</td></tr>
<tr><td>Forecast Capital Cost:
$45.1 million</td><td>In-Service Date:
Fiscal 2018</td></tr>
<tr><td>Development Phase:
Implementation</td><td>Filing Reference:
Amended F12-F14 RRA:
• Amended Appendix I, Page 12; Amended Appendix J, Page 50
• BCUC IR 1.204.1 Attachment 1
BC Hydro's F2014 Annual Report to the BCUC
• Attachment to Section 8 – Part 2
Appendix I, line 111
Appendix J, page 1</td></tr>
<tr><td colspan="2">Description:
The purpose of this project is to replace the six single-phase generating unit transformers in Poor condition at the Bridge River 1 generating facility.</td></tr>
<tr><td colspan="2">Key Drivers:
• Reliability of Supply
• Safety</td></tr>
<tr><td colspan="2">Issues Being Addressed:
The Bridge River 1 T1 and T2 transformers were installed and commissioned between 1957 and 1961. The six single-phase transformers connect the four Bridge River 1 generators to the transmission network by stepping up the generator output voltage of 13.8 kV to transmission voltage of 360 kV.

The Equipment Health Rating of each of the transformers is Poor. The health assessment found issues with degradation of insulation and increased off-gassing. Failure of one of the single phase transformers occurred in March 2013, and the failed transformer was replaced with the only spare.

A failure of any one of the single-phase transformers would result in a forced outage for two generators (due to the configuration), and it could be for a period of approximately 18 months.

Auxiliary systems for the transformers, such as the fire protection system, oil containment, foundations, surge arrestors and instrumentation, also require replacement as they are in poor condition.

The transformers contain PCB contaminated oil and must be removed from the system by the year 2025.</td></tr>
<tr><td colspan="2">Discussion of Alternatives:
Four alternatives were evaluated during Identification phase:
i. Do nothing: replace the transformers as they fail;
ii. Like-for-like: replace the transformers in a planned manner at the existing location;
iii. Two three-phase transformers at a new location: replace the six single-phase transformers with two three-phase transformers at a new location. This alternative would continue the current configuration of one unit transformer for two generators; and
iv. Four three-phase transformers at new location: replace the six single-phase transformers with four three-phase transformers at a new location. This alternative would provide one unit transformer for each generator.
The project is installing two three-phase transformers at a new location, as this is the lowest cost alternative that addresses the risk of unplanned outages due to transformer failure, and the safety concerns due to the close proximity of the existing transformers to a public road and rail line.</td></tr>
<tr><td colspan="2">Additional Information:
Project construction is aligned with the planned outages for Bridge River 1 maintenance and other projects.</td></tr>
</table>

<table>
<tr><td colspan="2">Project Name: Cheakamus Units 1 and 2 Generator Replacement</td></tr>
<tr><td>Forecast Capital Cost:
$73.4 million</td><td>In-Service Date:
Unit 1 – Fiscal 2019; Unit 2 – Fiscal 2020</td></tr>
<tr><td>Development Phase:
Implementation</td><td>Filing Reference:
F07/F08 RRA:
• Application: pages 7-65 and 7-76
• BCUC IR 2.347.00 Attachment 1
F09/F10 RRA:
• Application: Appendix I, page 1; Appendix J, page 12
F11 RRA:
• Application: Appendix I, page 2; Appendix J, page 37
• BCUC IRs 1.192.2, 1.192.3, 2.537.1, 1.257.1, 1.265.1 Attachment 1, 1.331.1 Attachment 1, 2.406.3, 2.537.1, 2.537.2 Attachment 1, 2.545.5 Attachment 1, 2.552.2, 2.2.9 Confidential
• JIESC IRs 1.12.4 Confidential Attachment 1, 2.27.1 Attachment 1;
• CECBC IR 1.9.3 Attachment 1
Amended F12-F14 RRA:
• Application: Amended Appendix I, Page 12, Amended Appendix J, Page 36
• BCUC IRs 1.204.1 Attachment 1, 1.219.6 Attachment 1
BC Hydro’s F2014 Annual Report to the BCUC
• Attachment to Section 8 – Part 2
Appendix I, line 84
Appendix J, page 5</td></tr>
<tr><td colspan="2">Description:
The purpose of this project is to replace the Cheakamus generators which are in Poor condition. There is also an opportunity to uprate the generators to achieve increased dependable capacity and energy.</td></tr>
<tr><td colspan="2">Key Drivers:
• Reliability of Supply</td></tr>
</table>

Issues Being Addressed:

Cheakamus generating station is a Strategic facility and is the largest hydro facility in the Lower Mainland. The existing Unit 1 and Unit 2 generators were installed in 1957 when the generating station was constructed and are each rated at 70 MW.

Inspection and testing of one of the generators in 2006 identified three areas of concern: stator core waves, hot spots and sole plate cracking. The generators were re-assessed in 2012 and 2013, and the Equipment Health Rating was confirmed as Poor for each unit. Some of the issues which adversely affect the health rating include high stator winding insulation leakage current, deterioration of the stator and rotor insulation, stator core waves, and bearing oil leaks.

A failure of a stator winding would likely result in an unplanned unit outage of up to 18 months and lost opportunity costs.

In addition to the need to address the Poor condition of the generators to maintain reliability of supply, there is an opportunity to increase the rated capacity of the Cheakamus generating units to 90 MW each. All other equipment required to support the increase to 90 MW per unit is already in service.

Discussion of Alternatives:

Three alternatives were evaluated during Identification phase:

i. Do nothing: replace the stator winding, stator core and rotor pole insulation at failure:

ii. Refurbish the generators via replacement of the stator core, stator winding and rotor pole insulation; no uprate of the generators would be achieved; and

iii. Replace the generators with increased capacity.

Replacing the generators with increased capacity was recommended as it is the lowest cost alternative based on the results of the NPV analysis.

Additional Information:

<table>
<tr><td colspan="2">Project Name: Bridge River 2 Upgrade Units 5 and 6</td></tr>
<tr><td>Forecast Capital Cost:
$83.3 million to $52.5 million</td><td>In-Service Date:
Fiscal 2019</td></tr>
<tr><td>Development Phase:
Definition</td><td>Filing Reference:

F07/F08 RRA:
• BCUC IR 1.193.0 Attachment 1
• BCUC IR 2.347.0 Attachment 1

F09/F10 RRA:
• Application: Appendix I, page 1; Appendix J, page 9

F11 RRA:
• Application, Appendix I, page 3; Appendix J, pages 55 and 56
• BCUC IRs 1.192.2, 1.192.3, 1.331.1 Attachment 1 and 2, 2.406.3, 2.545.5 Attachment 1

Amended F12-F14 RRA
• Application: Amended Appendix I, page 12; Amended Appendix J, page 36
• BCUC IRs 1.200.0, 1.204.1 Attachment 1, 1.211.0

BC Hydro’s F2014 Annual Report to the BCUC
• Attachment to Section 8 – Part 2
Appendix I, line 108
Appendix J, page 3</td></tr>
<tr><td colspan="2">Description:
The purpose of this project is to restore the reliability of the Unit 5 and 6 generators and their ancillary systems, as well as the reliability of other major components (governors, exciters and circuit breakers).
The project also presents an opportunity to uprate the generators to achieve incremental dependable capacity and energy.</td></tr>
<tr><td colspan="2">Key Drivers:
• Reliability of Supply</td></tr>
<tr><td colspan="2">Issues Being Addressed:
These units were placed into service in 1960. The primary drivers for this project are the lost capacity, unacceptable condition and unreliability of the Bridge River 2 generating Units 5 and 6.
The Equipment Health Rating of the generators is Unsatisfactory. Both generators have been de-rated by 32 per cent due to multiple winding insulation failures. There is a high risk of further winding failures, which would result in an unplanned unit outage of up to 18 months.
The Equipment Health Rating of the governors is Poor due to their condition, life expectancy, high rate of oil leakage in the distributing valve, and lack of spare parts. Similarly, the unit circuit breakers are rated Poor due to significant wear, lack of spare parts, and declining technical support. The exciters are also rated Poor due to degradation, age and difficulty in obtaining technical support.</td></tr>
</table>

Discussion of Alternatives: Alternatives evaluated during Identification phase: i. **Do nothing:** Replace components as they fail; ii. **Minimum refurbishment:** Replace the stator winding, stator core and rotor pole insulation; no uprate of the generators would be achieved. Other equipment required for reliable operation (e.g., governors, circuit breakers, exciters) would also be replaced; iii. **Refurbish the generators with increased capacity:** Replace most generator components (e.g., stator frame, winding, cores; and rotor insulation, poles, winding) and reuse other generator components (e.g., rotor rim, spider, shaft). Other equipment required for reliable operation would also be replaced (similar to minimum refurbishment); and iv. **Replace the generators with increased capacity**: Replace all stator and rotor components. Other equipment required for reliable operation would also be replaced (similar to minimum refurbishment). Replacing the generators with increased capacity was recommended for further evaluation in the Definition phase. Upgrading the units will mitigate the significant reliability risk, provide an opportunity to increase unit capacity and provide the lowest risk solution from the construction and future operating perspectives.
Additional Information: The project will be constructed considering the planned outages for Bridge River 2 maintenance and other projects.

Project Name: G.M. Shrum G1 to 10 Control System Upgrade	
Forecast Capital Cost: $77.2 million to $58.4 million	**In-Service Date:** Tranche 1 – Fiscal 2018 Tranches 2 and 3 – Fiscal 2022
Development Phase: Definition and Implementation (staged execution as three tranches of work)	**Filing Reference:** Amended F12-F14 RRA: • Application: Amended Appendix I, Page 12; Amended Appendix J, Pages 101 to 103 BC Hydro's F2014 Annual Report to the BCUC • Attachment to Section 8 – Part 2 Appendix I, line 91 Appendix J, page 10
Description: This purpose of this project is to improve the future reliability of G.M. Shrum by modernizing Units 1 to 10 control systems; replacing Units 6 to 10 governor control systems; replacing Units 9 and 10 exciters; replacing the controls for plant auxiliary systems; and replacing the G.M. Shrum control room controls..	
Key Drivers: • Reliability of Supply	
Issues Being Addressed: The existing G.M. Shrum unit control equipment was installed when the powerhouse was constructed in the late 1960s and early 1970s; it is analog-based and obsolete. The G.M. Shrum Units 6 to 8 governors have an Equipment Health Rating of Poor, due to the tendency of the analog controls to drift out of calibration, limited technical support, the governor frequency control being out of specification during standardized tests, and limited availability of spare parts. The Unit 9 analog governor has an Equipment Health Rating of Poor due to the forced outages attributed to the governor, limited technical support and limited spare parts availability. The Unit 10 analog governor, which is from the same manufacturer as Unit 9, has an Equipment Health Rating of Fair. The G.M. Shrum Units 9 and 10 Westinghouse Rapcon exciters have analog controls and are based on obsolete technology. Unit 9 has an Equipment Health Rating of Fair, and Unit 10 has an Equipment Health Rating of Poor. Concerns include component failures, limited availability of spare parts, and limited technical support.	
Discussion of Alternatives: Various options for completing this work were considered, but consolidating this work into a single project minimizes total outage time to complete the work and avoids designing and implementing interfaces between new digital and existing analog equipment.	

Additional Information:

This project is a consolidation of the following projects in BC Hydro's Fiscal F2012–Fiscal 2014 Amended Revenue Requirements Application:

- G.M. Shrum Unit 1-5 Control System Upgrade;
- G.M. Shrum Unit 6-10 Governor Replacement; and
- G.M. Shrum Unit 6-10 Control System Upgrade

Replacement of the Unit 9 and 10 exciters was added to the project scope to benefit from efficiencies in project delivery and engineering design.

The project has been organised into three tranches:

- Tranche 1: Units 1-5 controls and plant Local Area Network;
- Tranche 2: Units 6-10 controls, Unit 6-10 governor controls, and Units 9-10 exciters; and
- Tranche 3: Spillway, switchyard and intake controls, and G.M. Shrum control room controls.

<table>
<tr><td colspan="2">Project Name: Lake Buntzen 1 Coquitlam Tunnel Gates Refurbishment</td></tr>
<tr><td>Forecast Capital Cost:
$48.6 million to $ 20.8 million</td><td>In-Service Date:
Fiscal 2022</td></tr>
<tr><td>Development Phase:
Definition</td><td>Filing Reference:
F11 RRA:
• Application: Appendix I, Page 3; Appendix J, Page 51
Amended F12 – F14 RRA
• Application: Appendix I, line 101; Appendix J, page 42</td></tr>
<tr><td colspan="2">Description:
This project will address water conveyance reliability risks associated with the tunnel from the Coquitlam Reservoir to Lake Buntzen.</td></tr>
<tr><td colspan="2">Key Drivers:
• Safety
• Reliability of Supply</td></tr>
<tr><td colspan="2">Issues Being Addressed:
The purpose of the tunnel is to act as a reservoir discharge facility to manage year round control of the Coquitlam Reservoir elevation and supply water to Buntzen Lake and Lake Bunzten Generating facility. Control of the reservoir elevation by tunnel discharge is essential to minimize spilling into the Coquitlam River, downstream of the Coquitlam Dam. Spilling into the Coquitlam River risks moderate to severe municipal flooding and aquatic habitat impacts.
There are two Intake Operating Gates located in the tunnel to control flow. In addition, one Intake Maintenance Gate is provided for isolating the two Intake Operating Gates and the tunnel. Tunnel isolation is required to complete inspections and maintenance of the tunnel and Intake Operating Gates.
The Intake Operating Gates are in poor condition and are original equipment. The operating gates have failed in service a number of times due to broken rollers and wire ropes and have experienced difficulties opening under high head conditions.
The Intake Maintenance Gate is in fair condition, with Single Device Isolation certification expiring in October 2016, a WorkSafe BC requirement for maintenance of the tunnels and Intake Operating Gates. Issues with the Intake Maintenance Gate that must be corrected before re-certification can be achieved include replacing the bottom seals and guides and stripping and re-coating or replacing the gate.</td></tr>
</table>

Discussion of Alternatives:

The following alternatives were considered in the Identification phase:

i. Do nothing, and continue to repair the gates as they fail;

ii. Replace the two Intake Operating Gates at the existing location and install the Intake Maintenance Gate at a new location;

iii. Enlarge the Intake Operating Gates vertical access shaft and replace the concrete pier to provide a new location for two new Intake Operating Gates and replace the Intake Maintenance Gate with two new gates at the existing location of the two Intake Operating Gates;

iv. Replace the two Intake Operating Gates and the Intake Maintenance Gate at their existing locations and refurbish the existing Intake Maintenance Gate concrete gate wall; and

v. Refurbish the mechanical parts of the two Intake Operating Gates at their existing locations to achieve a 15-year service life, including re-use of gate system components; and replace the Intake Maintenance Gate at its existing location and refurbish the existing Intake Maintenance Gate concrete gate wall.

The preferred alternative is to refurbish the two Intake Operating Gates and replace the Intake Maintenance Gate, all at their existing locations. It is the optimum cost alternative that addresses the majority of the business risks associated with the unplanned loss of the tunnel due to gate failure.

Additional Information:

Project Name: Bridge River 1 Upgrade Unit 4 Generator and Governor	
Forecast Capital Cost: To be determined	**In-Service Date:** To be determined
Development Phase: Identification	**Filing Reference:** BC Hydro 2014 Annual Report to the BCUC • Attachment to Section 8 – Part 2 Appendix I, page line 139 Appendix J, page 2
Description: This project will restore the capacity and reliability of the Unit 4 generator and governor. The project also presents an opportunity to increase the capacity of the generators to achieve incremental dependable capacity and energy.	
Key Drivers: • Reliability of Supply	
Issues Being Addressed: The primary driver for the Project is the unacceptable condition of the Bridge River 1 Unit 4 generator and governor and the corresponding business risks. The equipment was initially placed in service in 1954, and the generator stator was re-wound in 1973. In 2011, Bridge River 1 Unit 4 experienced a stator winding failure during routine maintenance testing. Repairs necessitated cutting out and bypassing the failed windings. As a result, the unit was de-rated from 50 MW to 40 MW, and the Equipment Health Rating of the generator was downgraded to Unsatisfactory. Due to the deteriorated condition of the winding, there is a significant risk that another winding failure may occur, resulting in the permanent shutdown of the generator. The Equipment Health Rating of the Unit 4 governor is Poor due to its condition and the lack of spare parts and technical support from the manufacturer. Upgrading the generator and governor will mitigate the reliability risks and provide an opportunity for increased unit capacity.	
Discussion of Alternatives: The alternatives under consideration include: i. Do nothing: Replace the generator and other major / ancillary components as they fail; ii. Rewind the generator stator and replace other needed components to ensure the unit capability is restored to original generator rating. Maintain or replace other minor ancillary components as they fail; iii. Refurbish the generator and other major ancillary components. Unit capacity shall at least align with the current runner design and be optimized to an opportunistic capability of the overall system without making major modifications to the existing plant and civil structure; and iv. Replace the generator and other major ancillary components. Unit capacity shall at least align with the current runner design and be optimized to an opportunistic capability of the overall system without making major modifications to the existing plant and civil structure.	
Additional Information:	

Project Name: Bridge River 2 Upgrade Units 7 and 8	
Forecast Capital Cost: To be determined	**In-Service Date:** To be determined
Development Phase: Identification	**Filing Reference:** New

Description:

The purpose of this project is to restore the reliability of the Unit 7 and 8 generators and their ancillary systems, as well as the reliability of other major components such as the circuit breakers.

The project also presents an opportunity to uprate the generators to achieve incremental dependable capacity and energy.

Key Drivers:

- Reliability of Supply

Issues Being Addressed:

Bridge River 2 generating Units 7 and 8 were placed into service in 1960. The primary drivers for this project are the lost capacity, unacceptable condition and unreliability of the Bridge River 2 generating Units 7 and 8.

The Equipment Health Rating of both generators is Poor. Unit 8 was forced out of service in July 2015 due to a bus fault leading to failure of the generator stator winding. The unit has been returned to service and de-rated. For both units, there is a high risk of stator winding failures, which could result in an unplanned unit outage of up to 18 months.

The Equipment Health Rating of the circuit breakers is Poor due to significant wear, lack of spare parts, and declining technical support. A failure of this major component would also result in an extended unplanned outage for the unit.

Discussion of Alternatives:

The alternatives under consideration include:

i. **Do nothing:** Replace components as they fail;

ii. **Refurbish the generators with increased capacity:** Replace most generator components (e.g., stator frame, winding, cores; and rotor insulation, poles, winding) and reuse other generator components (e.g., rotor rim, spider, shaft). Other equipment required for reliable operation could also be replaced (e.g., circuit breakers); and

iii. **Replace the generators with increased capacity:** Replace all stator and rotor components. Other equipment required for reliable operation could also be replaced.

Additional Information:

<table>
<tr><td colspan="2">Project Name: Cheakamus Recoat Units 1 and 2 Penstocks (Interior and Exterior)</td></tr>
<tr><td>Forecast Capital Cost:
To be determined</td><td>In-Service Date:
To be determined</td></tr>
<tr><td>Development Phase:
Identification</td><td>Filing Reference:
BC Hydro’s F2014 Annual Report to the BCUC
• Attachment to Section 8 – Part 2
Appendix I, line 120
Appendix J, page 4</td></tr>
</table>

Description:

The purpose of this project is to strip and recoat the interior and exterior of the penstocks, thereby protecting the steel from further deterioration for approximately 25 years.

Key Drivers:

- Reliability of Supply
- Financial

Issues Being Addressed:

Two separate steel penstocks carry water over steep terrain to the Cheakamus Generating Station. Each penstock is 1,680 feet in length and 8.75 feet in diameter with an angle of declination of 45 degrees. The penstocks were installed in 1957 and are designed to withstand high head pressure.

The penstock protective coating prevents corrosion of the steel penstock, which reduces the metal thickness and strength of the penstock. To ensure the longevity of a penstock, the protective coating will typically be reapplied periodically throughout the penstock’s service life. The internal and external coatings of the Cheakamus penstocks have failed and active corrosion exists. Corrosion is reducing the thickness of the penstocks and could impact the penstock service life if recoating is not undertaken.

An inspection of the penstock concluded:

i. The penstock exterior coating has failed with rust blooms covering significant areas of the penstock. This could develop into aggressive corrosion and cause structural damage if not recoated; and

ii. The penstock interior coating has failed and extensive corrosion exists. Failure of the interior coating could lead to aggressive corrosion and structural damage if the internal coating is not replaced.

Discussion of Alternatives:

The alternatives under consideration include:

i. A “Do Nothing” Alternative was dismissed as it will result in increased safety and reliability risks each year, and result in an earlier retirement of the assets;

ii. Strip and Recoat Interior and Exterior Surface of Steel Penstocks;

iii. Strip and Recoat Only Exterior Surface of Steel Penstocks; and

iv. A “Complete Replacement” Alternative was also dismissed as significant life extension of the penstocks can be achieved through recoating. Replacement costs would also be significantly higher than recoating costs.

The leading alternative is Strip and Recoat Interior and Exterior Surface of Steel Penstock.

Additional Information:

Cost efficiencies and reduced mobilization and de-mobilization costs are expected to be realized by recoating all the surfaces as part of one project.

Project Name: Mica Modernize Controls	
Forecast Capital Cost: To be determined	**In-Service Date:** To be determined
Development Phase: Identification	**Filing Reference:** New

Description:

The purpose of this project is to modernize the original Mica Unit 1 to 4 analog unit and control room controls, alarms and metering; replace the excitation systems; upgrade the governor controls; and replace the unit protection equipment.

Key Drivers:

- Reliability of Supply

Issues Being Addressed:

The Mica Unit 1 to 4 control room equipment; unit protection and control equipment; exciter, and governor controls were installed in 1976 and 1977. This equipment enables safe and reliable operation of the facility as it provides operating and alarm information to the station operators as well as enabling them to control the generating facility equipment. Failures of this equipment could result in equipment problems not being detected quickly, causing greater damage than would otherwise occur.

The control room equipment is original analog equipment, which is no longer manufactured. The control systems equipment is difficult to maintain due to lack of spare parts and technical support.

The excitation systems are Westinghouse Rapcon exciters, which are no longer manufactured. The technology is no longer supported by the industry and technical expertise on this type of older technology is no longer readily available. Limited availability of spare parts is also a concern.

The original electromechanical unit protection systems are in poor condition and there is an increased risk that the protection relays may fail to operate during an electrical fault.

Due to the lack of readily available spare parts and technical expertise, a major failure of either the governor or exciter could result in a generator forced outage of the affected unit for up to 12 months.

Discussion of Alternatives:

To be determined

Additional Information:

<table>
<tr><td colspan="2">Project Name: Mica Upgrade Powerhouse Cranes</td></tr>
<tr><td>Forecast Capital Cost:
To be determined</td><td>In-Service Date:
To be determined</td></tr>
<tr><td>Development Phase:
Identification</td><td>Filing Reference:</td></tr>
<tr><td colspan="2">Description:
This project will upgrade the main Mica powerhouse cranes, each with a rated load capacity of 525 tons, as required for a tandem lift of any generator rotor.</td></tr>
<tr><td colspan="2">Key Drivers:
• Reliability of Supply</td></tr>
<tr><td colspan="2">Issues Being Addressed:
The primary drivers for the Project are: 1) the age and poor condition of the existing cranes and runway support structures; and 2) the requirement for two powerhouse cranes, each with a rated load capacity of 525 tons, to lift a generator rotor. Currently, the existing powerhouse cranes have been de-rated to a load capacity of 315 tons each and are inadequate for lifting a generator rotor.
The poor condition of the powerhouse cranes resulted in two recent crane failures. In June 2014, the cranes failed during the tandem lift of the Unit 5 rotor, resulting in delays to the Mica Units 5 and 6 project. Subsequently, in May 2015, the powerhouse cranes failed during a test load lift in advance of the Unit 6 rotor lift, resulting in further delays to the Mica Units 5 and 6 project.
The Mica Units 5 and 6 project is expected to be complete by December 2016. This project is being initiated to replace the existing powerhouse cranes, upgrade the crane runway support structure and improve emergency egress and rescue from the cranes.</td></tr>
<tr><td colspan="2">Discussion of Alternatives:
The alternatives under consideration include:
i. Install only the cranes;
ii. Install the cranes, and perform runway upgrades; and
iii. Stop or defer the project.</td></tr>
<tr><td colspan="2">Additional Information:
Site construction work for the Mica Units 5 and 6 project began in May 2011. The new powerhouse cranes were intended to be in service by October 2011. However, manufacturing delays created unacceptable installation schedule risks and it was decided to defer installation of the new cranes until after completion of the Mica Units 5 and 6 project.</td></tr>
</table>

<table>
<tr><td colspan="2">Project Name: Puntledge Recoat Interior and Exterior of Steel Penstock</td></tr>
<tr><td>Forecast Capital Cost:
To be determined</td><td>In-Service Date:
To be determined</td></tr>
<tr><td>Development Phase:
Identification</td><td>Filing Reference:
BC Hydro’s F2014 Annual Report to the BCUC
• Attachment to Section 8 – Part 2
Appendix I, line
Appendix J, page 26</td></tr>
<tr><td colspan="2">Description:
The purpose of this project is to strip and recoat the interior and exterior of the Puntledge Generating Station steel penstock, to protect it from corrosion and extend the life of the penstock.</td></tr>
<tr><td colspan="2">Key Drivers:
• Financial</td></tr>
<tr><td colspan="2">Issues Being Addressed:
Water conveyance to the single 24 MW generating unit at Puntledge Generating Station is supplied by a 5 km long penstock which also supplies water to the City of Courtenay. The 1,372 m long woodstave penstock starts at the Puntledge Diversion Dam and then transitions to a 3,598 m steel penstock which extends to the powerhouse.
The steel section of the penstock is exhibiting signs of coating failure. The Equipment Health Rating for the penstock coating is Unsatisfactory.
To ensure the longevity of a penstock, the protective coating will typically be reapplied periodically throughout the penstock’s service life. Periodic recoating of the penstock represents the lowest life-cycle cost.Without recoating, the extent of corrosion damage will increase and, over time, will impact the structural integrity of the steel material to the point where recoating is no longer an option and a penstock replacement is required.</td></tr>
<tr><td colspan="2">Discussion of Alternatives:
The alternatives under consideration include:
i. A “Do Nothing” Alternative was dismissed as it will result in increased safety and reliability risks each year, and result in an earlier retirement of the assets;
ii. Strip and Recoat Only Exterior Surface of Steel Penstock;
iii. Strip and Recoat Interior and Exterior Surface of Steel Penstock; and
iv. A “Complete Replacement” Alternative was dismissed as significant life extension of the penstocks can be achieved through recoating. Replacement cost would is significantly higher than recoating costs.
The leading alternative is Strip and Recoat Interior and Exterior Surface of Steel Penstock.</td></tr>
<tr><td colspan="2">Additional Information:</td></tr>
</table>

<table>
<tr><td colspan="2">Project Name: Mica Replace Units 1 to 4 Generator Transformers</td></tr>
<tr><td>Forecast Capital Cost:
To be determined</td><td>In-Service Date:
To be determined</td></tr>
<tr><td>Development Phase:
Future</td><td>Filing Reference:
New</td></tr>
<tr><td colspan="2">Description:
The purpose of this project is to replace twelve single-phase generating unit transformers at the Mica facility with explosion-resistant transformers due to the poor condition of the transformers and to mitigate the life safety risk of a transformer failure in the underground powerhouse.</td></tr>
<tr><td colspan="2">Key Drivers:
• Safety</td></tr>
<tr><td colspan="2">Issues Being Addressed:
The Mica unit transformers were commissioned in 1976 and 1977. The twelve single-phase transformers connect the Unit 1 to 4 Mica generators to the transmission network by stepping up the generator output voltage of 16 kV to transmission voltage of 500 kV.

The Equipment Health Rating of eight transformers is Poor, while the other four are rated as Fair. After nearly 40 years of service, several of the transformers are showing signs of overheating while others have indications of insulation degradation. BC Hydro’s recent experience with the transformer failure, and subsequent fire, at Atchelitz sub-station has increased awareness of the potential consequences after a transformer fault. As the Mica transformers are located in an underground powerhouse, a failure presents a life safety risk for people working in the underground powerhouse in addition to resulting in a forced outage. There is an increased risk of failure as these transformers age, and the life safety risk can be largely mitigated through the installation of modern explosion-resistant transformers (similar to those installed on Mica Units 5 and 6).</td></tr>
<tr><td colspan="2">Discussion of Alternatives:
To be determined.</td></tr>
<tr><td colspan="2">Additional Information:</td></tr>
</table>

Project Name: Seven Mile Overhaul Units 1 to 3 Turbines	
Forecast Capital Cost: To be determined	**In-Service Date:** To be determined
Development Phase: Future	**Filing Reference:** New
Description: The purpose of this project is to overhaul Units 1 to 3 turbines in order to provide continued reliable service.	
Key Drivers: • Reliability of Supply	
Issues Being Addressed: Seven Mile Units 1 to 3 have been in service for over 35 years without a major turbine overhaul, and the units are now demonstrating an elevated level of wear. Units 1 to 3 runner blades have excessive cavitation erosion, as well as a history of stainless steel cladding plate failures due to a poorly installed protective overlay. Cavitation has been an issue since the original installation, and significant weld repairs are undertaken at two-year intervals, with a significant maintenance cost. In addition, the efficiency of the Seven Mile Unit 1 to 3 turbines did not meet the original contract specifications. The expected efficiency gains for a modern design runner and wicket gates would be in range of 2 to 3 per cent. Given these potential benefits, during the identification phase of the project, a runner replacement may be considered as an alternative.	
Discussion of Alternatives: To be determined	
Additional Information:	

<table>
<tr><td colspan="2">Project Name: Courtenay Area Substation</td></tr>
<tr><td>Total Capital Cost:
$32.1 million</td><td>In-Service Date:
Fiscal 2017</td></tr>
<tr><td>Development Phase:
Implementation</td><td>Filing Reference:
BCUC Order No. G-87-09
Amended F12-F14 RRA:
• Application: Amended Appendix I, page 17 , Amended Appendix J, page 90
• BCUC IR 1.204.1 Attachment 1, 1.229.1, 1.237.1.
F2014 Annual Report to the BCUC:
• Appendix I, line 35;
• Appendix J, page 44.</td></tr>
<tr><td colspan="2">Description:
This project will construct a new 138/25 kV substation located south of Puntledge and Comox Substations in northern Vancouver Island. The new substation will be tapped to existing transmission circuits 1L101 and 1L119.</td></tr>
<tr><td colspan="2">Key Drivers:
• Load Growth</td></tr>
<tr><td colspan="2">Issues Being Addressed:
The Courtenay area is presently supplied by Puntledge and Comox. No other substations exist within a 25 km radius. Due to significant load growth in the area, the Courtenay area load presently exceeds the area firm supply capacity. The firm supply capacity for Courtenay area is 155 MVA. The latest load forecast indicates winter load in Courtenay exceeds station firm capacities by 25 MVA.
The impact of exceeding firm capacity prior to the in-service date of the new substation will be managed by Distribution Operations Planning through temporary transfer of some loads between Comox and Puntledge if this becomes necessary during forced outage conditions.</td></tr>
<tr><td colspan="2">Discussion of alternatives:
i. Construct a new substation located south of Puntledge and Comox substations: This alternative has the lowest present value for the combined transmission and distribution cost, and provides the best reliability improvement for both transmission and distribution systems. This alternative also results in transmission and distribution loss reduction. This is the selected alternative;
ii. Expand both or either of Puntledge and Comox substations: Expansion of Puntledge and Comox substations results in higher transmission losses than the recommended alternative based on power flow studies. The cumulative present value for the combined transmission and distribution cost of this alternative is higher than the selected alternative; and
iii. Do Nothing: Load curtailment of 8 MVA and 17 MVA will be required during single transformer failure in Puntledge and Comox stations respectively. Therefore, this alternative is considered unacceptable.</td></tr>
<tr><td colspan="2">Additional Information:
Commission Order No. G-87-09 approved the definition phase of this project.</td></tr>
</table>

Project Name: North Peace River Area RAS Add Capacity	
Total Capital Cost: $22 million	**In-Service Date:** Fiscal 2017
Development Phase: Implementation	**Filing Reference:** Amended F12-F14 RRA: • Application: Amended Appendix I, page 37, Amended Appendix J, page 138 • BCUC IRs 1.240.1, 1.240.2, 1.249.1, 1.249.2, 1.249.3 and 1.249.4 • BCOAPO IR 2.72.1
Description: This project will expand the generation shedding remedial action scheme in the Peace Region to facilitate the connection of new independent power producers (**IPP**) wind generation in the area awarded under the 2008 Clean Power Call.	
Key Drivers: • IPP Interconnection	
Issues Being Addressed: Five wind farm IPPs were selected in the BCH 2008 Clean Power Call, including the Wildmare, Tumbler Ridge, Quality, Meikle and Bullmoose projects with expected interconnection to the BC Hydro system by 2013. Two of the five projects have since proceeded, Quality (2012) and Meikle (fall 2016). In order to interconnect these wind farms into the BC Hydro system, a generation shedding scheme meeting North American Electric Reliability Corporation/Western Electricity Coordinating Council Mandatory Reliability Standards is required to protect the system and customer equipment against overloading, system instability, over frequency, and potential large voltage swings.	
Discussion of Alternatives: i. **Remedial Action Scheme using microwave communication:** This alternative can be constructed in time to interconnect the IPPs and meet the Mandatory Reliability Standards requirements. This is the selected alternative; ii. **Remedial Action Scheme using Power Line Carrier communication:** Western Electricity Coordinating Council Remedial Action Scheme Design Guide states that Power Line Carrier communication does not meet the reliability requirement for this system wide area protection scheme. This alternative is not acceptable; iii. **Transmission reinforcement:** This alternative would require a new 500/230 kV transformer at G.M. Shrum generating station, a new 500 kV transmission line from G.M. Shrum generating station to Kelly Lake at a cost exceeding hundreds of million dollars and requiring years to construct. This alternative is neither economical nor practical; and iv. **Do Nothing:** Do nothing is not a viable option as the BC Hydro system would violate mandatory reliability standards under contingencies.	
Additional Information:	

<table>
<tr><td colspan="2">Project Name: Wellington Substation (formerly Nanaimo Area Substation)</td></tr>
<tr><td>Total Capital Cost:
$28.9 million</td><td>In-Service Date:
Fiscal 2017</td></tr>
<tr><td>Development Phase:
Implementation</td><td>Filing Reference:
Commission Order No. G-87-10
Amended F12-F14 RRA:
• Application: pages 6-17, Amended Appendix I, page 17, Amended Appendix J, page 92
• BCUC IRs 1.181.1 Attachment 1, 1.204.1 Attachment 1, 1.229.1, 2.123.1 Attachment 1
• BCOAPO IRs 1.38.1 Attachment 2
F2014 Annual Report to the BCUC:
• Appendix I, line 34;
• Appendix J, page 75.</td></tr>
<tr><td colspan="2">Description:
Construct a new 138/25 kV substation in the Nanaimo area between Harewood and Ladysmith substations. This project will address the substation and distribution constraints in the south Nanaimo area.</td></tr>
<tr><td colspan="2">Key Drivers:
• Load growth</td></tr>
<tr><td colspan="2">Issues Being Addressed:
The Nanaimo area is being served from four substations: Harewood, Ladysmith, Lantzville and Northfield substations. Capacity constraints have been identified at Harewood and Ladysmith.
The firm transformation capacities at Harewood and Ladysmith are 94.5 MVA and 59.5 MVA respectively. The peak load at Harewood exceeded the firm capacity of this station by approximately 3 MVA in 2013 and is forecast to exceed it by 26 MVA by the end of the 10-year forecast. The peak load at Ladysmith exceeded the firm capacity of this station by approximately 5.7 MVA in 2013. The new Wellington Substation will provide an additional 100 MVA of capacity to the region.
There are distribution system constraints at both Harewood and Ladysmith. The limited number of remaining overhead feeder corridors and restrictions in the overhead feeder egress at Harewood and Ladysmith will require higher cost underground feeders to supply new load growth.</td></tr>
</table>

Discussion of alternatives:

i. **New Wellington Substation:** Construct a new 138/25 kV substation in the Nanaimo area between Harewood and Ladysmith. This is the selected alternative because it resolves the substation and distribution constraints and is the lowest cost alternative;

ii. **Expand Harewood:** Install another transformer and feeder section at Harewood. Harewood would supply load growth in the region and pick up load transfers from Ladysmith and Northfield substation. The distribution constraints would be resolved by installing underground feeders. This alternative has a higher cost than the selected alternative;

iii. **Expand Harewood and Ladysmith:** Install another transformer and feeder section at Harewood in addition to replacing the existing transformers at Ladysmith with larger units. Although Ladysmith would be upgraded, Harewood would still pick up most of the load growth in the region. The distribution constraints would be resolved by installing underground feeders. This alternative has a higher cost than the selected alternative;

iv. **Load transfer to Northfield:** Upgrade Northfield to facilitate load transfers from Harewood. This alternative was not recommended because the existing substation property was unlikely to be able to accommodate these station upgrades together with the equipment slated to be installed to facilitate the future 230 kV station conversion. In addition, the significant upgrades required at Northfield could disrupt service to customers during the construction phase; and

v. **Do Nothing:** Load curtailment of at least 9 MVA load will be required during single transformer failure in either Harewood or Ladysmith substation. Therefore, this alternative is considered unacceptable.

Additional Information:

Commission Order No. G-87-10 approved the definition phase of this project.

<table>
<tr><td colspan="2">Project Name: Horne Payne Substation Upgrade</td></tr>
<tr><td>Total Capital Cost:
$92.6 million</td><td>In-Service Date:
Fiscal 2019</td></tr>
<tr><td>Development Phase:
Implementation</td><td>Filing Reference:
Amended F12-F14 RRA:
• Application: pages 6-17, 6-52, Amended Appendix I, Page 17, Amended Appendix J, Page 89
• BCUC IRs 1.181.1 Attachment 1, 1.204.1 Attachment 1, 2.123 Attachment 1
• BCOAPO IR 1.38.1 Attachment 2
F2014 Annual Report:
• Appendix I, line 27;
• Appendix J, page 48.</td></tr>
<tr><td colspan="2">Description:
The North Burnaby Area study developed a 30-year plan for the Horne Payne, Lougheed and Barnard substations and service areas. The first resulting project from the study is the Horne Payne Substation Upgrade, which includes the addition of two 230/25 kV, 150 MVA transformers and three 25 kV, 50 MVA indoor gas-insulated feeder sections. A new control building will also be added, and the existing main control building will be decommissioned.</td></tr>
<tr><td colspan="2">Key Drivers:
• Load Growth
• Voltage Conversion
• Ageing assets</td></tr>
<tr><td colspan="2">Issues Being Addressed:
The existing firm capacity of Horne Payne is 190 MVA. The winter load demand is forecast to exceed the firm capacity in fiscal 2017. This project will increase the firm capacity, add much needed feeder positions, facilitate the gradual conversion of the area supply voltage from 12 kV to 25 kV, and allow for the implementation of an open-loop distribution topology. Conversion to 25 kV will eliminate the existing issue of high fault current on the distribution bus at Horne Payne and also reduce distribution losses. The additional capacity at Horne Payne will allow for the replacement of the 50/60 feeder section, as well as allow for the ageing Lougheed substation to be gradually offloaded to Horne Payne in preparation for its redevelopment in fiscal 2025.</td></tr>
</table>

Discussion of alternatives:

i. **25 kV Alternative:** Major redevelopment at Horne Payne in fiscal 2019, Lougheed in fiscal 2025 and Barnard in F2028 to add new 25 kV equipment to supply load at 25kV. This is to convert the area distribution supply from 12 kV to 25 kV over 30 years in alignment with the long term distribution strategy of voltage conversion to 25 kV. This is currently the selected alternative;

ii. **12 kV Alternative:** Major redevelopment/addition at Horne Payne in fiscal 2019 and Barnard in fiscal 2027 to add new 12 kV equipment to supply additional 12 kV load and transfer load in excess of station firm capacity at Lougheed to Horne Payne. The area distribution load will continue to be supplied at 12 kV. This alternative will not address the long term goal of distribution voltage conversion to 25 kV and the high fault current level on the distribution bus at Horne Payne;

iii. **Defer Investment:** Use cascaded load transfers from Horne Payne to Lougheed then to Barnard to utilize the spare capacity at Barnard. This alternative would require initial distribution investments of $23 million to transfer the loads and provided only three years deferral of investments before Horne Payne would require an upgrade; and

iv. **Do Nothing:** This alternative does not address any of the issues. The lack of feeder positions would mean that new customers could not be supplied and existing customers would face increased risk of outage due to the need to overload transformers during N-1 conditions.

Additional Information:

There were two planned projects in Horne Payne identified in the Amended F12-F14 ARRA Application: Horne Payne Substation Expansion (Appendix I, line 27 and Appendix J, page 89) and Horne Payne Substation – Add Feeder Section and Three Feeder Positions (Appendix I, line 65 and Appendix J, page 107). The projects were to add two new 230/25 kV 150 MVA transformers and a feeder section with three feeder positions at Horne Payne, respectively, to meet the load growth. This project is replacing the two previous projects.

The project as currently described will also add two 230/25 kV 150 MVA transformers, in addition to:

- Three 50 MVA gas insulated feeder sections with 18 feeder positions and three transfer ties;
- One gas insulated building; and
- One control building.

<table>
<tr><td colspan="2">Project Name: Kamloops Substation</td></tr>
<tr><td>Total Capital Cost:
$48.9 million</td><td>In-Service Date:
Fiscal 2019</td></tr>
<tr><td>Development Phase:
Implementation</td><td>Filing Reference:
F2014 Annual Report to the BCUC:
• Appendix I, line 30;
• Appendix J, page 52.</td></tr>
<tr><td colspan="2">Description:
The Kamloops Substation project will provide additional substation capacity to supply Kamloops for the next 30 years.</td></tr>
<tr><td colspan="2">Key Drivers:
• Load Growth</td></tr>
<tr><td colspan="2">Issues Being Addressed:
The Kamloops area load is forecast to increase by approximately 60 MVA over the next 10 years, 70 MVA over the next 20 years, and 85 MVA over the next 30 years. Kamloops area south of the Thompson River is supplied from Douglas Substation which is approaching its ultimate station capacity. Also, the load supplied by Brocklehurst Substation located north of the Thompson River has exceeded its summer firm capacity.</td></tr>
<tr><td colspan="2">Discussion of Alternatives:
i. Build New Kamloops Substation: Construct a new 138/25 kV distribution substation (with two 75 MVA transformers) at a new site on the west side of Kamloops City. The new substation will be supplied by looping transmission line (1L206) to the new substation and supply load growth in Kamloops. This is the selected alternative;
ii. Build New Distribution Substation at Kamwood Switching station: Construct a new 138/25 kV distribution substation (with two 75 MVA transformers) next to Kamwood switching station. This alternative is similar to the alternative (i) discussed above; except this would be built on a site located further from the load center and will increase distribution feeder costs.;
iii. Expand Brocklehurst Substation: Increase the transformation capacity at Brocklehurst Substation by installing a third 75 MVA, 138/25 kV transformer, build feeder circuits from Brocklehurst Substation to the area south of Thompson River, and transfer the load presently supplied by Douglas Substation to these feeders. This alternative would incur significant distribution costs because all feeders will require submarine cables to supply customers south of the Thompson River; and
iv. Do Nothing: As Brocklehurst Substation has exceeded its supply capacity and Douglas Substation is reaching its maximum supply capacity, this alternative is not viable.</td></tr>
<tr><td colspan="2">Additional Information:</td></tr>
</table>

Project Name: Fort St. John and Taylor Electric Supply	
Total Capital Cost: $ 53.1 millions	**In-Service Date:** Fiscal 2020
Development Phase: Implementation	**Filing Reference:** New

Description:

This project will maintain adequate supply capability to the loads in Fort St. John and Taylor area by the construction of a 138 kV switchyard at Site C Substation with two three-phase 300 MVA 500/138 kV transformers, and by re-terminating 1L360 and 1L374 at Site C Substation.

Key Drivers:

- Interconnection of Site C Clean Energy project

Issues Being Addressed:

Presently, Fort St. John 138/25 kV substation and Taylor 138 kV switching station supply the distribution and transmission voltage customers in the Fort St. John-Taylor area. G.M. Shrum generating station is the main power source for the Peace Region. Four 138 kV transmission circuits connect the Fort St. John-Taylor area to the main BC Hydro system: 1L364 and 1L374 from Fort St. John to G.M. Shrum generating station, 1L360 from Taylor to G.M. Shrum generating station, and 1L377 from Taylor to Dawson Creek. Circuits 1L364, 1L374 and 1L360 are required to deliver power from G.M. Shrum generating station to the Fort St. John-Taylor area.

On December 16, 2014, the B.C. Provincial Government approved the Site C Clean Energy project. The Site C Clean Energy project will add a third dam and hydroelectric generating station on the Peace River in northeast B.C. It will provide 1,100 MW of hydro generation capacity to the BC Hydro electric system in 2023/2024. The Site C Clean Energy project proposes to construct two 500 kV transmission lines from the Site C substation near Fort St. John to Peace Canyon generating station, which is the Point of Interconnection to the BC Hydro electric system.

To reduce the transmission footprint and minimize environmental impacts, the proposed 500 kV transmission lines from Site C Substation to Peace Canyon generating station will be built on the existing right-of-way currently occupied by 1L360 and 1L374. After the removal of 1L360 and 1L374 (between Site C Substation and G.M. Shrum generating station), the remaining 138 kV transmission lines 1L364 and 1L377 will not be adequate to serve the existing and future customers in the Fort St. John-Taylor area. Therefore, the interconnection System Impact Study for the Site C Clean Energy project recommended that 1L360 to Taylor and 1L374 to Fort St. John be supplied from a new 138 kV switchyard at Site C Substation.

Discussion of alternatives:

i. **Re-terminate 1L360 and 1L374 at Site C Substation:** The System Impact Study to interconnect Site C Energy project recommends to construct two 500 kV transmission lines from Site C Substation to Peace Canyon generating station and remove 1L360 and 1L374 in the section between Site C Substation to G.M. Shrum generating station, and re-terminate 1L360 and 1L374 at Site C Substation. This is the selected alternative; and

ii. **Do Nothing:** When the two 138 kV circuits 1L374 and 1L360 are removed from service to provide Right of Way for the 500 kV circuits proposed for the interconnection of the Site C Energy project, the remaining two 138 kV circuits 1L364 and 1L377 are not capable of supplying all loads in Fort St. John-Taylor area. Not re-terminating 1L374 and 1L360 at Site C Substation will result in over 250 MW of load supply capability shortfall in that area.

Additional Information:

This project has been separated from the Site C Clean Energy project as supplying Fort St. John and Taylor from Site C Substation provides benefits to the transmission system. The main benefit is a reduction in line losses by supplying Fort St. John and Taylor from a closer source and eliminating the two 138 kV lines between Site C Substation and G.M. Shrum generating station.

<table>
<tr><td colspan="2">Project Name: Metro North Transmission (MNT) (formerly Metro North System Supply Reinforcement)</td></tr>
<tr><td>Total Capital Cost:
TBD</td><td>In-Service Date:
TBD</td></tr>
<tr><td>Development Phase:
Identification</td><td>Filing Reference:
Fiscal 2014 Annual Report:
• Appendix I, line 22;
• Appendix J, page 60.</td></tr>
<tr><td colspan="2">Description:
Reinforce the Metro North Transmission System by constructing a new 230 kV transmission circuit between Coquitlam and Vancouver to serve the load growth and strengthen the Metro Vancouver Regional Transmission System.</td></tr>
<tr><td colspan="2">Key Drivers:
• Load Growth</td></tr>
<tr><td colspan="2">Issues Being Addressed:
The Metro North 230 kV Transmission System primarily supplies the local load in the Metro North area (covering Downtown Vancouver, Vancouver East, Burnaby, New Westminster, and the Coquitlam/Tri-Cities). This system is interconnected with the Metro South 230 kV Transmission System (primarily supplying Vancouver South, Vancouver West, and Richmond).
As a result of load growth, a shortfall of supply capacity is anticipated by winter 2018/2019 in the Metro North 230 kV Transmission System. The existing 230 kV underground transmission cable connecting Como Lake Substation in Coquitlam to Horne Payne Substation in Burnaby (Circuit 2L51) is anticipated to exceed its continuous rating during winter peak load conditions. Moreover, if any one of transmission circuits 2L11, 2L49, or 2L50 is forced out of service, up to 100 MW of load in the Metro Vancouver region (an amount equal to approximately 15 per cent of Downtown Vancouver) would need to be curtailed to avoid overloading and potentially damaging 2L51. A thermal overload constraint also exits on 2L50, a 230 kV transmission circuit that connects Burrard Thermal Substation in Port Moody to Murrin Substation in Vancouver. If 2L51 is forced out of service during peak load periods, an overload will occur on 2L50. An interim operational solution has been identified to temporarily resolve these constraints by reconfiguring the system with real-time switching operation, such that no load curtailment will be required until winter 2020, after which time this project is expected to resolve the constraints.</td></tr>
</table>

Discussion of alternatives:

The alternatives under consideration include:

i. **Como Lake Substation to Mount Pleasant Substation via south Coquitlam/central Burnaby:** Construct a new 20 km 230 kV overhead transmission line from Como Lake Substation in Coquitlam to Horne Payne substation in Burnaby using existing rights of way and extend circuit 2L51 with a new 9 km 230 kV underground transmission circuit using road corridors from Horne Payne Substation to Mount Pleasant Substation in Vancouver. This alternative will also require a second phase project in service by 2024 which includes constructing a 6 km 230 kV overhead transmission line from Meridian Substation in Coquitlam to Como Lake Substation using existing rights-of-way;

ii. **Meridian Substation to Mount Pleasant Substation via a Burrard Inlet Crossing:** Construct a new 21.5 km (consisting of 10.5 km of overhead and 11 km underground) 230 kV transmission circuit from Meridian Substation to Horne Payne Substation using existing rights-of-way and road corridors, and extend circuit 2L51 with a new 9 km 230 kV underground transmission circuit from Horne Payne Substation to Mount Pleasant Substation using road corridors;

iii. **Como Lake Substation to Mount Pleasant Substation through central Burnaby:** Construct a new 27 km 230 kV underground transmission line from Como Lake Substation to Mount Pleasant Substation using road corridors. This alternative will also require a second phase project in service by 2022 constructing a 6 km 230 kV overhead transmission line from Meridian Substation to Como Lake Substation using existing rights-of-way; and

iv. **Do nothing:** This option was rejected because without additional capacity, load growth cannot be supplied and the overload risks remain.

Additional Information:

Project Name: West Kelowna Transmission Project	
Total Capital Cost: TBD	**In-Service Date:** TBD
Development Phase: Identification	**Filing Reference:** New
Description: The West Kelowna Transmission Project will provide a second transmission line to supply Westbank Substation.	
Key Drivers: • Reliability	
Issues Being Addressed: This project is driven by reliability concerns associated with the single circuit radial transmission system that currently supplies the West Kelowna area. The West Kelowna area is supplied by a single substation, Westbank Substation, which in turn is supplied radially by a single 138 kV transmission line from Nicola Substation. An outage of the transmission line from Nicola results in an outage for all customers supplied from Westbank Substation. Such an outage occurred in October 2014. The combination of the outage duration (8.8 hours) and the number of customers that were impacted (approximately 22,000 customers) heightened BC Hydro's concerns for service reliability in the area.	
Discussion of Alternatives: The alternatives under consideration include: i. **New transmission line from the North:** Construct a new transmission line on the west side of Okanagan Lake connecting Westbank Substation to Vernon Substation; ii. **New transmission line from Nicola:** Construct a new transmission line from Nicola Substation to Westbank Substation using a different route than the existing transmission line; iii. **New transmission line from the East:** Construct a new transmission line, including a submarine cable across Okanagan Lake, connecting Westbank Substation to the FortisBC system; and iv. **Do Nothing:** This alternative does not address the reliability concerns.	
Additional Information: This project was included in the British Columbia Transmission Corporation Transmission Capital Plan F2010 and F2011 filing under the name of Westbank 138 kV System Reinforcement. Definition funding was approved by Commission Order No. G-87-09. The project was re-prioritized in 2010 prior to entering the definition phase and deferred.	

<table>
<tr><td colspan="2">Project Name: Peace Region Electricity Supply (PRES) (formerly GMS/Dawson Area Transmission)</td></tr>
<tr><td>Total Capital Cost:
TBD</td><td>In-Service Date:
TBD</td></tr>
<tr><td>Development Phase:
Identification</td><td>Filing Reference:
Amended F12-F14 RRA:
• Application: Amended Appendix I, page 17; Amended Appendix J, page 99
• BCUC IRs 1.204.1 Attachment 1, 1.250 series
• AMPC IR 1.46.1
• ESVI IRs 1.4 series
Dawson CreeklChetwynd Area Transmission CPCN Application:
• BCUC Order Nos. G-144-12 and C-5-13
F2014 Annual Report to the BCUC:
• Appendix I, line 48;
• Appendix J, page 65.</td></tr>
<tr><td colspan="2">Description:
Increase transmission capacity to the South Peace area by providing a new supply to Dawson Creek and Groundbirch area.</td></tr>
<tr><td colspan="2">Key Drivers:
• Load Growth
• Reliability</td></tr>
<tr><td colspan="2">Issues Being Addressed:
The Peace Region is supplied by a network of 138 kV and 230 kV transmission lines emanating from the GM Shrum generating station. The load growth in the Peace Region (particularly in the Dawson Creek and Groundbirch areas) is expected to increase such that the ability of the transmission system to maintain supply to all customers during system events will be exceeded. In addition to this, the ability of the system to supply the growing load under normal conditions is expected to be exceeded in the next 10 years. Therefore, the transmission system must be reinforced in order for BC Hydro to meet its obligation to serve customers.
A long lead time will be required to implement capacity additions on both the transmission and the distribution systems in the area. BC Hydro is making its best effort to meet its obligation to supply new industrial customers, without putting its existing customers at risk of interruption due to the increased load. BC Hydro is already restricting service to new industrial customers. It is important to proceed with Peace Region Electricity Supply so that as early an in service date as possible can be attained to meet the forecasted load in the area.</td></tr>
</table>

Discussion of alternatives:

Alternatives under considerations include: :

i. **Provide additional 230 kV supply to the South Peace from the Site C Substation**: This alternative will construct a 230 kV switchyard at the proposed Site C Substation (to be constructed as part of the Site C Clean Energy Project), and a new double circuit 230 kV transmission line between the new substation and the Shell Groundbirch Substation approximately 55 km to the south. This is the leading alternative;

ii. **Provide additional 230 kV supply to the South Peace from G.M. Shrum generating station**: This alternative will expand and rebuild the 230 kV switchyard and replace the existing 500/230 kV transformers at G.M. Shrum generating station, and provide new 230 kV transmission facilities. Transmission additions being considered include a new 230 kV line from G.M. Shrum generating station to Sundance Substation and upgrading the existing 230 kV lines from G.M. Shrum generating station to Sundance Substation; or a new double circuit 230 kV line from G.M. Shrum generating station to Sundance Substation;

iii. **Provide additional 230 kV supply to the South Peace from a new substation**: This alternative will construct a new 500/230 kV substation south of G.M. Shrum generating station, and provide new 230 kV transmission facilities. Transmission additions being considered include a new 230 kV line from this new substation to Sundance Substation and upgrading the existing 230 kV lines from G.M. Shrum generating station to Sundance Substation; or a new double circuit 230 kV line from the new substation to Sundance Substation;

iv. **Non-wire alternatives:** Non-wire alternatives, such as demand side management, will not materially change the planning analysis for the South Peace Area as the forecasted load growth in the region is too high. Non-wires alternatives, such as temporary generation, are being considered to assist with meeting the short term needs in the area until the Dawson Creek Chetwynd Area Transmission Project and Peace Region Electricity Supply projects are in service; and

v. **Do Nothing:** This alternative is not feasible as BC Hydro would not be able to serve load under system normal (N-0) or single contingency (N-1) system conditions. BC Hydro is restricting service to new industrial customers by requesting that they be prepared to be interrupted until a long-term transmission solution is in place.

Additional Information:

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Project Name: **West End Substation Construction Project (formerly Downtown Vancouver Redevelopment)**	
Total Capital Cost: TBD	**In-Service Date:** TBD
Development Phase: Future	**Filing Reference:** Amended F12-F14 RRA: • Application: pages 6-17, 6-24, 6-63, 6-64 • BCUC IRs 1.181.1 Attachment 1, 1.265.1, 2.101.2, 2.102.1, 2.123.1 Attachment 1 • BCOAPO IR 1.38.1 Attachment 2 • CEC IR 1.25.1 Attachment 1 F2014 Annual Report to the BCUC: • Appendix I, line 20; • Appendix J, page 46.

Description:

Build a new 230/12-25 kV, 400 MVA station in the West End neighbourhood of Downtown Vancouver in the first stage of a 30-year Downtown Vancouver Electricity Supply Plan.

Key Drivers:

- Load growth
- Ageing infrastructure
- Seismic

Issues Being Addressed:

Downtown Vancouver load is currently served by Cathedral Square, Murrin, Dal Grauer and the new Mount Pleasant substation.

The downtown Vancouver area has the following issues:

- The load growth in the area is forecast to exceed the total firm capacity by fiscal 2028;
- Murrin and Dal Grauer are both over 50 years old and are reaching end of life;
- Murrin sits on seismically unstable area, and is the only transmission supply for Dal Grauer; and
- Because of the lack of flexibility, the existing dual radial distribution system may result in degradation of reliability as the load increases

A 30-year Vancouver Downtown Electricity Supply Plan is being prepared to address the above issues. The plan includes the addition of one new distribution substation in the West End of Downtown Vancouver, and the replacement of Murrin and Dal Grauer. Due to the seismic and space issues, Murrin and Dal Grauer will need to be rebuilt at new locations. In addition, two of the alternatives consider taking advantage of the extra capacity remaining at Mount Pleasant. The plan will be implemented in stages and will be coordinated with the Distribution plan to gradually convert the existing 12 kV dual radial distribution system to a higher capacity and more reliable 25 kV open-loop distribution configuration.

Discussion of alternatives:

The alternatives under consideration include:

i. **West End Alternative:** This alternative considers building a new West End Substation in fiscal 2024, then replacing Murrin (fiscal 2027) and Dal Grauer (fiscal 2041);

ii. **New Dal Grauer Alternative:** This alternative starts with replacing Dal Grauer in fiscal 2024. The rest of the sequence of construction will be expanding Mount Pleasant (fiscal 2025), replacing Murrin (fiscal 2032) and building the new West End Substation (fiscal 2041); and

iii. **Mount Pleasant Alternative:** In this alternative, Mount Pleasant will be expanded in fiscal 2021 and Dal Grauer will be replaced in fiscal 2024. The rest of the sequence of work will be replacing Murrin (fiscal 2032) and building the new West End Substation (fiscal 2041).

Additional Information:

Project Name: Northwest Substations Upgrades Project (NSUP)	
Total Capital Cost: $113 million to $64 million	**In-Service Date:** Fiscal 2021
Development Phase: Definition	**Filing Reference:** New

Description:

The project involves upgrades at Williston, Glenannan, Telkwa, Skeena and Minette substations.

Key Drivers:

- Load Growth

Issues Being Addressed:

The northwest area of the province is connected to the main BC Hydro transmission system via a single radial 500 kV line. Currently, the line and substations cannot be maintained without line outages during which the northwest area is separated from the main transmission system. At this time, such outages are not an issue because the northwest area load can be supplied by local generation. However, future load growth associated with LNG and other industrial load interconnections will exceed the capacity of local generation meaning BC Hydro will be unable to meet normal reliability standards and customers' requirements.

Additionally, the proposed interconnection of LNG Canada requires additional line positions at Minette substation and will cause voltage issues in the area.

Discussion of alternatives:

i. **Upgrade Substations:** This alternative involves upgrading the substations along the radial line to reduce the number of planned outages required to maintain the equipment at these substations. This alternative will also expand Minette and install shunt capacitors for voltage support and additional line positions to supply LNG Canada. This is the recommended alternative;

ii. **Local Generation in the Northwest Region:** This alternative involves adding capacity by installing generation close to the load centres. Two categories of local generation alternatives were considered: 1) gas fired generation and 2) hydro pumped storage. This alternative was rejected for the following reasons:
   - The negative environmental impact of the gas fired generation alternative is significant. The cost of this alternative is also greater than the proposed solution; and
   - The lead time for the construction of pumped storage facilities is estimated to be several years longer than that for reactive compensation and would not meet the forecast in-service date for the LNG load. The cost of the pumped storage alternative is expected to be significantly greater than the proposed solution.

iii. **New 500 kV transmission line from Williston to Skeena:** This alternative was rejected for the following reasons:
   - The lead time for the delivery of a new line is approximately eight to 10 years. This includes time required for regulatory approval, First Nations consultation, public consultation, environmental permitting and construction. This would not meet the timing of the forecast load increase; and
   - The cost of building a new transmission line would be in the order of $1 billion which is significantly greater than modifying the substations (under this Northwest Substations Upgrades Project).

iv. **Do Nothing:** This alternative is not acceptable because there is insufficient system capacity to reliably supply load growth in the North Coast region.

Additional Information:

Progression into Implementation will be dependent on customers making positive final investment decisions, which is expected to occur by late fiscal 2017.

Project Name: Peace Region to Kelly Lake 500 kV Transmission Reinforcement	
Total Capital Cost: TBD	**In-Service Date:** TBD
Development Phase: Future	**Filing Reference:** New

Description:

Increase the Peace Region to Kelly Lake 500 kV transmission system transfer capacity to facilitate transmission of available generation from the Peace Region to the load centers in the Lower Mainland and Vancouver Island regions.

Key Drivers:

- Generation Additions
- Load Growth

Issues Being Addressed:

The Peace Region to Kelly Lake 500 kV system is part of the backbone of the BC Hydro system used to transfer power from the Peace Region to the load centers. It consists of two sections of three parallel 500 kV transmission lines: Peace to Williston section and Williston to Kelly Lake section. The first section is approximately 280 km and the second section is approximately 330 km. The transfer capacity of Peace Region to Kelly Lake 500 kV transmission lines is limited by thermal, voltage and transient stability. Additional generation will be added in the Peace Region in the next 20 years including the Site C Clean Energy Project and IPPs. The additional generation will require increased transfer capability of the Peace Region to Williston section to supply the growing system load south of the Peace region and of the Williston to Kelly Lake section to supply the growing load in the Lower Mainland.

Discussion of alternatives:

The alternatives under consideration include:

i. **Increase series compensation on 5L1, 5L2, 5L3&7, 5L11, 5L12 and 5L13 to 65 per cent:** This alternative includes either expanding the six existing series capacitor banks at Kennedy Capacitor Station and McLeese Capacitor Station to achieve 65 per cent series compensation on all six transmission lines or installing new series capacitors distributed on each transmission line to achieve 65 per cent series compensation. The alternative also requires thermal upgrade of 5L1, 5L2, 5L3&7 and a 250 MVAr switchable shunt capacitor at Williston substation;

ii. **Increase series compensation on 5L1, 5L2 and 5L3&7 to 60 per cent and add reactive shunt compensation at Williston and Kelly Lake:** This alternative includes expanding the three series capacitor banks at Kennedy Capacitor Station to achieve 60 per cent series compensation on 5L1, 5L2 and 5L3&7 and installing shunt compensation devices at Williston and Kelly Lake, including dynamic var compensation devices and mechanically switched capacitor banks. This alternative also requires thermal upgrade of 5L1, 5L2, and 5L3&7;

iii. **Build a new transmission line from Peace Canyon to Williston Substation and provide additional 15 per cent series compensation on 5L11, 5L12 and 5L13:** This alternative requires building of a new 500 kV transmission line, approximately 280 km from Peace Canyon to Williston with 50 per cent series compensation at Kennedy Capacitor Station. This alternative also requires an additional 15 per cent series compensation on 5L11, 5L12 and 5L13 at or near Williston; and

iv. **Do Nothing:** This alternative would put severe operational restriction on the new generation in the Peace Region. Approximately 1000 MW generation would need to be curtailed during forced outage of any of 500 kV transmission lines in the Peace Region to Kelly Lake system.

Additional Information:

The Site C Clean Energy Project is described in Appendix J page 86.

Project Name: Fort St-John Substation Transformer Upgrade	
Forecast Capital Cost: $29.2 million	**In-Service Date:** Fiscal 2017
Development Phase: Implementation	**Filing Reference:** Amended F12-F14 RRA: • Amended Appendix I, page 18, line 119; • Amended Appendix J, page 145

Description:

This project will add a 75 MVA transformer and two new feeder positions at the Fort St. John substation to address load growth in the area. The transformer will be installed alongside the existing two 56 MVA transformers and will require the expansion of the high voltage bus and addition of three 138 kV circuit breakers. The additional equipment will require expansion of the substation footprint (within the existing BC Hydro property) and expansion of the existing control building. The project also includes the replacement of ageing 138 kV equipment at Fort St. John.

Key Drivers:

- Load Growth
- Ageing Assets

Issues Being Addressed:

The Fort St. John peak load (70 MVA) has exceeded the substation firm capacity (67 MVA). The peak load is forecast to reach 88 MVA during the winter of 2015. In addition, there is insufficient capacity on the existing distribution feeders to supply this load growth and there are no feeder positions available at Fort St. John to terminate new feeders.

Fort St. John was built in 1977. The original 138 kV switchgear and instrument transformers are in poor condition and in need of replacement.

Discussion of alternatives:

i. **Add a 75 MVA transformer:** The alternative will increase the Fort St. John firm capacity to 100 MVA. This is the selected alternative to supply the load growth;

ii. **Replace the existing two transformers with 75 MVA units**: This alternative would have also increased the firm capacity of Fort St. John to 100 MVA but was rejected as it is more expensive to build;

iii. **Upgrade the existing two transformers:** This alternative would have installed auxiliary coolers to both existing Fort St. John transformers. This alternative would have only increased the firm capacity to 73 MVA and was rejected as it would be insufficient to serve the expected load growth;

iv. **Transfer load**: This option was rejected as it is more expensive than the recommended alternative to build long distribution feeders to the next closest BC Hydro distribution station in Fox Creek, and it would not add any new capacity to the growing area; and

v. **Do nothing:** This alternative was not recommended because the loss of a transformer during winter conditions would result in load shedding up to 21 MVA by 2015.

Additional Information:

This project was first approved for implementation in fiscal 2013. Subsequent to the approval, the scope of the project was increased to add:

- The replacement of ageing 138 kV switchgear and instrument transformers, which had been planned separately;
- A second feeder position to supply a new distribution load in the area; and
- The expansion of the control building to accommodate the new equipment.

The alternatives were reviewed at the time the scope was added, and the previously selected alternative was still recommended.

<table>
<tr><td colspan="2">Project Name: Arnott Capacity Upgrade</td></tr>
<tr><td>Total Capital Cost:
$38.5 million</td><td>In-Service Date:
Fiscal 2018</td></tr>
<tr><td>Development Phase:
Implementation</td><td>Filing Reference:
Amended F12-F14 RRA:
• Application: Amended Appendix I, page 17
• Appendix I, page 18, line 120
F2014 Annual Report to the BCUC:
• Appendix I, line 117;
• Appendix J, page 38.</td></tr>
<tr><td colspan="2">Description:
This project will increase the 25 kV load serving capacity in the Delta area.</td></tr>
<tr><td colspan="2">Key Drivers:
• Load growth
• Reliability</td></tr>
<tr><td colspan="2">Issues Being Addressed:
The Arnott Substation services the Delta area, specifically the areas of Ladner, Tsawwassen, Boundary Bay, Tilbury and Burns Bog. These areas are currently experiencing high load growth due to commercial and industrial spot load developments either underway or soon to begin.
The Arnott Substation load recently reached 91 MVA (normalized peak) in winter 2014/15, and is forecast to increase a further 40 per cent within the next five years. By winter 2015/16, station load will exceed the station’s firm capacity. To ensure existing load can continue to be served reliably, and the spot load requests for service can be met, additional capacity is required in the Arnott Substation service area.</td></tr>
<tr><td colspan="2">Discussion of alternatives:
i. Upgrade Arnott Capacity: Increase the 25 kV load serving capacity at Arnott Substation from 100 MVA to 200 MVA. This project will include the replacement of two 75 MVA transformers with new 230/25 kV 150 MVA transformers, a new 100 MVA feeder section with eight initial feeder positions and construction of a new control room. This alternative can meet over 20 years of forecast load growth in the Delta area with the least capital cost. This is the selected alternative;
ii. Build new 230 kV Substation: Construct a new 230 kV, 200 MVA station in North Delta. This alternative is more expensive than the selected alternative and cannot be built in time to service the area load growth;
iii. Build new 60 kV Substation: Construct a new 100 MVA Tsawwassen Substation to replace the existing Tsawwassen substation. This alternative is also more expensive than the selected alternative and could not be built in time to service the area load growth; and
iv. Do Nothing: If no new capacity is added in Delta, the general growth of the area along with the new industrial and commercial loads cannot be serviced.</td></tr>
<tr><td colspan="2">Additional Information:</td></tr>
</table>

<table>
<tr><td colspan="2">Project Name: Big Bend Substation (BBS) (formerly South Burnaby Reinforcement)</td></tr>
<tr><td>Total Capital Cost:
$67.0 million</td><td>In-Service Date:
Fiscal 2018</td></tr>
<tr><td>Development Phase:
Implementation</td><td>Filing Reference:
Amended F12-F14 RRA:
• Application: Amended Appendix I, page 18, Amended Appendix J, page 124
• BCUC IR 1.204.1 Attachment 1
F2014 Annual Report to the BCUC:
• Appendix I, line 112;
• Appendix J, page 39.</td></tr>
<tr><td colspan="2">Description:
This project involves construction of a new 60/12 kV, 67 MVA substation in the Big Bend area of South Burnaby to address the load growth of the area. With the implementation of this project, the 60 kV supply to Annacis Island Substation will also be reconfigured.</td></tr>
<tr><td colspan="2">Key Drivers:
• Load growth</td></tr>
<tr><td colspan="2">Issues Being Addressed:
South Burnaby area is currently served by Newell Substation. The firm capacity of Newell Substation is about 235 MVA, restricted by the distribution feeder egress. The load growth of the area is expected to reach the firm capacity of Newell Substation in winter 2018 and requires capacity addition in the area.</td></tr>
<tr><td colspan="2">Discussion of alternatives:
i. Build a new Substation: This alternative involves constructing a new substation in South Burnaby. The new Big Bend Substation will provide secure and reliable supply to the South Burnaby area. The new substation being within the load centre, the distribution feeders will be short and reliable. This is the selected alternative;
ii. Newell Substation Expansion: With this alternative, the area would be supplied by a single substation with long feeders. The long feeders mean higher distribution losses and less reliability. A present value analysis of the Newell alternative and of the Big Bend alternative showed that the long-term cost of expanding Newell substation is approximately the same as the Big Bend alternative. Even though the present values are comparable, the Newell alternative was rejected based on lower reliability and future constructability issues; and
iii. Do Nothing: If capacity is not added, the forecast load growth in South Burnaby would not be served. The load forecast shows Newell Substation firm transformer capacity being exceeded in winter 2018. This alternative was rejected.</td></tr>
<tr><td colspan="2">Additional Information:</td></tr>
</table>

Project Name: Campbell River Substation Capacity Upgrade	
Forecast Capital Cost: $29.4 million	**In-Service Date:** Fiscal 2018
Development Phase: Implementation	**Filing Reference:** F2014 Annual Report to the BCUC: • Appendix I, line 121

Description:

This project will add a third 75 MVA transformer, four new feeder positions, a new control building and four 138 kV breakers to the Campbell River substation to address load growth in the Campbell River area of Vancouver Island. The project also includes replacement of ageing assets.

Key Drivers:

- Load growth
- Ageing Assets

Issues Being Addressed:

Campbell River substation has two 75 MVA 138-25kV transformers, providing a winter firm capacity of 100 MVA. The forecasted winter peak load in fiscal 2016 is 109 MVA and increasing to 117 MVA by fiscal 2026. In the event of a transformer outage during peak load periods there will be a load curtailment up to 17 MVA. There is no existing feeder capacity to transfer load onto the neighbouring stations.

Campbell River substation was built in 1975. The original 25 kV switchgear and instrument transformers are in poor condition and in need of replacement.

Discussion of alternatives:

i. **Upgrade the Substation:** This alternative includes installing a new 75 MVA transformer, reconfiguring the high voltage bus by installing four 138 kV breakers, adding four new feeder positions, and replacing assets in poor condition. This option raises the firm capacity of the substation to its ultimate level of 185 MVA, adding 85 MVA to the existing firm capacity to serve growth for over the 20-year planning horizon. This is the selected alternative;

ii. **Transfer Load:** This alternative would add two 15 km feeders from Oyster River substation to supply load in the Campbell River area. This alternative would use most of the available capacity at Oyster River substation and would not add any firm station capacity to the Campbell River area. It would also degrade reliability of service due to longer feeder lengths. The sustainment work to replace assets in poor condition at Campbell River substation would still be required. Although the cost of this alternative is comparable to the recommended alternative, it was rejected because it did not add any capacity to the area for future load growth and would result in a degradation of service reliability;

iii. **Build a New Substation:** This alternative would build a new 100 MVA substation on a new site to be acquired in the industrial area north of the Campbell River. This alternative was rejected because it has a higher cost and would take longer to execute than the selected alternative; and

iv. **Do nothing:** The do nothing option was rejected as it would require curtailment of up to 17 MVA during the peak load periods in the event of a loss of a transformer.

Additional Information:

<table>
<tr><td colspan="2">Project Name: Fernie – Substation Upgrade</td></tr>
<tr><td>Total Capital Cost:
$27 million to $21 million</td><td>In-Service Date:
Fiscal 2018</td></tr>
<tr><td>Development Phase:
Definition</td><td>Filing Reference:
F2014 Annual Report:
• Appendix I, line 120;
• Appendix J, page 47.</td></tr>
<tr><td colspan="2">Description:
Replace transformer T2 with a larger unit, add one 25 kV feeder position and one tie position. Build a new control building and replace ageing equipment and wood pole structures at Fernie Substation. This project will also construct additional distribution egress and ties to the existing distribution system.</td></tr>
<tr><td colspan="2">Key Drivers:
• Load Growth
• Ageing Assets</td></tr>
<tr><td colspan="2">Issues Being Addressed:
Fernie Substation is a winter peaking 60 kV to 25 kV substation with T1 (25 MVA) and T2 (8.4 MVA) transformers providing a firm capacity of 10 MVA and 8.4 MVA in winter and summer, limited by T2 rating. Winter peak loads have exceeded the firm capacity of the substation by almost 9 MVA in fiscal 2016. Summer peak loads will begin to exceed firm capacity in fiscal 2016. At present, a mobile transformer needs to be brought in and connected to the substation to serve the load in the event of an outage of T1. The station load has reached a level when reliance on a mobile transformer is not acceptable due to the size of the load that will be curtailed for up to 36 hours until the mobile transformer is in service.
Besides the firm capacity constraints, the station equipment is at end-of-life and needs replacement.
The two existing distribution feeders are almost fully loaded and one more feeder is required to backup either feeders.</td></tr>
<tr><td colspan="2">Discussion of alternatives:
i. Upgrade Fernie Substation: Procure additional property adjacent to the existing site and rebuild the substation. All substation equipment other than the existing T1 transformer and associated disconnect switches will be replaced. T2 transformer would be replaced with a 25 MVA rated unit. The project will increase the firm capacity to 33 MVA which is approximately 12 MVA above the predicted load for fiscal 2026. This is the recommended alternative;
ii. Alternate Site: The city requested the substation to be removed and rebuilt on the outskirts of town and offered a site on Coal Creek Road. Developing a new site would be more costly than the recommended alternative, plus there are considerable unknowns about site suitability. All the feeders supplied from the substation would also need to be extended several kilometers to the new site. The cost premium is estimated to be $10 million for developing a new site and extending the feeders;
iii. Load Transfer: The nearest alternate sources are Winsor and Sparwood substations. Both are too far away to be feasible options; and
iv. Do Nothing: Given the capability shortfall, this is not a viable alternative.</td></tr>
<tr><td colspan="2">Additional Information:</td></tr>
</table>

Project Name: South Surrey Area Reinforcement	
Total Capital Cost: $35 million to $28 million	**In-Service Date:** Fiscal 2019
Development Phase: Definition	**Filing Reference:** New
Description: This project will add capacity in the South Surrey area.	
Key Drivers: • Load Growth • Reliability • Power Quality	
Issues Being Addressed: The South Surrey area is served by three 60 kV transmission lines, 60L100, 60L73, and 60L74, and two substations, Nicomekl and Whiterock. Area load is forecast to reach 189 MVA in 10 years, which exceeds the existing firm station (155 MVA) and transmission (157 MVA) capacity.There are several transmission, station, and feeder capacity constraints and issues that need to be resolved in order to meet load growth and ensure system reliability. Nicomekl also requires additional feeders to reduce distribution feeder loadings. The stations current configuration results in complete loss of load under single contingency loss of 60L100.	
Discussion of alternatives: The alternatives under consideration include: i. **Upgrade South Surrey Transmission System:** This alternative will reconfigure the existing radially connected transmission system to a networked mesh system and add capacity. The scope is to: - Expand and Reconfigure Nicomekl; - Reinforce and Reconfigure Whiterock; and - Re-conductor 5 km of 60L100 These system changes will improve power quality and reliability while also achieving better balanced power flows under normal and N-1 conditions. Nicomekl Substation load serving capacity will be increased by adding a third 75 MVA, 60/25 kV transformer, completing the station 60 kV ring, and adding three feeder positions. The reinforcement at Whiterock will add a 60 kV sectionalizing circuit breaker between the lines 60L73 and 60L74 and install six MVAR of capacitors on the distribution feeders. The Whiterock reinforcements will also help to balance power flows on the three transmission lines and improve power quality under normal and N-1 conditions. The reconductoring of a 5 km section of 60L100 will increase its transmission capacity from 57 MVA to 100 MVA. This work at Nicomekl, Whiterock, and 60L100, will together provide additional capacity to serve load at in the South Surrey area beyond the 10-year planning period and address the area overloads and reliability issues. This is the recommended alternative; and ii. **Do Nothing:** This would not resolve the capacity shortage, power quality and reliability issues in the South Surrey area. If no reinforcements are made to the area, new load growth cannot be served, overloads of equipment will be experienced, and the subsequent protection and operation activities required to safeguard the equipment will result in unavoidable degradation in area reliability of supply. This alternative is unacceptable.	
Additional Information:	

Project Name: Mount Lehman Substation Upgrade	
Total Capital Cost: TBD	**In-Service Date:** TBD
Development Phase: Identification	**Filing Reference:** F2014 Annual Report to the BCUC: • Appendix I, line 116; • Appendix j, page 61.
Description: This project will add capacity in the Abbotsford area.	
Key Drivers: • Load Growth • Reliability • Safety	
Issues Being Addressed: The Abbotsford area is currently served by four substations, Mount Lehman Substation, Clayburn Substation, Sumas Way Substation and Gloucester Substation. Several residential and industrial spot load developments are planned for the Abbotsford area, and a 5.1 per cent annual load growth is forecast over the next few years. Mount Lehman Substation is a 230/25 kV substation placed in service in 2007, with a total transformation capacity of 100 MVA. Load is forecast to exceed Mount Lehman substation firm capacity by 2016. The existing 25 kV feeder sections at Sumas Way Substation and Clayburn Substation are constructed with a now obsolete design. To ensure the safety of BC Hydro crews, and improve reliability for area customers, six feeder positions at Clayburn Substation are scheduled for removal, which would de-rate the Clayburn Substation capacity by 65 MVA, and cause a capacity shortfall. At Sumas Way Substation, safety concerns have suspended maintenance and the station is now scheduled for decommissioning. With the loss of capacity at Clayburn Substation and Sumas Way Substation, together with the Abbotsford area's heavy load growth, new capacity needs to be added in the area. A separate project has been initiated to address capacity issues at Clayburn Substation.	
Discussion of alternatives: The alternatives under consideration include: i. **Upgrade Mount Lehman Substation:** Increase the 25 kV station capacity at Mount Lehman Substation from 100 MVA to 170 MVA. The ultimate capacity of the station will be 200 MVA. This alternative will include the addition of a new 25 kV feeder section, one new 75 MVA 230/25 kV transformers, four 230 kV circuit breakers and the construction of a new control building; ii. **Expand Sumas Way substation to 100 MVA:** Expansion of Sumas Way Substation from 55 MVA to 100 MVA, will require a complete rebuild of the existing 60/25 kV substation along with 230/60 kV upgrades at Clayburn and new 60 kV transmission lines; iii. **Expand Clayburn Substation to 300 MVA:** Expansion of Clayburn Substation from its de-rated 115 MVA to 300 MVA will require two new 100 MVA GIS feeder sections, the expansion of the control building, five 230 kV circuit breakers, and a new 150 MVA 230/25 kV transformer; and iv. **Do Nothing:** If no project is initiated to add capacity in the area, the Clayburn Substation sustain project will still be required to proceed, and the area capacity will be reduced by 65 MVA. With this loss of capacity, and the end of life condition of the Sumas Way Substation, load growth in the area will not be serviced.	
Additional Information: This Mount Lehman Substation project is being planned in close coordination with the Clayburn Substation project,which is also described in Appendix J.	

Project Name: Westbank Substation Upgrade	
Total Capital Cost: TBD	**In-Service Date:** TBD
Development Phase: Identification	**Filing Reference:** New
Description: The Westbank Substation Upgrade project will increase the substation summer firm capacity to address the current capacity deficit and future load growth. The project will also add a second 138 kV line position to connect a new transmission line to be built under a separate project.	
Key Drivers: • Load Growth • Ageing Assets • Reliability	
Issues Being Addressed: Westbank substation is the only source of supply to the community of Westbank. The present Westbank substation summer load is 85.3 MVA while the summer firm capacity is 80 MVA. Westbank substation has three transformers T1 (50 MVA), T2 (28 MVA) and T3 (50 MVA). The station does not have sufficient firm capacity to supply the load in the event of an outage of T1 or T3. Several components of the substation are reaching end of life. It includes one 138 kV and one 25 kV oil circuit breakers, as well as two circuit switchers. There is no 138 kV line position available to terminate a second 138 kV line to supply Westbank substation. A second line is currently under consideration under the West Kelowna Transmission project to improve the reliability of the supply to the area.	
Discussion of alternatives: The following alternatives are under consideration: i. **Upgrade Westbank Substation:** This alternative would increase the winter and summer firm capacity of Westbank station by replacing one transformer, adding current limiting reactors to the existing feeder positions and replacing the end of life equipment. The alternative would also provide one line position for a second 138 kV line; ii. **Build a new substation in West Kelowna region:** This alternative would offload some of the existing Westbank substation load and provide capacity for future load growth. A separate project would be required to address the end-of-life Westbank substation assets; and iii. **Do Nothing:** This alternative would not provide increased firm capacity and load would continue to be curtailed during forced outages of T1 or T3. End-of-life equipment would remain in-service until they are replaced individually or at failure. There would be no new 138 kV termination and the area load will continue to depend only on one source.	
Additional Information: The scope of this project is dependent on the alternative that will be selected for the West Kelowna Transmission project, which is also described in Appendix J.	

<table>
<tr><td colspan="2">Project Name: Capilano Substation 25 kV Conversion (formerly Capilano Substation Upgrade)</td></tr>
<tr><td>Total Capital Cost:
TBD</td><td>In-Service Date:
TBD</td></tr>
<tr><td>Development Phase:
Identification</td><td>Filing Reference:
Amended F12-F14 RRA:
• Application: Amended Appendix I, page 18; Amended Appendix J, page 125
• BCUC IR 1.204.1 Attachment 1
F2014 Annual Report:
• Appendix I, line 113;
• Appendix J, page 41.</td></tr>
<tr><td colspan="2">Description:
This project will rebuild Capilano substation. This project involves installing two transformers, a new indoor 25 kV feeder section, a new control room and an indoor five-position 60 kV GIS ring bus, and transfer all loads to the new feeder section. The existing equipment at Capilano substation will be decommissioned.</td></tr>
<tr><td colspan="2">Key Drivers:
• Load Growth
• Voltage Conversion
• Ageing Assets</td></tr>
<tr><td colspan="2">Issues Being Addressed:
Distribution Planning is actively pursuing 12 kV to 25 kV feeder voltage conversion in the Metro North Shore area to address long term load growth. Capilano substation, as well as Lynn Valley and North Vancouver substations will require conversion from 12 kV to 25 kV over the next 10 years.
Most of the major equipment at Capilano substation is near end-of-life and needs to be replaced within the next five to 10 years. In particular, the 60 kV bulk-oil and 12 kV air-blast circuit breakers are obsolete, and pose a reliability risk. There are also various safety and environmental risk associated with these assets. There is an opportunity to rebuild the entire substation.</td></tr>
<tr><td colspan="2">Discussion of alternatives:
The alternatives being considered include:
i. Rebuild Capilano Substation: This alternative will rebuild the station within the existing fence at 25 kV and decommission the existing ageing 12 kV station. The new station capacity will be sufficient to supply the area load for the next 30 years. This is the leading alternative;
ii. Add one 12kV Feeder Section and One Transformer: This alternative could meet the immediate area load requirements but does not resolve the end of life issues and does not align with the future 25 kV supply requirement to address long term load growth; and
iii. Do Nothing: This would lead to an increased risk with customer reliability due to the failure of the ageing equipment and can be a safety hazard for a person working in the station. It also does not allow the planned voltage conversion required to address the area load growth.</td></tr>
<tr><td colspan="2">Additional Information:
This is the same project included in the Amended F12-F14 RRA filing and the F2014 Annual Report to the British Columbia Utilities Commission as noted in the reference above but with a later in-service date. The in-service date for this project was deferred beyond fiscal 2019 until it is needed to decommission the 12 kV end-of-life equipment at the substation. The deferral was possible through advancing planned distribution work in the area. The alternative to rebuild the substation and transferring the 12 kV load immediately replaced the previous alternative of upgrading the substation to add capacity at 25 kV while retaining 12 kV equipment for multiple years.</td></tr>
</table>

<table>
<tr><td colspan="2">Project Name: Squamish Area Reinforcement (formerly Cheekye (CKY) Substation Upgrade – Add Capacity)</td></tr>
<tr><td>Total Capital Cost:
TBD</td><td>In-Service Date:
TBD</td></tr>
<tr><td>Development Phase:
Identification</td><td>Filing Reference:
Amended F12-F14 RRA:
• Amended Appendix I, page 18,
• Amended Appendix J, page 123
F2014 Annual Report:
• Appendix I, line 147;
• Appendix J, page 71.</td></tr>
<tr><td colspan="2">Description:
Provide new transformation capacity to supply the Squamish area load for the next 30 years.</td></tr>
<tr><td colspan="2">Key Drivers:
• Load Growth
• Reliability
• Ageing Infrastructure
• Safety</td></tr>
<tr><td colspan="2">Issues Being Addressed:
Two substations, Squamish and Cheekye, serve the Squamish area load. The Squamish Substation firm capacity is 52 MVA and it serves the main city and downtown load. The Cheekye Substation firm capacity is 11.2 MVA and serves the rural load north of Squamish. The Squamish Substation capacity will be exceeded in fiscal 2020 when the planned transfer of all Cheekye Substation load to Squamish Substation takes place.
The Cheekye Substation has high ground potential rise issue, which is a safety hazard to the public and anyone working on the Distribution feeders. No effective solution of mitigating this risk has been identified. Consequently, there is a planned transfer of load from Cheekye Substation to Squamish Substation.
The 25 kV infrastructure at Squamish Substation substation is experiencing significant asset health issues and many of the assets will be reaching their end of life in the next 10 years. There are also fire safety issues at Squamish Substation. As a result, some of the main equipment at Squamish Substation is kept in non-energized standby mode and switching results in short outages to all customers served by the substation.</td></tr>
<tr><td colspan="2">Discussion of alternatives:
The alternatives under consideration include:
i. Rebuild Squamish Substation: A new 100 MVA substation with two 60/25 kV, 75 MVA transformers, a 100 MVA MV GIS feeder section, 60 kV GIS five-breaker ring and a control room will be built within the existing Squamish Substation property boundary. With commissioning of the new Squamish substation, all the existing station equipment will be decommissioned. All Cheekye Substation load will be transferred to the rebuilt Squamish Substation;
ii. Build new Tantalus (TAN) substation and remove Squamish Substation 25 kV infrastructure: A new 100 MVA substation with two 60/25 kV, 75 MVA transformers, a 100 MVA MV GIS feeder section, 60 kV GIS six-breaker ring and a control room will be built at a new site near Tantalus road. Both 60L68 and 60L70 will be looped into this substation. All loads presently served by Squamish Substation and Cheekye Substation will be transferred to the new station. Existing 25 kV infrastructure at Squamish Substation will be decommissioned; and
iii. Do Nothing: Maintain existing Squamish and Cheekye substations, along with transmission/distribution systems.</td></tr>
</table>

Additional Information:

This project originally appeared in the Fiscal 2012-Fiscal 2014 Amended Revenue Requirements Application (Appendix I, line 114, Appendix J, page 123) as ‘Cheekye (CKY) Substation Upgrade – Add Capacity’ project. The leading alternative at the time of that filing was to upgrade Cheekye Substation by adding 22 MVA of capacity. During the definition phase, it was determined that expanding the Cheekye Substation load serving capacity is not a viable alternative due to the technical challenge of high ground potential rise on feeder neutrals, which can only be resolved at a very high cost.

<table>
<tr><td colspan="2">Project Name: Horsey GIS Replacement Program</td></tr>
<tr><td>Total Capital Cost:
$32.4 million</td><td>In-Service Date:
Fiscal 2017</td></tr>
<tr><td>Development Phase:
Implementation</td><td>Filing Reference:
F2014 Annual Report to the BCUC:
• Appendix I, line 14
• Appendix J, page 49</td></tr>
<tr><td colspan="2">Description:
This project involves replacing the existing outdoor four-bay 230 kV Gas Insulated Switchgear with a new indoor seven-bay 253 kV Gas Insulated Switchgear, and removing the old Gas Insulated Switchgear.</td></tr>
<tr><td colspan="2">Key Drivers:
• Aging Infrastructure
• Reliability
• Seismic</td></tr>
<tr><td colspan="2">Issues Being Addressed:
The existing 230 kV Gas Insulated Switchgear is connected by two-230 kV cables (2L143 from Esquimalt substation and 2L146 from Goward). In turn, the Gas Insulated Switchgear is the switching installation for four-150 MVA power transformers that are serving most customers in the city of Victoria. Due to the configuration of the existing four-bay Gas Insulated Switchgear, it is currently not possible to automatically isolate the individual power transformers for switching, without interrupting some of the supply.
The existing 230 kV Gas Insulated Switchgear has deteriorated significantly due to aging. It is no longer possible to isolate any compartment due to the weakness of the compartment barriers. In 2012, the compartment containing a disconnect switch failed when a barrier failed.
There is also the risk the existing Gas Insulated Switchgear will not withstand a seismic event.</td></tr>
<tr><td colspan="2">Discussion of alternatives:
i. Replacement of existing outdoor four-bay 230 kV Gas Insulated Switchgear: This alternative will replace the existing outdoor Gas Insulated Switchgear with a new indoor seven-bay 253 kV Gas Insulated Switchgear. The new Gas Insulated Switchgear will be built to seismic standards and provide N-1 reliability to allow for the isolation of one transformer without interrupting load. This is the selected alternative;
ii. Continue maintaining the existing 230 kV Gas Insulated Switchgear installation: This was not a practical alternative. Moisture levels in numerous compartments of the Gas Insulated Switchgear are approaching failure levels, yet measures to remove the moisture cannot be applied due to the fragility of the compartment separators that can shatter and render the installation unusable; and
iii. Do Nothing: This alternative was rejected given the level of deterioration of the existing Gas Insulated Switchgear and the unavailability of replacement parts and manufacturer’s support.</td></tr>
<tr><td colspan="2">Additional Information:</td></tr>
</table>

<table>
<tr><td colspan="2">Project Name: Terrace to Kitimat Transmission (TKT)</td></tr>
<tr><td>Total Capital Cost:
$177 million to $100 million</td><td>In-Service Date:
Fiscal 2020</td></tr>
<tr><td>Development Phase:
Definition</td><td>Filing Reference:
F2014 Annual Report:
• Appendix I, line 7;
• Appendix J, page 73.</td></tr>
<tr><td colspan="2">Description:
Replacement of the 59 km transmission line 2L99 between Skeena Substation and Minette substation and the 2.5 km transmission line 2L103 between Minette Substation and the Rio Tinto Alcan owned Kitimat substation.</td></tr>
<tr><td colspan="2">Key Drivers:
• Ageing Assets
• Reliability
• Safety</td></tr>
<tr><td colspan="2">Issues Being Addressed:
The existing line 2L99 that supplies Minette Substation and serves the Kitimat area has reached the end of its serviceable life. The 2L103 line, which connects Minette Substation to Kitimat Substation and the Rio Tinto Alcan smelter and Kemano Generating Station, is in a similar state and is at the end of its life. BC Hydro relies on the Kemano Generating Station and the two existing lines to provide supply redundancy to the North Coast area.
Both of these lines have been de-rated due to defects and deficiencies, and cannot supply current load and forecast load demands. LNG-related economic activity in the Kitimat area could add new industrial load in the next decade. Due to inadequate electrical clearances, the lines can only be safely maintained while out of service and there is limited outage availability, which hinders timely required line maintenance and upgrades.</td></tr>
<tr><td colspan="2">Discussion of Alternatives:
i. Build new lines to existing voltage on a new right of way: This alternative will require the acquisition of right-of-way and significant stakeholder and First Nations engagement. This is the recommended alternative;
ii. Rebuild at 500 kV and operate at 287 kV to meet current load demand: The most optimistic load projections do not indicate that load demands will require a 500 kV transfer; and
iii. Do Nothing: This option is not acceptable as the lines are at end of life and cannot be safely maintained to provide adequate and reliable supply to the area. The lack of reliability would be an issue for customers in Kitimat and Skeena areas as well as commercial concerns that might be looking to expand their operations in the area.</td></tr>
<tr><td colspan="2">Additional Information:</td></tr>
</table>

Project Name: George Massey Tunnel Transmission (GMTT) Relocation	
Total Capital Cost: TBD	**In-Service Date:** TBD
Development Phase: Identification	**Filing Reference:** New
Description: Relocate 230 kV circuits 2L62 and 2L58 in the vicinity of the George Massey Tunnel.	
Key Drivers: • Ministry of Transportation request	
Issues Being Addressed: The Ministry of Transport and Infrastructure is planning to replace the George Massey Tunnel with a new bridge to cross the Fraser River and connect the districts of Richmond and Delta. This work will require the relocation of two of BC Hydro's key 230 kV circuits (2L62 and 2L58) along Highway 99 and through the tunnel. The circuits form part of the transmission system supplying Richmond, Delta and the Greater Vancouver area.	
Discussion of Alternatives: The alternatives under consideration include: i. **Overhead crossing of the Fraser River:** This alternative will require the construction of tall lattice towers on either side of the river to enable an overhead line to cross the river in a single span; ii. **Underground, horizontal directional drilled crossing of the Fraser River:** This alternative would involve boring a tunnel beneath the river, which would contain ducts into which a cable circuit would be installed. New potheads would need to be installed at either end of this horizontal directional drilled tunnel to connect the underground cable to the overhead line; iii. **Cable installed on the new bridge:** This alternative would require some novel design to attach a transmission cable onto or inside the bridge. New potheads would need to be installed at either end of the main bridge span to connect the cable to the overhead line; and iv. **Do Nothing:** This option is not acceptable as it would prevent the Ministry of Transport and Infrastructure project from proceeding.	
Additional Information:	

<table>
<tr><td colspan="2">Project Name: Mainwaring Substation Upgrade</td></tr>
<tr><td>Total Capital Cost:
TBD</td><td>In-Service Date:
TBD</td></tr>
<tr><td>Development Phase:
Identification</td><td>Filing Reference:
Annual Report to the BCUC:
• Appendix I, line 15;
• Appendix J, page 57.</td></tr>
<tr><td colspan="2">Description:
This project is to replace the power transformers T1 and T3,the two 12 kV feeder sections and the control building that have reached end of life at Mainwaring Substation.</td></tr>
<tr><td colspan="2">Key Drivers:
• Ageing Infrastructure
• Reliability
• Safety</td></tr>
<tr><td colspan="2">Issues Being Addressed:
Mainwaring Substation T1 and T3, two feeder sections and the control building have reached end of life, resulting in an increased reliability and safety risk. The electrical equipment in the two feeder sections (e.g., bulk oil breakers and disconnect switches) is in poor condition, and failures may cause safety hazards and long outages to a number of heavily loaded feeders. The design of the feeder sections is also obsolete, with Limits of Approach safety issue. Maintenance activities can no longer be performed safely without customer outages. The safety issue also prevents overhauling the existing equipment.</td></tr>
<tr><td colspan="2">Discussion of alternatives:
The alternatives under consideration include:
i. Build new feeder sections at Mainwaring Substation: This alternative requires building new feeder sections within the existing site and transferring the load from the existing feeder sections to the new feeder sections. The existing feeder section would then be decommissioned. This alternative would also replace T1, T3 and the control building which have reached end of life;
ii. Build new substation: This alternative requires building a substation in a new site and offload the Mainwaring Substation load; and
iii. Do nothing: Doing nothing would result in declining reliability and unaddressed safety issues.</td></tr>
<tr><td colspan="2">Additional Information:</td></tr>
</table>

Project Name: Esquimalt Feeder Section Replacement	
Total Capital Cost: TBD	**In-Service Date:** TBD
Development Phase: Identification	**Filing Reference:** New

Description:

This project is to replace the outdoor 12 kV feeder section that has reached end of life at Esquimalt Substation

Key Drivers:

- Ageing Infrastructure
- Reliability
- Safety
- Voltage Conversion
- Load Growth

Issues Being Addressed:

The Esquimalt Substation feeder section is near end of life, resulting in increased reliability and safety risk. The electrical equipment in the feeder section (e.g., bulk oil breakers and disconnect switches) is in poor condition, and failures would be safety hazards and cause extended outages to a number of heavily loaded feeders. The design of the feeder section is obsolete, with Limits of Approach safety issues. Maintenance activities can no longer be performed safely without customer outages. The safety issues also prevent overhauling the existing equipment.

Distribution Planning has plans for 12 kV to 25 kV feeder voltage conversions in the area to address long-term load growth. Additional feeder positions will also be required at Esquimalt Substation for load growth.

Discussion of alternatives:

The alternatives under consideration include:

i. **Build new feeder section:** This alternative requires building a new indoor feeder section within the existing site and transferring the load from the existing feeder section. The new feeder section would be capable of operating at 25 kV to allow for long term voltage conversion in the area. The existing feeder section would be removed to allow for a future feeder section; and

ii. **Do nothing:** Doing nothing would result in declining reliability and unaddressed safety issues.

Additional Information:

Project Name: 5L63 Telkwa Relocation

Total Capital Cost: TBD	**In-Service Date:** TBD
Development Phase: Identification	**Filing Reference:** New

Description:

Relocate 500 kV circuits 5L063 in the vicinity of the Bulbous Toe landslide area.

Key Drivers:

- Safety
- Reliability

Issues Being Addressed:

5L063 is a 500kV transmission line that forms part of the radial transmission system between Telkwa Substation and Skeena substation. The section between structures 209/4 and 210/4 cross the landslide area known as the “Bulbous Toe”. One tower (Str. 210/1) is located in this geo-technically unstable area which has been gradually sliding downhill for the last 15 years resulting in the tower moving approximately 0.3 m per year. Continued movement of the tower had led to significant safety risks for crew carrying out maintenance activities. In addition, the tower has started rotating and deforming which could lead to failure and an extended line outage. A sudden landslide would destroy the tower and sever the line also resulting in a sustained outage.

Discussion of Alternatives:

The alternatives under consideration include:

i. Relocate the circuit around the slide area;
ii. Span across the unstable area with taller and larger structures; and
iii. Do Nothing.

Additional Information:

Project Name: Barnard 50/60 Feeder Section Replacement	
Total Capital Cost: TBD	**In-Service Date:** TBD
Development Phase: Identification	**Filing Reference:** New
Description: This project is to replace 50/60 series feeder section that has reached end of life at Barnard Substation.	
Key Drivers: • Ageing Infrastructure • Reliability • Safety	
Issues Being Addressed: The Barnard Substation 50/60 feeder section equipment has reached end of life, resulting in increased reliability and safety risk. The electrical equipment in the feeder section (e.g., bulk oil breakers and disconnect switches) is in poor condition, and failures may cause safety hazards and long outages to a number of heavily loaded feeders. The design of the feeder section is obsolete, with Limits of Approach safety issues. Maintenance activities can no longer be performed safely without customer outages. The safety issue also prevents overhauling the existing equipment.	
Discussion of alternatives: The alternatives under consideration include: i. **Build new feeder section:** This alternative requires building a new feeder section within the existing site and transferring the load from the 50/60 feeder section. The 50/60 feeder section would then be decommissioned. The new feeder section would be capable of operating at 25 kV to allow for future voltage conversion in the area. The building will be sized to accommodate a second feeder section in the future. ii. **Do nothing:** Doing nothing would result in declining reliability and unaddressed safety issues.	
Additional Information:	

<table>
<tr><td colspan="2">Project Name: North American Energy Reliability Council (NERC) Critical Infrastructure Protection (CIP) V5 Compliance at Medium Impact Transmission & Distribution Stations</td></tr>
<tr><td>Total Capital Cost:
TBD</td><td>In-Service Date:
TBD</td></tr>
<tr><td>Development Phase:
Identification</td><td>Filing Reference:
New</td></tr>
<tr><td colspan="2">Description:
This project will upgrade electronic and physical security for critical cyber assets at up to 43 medium impact Bulk Electric System stations. Medium impact stations are those meeting the following criteria defined by the North American Electric Reliability Corporation:
• Operates at a voltage level of 500 kV or higher;
• Operates at a voltage level of 230 kV or higher, with sufficient transmission lines to meet an aggregate weighting formula;
• Generator interconnection stations where the generation station is medium impact; and
• Stations with Remedial Action Scheme systems that affect Interconnection Reliability Operating Limits or have centralized Under Voltage Load Shedding or Under Frequency Load Shedding above 300 MW.</td></tr>
<tr><td colspan="2">Key Drivers:
• Regulatory Compliance</td></tr>
<tr><td colspan="2">Issues Being Addressed:
North American Electric Reliability Corporation Critical Infrastructure Protection Reliability Standard version 5 was adopted in B.C by the British Columbia Utilities Commission in July 2015. Through British Columbia Utilities Commission Order R-38-15, BC Hydro is required to reach compliance with version 5 of the standard by October 2018.</td></tr>
<tr><td colspan="2">Discussion of alternatives:
The alternatives under consideration include:
i. Upgrade Stations: Provide electronic and physical security protection at medium impact stations as required by North American Electric Reliability Corporation Critical Infrastructure Protection version 5; and
ii. Do nothing: Doing nothing would result in not meeting mandatory reliability standards as set by the British Columbia Utilities Commission.</td></tr>
<tr><td colspan="2">Additional Information:
This project covers the compliance requirements for the Transmission & Distribution assets. Compliance requirements will also require IT work and minor upgrades to the Grid Operation Control Centers and Generation assets. The Technology group project will address the general IT scope and overall revisions to common cross-business Critical Infrastructure Protection programs, policies and procedures. The technology project scope will also include common IT tools that will be utilized across the business groups. The Technology project is described in Appendix I, page 7, line 2. The Generation expenditures are included under Generation Sustaining Projects – Redevelopment / Rehabilitation described in section 6.5.1.2.</td></tr>
</table>

<table>
<tr><td colspan="2">Project Name: Newell Substation Upgrade</td></tr>
<tr><td>Total Capital Cost:
TBD</td><td>In-Service Date:
TBD</td></tr>
<tr><td>Development Phase:
Future</td><td>Filing Reference:
New</td></tr>
<tr><td colspan="2">Description:
This project is to replace the power transformer T1 and two 12 kV feeder sections that have reached end of life at Newell Substation.</td></tr>
<tr><td colspan="2">Key Drivers:
• Ageing Infrastructure
• Reliability
• Safety</td></tr>
<tr><td colspan="2">Issues Being Addressed:
Newell Substation T1 and two feeder sections have reached end of life, resulting in increased reliability and safety risk. The electrical equipment in the two feeder sections (e.g., bulk oil breakers and disconnect switches) is in poor condition, and failures may cause safety hazards and long outages to a number of heavily loaded feeders. The design of the feeder sections is obsolete, with Limits of Approach safety issues. Maintenance activities can no longer be performed safely without customer outages.</td></tr>
<tr><td colspan="2">Discussion of alternatives:
The alternatives to be considered will include:
i. Overhaul Newell Substation: This alternative requires replacing the power transformer, the electrical equipment in the feeder sections and the supporting structure within the same footprint while serving the existing load. This alternative would require complex staging during construction to safely replace equipment, and may not eliminate the safety issues with the current design;
ii. Build new feeder sections at Newell Substation: This alternative requires replacing T1 and building new feeder sections within the existing site and transferring the load from the existing feeder sections. The existing feeder sections would then be decommissioned;
iii. Build new substation: This alternative requires building a substation in a new site and offloading the Newell Substation load to the new substation; and
iv. Do nothing: Doing nothing would result in declining reliability and unaddressed safety issues.</td></tr>
<tr><td colspan="2">Additional Information:</td></tr>
</table>

<table>
<tr><td colspan="2">Project Name: Supply Chain Applications</td></tr>
<tr><td>Forecast Capital Cost:
$71.0 to $58.4 million</td><td>In-Service Date:
Fiscal 2019</td></tr>
<tr><td>Development Phase:
Definition</td><td>Filing Reference:
Amended F12-F14 RRA:
• Application, page 6-71
• Amended Appendix I, page 25
• Amended Appendix J, page 154
• BCUC IRs: 1.204.1, 1.275.0. 1.280.1, 1.280.1.1, 1.433.5, 2.136.1.1, 2.136.2.1, 2.137 Series, 2.139.3, 2.190.1 – Att. 6
• Intervener IRs: AMPC IRs 1.58.1, 1.58.2.1, 1.58.4 and Attachment 1, 1.58.7.</td></tr>
<tr><td colspan="2">Description:
The Supply Chain Applications project involves the design and implementation of new business processes and information technology to support the acquisition of materials and services from third-parties.</td></tr>
<tr><td colspan="2">Key Drivers:
• Increased operational efficiency,
• Reduced material and service costs,
• Risk reduction.</td></tr>
<tr><td colspan="2">Issues Being Addressed:
In 2013, BC Hydro approved a new Supply Chain Business Model, which sets out what BC Hydro requires of its supply chain. BC Hydro has studied its existing technology and processes and has identified numerous capability gaps that require technology and process changes to address. The Supply Chain Applications Project is intended to fill these gaps and achieve operational efficiencies, reduced material and service costs and an overall reduction in risk.</td></tr>
<tr><td colspan="2">Discussion of Alternatives:
In 2008, BC Hydro chose SAP as the default information technology platform for its enterprise resource planning technology solutions. As a result, BC Hydro undertakes enterprise resource planning solutions using SAP technology unless an alternative system is identified which is materially superior to SAP either in cost or range of function. BC Hydro has performed an evaluation comparing an SAP-based technology solution to a solution based on the existing Ventyx PassPort-based technology. The evaluation indicates that an SAP-based technology solution better supports the Supply Chain Business Model and is expected to provide greater overall net benefits to BC Hydro.</td></tr>
<tr><td colspan="2">Additional Information:
BC Hydro is planning to submit a separate application to the British Columbia Utilities Commission.</td></tr>
</table>

Project Name: Vernon – Field Building	
Forecast Capital Cost: $46.3 million	**In-Service Date:** Fiscal 2018
Development Phase: Implementation	**Filing Reference:** Amended F12-F14 RRA: • Application Section 6.11.1 • Appendix I, line 8 • Appendix J, page 176 • BCUC IR 1.287.1

Description:

This project involves the construction of a new facility at the existing Vernon Field Building site to address significant deficiencies and issues with the existing facilities.

Key Drivers:

- Operational Requirements
- Safety
- Reliability

Issues Being Addressed:

The 12.8 acre Vernon facility is located at Kalamalka Road in a commercial light industrial area south of the downtown core. It is the Southern Interior Regional Office for BC Hydro. It is comprised of three occupied buildings; a main office, a warehouse and a Quonset hut, as well as various partially-enclosed auxiliary storage structures. The office and warehouse buildings are 40-plus years old, and total 54,000 ft^2. A total of 220 employees currently work out of this location, including the following functional groups: Distribution Line Services, Distribution Engineering & Design, Transmission Stations, Transmission Operations, Construction Services, Vegetation Management, Electrical Meter Shop, Generation Engineering & Design, Material Management, Fleet, Safety & Security, Properties, Field Services, Customer Care, and Environmental Risk Management.

There is a long-term need for a suitable regional office to provide post-disaster recovery and emergency operational support and meet customer needs in the region. This includes appropriate outage response, planning and execution of the electric system to support local/regional development, and maintenance and upgrades to electric system infrastructure to ensure ongoing system reliability in the region. In order to "keep the lights on", the facility must remain operational to support 24/7 emergency response in the worst weather conditions and in the event of a natural disaster.

The Vernon buildings have been identified as a priority due to the combined issues of functional obsolescence, seismic risks, building code and safety issues, and building condition. The key issues are that the facilities:

- Do not meet current functional and operational needs, with no room for potential future growth, i.e., do not provide sufficient space to house all current staff, necessitating for example the need for an external lease of office space off-site; do not provide adequate truck bays for Fleet's current needs; and do not provide adequate interior amenities, with aging and undersized change and shower facilities, washrooms, and drying facilities;
- Meet less than 50 per cent seismic resistance capacity as designated by the current B.C. Building Code for a normal building, and less than 33 per cent seismic resistance capacity for a post disaster resistance designated building;
- Were designed to pre-1970 Building Codes with some modifications since then, and do not conform to current building and fire code provisions;
- Compromise staff safety with respect to fire exit travel distances and exit requirements, fire separations and stopping, rated openings and accessibility, inadequate sprinklers, and presence of hazardous materials; and
- Have numerous issues affecting the building envelope, structural, electrical and mechanical components.

The lack of space and the resulting dispersed workforce as well as the condition of the facility negatively impacts the ability of staff to perform their duties – outage response, electric system construction, and upgrade and maintenance work.

Discussion of Alternatives:

Five alternatives were considered:

i. **Do Nothing:** This option does not address the known and growing concerns at the site. It does not meet functional needs and exposes BC Hydro to the consequences of ignoring code, safety, and reliability issues. Aging components will fail and must be replaced in an inefficient reactive rather than proactive manner. Business continuity, employee safety and customer reliability are all at risk;

ii. **Renovate existing buildings and lease additional space:** This option involves operating from the existing facilities, and completing only mandatory, minimum upgrades to bring the buildings into conformance with current building codes. This option will not include post disaster upgrades, thereby limiting emergency response capabilities and effectiveness in a disaster. To meet functional requirements, a significant additional lease of office and warehouse space will be required. This will further increase the number of staff in dispersed locations;

iii. **Renovate the existing office and warehouse buildings. Build a new extension to link both existing buildings:** This option will bring the existing facility up to current building code and will address critical issues to improve the work environment, but will not address post disaster upgrade requirements;

iv. **Retain and renovate the existing office building. Demolish the existing warehouse building and replace with a new office/industrial building extension adjacent to the existing office building:** This option will address many building deficiencies and will bring the existing facility up to current building code but will not address post disaster upgrade requirements; and

v. **Replace the existing buildings with a new facility:** This option will meet all current and anticipated operational requirements. The new buildings will be code compliant and optimized for safety, efficiency and flexible operations and will target advanced energy intensity standards. They will meet post-disaster seismic requirements and will ensure that employees have a safe, productive, fully accessible and functionally effective workplace.

Alternative v. was deemed superior to options i, ii, iii, and iv as it provides the best value when considering the longer life span of a new building compared to more limited life span of a renovated building. It is also the only alternative that would allow for post disaster construction.

Additional Information:

The Vernon Field Building was identified in the Fiscal 2012-Fiscal 2014 Amended Revenue Requirements Application as one of the high priority sites requiring work during the test period. At the time of the Fiscal 2012-Fiscal 2014 Amended Revenue Requirements Application, the scope of the project was under development.

<table>
<tr><td colspan="2">Project Name: Victoria - Field Building</td></tr>
<tr><td>Forecast Capital Cost:
$41.6 million</td><td>In-Service Date:
Fiscal 2018</td></tr>
<tr><td>Development Phase:
Implementation</td><td>Filing Reference:
Amended F12-F14 RRA:
• Application Section 6.11.1
• Appendix I, line 9
• Appendix J, page 178
BCUC IR 1.287.1</td></tr>
<tr><td colspan="2">Description:
This project involves the construction of a new facility at the existing Victoria Field Building site to address significant deficiencies and issues with the existing facilities.</td></tr>
<tr><td colspan="2">Key Drivers:
• Operational Requirements
• Safety
• Reliability</td></tr>
<tr><td colspan="2">Issues Being Addressed:
The existing BC Hydro Victoria facility is comprised of an operations / warehouse building and an office with a combined size of 75,000 ft^2 on 14.2 acres of land located at 4400 Saanich Road in Victoria. The Victoria Facility is a vital operating site on Vancouver Island and is approaching 40 years of age. It is centrally located in Victoria to service a large area comprising the whole Victoria Capital Regional District (approximately 360,000 customers). A total of approximately 150 employees work out of this facility. The majority of these employees are from Transmission and Distribution but there are a total of 26 business operations working out of the facility.

There is a long-term need for a suitable regional office to provide post-disaster recovery and emergency operational support and to meet customer needs in the surrounding area. This includes appropriate outage response, planning and execution of the electric system to support local/regional development, and maintenance and upgrades to infrastructure to ensure ongoing system reliability in the region. In order to “keep the lights on”, the facility must remain operational to support 24/7 emergency response in the worst weather conditions and in the event of a natural disaster.

The existing facility has been prioritized for redevelopment due to the combined issues of seismic and safety risk, building condition, operational considerations, lack of adequate space and future growth potential, and strategic location. The key issues are that the facilities:
• Are located in the highest seismic vulnerability region in Canada and meet less than 50 per cent seismic resistance capacity as designated by the current BC Building Code for a normal building, and less than 33 per cent seismic resistance capacity for a post disaster resistance designated building;
• Further compromise staff safety with respect to inadequate fire safety and accessibility, presence of hazardous materials, and unsafe yard and traffic flow conditions;
• Have numerous issues and Building Code deficiencies affecting the roof, building envelope, HVAC, and plumbing components; and
• Do not meet current functional and operational needs, with no ability to reconfigure the space to meet existing needs, and lacks the room for potential future growth i.e., insufficient number and size of truck bays, and disconnection of business units in two separate buildings
The inefficient layouts that include a mix of office and industrial space, and current conditions negatively impact the ability of staff to perform their duties, i.e., outage response, electric system construction, and upgrade and maintenance work.</td></tr>
</table>

Discussion of Alternatives:

Four alternatives were considered:

i. **Do nothing:** This option does not address the known and growing concerns at the site. It does not meet functional needs and exposes BC Hydro to the consequences of ignoring code, safety, and reliability issues. Aging components will fail and must be replaced in an inefficient reactive rather than proactive manner. Business continuity, employee safety and customer reliability are all at risk;

ii. **Construct a new building on site. Demolish the existing buildings:** All current and anticipated functional and operational requirements for the Victoria Facility will be met. The new building will be code compliant and optimized for safety, efficiency and flexible operations and will target advanced energy intensity standards. The new facility will have efficient layouts and site utilization to allow for optimal vehicle movement and exterior storage areas;

iii. **Conduct renovations and expansions to the existing facilities:** Will improve current building conditions and bring the facility up to code compliance but does not address the operational deficiencies, and does not resolve the significant issues related to the facility configuration, lack of connectivity, and current and future business requirements; and

iv. **Acquire a new site and construct a new facility; sell the existing property:** There is a very limited supply of properties that meet the business requirements for zoning, location, access to major roads and related response times, site dimensions, and customer base. Site acquisition costs would be significant. In addition, there would be added time and uncertainly around potential acquisition due diligence activities and negotiations, as well as project planning, scheduling, and budgeting. There would also be uncertainly related to the selling price and the timing of the sale of the existing property.

Alternative ii was determined to be the most prudent and practical way of addressing the identified building issues.

Additional Information:

The Victoria Field Building was identified in the Fiscal 2012-Fiscal 2014 Amended Revenue Requirments Application as one of the high priority sites requiring work during the test period. At the time of the Fiscal 2012-Fiscal 2014 Amended Revenue Requirments Application, the scope of the project was under development.

Project Name: Construction Services/Lower Mainland Transmission Building	
Forecast Capital Cost: $36.5 million	**In-Service Date:** Fiscal 2020
Development Phase: Definition	**Filing Reference:** New

Description:

This project involves the construction of a new facility at the existing or a new site, to address significant deficiencies and issues with the existing facilities.

Key Drivers:

- Operational Requirements
- Safety
- Reliability

Issues Being Addressed:

The existing Construction Services facilities are located at 12685 82nd Avenue, in Surrey, BC, occupying approximately 38,000 ft^2 of building area and 342,000 ft^2 of yard space. The Lower Mainland Transmission facilities are located at 12332 88th Avenue in Surrey and occupy approximately 17,000 ft^2 of building area with an associated 152,000 ft^2 yard. Construction Services provides services to support capital replacement, maintenance and expansion of Transmission and Distribution and Generation assets. Lower Mainland Transmission provides transmission field services primarily in the Lower Mainland. Both business units are key facets of BC Hydro's Field Operations. Both facilities also serve the entire province for major storm response and in support of capital projects. The Construction Services and Lower Mainland Transmission buildings were built in 1974 and 1965 respectively, to basic commercial construction standards at the time. There are 132 employees who work from Construction Services and 37 employees who work from Lower Mainland Transmission.

The Construction Services and Lower Mainland Transmission business groups have long-term operational requirements in the Lower Mainland. In order to "keep the lights on", the facilities must remain operational for 24/7 emergency response in the worst weather conditions and in the event of a natural disaster.

The existing facilities have been prioritized for redevelopment due to the combined issues of seismic and safety risk, building condition and code compliance, and operational challenges and lack of space. There are anticipated synergies and cost savings in locating these operations in a single facility; therefore, a single project has been considered to address both business groups' requirements. The key issues are that the facilities:

- Are located in a high seismic vulnerability region and meet less than 50 per cent seismic resistance capacity as designated by the current B.C. Building Code for a normal building, and less than 33 per cent seismic resistance capacity for a post disaster resistance designated building;
- Compromise staff safety with respect to inadequate fire safety and accessibility, presence of hazardous materials, and unsafe yard and traffic flow conditions;
- Are 40 to 50 years old and built to dated building code standards, with numerous building components (building envelope, mechanical, electrical, interiors) requiring replacement;
- Do not provide adequate space and lack adaptability, thereby requiring the use of temporary modular buildings for Construction Services staff; and
- Do not provide an adequate number and size of truck bays to service and store trucks at both facilities; the existing Construction Services yard lacks sufficient space for traffic flow and maneuverability.

The shortage of space, the condition of the facilities, and the disconnection of staff in trailers negatively impacts the ability of staff to perform their duties – outage response, electric system construction, and upgrade and maintenance work.

Discussion of Alternatives:

The following alternatives were considered in the Identification phase:

i. Do nothing: defer any major projects, continue maintenance as required and replace various building components as they fail;

ii. Renovate and expand the existing facilities;

iii. Construct two new facilities on the existing site or new sites; and

iv. Construct a new combined facility on an existing or new site. This is the recommended alternative.

Additional Information:

Alternative iv proposes relocating a new combined facility on a new or existing location. As there are financial advantages to relocating the site on the existing BC Hydro owned Surrey Campus, a number of locations on campus are being considered. Each of these locations will be evaluated to assess their ability to meet the program requirements and the Construction Services and Lower Mainland Transmission stakeholders' functional requirements. Criteria include capital and operating costs over the life of the building, compliance with zoning restrictions, which vary across the Campus, environmental regulation compliance, site fit and efficiency, synergies and adjacencies to other business units, and ability to allow for business growth and future expansion of core business operations on Surrey Campus.

One location under consideration is to develop a new Construction Services/Lower Mainland Transmission facility at the location of the existing Material Classification Facility site, located north of 88th Avenue. This option would require that the existing Material Classification Facility be relocated and is therefore only feasible if there is independent business rationale and approvals to move and redevelop Material Classification Facility. Therefore, if this option is chosen, this project and the Material Classification Facility project (see Appendix J, Page 82) will need to be planned and coordinated jointly to ensure that implementation phase activities are appropriately aligned. Due to the land swap proposed under this option, one project cannot advance without the other and together have an expected capital cost in excess of $50 million. Therefore, in accordance with BC Hydro's Capital Project Filing Guidelines BC Hydro would plan to submit a joint application for both the Material Classification Facility and Construction Services/Lower Mainland Transmission projects to the Commission pursuant to section 44.2 of the *Utilities Commission Act*.

Project Name: Material Classification Facility	
Forecast Capital Cost: TBD	**In-Service Date:** TBD
Development Phase: Identification	**Filing Reference:** New

Description:

This project involves the construction of a new facility on a new site likely on BC Hydro's Surrey Campus to address significant deficiencies and environmental compliance and zoning issues with the existing facilities.

Key Drivers:

- Environmental
- Operational Requirements
- Safety

Issues Being Addressed:

The Material Classification Facility is located at 12345 88th Avenue in Surrey, BC on the BC Hydro Surrey Campus. The facility comprises the Transformer Shop and Hazardous Waste Operations including salvage and disposal operations and occupies an area of 19,766 ft^2 of building area and 8.6 acres of yard space. The buildings were constructed throughout the 1970's and 1980's as business needs required. Approximately 27 employees work out of this facility.

On a daily basis, the facility receives, classifies, separates, decontaminates, stores and arranges the processing or disposal of multiple waste streams, including hazardous wastes, generated by BC Hydro. Material Classification Facility centralizes its operations for the entire province from this facility, making it critical in supporting other business units' waste needs.

The Material Classification Facility has been identified as a priority for redevelopment due to the combined issues of environmental regulation requirements, zoning non-compliance, operational challenges, building conditions, and code compliance. The key issues are that the facilities:

- Will need to meet the Ministry of Environment's expectation that BC Hydro will implement further environmental protection measures to prevent the release of contaminants of concern and prevent pollution;
- Contravene existing zoning regulations from the City of Surrey;
- Do not provide sufficient enclosed areas to sort and store materials;
- Cannot support current business requirements of oil storage and Paper Insulated Lead Covered cable sampling;
- Are located in a high seismic vulnerability region and some of the facilities meet less than 50 per cent seismic capacity as designated by the current BC Building Code for a normal building, and less than 33 per cent seismic resistance capacity for a post disaster resistance designated building; and
- Do not meet current building codes with some of the key building components (building envelope, mechanical and electrical systems) being at the end of their useful life and needing replacement.

The environmental regulations and zoning contraventions, functional limitations, limited seismic withstands, and code issues negatively impact the ability of staff to perform their duties and support BC Hydro operations.

Discussion of Alternatives:

The following five alternatives are being considered in the Identification phase:

i. Do nothing: continue with existing facilities;
ii. Apply for rezoning, and renovate and expand the existing facilities to meet current building code, safety and program requirements;
iii. Apply for rezoning and construct a new facility on the existing site and demolish the existing building;
iv. Construct a new facility at a new location on Surrey Campus; and
v. Acquire a new site and construct a new facility.

Additional Information:

Alternative iv proposes relocating the Material Classification Facility to a new location on Surrey Campus. As there are financial advantages to relocating the site on the existing BC Hydro owned Surrey Campus, a number of locations on Campus are being considered. Each of these sites will be evaluated to assess their ability to meet the program requirements and the Material Classification Facility stakeholders' functional requirements. Criteria include capital and operating costs over the life of the building, compliance with zoning restrictions, which vary across the Campus, environmental regulation compliance, site fit and efficiency, synergies and adjacencies to other business units, and ability to allow for business growth and future expansion of core business operations on Surrey Campus.

One location under consideration is the existing Lower Mainland Transmission facility site, located south of 88th Avenue, which meets the zoning requirements for the hazardous waste management activities undertaken at Material Classification Facility. This option would require that the existing Lower Mainland Transmission be relocated and is therefore only feasible if there is independent business rationale and approvals to move and redevelop Lower Mainland Transmission elsewhere. Therefore, if this option is chosen (and Lower Mainland Transmission and Material Classification Facility swap locations), this project and the Construction Services/Lower Mainland Transmission project (see Appendix J, Page 80) will need to be planned and coordinated jointly to ensure that implementation phase activities are appropriately aligned. Due to the land swap proposed under this option, one project cannot advance without the other and together have an expected capital cost in excess of $50 million. BC Hydro would plan to submit a joint application for both the Material Classification Facility and Construction Services/Lower Mainland Transmission projects to the Commission.

Project Name: Chilliwack – Field Building	
Forecast Capital Cost: TBD	**In-Service Date:** TBD
Development Phase: Identification	**Filing Reference:** New

Description:

This project involves the construction of a new facility at a new site to address significant deficiencies and issues with the existing facilities.

Key Drivers:

- Operational Requirements
- Safety
- Reliability

Issues Being Addressed:

BC Hydro operations in the Chilliwack area are based at two locations, Chilliwack and Atchelitz. The existing Chilliwack facility is a leased property within a multi-tenanted facility, consisting of approximately 12,000 ft^2 of office and warehouse space at 44550 South Sumas Road. The Atchelitz facility is owned by BC Hydro and was built approximately 40 years ago, and comprises about 5,500 ft^2 of office space. It is located at 6155 Lickman Rd in Chilliwack, within the Atchelitz substation property boundaries. A total of approximately 35 staff are based at these two sites.

There is a long-term need for a suitable field office to provide post-disaster recovery and emergency operational support and to meet customer needs in the surrounding area. This includes appropriate outage response, planning and execution of the electric system to support local/regional development, and maintenance and upgrades to infrastructure to ensure ongoing system reliability in the region. In order to "keep the lights on", the facilities must remain operational to support 24/7 emergency response in the worst weather conditions and in the event of a natural disaster. The Eastern Fraser Valley is continuing to grow at a fast pace. The population of Chilliwack increased 26 per cent between 1996 and 2011, and is expected to continue to grow at a similar rate.

The existing facilities have been prioritized for redevelopment due to the combined issues of lack of adequate space for current and projected business operations; the inability to expand either the Chilliwack facility, as it is leased, or the Atchelitz location, as it is in close proximity to a substation; their strategic location in a growing region; as well as the condition and associated seismic concerns of the existing buildings. The key issues are that the facilities:

- Have inadequate space for existing staff and materials, requiring some staff to work out of the Abbottsford facility, approximately 35 km away, and requiring the Abbotsford office to store a large volume of materials for the Chilliwack/Atchelitz operations. This can delay response time, especially in the winter or during emergencies;
- Are inadequate for working, maneuvering and loading line trucks. The location of the Atchelitz office on the same site as a substation prevents office expansion and puts a strain on the safe and efficient use of yard space. It is also difficult to safely move and load line vehicles in the multi-tenanted Chilliwack office complex;
- Are both located in a high seismic vulnerability region; and
- In Atchelitz compromise staff safety with respect to inadequate fire suppression and sprinklers and presence of hazardous materials; lack an emergency generator; and require replacement of the end of life roof.

The severe space shortage and the resulting disconnection of staff in three separate facilities negatively impact the ability of staff to perform their duties – outage response, electric system construction, and upgrade and maintenance work.

Discussion of Alternatives: The following five alternatives are being considered in the Identification phase: i. Do nothing - continue with existing facilities; ii. Lease additional space in the existing facility or in a different facility; iii. Renovate and expand the existing Atchelitz facility, or build new, and maintain the leased Chilliwack facility; iv. Construct a new facility at a new BC Hydro owned location; and v. Acquire a new site and construct a new facility.
Additional Information:

Project Name: Site C Clean Energy Project	
Forecast Capital Cost: $8.335 Billion*	**In-Service Date:** November 2024**
Development Phase: Implementation	**Filing Reference:** Amended F12-F14 RRA: • BCUC IRs 1.27.1 to 1.27.7, 1.108.1, 1.108.2, 1.139.2, 2.37.1 to 2.37.4, 2.78.2
Description: Site C will be a third dam and hydroelectric generating station on the Peace River approximately seven kilometres southwest of Fort St. John. It will be capable of producing approximately 5,100 gigawatt-hours of electricity annually and 1,100 megawatts of capacity.	
Key Drivers: Generation Growth	
Issues Being Addressed: As the third project on one river system, Site C will gain significant efficiencies by taking advantage of water already stored in the Williston Reservoir. This means that Site C will generate approximately 35 per cent of the energy produced at W.A.C. Bennett Dam, with only five per cent of the reservoir area.	
Discussion of Alternatives: • Compared to other resource alternatives, Site C is an attractive resource option from the perspective of reliability and cost. • Site C will be a clean and renewable source of firm electricity for over 100 years. • Site C will produce among the lowest GHG emissions per GWh, when compared to other forms of electricity generation.	
Additional Information: The Site C Clean Energy Project received environmental approvals from the federal and provincial governments in October 2014. In December 2014, the project received approval from the provincial government to proceed to construction. Project components include: • Access roads and a temporary construction access bridge across the river at the dam site; • A worker accommodation camp at the dam site; • Upgrades to roads and realignment of six segments of Highway 29; • Two new 500 kV transmission lines connecting Site C to the existing Peace Canyon Substation, along an existing right-of-way.; • Shoreline protection at Hudson's Hope; • An 800-metre roller-compacted concrete buttress to improve foundation stability and seismic protection; • An earthfill dam, approximately 1,050 metres long and 60 metres high above the riverbed; • A generating station with six 183 MW generating units, and spillways; and • An 83-kilometre-long reservoir that would be, on average, two to three times the width of the current river. *Total forecast cost presented excludes the Project Reserve of $440 million (established by Government to account for events outside of BC Hydro's control that could occur during construction) which is held by the Treasury Board. **Planned in-service date for the final unit. This timeline is subject to change based on reviews of the construction schedule.	

Fical 2017 to Fiscal 2019
Revenue Requirements Application

Appendix K

Fiscal 2015 and Fiscal 2016 Variance Explanations

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1 Introduction

This appendix provides variance explanations for BC Hydro's load forecast, cost of energy, operating costs and capital projects between the fiscal 2015 plan and fiscal 2016 plan in the Fiscal 2015 - Fiscal 2016 Revenue Requirements Rate Application (**fiscal 2015 Plan** and **fiscal 2016 Plan** respectively) and actual results in those fiscal years. Please note, in the tables in this Appendix, references to F2015 RRA or F2016 RRA signifies the Plan amount from the Fiscal 2015 - Fiscal 2016 Revenue Requirements Rate Application.

2 Load Forecast and Revenue Variance Explanations (Chapter 3)

Chapter 3 of the Application addresses the load forecast and revenues. This section of Appendix K addresses the load forecast and revenue variance explanations for fiscal 2015 and fiscal 2016. Load and revenues always have a degree of variability between the forecast and actual, but as described below, the variances are relatively small in fiscal 2015 and fiscal 2016, ranging from 3.6 per cent to 6.0 per cent. These variances are captured in the Cost of Energy Deferral Accounts and BC Hydro and customers pay actual costs only.

2.1 Load Variance

2.1.1 Load Variance - Fiscal 2015

Table K-1 shows the fiscal 2015 Plan to fiscal 2015 actual results with variance explanations below to highlight significant differences for the total domestic energy sales **(GWh)**.

Table K-1 Fiscal 2015 Domestic Energy Sales - Variance

	(GWh)	Fiscal 2015 RRA	Fiscal 2015 Actual	Fiscal 2015 Variance	Fiscal 2015 %
		1	2	3 = 2 - 1	4 = 3 / 1
1	Residential	18,805	17,047	(1,758)	(9.3%)
2	Light Industrial and Commercial	18,277	18,564	287	1.6%
3	Large Industrial	14,444	14,020	(423)	(2.9%)
4	Other	1,604	1,567	(37)	(2.3%)
5	Total	53,130	51,199	(1,932)	(3.6%)

Actual accrued domestic energy sales in fiscal 2015 were 1,932 GWh or 3.6 per cent lower than the demand projections included in the fiscal 2015 Plan.

Actual residential energy demand was 1,758 GWh or 9.3 per cent lower than the fiscal 2015 Plan. A significant portion of this was due to warmer than normal temperatures. Actual heating degree days in the Lower Mainland for fiscal 2015 were 2,402 versus predicted heating degree days of 2,812.

Light industrial and commercial energy demand was 287 GWh or 1.6 per cent higher than the fiscal 2015 Plan. Most of this variance comes from the industrial distribution sector as actual sales were stronger than forecast in wood, oil and gas, and the other small industrial segments. Sales to the distribution wood sector have somewhat recovered following the 2008 U.S. housing downturn; however, U.S. housing starts have yet to recover to pre-2008 levels.

Sales to the large industrial sector were 423 GWh or 2.9 per cent lower than the fiscal 2015 Plan. Most of the variance was due to delays in start-ups in the oil and gas sector.

Energy sales to other customer classes were 37 GWh or 2.3 per cent lower than the fiscal 2015 Plan. This variance was primarily due to lower sales than expected to the City of New Westminster.

2.1.2 Load Variance - Fiscal 2016

Table K-2 shows the fiscal 2016 Plan to fiscal 2016 actual results with variance explanations below to highlight significant differences for the total domestic energy sales (GWh).

Table K-2 Fiscal 2016 Domestic Energy Sales - Actuals

	(GWh)	F2016 RRA	F2016 Actual	F2016 Diff	F2016 % Diff
		1	2	3 = 2 - 1	4 = 3 / 1
1	Residential	18,743	17,331	(1,412)	(7.5%)
2	Light Industrial and Commercial	18,346	18,421	75	0.4%
3	Large Industrial	15,032	13,669	(1,363)	(9.1%)
4	Other	1,638	1,602	(36)	(2.2%)
5	Total	53,759	51,023	(2,737)	(5.1%)

Actual accrued domestic energy demand in fiscal 2016 was 2,737 GWh or 5.1 per cent lower than the demand projections included in the fiscal 2016 Plan. The fiscal 2016 Plan was based on demand projections developed in the fall of 2013.

Residential energy demand in fiscal 2016 was 1,412 GWh or 7.5 per cent lower than the fiscal 2016 Plan. A significant portion of this was due to warmer than normal temperatures. The actual heating degree days in the Lower Mainland for fiscal 2016 was 2,543 versus the predicted heating degree days of 2,796.

Light industrial and commercial energy sales were 75 GWh or 0.4 per cent higher than the fiscal 2016 Plan. The positive variance (actual results above forecast) in the industrial sector offset the negative variance (actual results below forecast) in the commercial distribution sector.

Large industrial energy sales in fiscal 2016 were 1,363 GWh or 9.1 per cent lower than the fiscal 2016 Plan. Most of the variance came from the oil and gas, mining and other transmission sectors. The variance in the oil and gas sector was from delays in customers' start-ups. The variance in mining was due to slower sales driven by lower commodity prices, and the variance from other transmission customers was due to lower loads at bulk terminals than anticipated.

Energy sales to the other customer classes were 36 GWh or 2.2 per cent lower than the fiscal 2016 Plan. This variance was primarily due to lower sales than expected to other utilities including FortisBC Inc and the City of New Westminster.

2.2 Revenue Variance

2.2.1 Revenue Variance - Fiscal 2015

Table K-3 below compares the actual fiscal 2015 domestic revenues to the forecast of domestic revenues included in the fiscal 2015 Plan.

Table K-3 Fiscal 2015 Domestic Revenues - Variance

		Fiscal 2015			
	($ million)	RRA	Actual	Variance	%
		1	2	3 = 2 - 1	4 = 3 / 1
1	Residential	1,812.0	1,630.8	(181.2)	(10.0%)
2	Light Industrial and Commercial	1,512.4	1,521.1	8.8	0.6%
3	Large Industrial	744.0	712.9	(31.1)	(4.2%)
4	Other	116.2	114.7	(1.4)	(1.2%)
5	Subtotal	4,184.5	3,979.5	(204.9)	(4.9%)
6	Revenue from Deferral Rider	208.4	198.1	(10.3)	(5.0%)
7	Total	4,392.9	4,177.6	(215.3)	(4.9%)

Actual domestic revenues in fiscal 2015 were $215.3 million or 4.9 per cent lower than the fiscal 2015 Plan. The reasons for the variances in domestic revenues are the same as the reasons for the variances in the domestic energy sales described in section 2.1.1. The percentage reduction in total domestic revenue of 4.9 per cent was higher than the percentage reduction in total domestic energy sales of 3.6 per cent because the reduction in energy sales was primarily from residential customers, whose average revenue rate of $95.7 per MWh was higher than the average fiscal 2015 rate of $81.6 per MWh paid by all customers.

2.2.2 Revenue Variance - Fiscal 2016

Table K-4 below compares the actual fiscal 2016 domestic revenues to the forecast domestic revenues included in the fiscal 2016 Plan.

Table K-4 Fiscal 2016 Domestic Revenues - Variance

		Fiscal 2016			
	($ million)	RRA	Actual	Variance	%
		1	2	3 = 2 - 1	4 = 3 / 1
1	Residential	1,917.6	1,754.2	(163.4)	(8.5%)
2	Light Industrial and Commercial	1,608.5	1,604.7	(3.7)	(0.2%)
3	Large Industrial	826.1	730.0	(96.1)	(11.6%)
4	Other	124.2	120.2	(4.0)	(3.2%)
5	Subtotal	4,476.3	4,209.1	(267.2)	(6.0%)
6	Revenue from Deferral Rider	223.0	209.6	(13.4)	(6.0%)
7	Total	4,699.3	4,418.7	(280.6)	(6.0%)

Actual domestic revenues in fiscal 2016 were $280.6 million or 6.0 per cent lower than the fiscal 2016 Plan. The reasons for the variances in domestic revenues are the same as the reasons for the variances in the domestic energy sales described in Chapter 1, section 1.3.3. The percentage reduction in total domestic revenue of 6.0 per cent was higher than the percentage reduction in total domestic energy sales of 5.1 per cent because the reduction in energy sales was primarily from residential customers, whose average revenue rate of $101.2 per MWh was higher than the average fiscal 2016 rate of $86.6 per MWh paid by all customers.

3 Cost of Energy Variance Explanations (Chapter 4)

Chapter 4 of the Application addresses BC Hydro's Cost of Energy. This section provides variance explanations for sources of energy supply and Cost of Energy for fiscal 2015 and fiscal 2016.

3.1 Fiscal 2015 Sources of Supply Actuals

As shown in Table K-5, actual fiscal 2015 energy supplied was 2,252 GWh or 4 per cent lower than forecasted in the fiscal 2015 Plan.

Table K-5 Fiscal 2015 Sources of Supply

(GWh)	F2015			
	RRA	Actual	Diff	% Diff (%)
	1	2	3 = 2 - 1	4 = 3 / 1
Hydroelectric (including Waneta)	47,478	41,230	(6,248)	(13)
IPPs and Long-Term Commitments	13,339	13,377	38	0
Market Electricity Purchases	1,224	207	(1,017)	(83)
Natural Gas for Thermal Generation	290	213	(77)	(27)
Surplus Sales	(3,756)	(15)	3,741	100
Net Purchases (Sales) from Powerex	(199)	512	711	357
Non-Integrated Area	133	115	(18)	(14)
Exchange Net	(530)	88	618	117
Total	57,979	55,727	(2,252)	(4)

Inflows to the system for fiscal 2015 were 102 per cent of normal, higher than the forecast of 100 per cent of normal included in the fiscal 2015 Plan. The amount and timing of the inflows was unusual due to a drier than average summer followed by a fall and winter that were warmer and wetter than average. Despite higher inflows, hydro generation was lower than forecast in the fiscal 2015 Plan due to lower loads from milder winter weather and lower than forecast exports due to low market prices. Only 15 GWh of surplus sales occurred in fiscal 2015 as compared to 3,756 GWh forecasted in the fiscal 2015 Plan. Domestic market electricity purchases were also lower due to below forecast domestic loads and above forecast purchases by

Powerex due to increased opportunities to import. As a result, more water was retained in system storage for generation in future years.

3.2 Fiscal 2015 Cost of Energy Actuals

Table K-6 below compares the actual fiscal 2015 Cost of Energy to the fiscal 2015 Plan.

Table K-6 Fiscal 2015 Cost of Energy

($ million)	F2015			
	RRA	Actual	Diff	% Diff (%)
	1	2	3 = 2 - 1	4 = 3 / 1
Water Rentals (including Waneta)	392.8	368.7	(24.1)	(6)
IPPs and Long-Term Commitments	1,028.6	1,064.0	35.4	3
IPP Capital Leases	0.0	0.0	0.0	N/A
Market Electricity Purchases	44.7	6.0	(38.7)	(87)
Natural Gas for Thermal Generation	26.6	24.0	(2.6)	(10)
Domestic Transmission	30.5	18.4	(12.1)	(40)
Non-Treaty Storage Agreement	(7.8)	13.7	21.5	(276)
Surplus Sales	(122.6)	(0.2)	122.4	(100)
Net Purchases (Sales) from Powerex	(8.1)	16.2	24.3	(300)
Non-Integrated Area	32.9	25.5	(7.4)	(22)
Gas & Other Transportation	11.8	10.6	(1.2)	(10)
Other	(44.9)	(34.4)	10.5	(23)
Total	1,384.5	1,512.5	128.0	9

The actual Cost of Energy was $128.0 million or nine per cent higher than the fiscal 2015 Plan, due to lower surplus sales, higher purchases from Powerex under the Transfer Price Agreement, and higher energy costs resulting from more net storage into Non-Treaty storage accounts due to low market prices. Costs from Independent Power Producers (**IPP**) were also higher than fiscal 2015 Plan due to a change in accounting for one Electricity Purchase Agreement from a capital lease to an operating lease, as discussed in Chapter 8, section 8.11.1. The Cost of Energy was partially offset by lower water rentals due to lower hydro generation volumes in the prior year as compared to the fiscal 2015 Plan.[1] Finally, market electricity purchase costs were lower due to below forecast domestic loads and domestic transmission charges were lower due to lower surplus sales.

3.3 Fiscal 2016 Sources of Supply

As shown in Table K-7 below, actual fiscal 2016 energy supplied was 1,643 GWh or three per cent lower than the fiscal 2016 Plan.

Table K-7 Fiscal 2016 Sources of Supply

	F2016 RRA (GWh)	F2016 Actual (GWh)	F2016 Diff (GWh)	% Diff (%)
	1	2	3 = 2 - 1	4 = 3/1
Hydroelectric (including Waneta)	46,907	49,352	2,445	5
IPPs and Long-Term Commitments	12,002	14,319	2,317	19
Market Electricity Purchases	1,553	122	(1,431)	-92
Natural Gas for Thermal Generation	301	215	(86)	-29
Surplus Sales	(2,446)	(6,277)	(3,832)	157
Net Purchases (Sales) from Powerex	255	(6)	(261)	-102
Non-Integrated Area	135	111	(24)	-18
Exchange Net	(204)	(976)	(772)	379
Total	58,502	56,859	(1,643)	-3

[1] Water rental fees are payable based on current rates, but on the prior year's generation.

Water inflows to the system for fiscal 2016 were 97 per cent of normal, lower than the forecast of 100 per cent of normal included in the fiscal 2016 Plan. The lower inflows in fiscal 2016 were due to lower than average inflows in the Kootenay and Pend-d'Oreille basins and at most of BC Hydro's smaller plants. Despite lower inflows, hydro generation was higher than forecast in the fiscal 2016 Plan. This was driven by a need to meet Arrow Lake reservoir requirements and Columbia River Treaty obligations as well as to reduce spill risk at the large reservoirs, resulting in above forecast surplus sales. In addition, IPP deliveries were higher than the fiscal 2016 Plan due to delayed completion of Rio Tinto Alcan's Kitimat Modernization Project resulting in Rio Tinto Alcan selling more energy to BC Hydro in fiscal 2016. This was partially offset by lower domestic market electricity purchases due to lower than forecast domestic loads and above forecast system storage.

3.4 Fiscal 2016 Cost of Energy

The table below compares the actual fiscal 2016 Cost of Energy to the forecast Cost of Energy in the fiscal 2016 Plan.

Table K-8 Fiscal 2016 Cost of Energy

	F2016 RRA ($ million)	F2016 Actual ($ million)	F2016 Diff ($ million)	F2016 % Diff (%)
	1	2	3 = 2 - 1	4 = 3/1
Water Rentals (including Waneta)	391.9	365.3	(26.6)	-7
IPPs and Long-Term Commitments	975.5	1,228.9	253.3	26
IPP Capital Leases	0.0	0.0	0.0	N/A
Market Electricity Purchases	56.6	2.8	(53.8)	-95
Natural Gas for Thermal Generation	26.9	20.0	(6.9)	-26
Domestic Transmission	25.7	52.6	26.9	105
Non-Treaty Storage Agreement	(19.8)	(14.4)	11.5	-44
Surplus Sales	(84.2)	(174.1)	(89.9)	107
Net Purchases (Sales) from Powerex	4.8	(0.1)	(5.0)	-103
Non-Integrated Area	34.3	22.6	(11.6)	-34
Gas & Other Transportation	12.1	10.5	(1.6)	-13
Other	(32.1)	(38.6)	(12.5)	48
Total	1,391.7	1,475.6	83.8	6

The actual Cost of Energy was $83.8 million or 6 per cent higher than the fiscal 2016 Plan. This was largely due to higher costs from IPPs associated with (i) higher deliveries from Rio Tinto Alcan and (ii) higher costs for one Electricity Purchase Agreement as a result of a change in accounting from capital lease to operating lease - discussed further in Chapter 8, section 8.11.1. This was partially offset by higher revenue from surplus sales. In addition, domestic market electricity purchase costs were lower than forecast due to lower import volumes and water rental costs were lower due to lower hydro generation in the prior year as compared to the fiscal 2016 Plan.[2]

[2] Water rental fees are payable based on current rates, but on the prior year's generation.

4 Summary Operating Costs Variance Explanations (Chapter 5)

The following section provides a summary of the variance explanations pertaining to the fiscal 2015 actual and fiscal 2016 actual gross operating costs and provisions compared to the fiscal 2015 Plan and fiscal 2016 Plan.

Table K-9 Fiscal 2015 Operating Cost Variances

($ million)	F2015			
	RRA	**Actual**	**Diff**	**% Diff**
	1	2	3=2-1	4=3/1
Training, Development and Generation	132.9	134.0	1.1	1%
Transmission, Distribution and Customer Services	513.4	517.6	4.2	1%
Capital Infrastructure Project Delivery	48.7	52.7	4.0	8%
Operations Support	98.2	93.3	(4.9)	-5%
Total Operating Cost by Business Group (schedule 5.0, line 12)	**793.2**	**797.6**	**4.4**	1%
Deferred Account Additions (schedule 5.0, line 50)	-	(8.1)	(8.1)	
Regulatory Account Additions (schedule 5.0, line 64)	339.2	380.3	41.1	12%
Total Gross Operating Costs (schedule 5.0, line 65)	**1,132.4**	**1,169.8**	**37.4**	3%
Provisions before Regulatory Accounts (schedule 5.0, line 92)	38.4	51.0	12.6	33%
Deferred Provisions (schedule 5.0, line 100)	-	82.2	82.2	
Total Gross Operating and Provisions (schedule 5.0, line 124)	**1,170.8**	**1,303.0**	**132.2**	11%

The Operating Cost Business Group variance for fiscal 2015 Plan to fiscal 2015 actual costs were within $4.4 million or 0.55 per cent of the fiscal 2015 Plan. The business groups work together to meet the annual operating cost target for BC Hydro. When business groups encounter unforeseen or unavoidable costs, the other business groups examine their programs for opportunities to reduce costs to offset these additional costs. This minimizes the variance to the overall corporate target.

Overall actual operating costs and provisions in fiscal 2015 were $132.2 million or 11.3 per cent higher than fiscal 2015 Plan. Of this amount, $118.4 million related to variances in transfers to regulatory accounts, including the following:

- An increase in the Environmental Provisions Regulatory Account of $63.8 million resulting from an increase to the Polychlorinated Biphenyl provision of $13.9 million and the Asbestos provision of $49.9 million due to changes to the discount rate used to calculate the present value of the obligation and an increase in the expected future asbestos remediation costs;
- An increase in the Site C Regulatory Account of $65.4 million due to a later than assumed final investment decision, which resulted in approximately nine months spend flowing through the Site C Regulatory Account rather than being capitalized;
- An increase in the Smart Metering and Infrastructure Regulatory Account of $9.1 million is related to the Distribution System Metering Device write off of $19.1 million, offset by $10.0 million due to a settlement with a third party for liquidated damages resulting from non-delivery of certain aspects of the contract. The Distribution System Metering Device write off was due to the decision to move to a more optimal technology. This more optimal technology aids in the measurement and detection of electricity theft. Overall, these decisions lowered upfront costs and increased operating benefits, resulting in savings of $32.0 million to the Smart Metering and Infrastructure Program costs;
- An increase in the Real Property Sales Regulatory Account due to the lower than planned gains from sale of real property of $7.9 million; and
- An increase in the Storm Restoration Regulatory Account due to higher than plan storm restoration costs of $9.0 million;

Partially offset by:

- A decrease in the Demand-Side Management Regulatory Account due to lower than planned demand side management expenditures of $25.7 million primarily due to lower incentive spend on Industrial programs resulting from customer project delays or cancellations and costs related to fewer customer project completions than planned; and

- A decrease in the Non-Heritage Deferral Account due to a transfer of planned operating expenses related to a change in the accounting treatment of an Electricity Purchase Agreement from capital lease to operating lease of $11.1 million (please refer to Chapter 8, section 8.11.1 for further information).

The remaining $13.8 million of the $132.2 million variance relates to items unrelated to regulatory account transfers, including the following:

- Dismantling costs of $8.0 million;
- Electricity Purchase Agreement termination costs of $6.7 million;
- Decrease of $5.0 million due to the non-deferred portion of the settlement amounts received from the third-party related to non-delivery of certain aspects of the contract as discussed above;
- Higher than planned business group operating costs of $4.4 million; and
- All other variances, totalling a decrease of $0.3 million.

The following paragraphs summarize the variance explanations pertaining to the fiscal 2016 actual costs and fiscal 2016 Plan.

Table K-10 Fiscal 2016 Operating Cost Variances

($ million)	F2016			
	RRA	Actual	Diff	% Diff
	1	2	3=2-1	4=3/1
Training, Development and Generation	131.3	136.3	5.0	4%
Transmission, Distribution and Customer Services	510.9	513.6	2.7	1%
Capital Infrastructure Project Delivery	48.7	61.0	12.3	25%
Operations Support	136.0	118.4	(17.6)	-13%
Total Operating Cost by Business Group (schedule 5.0, line 12)	**826.9**	**829.3**	2.4	0%
Deferred Account Additions (schedule 5.0, line 50)	-	(7.1)	(7.1)	
Regulatory Account Additions (schedule 5.0, line 64)	290.0	342.3	52.3	18%
Total Gross Operating Costs (schedule 5.0, line 65)	**1,116.9**	**1,164.5**	47.6	4%
Provisions before Regulatory Accounts (schedule 5.0, line 92)	29.7	34.8	5.1	17%
Deferred Provisions (schedule 5.0, line 100)	-	52.3	52.3	
Total Gross Operating and Provisions (schedule 5.0, line 124)	**1,146.6**	**1,251.6**	105.0	9%

The Operating Cost Business Group variances for fiscal 2016 Plan to fiscal 2016 actual costs were within $2.4 million or 0.3 per cent of the fiscal 2016 Plan. As stated above the business groups work together to meet the annual operating cost target for BC Hydro.

Overall, actual operating costs in fiscal 2016 were $105.0 million or 9.1 per cent higher than fiscal 2016 Plan. Of this amount, $2.4 million relates to business group operating costs and $5.1 million relates to provision variances, with the remaining $97.5 million related to variances in transfers to regulatory accounts as follows:

- Increase in the Environmental Provisions regulatory account of $47.1 million resulting from an increase to the Polychlorinated Biphenyl provision of $39.2 million and the Asbestos provision of $7.9 million due to an increase in the forecast remediation costs;
- Increase in the Storm Restoration Costs regulatory account of $19.6 million due to higher than plan storm restoration costs as a result of the severity and number of storms experienced with the August, 2015 wind storm resulting in the largest amount of damage;

- Increase in the Non-Current Pension Costs regulatory account of $17.2 million. By Order No. G-148-15 the Commission approved the deferral of the fiscal 2016 operating cost variance for post-employment benefits current service costs (current pension costs) arising from a change in the actuarial discount rate;
- Increase in the Demand-Side Management Regulatory Account of $14.1 million due to the implementation of the Thermo-Mechanical Pulp Program which was approved by Order in Council No. 404 after the fiscal 2015 and fiscal 2016 Plan was filed. Fiscal 2016 actual results include $19.7 million of expenditures related to the Thermo-Mechanical Pulp Program, offset by a decrease of $5.6 million due to timing or project completions across multiple programs;
- Increase in the Real Property Sales Regulatory Account of $9.5 million due to the lower than planned gains from sale of real property;
- Increase in the Non-Heritage Deferral Account of $5.9 million due to deferral of Burrard costs. By Order No. G-48-14 pursuant to Directive No. 7, the Commission approved the deferral of Burrard costs arising from the decommissioning of those portions of Burrard Thermal that are not required for transmission support services; and
- Increase in the Smart Metering and Infrastructure Regulatory Account of $3.0 million due to project underspend in fiscal 2015. The Smart Metering and Infrastructure Program was forecast for completion at the end of fiscal 2015 in the fiscal 2015 and fiscal 2016 Plan, but a shift in capital expenditures into fiscal 2016 resulted also in a shift in the deferred expenditures; and
- Increase in the Heritage Deferral Account of $2.5 million due to an increase in the water licence expenditures mainly due to an increase in boat ramp work;

These cost increases were partially offset by:

- Decrease in the Non-Heritage Deferral Account of $15.5 million due to a transfer of planned operating expenses related to a change in the accounting treatment of an Electricity Purchase Agreement from capital lease to operating lease (please refer to Chapter 8, section 8.11.1 for further information); and
- Decrease in the First Nations Settlement Provisions Regulatory Account of $5.0 million mainly due to a lower than plan Consumer Price Index factor used to calculate the net present value of the settlement payment obligation.

All other variances total a decrease of $0.9 million.

5 Capital Expenditures and Capital Additions Fiscal 2015 and Fiscal Plan Versus Actuals Variance Explanations (Chapter 6)

The following tables and discussion provide information on the variances for BC Hydro's fiscal 2015 and fiscal 2016 actual capital expenditures and capital additions compared to the fiscal 2015 and fiscal 2016 Plan. Generally, explanations are provided where variances between actual and planned amounts are greater than 10 per cent, with a minimum variance threshold of $10 million. Variances are provided for each main asset category in the tables below, with variance explanations provided following the tables. The amounts and variance explanations provided in this section exclude amounts for the Site C Clean Energy Project. In some cases the tables in this section will not match those in Chapter 6 as the grouping of capital expenditures and capital additions between business units may differ. The amounts presented in the tables in this section may not add due to rounding.

Capital expenditures and capital additions in a fiscal year are impacted by a number of factors that may give rise to variances from plan, including project phase and timing, potential change in scope to meet business requirements, or cost changes due to market conditions or other factors. In addition, capital projects frequently extend over several years before completion, and any variances from plan in a particular year can be offset by project expenditures and additions in a subsequent year. As indicated in Chapter 2, section 2.3.6.2, over the last five years, BC Hydro has delivered its capital projects below the initial implementation budgets on a total aggregated portfolio basis. From fiscal 2012 to fiscal 2016 BC Hydro completed 563 capital projects, with capital expenditures totalling $6.5 billion. These projects in aggregate were delivered $11.7 million or 0.18 per cent under budget.

This section includes information regarding the fiscal 2015 - fiscal 2016 capital expenditures and capital additions for the Smart Metering and Infrastructure Program. The Smart Metering and Infrastructure Program was completed in fiscal 2016, with a total project cost of $779 million which is $151 million below the budget of $930 million. A full discussion is available in the Smart Metering and Infrastructure Program Quarterly Updates to the BCUC and the "Smart Metering and Infrastructure Final Report to the BCUC" which is planned to be filed during the time period of this proceeding. Information regarding fiscal 2015 - fiscal 2016 actual capital expenditures and capital additions are presented in three sections, depending on the nature of the Smart Metering and Infrastructure assets and the organization area where expenditures were budgeted, including:

- Section 5.3 Distribution Fiscal 2015 - Fiscal 2016 Capital Expenditures and Additions Actual to Plan
- Section 5.4.1 Technology Fiscal 2015 - Fiscal 2016 Capital Expenditures and Additions Actual to Plan

- Section 5.4.2 Properties Fiscal 2015 - Fiscal 2016 Capital Expenditures and Additions Actual to Plan

Table K-11 and Table K-12, below provide BC Hydro fiscal 2015 - fiscal 2016 capital expenditures and capital additions by main asset category, excluding the Site C Clean Energy Project.

Table K-11 BC Hydro - Capital Expenditures Fiscal 2015 and Fiscal 2016 Actual to Plan

($ millions)	F2015			F2016		
	RRA	Actuals	Variance	RRA	Actuals	Variance
Generation (excluding Site C Clean Energy)	632.5	526.2	106.3	607.0	497.9	109.1
Transmission & Distribution	1,329.8	1,361.4	(31.6)	1,101.2	1,034.9	66.3
Business Support						
Technology	164.1	115.2	48.9	109.3	122.3	(13.0)
Properties	96.3	83.9	12.4	85.1	78.8	6.3
Fleet / Other	29.7	47.9	(18.2)	36.6	72.5	(35.9)
Total	2,252.4	2,134.6	117.8	1,939.2	1,806.4	132.8
Less: Contribution in Aid	(85.1)	~~(333.9)~~ (334.4)	~~248.8~~ 249.3	(124.1)	(133.8)	9.7
TOTAL	2,167.3	~~1,800.7~~ 1,800.2	~~366.6~~ 367.1	1,815.1	1,672.6	142.5

Table K-12 BC Hydro - Capital Additions Fiscal 2015 and Fiscal 2016 Actual to Plan

($ millions)	F2015			F2016		
	RRA	Actual	Variance	RRA	Actual	Variance
Generation (excluding Site C Clean Energy)	613.2	483.0	130.2	604.3	534.5	69.8
Transmission & Distribution	1,643.3	1,478.4	164.9	2,027.3	1,918.3	109.0
Business Support						
Technology	113.7	82.3	31.4	103.0	145.2	(42.2)
Properties	113.4	83.6	29.8	92.4	160.9	(68.5)
Fleet / Other	28.0	26.5	1.5	35.2	23.7	11.5
Total	2,511.6	2,153.8	357.8	2,862.2	2,782.6	79.6
Less: Contribution in Aid	~~(162.7)~~ (85.1)	~~(333.2)~~ (388.3)	~~170.5~~ 303.2	~~(129.3)~~ (124.1)	~~(110.9)~~ (111.1)	~~(18.5)~~ (13.0)
TOTAL	~~2,348.9~~ 2,426.5	~~1,820.6~~ 1,765.5	~~528.3~~ 661.0	~~2,732.9~~ 2,738.1	~~2,671.8~~ 2,671.5	~~61.2~~ 66.6

5.1 Generation Capital Expenditures and Additions Fiscal 2015 and Fiscal 2016 Actual to Plan Variances

Generation capital expenditures and capital additions for fiscal 2015 and fiscal 2016 are presented in Table K-13 and Table K-14 below. Variance explanations are provided in the discussion following the tables. Results exclude amounts for the Site C Clean Energy Project.

Table K-13 Generation Capital Expenditures Fiscal 2015 and Fiscal 2016 Actual to Plan (excluding Site C Clean Energy Project)

($ millions)	F2015			F2016		
	RRA	Actual	Variance	RRA	Actual	Variance
Hydroelectric Generation						
Growth	112.1	107.0	5.1	62.9	61.6	1.3
Redevelopment / Rehabilitation	272.4	227.7	44.7	296.4	268.3	28.1
Dam Safety	78.7	49.8	28.9	82.0	42.4	39.7
Sustaining - Other	157.0	133.1	23.9	145.5	103.8	41.7
Total Hydroelectric Generation	620.1	517.6	102.6	586.9	476.1	110.7
Non Integrated Areas						
Growth	4.0	0.9	3.1	8.3	-	8.3
Sustaining	4.7	4.4	0.3	4.4	12.7	(8.3)
Total Non Integrated Areas	8.7	5.3	3.4	12.7	12.7	0.0
Thermal Generation						
Growth	-	0.1	(0.1)	-	(0.4)	0.4
Sustaining	3.7	3.2	0.5	7.4	9.7	(2.3)
Total Thermal Generation	3.7	3.3	0.5	7.4	9.3	(1.9)
Total Generation	632.6	526.2	106.4	607.0	498.1	108.9
Less: Contribution in Aid	~~-~~ (0.7)	~~-~~ (1.1)	~~-~~ 0.4	~~-~~ (3.9)	(1.7)	~~1.7~~ (2.3)
TOTAL	~~632.6~~ 631.9	~~526.2~~ 525.1	~~106.4~~ 106.8	~~607.0~~ 603.1	496.4	~~110.6~~ 106.7

Table K-14 Generation Capital Additions Fiscal 2015 and Fiscal 2016 Actual to Plan (excluding Site C Clean Energy Project)

($ millions)	F2015			F2016		
	RRA	Actual	Variance	RRA	Actual	Variance
Hydroelectric Generation						
Growth	298.4	293.3	5.2	298.7	245.4	53.3
Redevelopment / Rehabilitation	30.0	19.7	10.3	40.0	58.6	(18.6)
Dam Safety	45.6	34.4	11.2	93.4	67.3	26.0
Sustaining - Other	223.9	122.1	101.7	155.1	153.5	1.7
Total Hydroelectric Generation	597.9	469.5	128.4	587.2	524.8	62.4
Non Integrated Areas						
Growth	-	-	0.0	-	-	0.0
Sustaining	8.9	10.4	(1.5)	11.9	5.6	6.3
Total Non Integrated Areas	8.9	10.4	(1.5)	11.9	5.6	6.3
Thermal Generation						
Growth	-	0.1	(0.1)	-	-	0.0
Sustaining	6.4	3.0	3.4	5.2	4.0	1.2
Total Thermal Generation	6.4	3.1	3.3	5.2	4.0	1.2
Total Generation	613.2	483.0	130.2	604.3	534.5	69.9
Less: Contribution in Aid	-	~~-~~ (3.0)	~~-~~ 3.0	-	~~(1.7)~~ (2.3)	~~1.7~~ 2.3
TOTAL	613.2	~~483.0~~ 480.0	~~130.2~~ 133.2	604.3	~~532.8~~ 532.2	~~71.5~~ 72.2

The following are capital expenditure variance explanations for fiscal 2015 Hydroelectric and Thermal Generation actual expenditures compared to the fiscal 2015 and fiscal 2016 Plan.

5.1.1 Growth Capital Expenditures and Additions

5.1.1.1 Capital Expenditures

Growth capital expenditure variances did not exceed the 10 per cent or $10 million thresholds in fiscal 2015 and fiscal 2016.

5.1.1.2 Capital Additions

The fiscal 2015 capital additions variance did not exceed the 10 per cent or $10 million threshold.

Fiscal 2016 capital additions were $53.3 million below plan, primarily due to the Upper Columbia Capacity Additions at Mica Units 5 and 6 project being $54.3 million (18 per cent) below plan due to lower than expected projects costs including lower camp construction and leasing costs and site restoration costs, and deferral of the replacement of the powerhouse crane.

5.1.2 Redevelopment/Replacement Capital Expenditures and Additions

5.1.2.1 Capital Expenditures

Fiscal 2015 capital expenditures were $44.7 million below fiscal 2015 Plan, due primarily to the John Hart Generating Station Replacement project being $43.8 million (24 per cent) below plan. This was due to the timing of cash flows and work activities. Refer to Appendix I, page 1, line 2 and Appendix J, page 2 for additional information on the project.

Fiscal 2016 capital expenditures were $28.1 million below plan, due primarily to the John Hart Generating Station Replacement project being $26.2 million (14 per cent) below plan due to the timing of cash flows and work activities.

5.1.2.2 Capital Additions

Fiscal 2015 capital additions were $10.3 million below plan, due primarily to the Ruskin Dam Safety and Powerhouse Upgrade project which was $11.3 million (38 per cent) below plan due to construction and schedule delays.

Fiscal 2016 capital additions were $18.6 million over plan, due to the Ruskin Dam Safety and Powerhouse Upgrade project being $18.6 million (46 per cent) higher than plan as a result of construction schedule delays from fiscal 2015 and contractor claim settlements.

5.1.3 Dam Safety Capital Expenditures and Additions

5.1.3.1 Capital Expenditures Variances

Fiscal 2015 capital expenditures were $28.9 million below plan, due primarily to the following:

- The Peace Canyon Flood Discharge Gates Reliability Improvement project expenditures were $6.5 million (87 per cent) below plan due to more extensive project planning and evaluation required than originally anticipated, resulting in an extension to the Definition phase of the project. Refer to Appendix I, page 1, line 8 and Appendix J, page 10, for additional information on the project;
- The Hugh Keenleyside Spillway Gate Reliability Upgrade project expenditures were $10.3 million (34 per cent) below plan due to a change in project timing as a result of a scope change, resulting in a change in cash flows; and
- The W.A.C. Bennett Dam Spillway Gate Upgrade project expenditures were $7.1 million (90 per cent) below plan due to more extensive project planning and evaluation required than originally anticipated, which resulted in an extension to the Definition phase of the project. Refer to Appendix I, page 1, line 10 and Appendix J, page 12, for additional information on the project.

Fiscal 2016 Capital Expenditures were $39.7 million below plan due primarily to the following:

- The W.A.C. Bennett Dam Spillway Chute Rehabilitation project was $7.7 million (89 per cent) below plan as a result of high reservoir conditions requiring the spillway to remain in service, thereby forcing the delay of the work for at least one year. Refer to Appendix I, page 1, line 6, for additional information on the project;

- The Peace Canyon Flood Discharge Gates Reliability Improvement project was $7.4 million (91 per cent) below plan due to more extensive project planning and evaluation required than originally anticipated, resulting in an extension to the Definition phase of the project. Refer to Appendix I, page 1, line 8, and Appendix J, page 10 for additional information on the project; and
- The Revelstoke Improve Left Bank Slope Stability project was $20.9 million (100 per cent) below plan due to additional studies that were undertaken as part of the Revelstoke Left Bank Slopes Instrumentation Improvements project. Based on the results of this additional work, the project is forecast to start in fiscal 2017, with reduced scope and lower expected costs. Refer to Appendix I, page 1, line 16 for additional information on the project.

5.1.3.2 Capital Additions Variances

Fiscal 2015 capital additions were $11.2 million below plan due primarily to the following:

- The Hugh Keenleyside Spillway Gate Reliability Upgrade project was $17.9 million (63 per cent) below plan due to a change in project timing and scope, which resulted in a change to the in-service date to fiscal 2016; and
- The W.A.C. Bennett Dam Spillway Chute Rehabilitation project was $5.8 million higher than plan (no planned additions) due to early completion of one of the sections.

Fiscal 2016 capital additions were $26 million below plan, due primarily to the following:

- The Peace Canyon Flood Discharge Gates Reliability Improvement project was $18 million (100 per cent) below plan due a change in project timing, as more extensive project planning and evaluation was required than originally anticipated, resulting in an extension to the Definition phase of the project;

- The Salmon River Undertake Partial Refurbishment of Canal and Dam project was $7.6 million (100 per cent) below plan due to a change in project timing, resulting in an extension to the Definition phase of the project to allow for additional project planning;
- The Revelstoke Improve Left Bank Slope Stability project was $22.4 million (100 per cent) below plan due to a change in project timing to meet the requirement for additional studies undertaken as part of the Revelstoke Left Bank Slopes Instrumentation Improvements Project. Based on the results of this additional work, the project is forecast to start in fiscal 2017, with reduced scope and lower expected costs;
- The W.A.C. Bennett Dam Spillway Gate Upgrade project was $14.3 million (100 per cent) below plan due to more extensive project planning and evaluation required than originally anticipated, which has resulted in an extension to the Definition phase of the project. As a result, the in-service date will be delayed to fiscal 2020; and
- The Hugh Keenleyside Spillway Reliability Gate Upgrade was $31.3 million (110 per cent) above plan due to a substantial increase in project scope, which resulted in a change to the in-service date to fiscal 2016.

5.1.4 Sustaining - Other - Capital Expenditure and Additions Variances

5.1.4.1 Capital Expenditures

Fiscal 2015 capital expenditures were $23.8 million below plan, due primarily to the following:

- The Cheakamus Units 1 and 2 Generator Replacement project expenditures were $ 7.4 million (84 per cent) below plan due to delays resulting from adding to the scope of the project, and the development of a Generator Master Agreement for the purchase of medium and small size generators. Refer to

Appendix I, page 1, line 28 and Appendix J, page 20 for additional information on the project; and

- The Mica SF_6 Gas Insulated Switchgear Replacement project expenditures were $12.1 million (41 per cent) below plan due to change in project timing, as some of the work was completed prior to Plan.

Fiscal 2016 capital expenditures were $45 million below plan, due primarily to the following:

- The G.M. Shrum Units 1 to 5 Turbine Replacement project was $23.2 million (60 per cent) below plan due to schedule acceleration which resulted in permanent cost savings;
- The Key Facilities 600 V Breaker Replacement Program was $5.1 million (100 per cent) below plan. When the program was created, it was anticipated that all costs would be charged to the program. Subsequently, it was decided that Identification phase costs would be charged to the program and individual projects would be created for each generating station for the Definition and Implementation phases. This has resulted and will result in a number of individual projects during and after the test period, including the Mica Upgrade 600V Circuit Breakers project which is identified in Appendix I, line 40; and
- The Cheakamus Units 1 and 2 Generator Replacement project was $7.6 million (61 per cent) below plan due to delays resulting from adding to the scope of the project, the development of a Generator Master Agreement for the purchase of medium and small size generators. Refer to Appendix I, page 1, line 28 and Appendix J, page 20 for additional information on the project.

5.1.4.2 Capital Additions

Fiscal 2015 Capital Additions were $101.4 million below plan, due primarily to the following:

- The Mica SF6 Gas Insulated Switchgear (GIS) Replacement project was $74.0 million (84 per cent) below plan due to timing, as some of the assets were put into service in the previous years, earlier than the planned date;
- The G.M. Shrum Units 1 to 5 Turbine Replacement project was $24.9 million (33 per cent) below plan due to schedule acceleration which resulted in permanent cost savings; and
- The G.M. Shrum Fire Alarm Upgrade project was $10 million higher than plan as the project achieved the in-service date in fiscal 2015 rather than fiscal 2016 as planned (there were no planned additions for the project in fiscal 2015).

The fiscal 2016 capital additions variance did not exceed the 10 per cent or $10 million threshold on a cumulative basis.

5.2 Transmission Capital Expenditures and Additions Fiscal 2015 and Fiscal 2016 Actual to Plan

Transmission fiscal 2015 and fiscal 2016 actual to plan capital expenditures and capital additions are provided in Table K-15 and Table K-16, below.

Table K-15 Transmission Capital Expenditures Fiscal 2015 and Fiscal 2016 Actual to Plan

($ million)	F2015 RRA	F2015 Actual	F2015 Variance	F2016 RRA	F2016 Actual	F2016 Variance
Transmission Growth						
Regional System Reinforcement	483.2	496.9	(13.7)	279.0	174.0	105.0
Bulk System Reinforcement	232.0	213.6	18.4	84.3	97.8	(13.4)
Station Expansion & Modifications	40.3	46.4	(6.1)	101.4	69.4	32.0
Feeder Position/ Section Additions	13.4	12.2	1.2	10.5	4.0	6.5
Generator Interconnections	23.6	22.6	1.0	4.7	24.6	(19.8)
Customer Requested Projects	18.4	30.7	(12.2)	8.4	13.0	(4.6)
Growth Total	810.9	822.3	(11.4)	488.4	382.7	105.7
Transmission Sustain - Stations						
Circuit Breakers	28.0	38.2	(10.2)	45.6	37.1	8.5
Other Power Equipment	30.1	41.8	(11.7)	29.7	52.4	(22.6)
Protection and Control	11.2	14.2	(2.9)	24.2	13.2	10.9
Stations Auxiliary Equipment	12.9	8.5	4.4	15.5	16.6	(1.1)
Stations Risk Mitigation	3.1	2.7	0.5	9.8	5.6	4.2
Telecommunications	7.8	3.4	4.4	10.6	3.6	7.0
Sustain Stations Total	93.2	108.7	(15.5)	135.4	128.5	6.8
Transmission Sustain - Lines						
Cable Sustainment	7.1	2.0	5.1	12.1	2.1	10.1
O/H Lines Life Extension	47.1	47.5	(0.4)	76.1	52.0	24.1
OH Lines Performance Improvement	5.2	9.3	(4.1)	6.2	9.0	(2.8)
OH Lines Risk Mitigation	9.2	10.6	(1.4)	5.0	26.0	(21.0)
ROW Sustainment	9.0	13.6	(4.6)	11.6	13.3	(1.6)
OH/UG Relocations	4.6	2.1	2.5	10.3	4.1	6.2
Sustain Lines Total	82.2	85.2	(3.0)	121.4	106.5	14.9
Total Gross (Schedule 13)	986.3	1,016.2	(30.0)	745.2	617.7	127.4
Less Contributions in Aid	(19.8)	(243.9)	224.1	(49.3)	(19.4)	(29.8)
Total Net	966.4	772.3	194.1	695.9	598.3	97.6

Table K-16 Transmission Capital Additions Fiscal 2015 and Fiscal 2016 Actual to Plan

($ million)	F2015 RRA	F2015 Actual	F2015 Variance	F2016 RRA	F2016 Actual	F2016 Variance
Transmission Growth						
Regional System Reinforcement	989.0	798.5	190.5	596.0	538.2	57.7
Bulk System Reinforcement	19.1	40.1	(21.1)	692.6	705.1	(12.5)
Station Expansion & Modifications	69.3	62.7	6.6	113.4	16.3	97.1
Feeder Position/ Section Additions	26.4	13.7	12.7	6.2	15.1	(8.9)
Generator Interconnections	44.7	40.4	4.2	8.2	1.2	7.0
Customer Requested Projects	5.0	18.4	(13.4)	23.4	35.0	(11.6)
Growth Total	1,153.4	973.8	179.5	1,439.7	1,310.8	128.9
Transmission Sustain - Stations						
Circuit Breakers	30.8	30.6	0.2	42.1	25.2	16.9
Other Power Equipment	29.6	30.6	(1.0)	29.8	50.8	(21.0)
Protection and Control	11.4	8.5	2.9	21.6	21.1	0.5
Stations Auxiliary Equipment	12.9	6.0	6.9	15.0	14.9	0.0
Stations Risk Mitigation	2.8	0.8	1.9	8.5	0.4	8.1
Telecommunications	6.9	2.6	4.3	10.0	1.4	8.6
Sustain Stations Total	94.5	79.2	15.3	126.9	113.7	13.2
Transmission Sustain - Lines						
Cable Sustainment	6.6	3.5	3.1	11.1	0.1	11.0
O/H Lines Life Extension	42.3	59.0	(16.7)	70.2	57.2	13.0
OH Lines Performance Improvement	6.0	0.8	5.2	6.0	16.8	(10.8)
OH Lines Risk Mittigation	10.9	1.2	9.7	5.8	18.4	(12.6)
ROW Sustainment	9.8	12.3	(2.5)	11.1	9.7	1.4
OH/UG Relocations	5.1	4.4	0.7	9.2	1.1	8.1
Sustain Lines Total	80.6	81.2	(0.6)	113.5	103.3	10.2
Total Gross	1,328.4	1,134.2	194.2	1,680.1	1,527.8	152.3
Less CIA Expenditures	~~(96.9)~~ (19.8)	(317.5)	~~220.6~~ 297.7	~~(59.0)~~ (49.3)	~~(24.7)~~ (24.3)	~~(34.4)~~ (25.0)
Total Net	~~1,231.5~~ 1,308.6	816.8	~~414.8~~ 491.9	~~1,621.1~~ 1,630.8	~~1,503.1~~ 1,503.6	~~117.9~~ 127.3

Note: Fiscal 15 and fiscal 16 planned amounts shown are per Schedule 13. The actual amounts shown differ from Schedule 13 as final assets are recorded at a more detailed level when put in service.

5.2.1 Transmission Growth

5.2.1.1 Regional System Reinforcement

- Capital expenditures were $14 million above plan in fiscal 2015 and $106 million below plan in fiscal 2016. This was primarily due to the advancement from fiscal 2016 into fiscal 2015 of the acquisition under the Iskut Extension project of the transmission line from Bob Quinn Substation to Tatogga built by Imperial Metals. The higher expenditures in fiscal 2015 of the Iskut Extension project were offset mainly by lower cost for the Northwest Transmission Line project than forecast in the fiscal 2015 - fiscal 2016 Plan, and by lower expenditures for the Dawson Creek/Chetwynd Area Transmission project, which occurred earlier in fiscal 2014; and
- Capital additions were $191 million below plan in fiscal 2015 and $58 million below plan in fiscal 2016. This was primarily due to the advancement of the in-service date for the addition for the Vancouver City Central Transmission from fiscal 2015 to fiscal 2014, the advancement of the in-service date for the addition for the Iskut Extension project from fiscal 2016 to fiscal 2015, the bringing into service of the Northwest Transmission Line project in fiscal 2015 at a lower overall cost than forecast in the fiscal 2015 and fiscal 2016 Plans, and a delay in the completion of the Merritt Area Transmission project from fiscal 2015 to fiscal 2016 because of delays caused by quality issues with the supply of a new transformer.

5.2.1.2 Bulk System Reinforcement

- Capital expenditures were $18 million below plan in fiscal 2015 and $13 million above plan in fiscal 2016. This is primarily due to the Interior to Lower Mainland project, which experienced construction delays in fiscal 2015 and higher total project costs than forecast in the fiscal 2015 and fiscal 2016 Plans. The Interior to Lower Mainland project also incurred additional financing and staff costs stemming from the overall project delay; and

- Capital additions were $21 million above plan in fiscal 2015 and $13 million above plan in fiscal 2016. This is primarily due to delays of the Meridian Transformer Addition project from fiscal 2014 to fiscal 2015 due to outage restrictions on the 230kV system, and the higher total project cost for the Interior to Lower Mainland project than forecast in the fiscal 2015 and fiscal 2016 Plans.

5.2.1.3 Station Expansion and Modifications

- Capital expenditures were $32 million below plan in fiscal 2016 due to delays in completing the Definition phase of the Fernie Substation Upgrade project to address site environmental issues and distribution related scope elements, delays in selecting the recommended alternative for the Clayburn Substation Upgrade project given the multiple issues to be addressed, delays in finalizing the site for the Big Bend Substation project due to longer than anticipated negotiations with local authorities, and the deferral of the Ah-Sin-Heek Substation Upgrade project following the deferral of a new customer load in the area. The Big Bend Substation and Fernie Substation Upgrade projects are described in Appendix J, pages 57 and 59; and
- Capital additions were $7 million below plan in fiscal 2015 and $97 million below plan in fiscal 2016. This is primarily due to the delay of the Big Bend Substation project and a delay of the in-service date of the Arnott Capacity Upgrade after the scope of the project was increased to address constructability issues and outage constraints identified during the Definition phase. The Fort St. John Substation Transformer Upgrade project was also delayed by the need to address end-of-life equipment and space constraints at the existing substation. The Fort St. John Substation Transformer Upgrade and Arnott Capacity Upgrade projects are described in Appendix J, pages 55 and 56.

5.2.1.4 Feeder Position/Section Additions

- Capital additions were $13 million below plan in fiscal 2015 and $9 million above plan in fiscal 2016 primarily due to the Horsey Substation - Add Feeder Section and Five Feeder Positions project being placed in service in fiscal 2016. The project was temporarily suspended to accommodate the urgent need to replace the 230kV outdoor GIS at the same location under the Horsey Gas-Insulated Switchgear Replacement Program, described in Appendix J at page 66.

5.2.1.5 Generator Interconnections and Customer Requested Projects

- These capital expenditures and additions are third-party driven and, as a result, the timing and scope of these projects are highly uncertain. BC Hydro only includes projects with a high probability of proceeding in its capital forecasts. Variances to forecast are due to changes in scope and timing of planned projects as well as the additions of new projects.

5.2.2 Transmission Sustain - Stations

5.2.2.1 Circuit Breakers

- Fiscal 2015 capital expenditures were $10 million above plan primarily due to carryover of expenditures planned in prior years. The fiscal 2015 increase was offset by the deferral of the circuit breakers planned for replacement at Barnard Substation. The replacement of the circuit breakers is now included in the Barnard 50/60 Feeder Section Replacement project, which is described in Appendix J, page 72;
- Fiscal 2016 capital expenditures were $9 million below plan mainly due to the deferral of the Barnard Substation circuit breaker replacements and lower expenditures for the replacement of 230 kV circuit breakers. The expenditures to replace 230 kV circuit breakers required a longer definition phase and the implementation phase was delayed to fiscal 2017. These lower than planned

expenditures were offset by higher than planned expenditures on the Horsey GIS Replacement Program due to schedule changes that shifted expenditures from prior years into fiscal 2016. The in-service date for the Horsey Gas-Insulated Switchgear was delayed due to a need to mitigate the reliability risk to the City of Victoria during the project implementation by installing a new transmission circuit from Horsey to George Trip Substation. In addition, there were unplanned replacements of various failed circuit breakers. The Horsey GIS Replacement Program is described in Appendix J at page 66; and

- Fiscal 2016 additions were $17 million below plan primarily due to the deferral of the Barnard Substation circuit breakers replacements and delays completing 230 kV circuit breaker replacements.

5.2.2.2 Other Power Equipment

- Fiscal 2015 capital expenditures were $12 million above plan primarily due to the addition to the plan of the procurement of two mobile substations due to increased demands on the mobile fleet used to ensure power can be restored within an acceptable time frame, and due to emergency replacements of failed transformers at Murrin and Armstrong substations. There was also an increase in the cost and a schedule delay to refurbish an out of service synchronous condenser at Vancouver Island Terminal whose condition was found to be worse than anticipated after disassembly of the equipment;

- Fiscal 2016 capital expenditures were $23 million above plan primarily due to a number of unplanned replacements of failed equipment including reactors at Nicola and Gordon M. Shrum Substations and transformers at Atchelitz and Horne Payne Substations. We also had to procure a spare shunt reactor for Bob Quinn Substation to mitigate the risk of a lengthy outage in the event of a reactor failure due to the lack of an available spare unit. In addition, there were delayed expenditures from prior years and increased asset needs for outdoor metalclad switchgear replacements, 500kV oil filled current transformer replacements, and voltage regulator replacements. These higher amounts were off-set by lower expenditures on the Mainwaring Substation Upgrade project, the start of which was delayed due to the complexity of the project. The Mainwaring Substation Upgrade project is described in Appendix J, page 69;

- Fiscal 2015 capital additions were essentially on plan even though expenditures were higher than plan. The investments contributing to the fiscal 2015 higher than planned expenditures were mostly placed in service in fiscal 2016; and
- Fiscal 2016 capital additions were $21 million above plan primarily due to the need to replace failed equipment and procure two mobile substations. Capital additions were above plan also due to the completion of the refurbishment of the Vancouver Island Terminal synchronous condenser, which was placed in service in fiscal 2016 while the capital additions for this work were forecast prior to fiscal 2015. These above plan expenditures were offset by an under plan expenditures caused by delays in the Mainwaring Substation Upgrade project.

5.2.2.3 Protection and Control

- Fiscal 2016 was $11 million below plan primarily due to delays of a number of programs to replace end of life Protection & Control equipment due to investments requiring longer time in the Planning and Identification phases than anticipated or due to limited resources to implement the work.

5.2.3 Transmission Sustain - Lines

5.2.3.1 Cable Sustainment

- Fiscal 2015 capital expenditures were $5 million below plan. Fiscal 2016 was $10 million below plan primarily due to the suspension of the upgrades to pumping plants as a result of escalating costs to deliver this work while the asset management strategy is reviewed. Delays initiating cable replacements due to work requiring longer time in the Planning and Identification phases than anticipated also contributed to the lower than anticipated costs. The underspend was partially offset by the initiation of the George Massey Tunnel Transmission Relocation project listed in Appendix I, page 4, line 42 and described in Appendix J, page 68; and

- Fiscal 2015 additions were $3 million below plan. Fiscal 2016 additions were $11 million below plan primarily due the variance in the capital expenditures described above.

5.2.3.2 Overhead Lines Life Extension

- Fiscal 2016 capital expenditures were $24 million under plan. This was due to reductions across a number of areas of work to redirect resources and budget to accommodate increased expenditures in the Overhead Lines Risk Mitigation portfolio described below; and
- Fiscal 2015 additions were $17 million above plan primarily due to expenditures from fiscal 2014 that were placed in service later than expected. Fiscal 2016 additions were $13 million below plan primarily due to the reduction in expenditures described above.

5.2.3.3 Overhead Lines Performance Improvement

- Fiscal 2015 additions were $5 million below plan and fiscal 2016 additions were $11 million above plan primarily due to a delay in the closing of some of the fiscal 2015 arcing horn installation expenditures, until fiscal 2016.

5.2.3.4 Overhead Lines Risk Mitigation

- Fiscal 2016 capital expenditures were $21 million over plan due to higher than planned activity levels to address high priority ground clearance deficiencies including a transmission circuit 60L129 requested by Telus, which was partially offset by a Contribution in Aid. The higher than planned expenditures were also due to a number of emergency transmission line restorations and civil protective upgrades. Resources and budget were redirected to this portfolio from programs under the Overhead Lines Life Extension program; and

- Fiscal 2015 additions were $10 million below plan primarily due to lower than planned additions for a number of circuits with ground clearances deficiencies that will be capitalized when fully completed in fiscal 2017. Fiscal 2016 additions were $13 million higher than plan primarily due to the expenditures related to civil protective works from the prior year being placed in service later than expected and the expenditures described above.

5.2.4 Contribution-in-Aid

Transmission expenditures and additions were partially offset by Contributions in Aid of construction which were $224 million and $~~221~~298 million higher than plan in fiscal 2015, and $30 million and $~~34~~ 25 million lower than plan in fiscal 2016. The higher than plan amounts in fiscal 2015 were due to a change in accounting for the payments received under the umbrella agreement between Altagas and BC Hydro for the construction and development of the Northwest Transmission Line project, and due to the advancement from fiscal 2016 into fiscal 2015 of the acquisition under the Iskut Extension project of the transmission line from Bob Quinn Substation to Tatogga built by Imperial Metal. The lower than plan amounts in fiscal 2016 were mainly due to the fact that we received the Iskut Extension Contributions in Aid in fiscal 2015, earlier than anticipated.

5.3 Distribution - Capital Expenditures and Additions Fiscal 2015 and Fiscal 2016 Actual to Plan

Distribution fiscal 2015 and fiscal 2016 actual to fiscal 2015 and fiscal 2016 Plan capital expenditures and capital additions are provided in Table K-17 and Table K-18, below.

Table K-17 Distribution Capital Expenditures Fiscal 2015 and Fiscal 2016 Actual to Plan Variances

($ million)	F2015 RRA	F2015 Actual	F2015 Variance	F2016 RRA	F2016 Actual	F2016 Variance
Distribution Growth						
Customer Driven						
Customer Connections	103.3	136.8	(33.5)	111.3	157.2	(45.9)
Major Customer Connections	14.9	3.5	11.5	15.4	6.4	9.0
IPP	-	9.5	(9.5)	-	5.6	(5.6)
Customer Driven Total	118.3	149.7	(31.4)	126.7	169.2	(42.5)
System Expansion and Improvement	42.9	56.5	(13.7)	64.6	55.3	9.3
Uneconomic Extension Assistance	0.1	0.4	(0.3)	0.2	0.2	(0.1)
Growth Total (Schedule 13.0)	161.3	206.7	(45.4)	191.4	224.7	(33.3)
Distribution Sustain						
System Expansion and Improvement	30.7	35.5	(4.8)	43.2	60.7	(17.5)
Asset Replacement						
Poles	48.2	68.9	(20.7)	75.0	74.4	0.6
Overhead Equipment	2.4	2.3	0.1	3.2	11.2	(8.1)
Underground Equipment	17.8	16.1	1.7	26.6	27.6	(1.0)
Trouble	10.2	10.0	0.3	10.4	15.8	(5.4)
Asset Replacement Total	78.6	97.3	(18.7)	115.2	129.1	(13.9)
Beautification	1.4	0.3	1.1	1.4	1.4	0.0
Smart Metering	71.5	5.4	66.1	4.8	1.4	3.4
Sustain Total (Schedule 13.0)	182.2	138.5	43.7	164.6	192.5	(27.9)
Total Gross	343.4	345.1	(1.7)	356.0	417.2	(61.2)
Less Contributions in Aid	(64.6)	~~(89.1)~~ (89.4)	~~24.5~~ 24.8	(70.9)	~~(112.6)~~ (112.7)	~~41.7~~ 41.8
Total Net	278.8	~~256.0~~ 255.7	~~22.8~~ 23.1	285.1	~~304.6~~ 304.5	~~(19.5)~~ (19.4)

Table K-18 Distribution Capital Additions Fiscal 2015 and Fiscal 2016 Actual to Plan Variances

($ million)	F2015 RRA	F2015 Actual	F2015 Variance	F2016 RRA	F2016 Actual	F2015 Variance
Distribution Growth						
Customer Driven						
Customer Connections	104.6	107.4	(2.8)	109.4	143.2	(33.8)
Major Customer Connections	13.9	2.9	11.0	15.3	3.8	11.5
IPP	-	8.0	(8.0)	-	5.5	(5.5)
Customer Driven Total	118.5	118.3	0.2	124.6	152.5	(27.8)
System Expansion and Improvement	41.2	45.3	(4.1)	62.5	47.5	15.0
Uneconomic Extension Assistance	0.1	0.5	(0.4)	0.2	0.2	(0.1)
Growth Total	159.9	164.1	(4.2)	187.3	200.2	(12.9)
Distribution Sustain						
System Expansion and Improvement	32.4	61.2	(28.7)	45.3	53.2	(8.0)
Asset Replacement						
Poles	49.7	75.2	(25.5)	69.7	75.6	(5.9)
Overhead Equipment	2.5	8.9	(6.4)	3.0	5.8	(2.8)
Underground Equipment	18.4	19.6	(1.2)	24.8	20.1	4.7
Trouble	10.2	5.9	4.3	10.4	22.0	(11.6)
Asset Replacement Total	80.7	109.7	(28.9)	107.9	123.4	(15.6)
Beautification	1.4	1.0	0.4	1.4	0.0	1.4
Smart Metering	40.4	8.9	31.5	5.3	33.8	(28.5)
Sustain Total	155.0	180.7	(25.8)	159.9	210.5	(50.6)
Total Gross	314.9	344.8	(30.0)	347.2	410.7	(63.5)
Less Contributions in Aid	~~(65.8)~~ (65.3)	(67.8)	~~2.0~~ 2.5	~~(70.3)~~ (74.8)	(84.5)	~~14.2~~ 9.7
Total Net	~~249.1~~ 249.6	~~277.1~~ 277.0	~~(28.0)~~ (27.5)	~~276.9~~ 272.4	326.2	~~(49.3)~~ (53.8)

Note: Fiscal 15 and fiscal 16 planned amounts shown are per Schedule 13. The actual amounts shown differ from Schedule 13 as final assets are recorded at a more detailed level when put in service.

5.3.1 Distribution Growth

5.3.1.1 Customer Driven Expenditures

- Capital expenditures in fiscal 2015 were $31 million above plan primarily due to higher than planned effort required for: (i) design; (ii) changes to capitalize costs earlier upon energizing of customer build projects rather than at the receipt of customer invoices; (iii) and upon the purchase of customer meters rather than installation.
- Capital expenditures in fiscal 2016 were $43 million above plan primarily due to a larger than expected volume of work for the Customer Design Connect program, including connecting several large subdivisions.
- Capital additions in fiscal 2015 were close to plan while capital additions in fiscal 2016 were $28 million above plan while the capital expenditures were higher in both years. This is primarily due to delays in closing work orders.

5.3.1.2 System Expansion and Improvement (Growth)

- Capital expenditures were $14 million above and $9 million below the fiscal 2015 and fiscal 2016 Plan, respectively. The variances to plan were due to planned work advancing from fiscal 2016 to fiscal 2015, maintaining a balanced level of project work delivery in both years at around $56 million.
- Capital additions were $4 million above plan in fiscal 2015 and $15 million below plan in fiscal 2016. The below plan additions in fiscal 2016 were primarily due to: (i) the delay of the New Feeder from Gibson Substation to Bowen Island project following a re-evaluation of the alternatives; (ii) lower than planned additions for the Tofino and Ahousaht Long Term Power Supply project, as the completion of the last phase of the project is now required in fiscal 2018.

5.3.2 Distribution Sustain

5.3.2.1 System Expansion and Improvement (Sustain)

- Capital expenditures were $5 million above plan in fiscal 2015 and $18 million above plan in fiscal 2016 primarily due to the reprioritization and advancement of higher risk work.
- Capital additions were $29 million above plan in fiscal 2015 and $8 million above plan in fiscal 2016. The large variance in fiscal 2015 was primarily as a result of the delay in closing numerous small projects that had been placed in service in fiscal 2014.

5.3.2.2 Asset Replacement

- Capital expenditures were $19 million above plan in fiscal 2015 primarily due to the completion of more wood pole replacements than planned in order to address a larger number of poles that were determined to be at end of life during scheduled inspections.
- Capital expenditures were $14 million above plan in fiscal 2016 primarily due to higher than planned number of replacements of porcelain fused cut-out switches to mitigate failure risk, and due to a higher volume of trouble call replacements as a result of a greater number of inclement weather events including a severe wind storm in Metro Vancouver in August 2015.
- Capital additions were $29 million and $16 million above plan in fiscal 2015 and fiscal 2016, respectively. Similar to the capital expenditures, the capital addition variances in fiscal 2015 were primarily due to a higher than planned number of pole replacements. In fiscal 2016, the variances were due to the higher than planned number of cut-out switch and trouble replacements. The variance in fiscal 2015 is also due to a delay in closing some work orders from fiscal 2014.

5.3.2.3 Smart Metering

The Smart Metering and Infrastructure capital expenditures related to the distribution system were $66 million and $4 million lower than plan in fiscal 2015 and fiscal 2016, respectively. The lower expenditures are due to a change in strategy for the Theft Detection Solution, which resulted in lower costs. Capital additions were $32 million lower than plan and $29 million above plan in fiscal 2015 and fiscal 2016, respectively. The lower additions in fiscal 2015 are related to the lower expenditures while the higher additions in fiscal 2016 are from expenditures incurred prior to fiscal 2015.

5.3.3 Contribution-in-Aid

- Distribution expenditures were partially offset by Contributions in Aid of construction, which were $25 million and $42 million higher than plan in fiscal 2015 and fiscal 2016, respectively. This was mainly due to the higher than planned expenditures for Distribution Customer Driven work.
- Distribution additions were partially offset by Contributions in Aid, which were close to plan in fiscal 2015. Higher than planned volume of work for Distribution Customer Driven work resulted in fiscal 2016 additions of $~~14~~ 10 million above plan.

5.4 Business Support- Capital Expenditures and Additions Fiscal 2015 and Fiscal 2016 Actual to Plan

Business Support includes capital expenditures and additions for Technology, Properties and Fleet / Other categories. Table K-19 and Table K-20 provide Business Support fiscal 2015 and fiscal 2016 capital expenditures and capital additions respectively, by category.

Table K-19 Business Support - Capital Expenditures Fiscal 2015 and Fiscal 2016 Actual to Plan

	F2015 RRA ($ million)	F2015 Actual ($ million)	F2015 Variance ($ million)	F2016 RRA ($ million)	F2016 Actual ($ million)	F2016 Variance ($ million)
Business Support						
Technology	164.1	115.2	48.9	109.3	122.3	(13.0)
Properties	96.3	83.9	12.4	85.1	78.8	6.3
Fleet/Other	29.7	47.9	(18.2)	36.6	72.5	(35.9)
Total (Schedule 13.0)	290.1	247.0	43.1	231.0	273.6	(42.6)
TOTAL	290.1	247.0	43.1	231.0	273.6	(42.6)

Table K-20 Business Support - Capital Additions Fiscal 2015 and Fiscal 2016 Actual to Plan

	F2015 RRA ($ million)	F2015 Actual ($ million)	F2015 Variance ($ million)	F2016 RRA ($ million)	F2016 Actual ($ million)	F2016 Variance ($ million)
Business Support						
Technology	113.7	82.3	31.4	103.0	145.2	(42.2)
Properties	113.4	83.6	29.8	92.4	160.9	(68.5)
Fleet / Other	28.0	26.5	1.5	35.2	23.7	11.5
Total (Schedule 13.0)	255.1	192.4	62.7	230.6	329.8	(99.2)

5.4.1 Technology Fiscal 2015 and Fiscal 2016 Capital Expenditures and Additions Actual to Plan Variances

Technology capital expenditures and additions presented in tables K-19 and K-20 above include amounts for the sub-categories of Technology, Smart Metering and Infrastructure and Other categories. The capital expenditures and capital additions amounts for each sub-category, for fiscal 2015 and fiscal 2016 are presented in tables K-21 and K-22, below.

Table K-21 Technology Sub-Categories - Capital Expenditures Fiscal 2015 and Fiscal 2016 Actual to Plan

($ millions)	F2015			F2016		
	RRA	Actual	Variance	RRA	Actual	Variance
Technology	88.4	69.8	18.6	95.4	78.4	17.0
Smart Metering and Infrastructure	70.2	44.3	25.9	11.2	44.0	(32.8)
Security and Other Technology	5.5	1.1	4.4	2.7	-	2.7
Total	164.1	115.2	48.9	109.3	122.3	(13.0)

Table K-22 Technology Sub-Categories - Capital Additions Fiscal 2015 and Fiscal 2016 Actual to Plan

($ millions)	F2015			F2016		
	RRA	Actual	Variance	RRA	Actual	Variance
Technology	85.2	54.6	30.6	85.5	73.1	12.4
Smart Metering and Infrastructure	26.1	22.5	3.6	11.3	67.8	(56.5)
Security and Other Technology	2.4	5.2	(2.8)	6.2	4.3	1.9
Total	113.7	82.3	31.4	103.0	145.2	(42.2)

5.4.2 Technology Variance Explanations

Technology requirements to meet business needs are dynamic due to constraints and opportunities that arise during the planning and delivery phases. Changing business needs and priorities, technologies and resources may result in cost variability across the technology capital portfolio during the plan years.

The fiscal 2015 and fiscal 2016 Technology capital expenditure plan included portfolio level adjustments of $6.2 million in fiscal 2015 and $18.7 million in fiscal 2016, which were estimates of how the capital expenditure forecast for the Technology capital portfolio as a whole could change from the planned amounts. The adjustments reflect an increase in total planned capital expenditures in these fiscal years to reflect plan reserve amounts where specific projects had not yet been identified or defined.

5.4.3 Capital Expenditures Variances - Fiscal 2015 - Fiscal 2016

Technology capital expenditures were $18.6 million lower than plan in fiscal 2015 and $17.0 million lower than plan in fiscal 2016. The fiscal 2015 variance was primarily due to the following:

- Lower than plan expenditures on Foundational Information Technology Applications due to the delay of the Smart Metering and Infrastructure Application Upgrade project, the Hewitt Packard Service Center Retirement project, and the reprioritization of Enterprise Service Bus projects. In addition, Foundational Information Technology Infrastructure projects were delayed.
- The inclusion of a portfolio adjustment of $6.2 million in the fiscal 2015 Plan that was not required.

The fiscal 2016 variance was due primarily to the inclusion of a portfolio adjustment of $18.7 million in the fiscal 2016 Plan that was not required.

5.4.4 Capital Additions Variances - Fiscal 2015 - Fiscal 2016

Technology capital additions were $30.6 million lower than plan in fiscal 2015 and $12.4 million lower than plan in fiscal 2016.

The fiscal 2015 variance was due primarily to the following:

- Business driven Information Technology additions were $6.3 million or 16 per cent lower than plan, primarily due to the delays and reprioritization of several Customer projects.
- Foundational Information Technology additions were $22.8 million or 53 percent lower than plan. The variance is primarily driven by Infrastructure projects and the Enterprise Identity Management project due to schedule delays. In addition, lower than plan additions resulted from the delay in the expected in-service date for the Smart Metering and Infrastructure Application Upgrade and

Enterprise Service Bus projects, which are partially offset by additions for the Call Center Upgrade project.

The fiscal 2016 variance was due primarily to

- Business driven IT additions were $13.4 million or 27 per cent lower than plan. The variance is primarily due to lower than plan additions for the Customer Connections Foundation Technology project which was cancelled.

Foundational IT additions were $3 million or 9 per cent higher than plan. This variance was primarily due to additions for the Oracle Database License True-up, Supply Chain Work Space and the PassPort Technical Upgrade projects, partially offset by below plan additions for deferred Cyber Security projects.

5.4.5 Smart Metering and Infrastructure

5.4.5.1 Capital Expenditures Variances

The fiscal 2015 capital expenditures were $25.9 million lower than plan, offset by fiscal 2016 capital expenditures being $32.8 million higher than plan, due to a change in the timing of expenditures. In the Fiscal 2015 - Fiscal 2016 Revenue Requirements Rate Application the program was forecast for completion at the end of fiscal 2015; however a change in the strategy for the Theft Detection Solution resulted in a shift in capital expenditures to fiscal 2016.

5.4.5.2 Capital Additions Variances

The fiscal 2016 capital additions are $56.5 million greater than plan, due primarily to the change in the project completion date to fiscal 2016. This resulted in certain project assets with capital expenditures prior to fiscal 2015 entering service in fiscal 2016.

5.4.6 Properties Fiscal 2015 - Fiscal 2016 Capital Expenditures and Additions Actual to Plan Variances

Table K-23 Properties Capital Expenditures Fiscal 2015 and Fiscal 2016 Actual to Plan Variances

($ millions)	F2015			F2016		
	RRA	Actual	Variance	RRA	Actual	Variance
Properties						
Interior Space Renovations	26.7	16.5	10.2	17.4	16.3	1.1
Building Development	52.3	41.7	10.6	52.0	36.9	15.1
Building Improvements and Other	17.3	19.6	(2.3)	15.7	24.2	(8.5)
Other Properties	-	6.1	(6.1)	-	1.3	(1.3)
Total	96.3	83.9	12.4	85.1	78.7	6.4

Table K-24 Properties Capital Additions Fiscal 2015 and Fiscal 2016 Actual to Plan Variances

($ millions)	F2015			F2016		
	RRA	Actual	Variance	RRA	Actual	Variance
Properties						
Interior Space Renovations	12.7	20.1	(7.4)	26.7	10.9	15.8
Building Development	88.6	50.8	37.8	48.4	39.4	9.0
Building Improvements and Other	12.1	12.7	(0.6)	17.3	25.7	(8.4)
Other Properties	-	-	-	-	7.5	(7.5)
Other Equipment						
Generation	-	-	-	-	5.3	(5.3)
Transmission and Distribution	-	-	-	-	2.4	(2.4)
Smart Metering and Infrastructure	-	-	-	-	49.5	(49.5)
Total	113.4	83.6	29.8	92.4	140.7	(48.3)

Capital expenditures in fiscal 2015 were $12.4 million below the fiscal 2015 Plan, as several projects experienced delays that shifted capital expenditures from fiscal 2015 to fiscal 2016. In all cases, the delays were less than $5 million on each individual project. Capital expenditures in fiscal 2016 were $6.4 million below plan, also due to delays that shifted capital expenditures into fiscal 2017, including the delay in the commencement of construction of the Victoria facility.

Capital additions in fiscal 2015 were $29.8 million below fiscal 2015 Plan due primarily to the Prince George facility going into service one year earlier than planned, shifting Capital Additions of $32 million from fiscal 2015 to fiscal 2014.

The fiscal 2016 capital additions were $48.3 million above fiscal 2016 Plan primarily due to additions related to Other Equipment. The actual capital additions for Other Equipment are included in Properties category in fiscal 2016 due to a change in presentation to reflect the categorization based on the Uniform System of Accounts, whereby actual results are presented based on the business unit delivering the project, consistent with Schedule 13 of Appendix A. The fiscal 2016 variance is mainly due to additions related to the Smart Meter Infrastructure project. Expenditures for the project were incurred prior to fiscal 2015, however the assets were not put into service until fiscal 2016 due to a change in strategy for the Theft Detection Solution and a general delay in other smart grid related implementation activities.

Other Equipment for Generation and Transmission and Distribution are mainly related to communication structures and equipment, and tools and work equipment.

5.4.7 Fleet/Other Fiscal 2015 - Fiscal 2016 Capital Expenditures and Additions

Fleet/Other fiscal 2015- fiscal 2016 capital expenditures and capital additions are provided in tables K-25 and K-26 respectively, below.

Table K-25 Fleet/Other Fiscal 2015 to Fiscal 2016 Capital Expenditures

($ millions)	F2015			F2016		
	RRA	Actual	Variance	RRA	Actual	Variance
Fleet / Other						
Fleet	15.0	19.7	(4.7)	24.2	30.7	(6.5)
Other	14.7	28.2	(13.5)	12.4	41.8	(29.4)
Total	29.7	47.9	(18.2)	36.6	72.5	(35.9)

Table K-26 **Fleet /Other Fiscal 2015 to Fiscal 2016 Capital Additions**

($ millions)	F2015			F2016		
	RRA	Actual	Variance	RRA	Actual	Variance
Fleet / Other						
Fleet	13.8	16.1	(2.3)	22.4	21.2	1.2
Other	14.2	10.4	3.8	12.8	2.5	10.3
Total	28.0	26.5	1.5	35.2	23.7	11.5

5.4.7.1 Fleet Fiscal 2015 - Fiscal 2016 Actual to Plan Variances

Fleet capital expenditures and capital addition variances in fiscal 2015 and fiscal 2016 were less than the $10 million per year threshold for variance reporting.

5.4.7.2 Other Fiscal 2015 - Fiscal 2016 Actual to Plan Variances

Other includes expenditures and additions related to Materials Management upgrades, Field Operations tools and equipment, Control Centre systems upgrades, and workforce training equipment.

Capital expenditures in fiscal 2015 and fiscal 2016 were $13.5 million and $29.4 million above fiscal 2015 Plan respectively, mainly due to a number of variances less than $5 million per project in each of the Other capital categories.

The capital addition variance in fiscal 2015 was below the $10 million threshold for variance reporting. The fiscal 2016 actual capital additions were $10.3 million lower than fiscal 2016 Plan mainly due to variances less than $5 million in each of the Other capital categories.

Fiscal 2017 to Fiscal 2019

Revenue Requirements Application

Appendix L

Fiscal 2016 Annual Deferral Account Report

BC Hydro
Power smart

Tom A. Loski
Chief Regulatory Officer
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Fax: 604-623-4407
bchydroregulatorygroup@bchydro.com

July 21, 2016

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)
F2016 Annual Deferral Accounts Report
for the Twelve Months ended March 31, 2016

BC Hydro writes to provide its F2016 Annual Deferral Account Report for the twelve-month period ending March 31, 2016, in compliance with Directive No. 17 of the Commission's Decision on BC Hydro's F2005/F2006 Revenue Requirements Application (Commission Order No. G-96-04) and Commission Order No. G-112-14. This report contains information on the Heritage Deferral Account, the Non-Heritage Deferral Account, and the Trade Income Deferral Account.

For further information, please contact Fred James at 604-623-4317 or by email at bchydroregulatorygroup@bchydro.com.

Yours sincerely,

Tom Loski
Chief Regulatory Officer

df/ma

Enclosure (1)

BC Hydro
Power smart

Deferral Account Report

F2016 Annual Report

For the Twelve Months Ended

March 31, 2016

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British Columbia Hydro and Power Authority
Summary of Deferral Accounts
For the Twelve Months Ended March 31, 2016
($ million)

Line No.	Particulars (Note 1)	Opening Balance at April 1, 2015	Changes (Schedule B)		Amortization (Note 4)	Interest (Note 5)	Net Change (Appendix 1 Lines 30 - 32)	Ending Balance at March 31, 2016
	(1)	(2)	(3)		(4)	(5)	(6) = (3)+(4)+(5)	(7)=(2)+(6)
1	Heritage Deferral Account (HDA)	164.7	(151.9)	Note 2	(37.0)	0.3	(188.6)	(23.9)
2	Non-Heritage Deferral Account (NHDA)	524.1	482.9	Note 3	(117.7)	27.5	392.7	916.8
3	Trade Income Deferral Account (TIDA)	244.6	51.3		(54.9)	9.1	5.5	250.0
4	Total	933.4	382.3		(209.5)	36.8	209.6	1,142.9

Note 1: In the October 29, 2004 Commission Decision (Order No. G-96-04), the Commission approved the creation of four deferral accounts to capture the differences between forecasts used in setting rates and actual costs. By Order No. G-16-11, the Commission approved the termination of the BCTC Deferral Account.

Note 2: The transfers of ($151.9) million out of the HDA are primarily due to higher than approved surplus sales and lower than approved water rental costs and market electricity purchases. This is partially offset by higher than approved domestic transmission costs. Low market prices through the fall and winter of the prior year resulted in higher reservoir levels at the start of the current fiscal year. Therefore in order to reduce spill risk higher than approved surplus sales were required during the year. In addition, increased generation at Mica was required in the current year to maintain downstream Arrow Reservoir levels and to meet Columbia River Treaty obligations, this also contributed to an increase in surplus sales. Water rental costs were lower than approved as water rental payments in F2016 are based on prior year's generation volume, which was lower than the approved, at current year's rates. Market electricity purchases were lower than approved as there was little need to import energy given the high hydro generation. Higher than approved transmission costs were the result of increased surplus sales in the current year. Please see Schedule B and C for details.

Note 3: The transfers into the NHDA of $482.9 million are primarily due to lower than approved domestic revenues as a result of lower than approved residential revenues and large industrial revenues and higher IPP costs. Lower residential revenues are mainly due to warmer than normal weather and a lower number of customer accounts (compared to the approved). Lower large industrial revenues were primarily driven by lower volumes sold to the oil and gas sectors mainly as a result of lower than planned start-ups, temporary shutdown of one metal mine in the mining sector, and lower than planned new and expansion projects in other sectors. Higher IPP costs are primarily due to higher deliveries from one large IPP, higher biomass IPP output and higher wind IPP deliveries. Please see Schedule B and C for details.

Note 4: Revenues collected via the Deferral Account Rate Rider (DARR) are used to amortize (reduce) the deferral account balances. The reduction is allocated to each deferral account based on the proportion of the ending Fiscal 2015 deferral account balances.

Note 5: Interest is calculated on the ending monthly balance (before interest) in each deferral account. The interest rate used is BC Hydro's actual weighted cost of debt for the current period as per Directive 1 (xxv) of the F12-F14 RRA Decision in Commission Order No. G-77-12A.

Due to minor rounding some totals may not add.

British Columbia Hydro and Power Authority
Summary of Deferral Account Changes
For the Twelve Months Ended March 31, 2016
($ million)

Line No.	Particulars	Approved	Actual	Variance	Ref.
	(1)	(2)	(3)	(4) = (3) - (2)	(5)
1	**Heritage Deferral Account**				
2	Cost of Energy - Heritage	357.6	206.1	(151.5)	Note 10
3	Notional Water Rental (Displaced Hydro)	1.9	0.0	(1.9)	Note 1
4	Skagit Valley Treaty & Ancillary Revenue	(16.5)	(18.2)	(1.7)	
5	Costs in Operating / Amortization	13.0	12.9	(0.1)	Note 2
6	Deferred Operating Costs in HDA	0.0	2.5	2.5	Note 3
7	Other	43.2	44.1	0.9	Note 4
8	Total	399.2	247.3	(151.9)	Schedule A Line 1
9					
10	**Non-Heritage Deferral Account**				
11	Cost of Energy - Non-Heritage	1,034.1	1,269.5	235.4	Note 10
12	Commodity Risk	-	(0.5)	(0.5)	Note 5
13	Notional Water Rental (Displaced Hydro)	(1.9)	-	1.9	Note 1
14	Domestic Revenue Variance	-	268.9	268.9	Note 6
15	Deferred Operating Costs in NHDA	-	9.0	9.0	Note 7
16	Other	-	(31.7)	(31.7)	Note 8
17	Total	1,032.2	1,515.1	482.9	Schedule A Line 2
18					
19	**Trade Income Deferral Account**				
20	Trade Income			58.7	Note 9
21	Less: Trade Income from the Approved F15-F16 RRA			(110.0)	
22	Total			51.3	Schedule A Line 3

Note 1: Notional water rentals (Displaced Hydro) relates to water rentals associated with trade income. The notional water rental mechanism is described in the response to BCUC IR 1.2.36 dated January 23, 2004. The transactions relating to the notional water rental are eliminated on consolidation and there is no net impact on the combined HDA and NHDA as the transactions are mirrored within each account.

Note 2: Costs associated with compensation and mitigation efforts to fund fish and wildlife programs, Water Use Plan amortization, and Water Use Plan license costs were reclassified from cost of energy to other line items on the financial statements under IFRS. Since the nature of these costs has not changed, they continue to be treated as Heritage cost of energy for deferral accounting purposes, pursuant to Schedule A of Appendix A in Special Direction No. 7 regarding the Heritage Payment Obligation.

Note 3: Deferred Operating Costs in HDA includes a variance of $2.6 million related to the costs associated with maintaining water use plan licenses.

Note 4: Other amounts in the Heritage Payment Obligation mainly include $0.6 million of amortization on unplanned costs related to First Nations as per Commission Order No. G-53-02.

Note 5: Commodity Risk of ($0.5) million consists of gains/losses on intercompany transactions that are offset by corresponding transactions in the TIDA. There is no net impact on the combined NHDA and TIDA balances due to these transactions.

Note 6:

Domestic Revenue Variance ($ million)	Approved	Actual	Variance
Residential	1,917.6	1,754.2	163.3
Light industrial and commercial	1,608.5	1,604.7	3.8
Large industrial	826.1	730.0	96.1
Other energy sales	107.7	101.9	5.7
Domestic Revenue Variance deferred in NHDA (Line 14)	4,459.8	4,190.9	268.9

Load Variance: as per Directive 5 of the F15-F16 RRA Decision per Commission Order No. G-48-14, BC Hydro is allowed to continue to defer in the NHDA the variances between the actual and forecast cost of energy arising from differences between forecast and actual domestic customer load. The net cost of energy variance due to domestic customer load is calculated by adding the domestic revenue variance (Line 14) to the gross cost of energy variance (Line 2 + Line 11) as shown below.

Gross Cost of Energy Variance ((151.5) + 235.4)	83.8
Domestic Revenue Variance	268.9
Net Cost of Energy deferred	352.7

Note 7: Deferred Operating Costs in the NHDA includes $9 million incurred in F2016 as Burrard Costs as defined in Special Direction No. 7 of the F15-F16 RRA Decision and approved in Commission Order No. G-48-14. The $9 million of Burrard Costs include $6 million incurred as deferred operating costs and $3 million incurred as deferred amortization expense.

Note 8: Other amounts deferred in the NHDA include ($31) million related to an EPA that achieved commercial operations during the period. As the EPA was originally planned as a finance lease but is now being accounted for as an operating lease it would have resulted in a favorable increase to net income of $31 million. As a result of the change in accounting treatment, BC Hydro deferred the favorable variance as Other in the NHDA, with the ratepayer receiving the benefit of the favourable variance. Also included is ($0.7) million deferred as per Order No. G-16-11, in which the Commission approved the deferral of the difference between forecast an actual transmission service net costs into the NHDA. The variance from the corresponding intercompany entry on Powerex's financial statements is deferred via the TIDA. Total amount deferred in the NHDA includes a variance of ($1.7) million on PTP wheeling charges with Powerex (via Intersegment Revenues) and a variance of $1 million on External OATT revenues (via Miscellaneous Revenues).

Note 9: Powerex net income (loss) reported for regulatory purposes is net of $3 million corporate overhead allocation from BC Hydro to Powerex in accordance with Directive 9 of the F09/F10 RRA Decision.

Note 10: For further breakdown of Cost of Energy - Heritage please see Schedule C Line 9. For further breakdown of Cost of Energy - Non-Heritage please see Schedule C Line 17.

Due to minor rounding some totals may not add.

British Columbia Hydro and Power Authority
Domestic Cost of Energy
For the Twelve Months Ended March 31, 2016
($ in million)

Line No.	Particulars	Approved	Actual	Variance	Ref.
	(1)	(2)	(3)	(4) = (3) - (2)	(5)
1	**Heritage Energy:**				
2	Water rentals	384.5	357.7	(26.8)	
3	Market electricity purchases	56.6	2.8	(53.8)	
4	Natural gas for thermal generation	26.9	20.0	(6.9)	
5	Domestic Transmission	25.7	52.6	26.9	
6	Non-Treaty Storage Agreement	(19.8)	(14.4)	5.4	
7	Surplus Sales	(84.2)	(174.1)	(89.9)	
8	Other	(32.1)	(38.6)	(6.5)	
9		357.6	206.1	(151.5)	Schedule B Line 2
10					
11	**Non-Heritage Energy:**				
12	Waneta (water rentals)	7.4	7.6	0.2	
13	IPP's and long-term purchase commitments	975.5	1,228.9	253.3	
14	Non-Integrated Areas	34.3	22.6	(11.7)	
15	Gas and Other Transportation	12.1	10.5	(1.6)	
16	Net purchases / (sales) from / to Powerex (Trade Account)	4.8	(0.1)	(4.9)	Note 1
17		1,034.1	1,269.5	235.4	Schedule B Line 11
18					
19	**Total Domestic Cost of Energy**	**1,391.7**	**1,475.6**	**83.9**	
20					
21	**Heritage Energy (GWh):**				
22	Water rentals	46,312	48,945	2,633	
23	Net purchases from Powerex (Displaced Hydro)	255	(6)	(261)	
24	Market electricity purchases	1,553	122	(1,431)	
25	Natural gas for thermal generation	301	215	(86)	
26	Surplus Sales	(2,446)	(6,277)	(3,831)	
27	Exchange net	(204)	(976)	(772)	
28		45,771	42,023	(3,749)	
29					
30	**Non-Heritage Energy (GWh):**				
31	Waneta (water rentals)	594	407	(187)	
32	IPP's and long-term purchase commitments	12,002	14,319	2,317	
33	Non-Integrated Areas:	135	111	(24)	
34		12,731	14,837	2,106	
35					
36	Total sources of supply	58,502	56,859	(1,643)	
37	Less : Line loss and system use	(4,742)	(5,836)	(1,094)	
38					
39	**Total Domestic Sales Volumes**	53,760	51,023	(2,737)	

Note 1: These sales / purchases relate to allocations of energy between BC Hydro and Powerex. These sales / purchases are eliminated against trade cost of energy on consolidation. The transactions between BC Hydro and Powerex have no net impact on the combined NHDA and the TIDA.

British Columbia Hydro and Power Authority
Consolidated Statement of Operations
For the Twelve Months Ended March 31, 2016
($ in million)

Line No.	Particulars	Approved	Actual	Variance	Ref.
	(1)	(2)	(3)	(4) = (3) - (2)	(5)
1	**REVENUES**				
2	Domestic				
3	Residential	1,917.6	1,754.2	(163.4)	
4	Light industrial and commercial	1,608.3	1,604.7	(3.6)	
5	Large industrial	826.1	730.0	(96.1)	
6	Other energy sales	107.7	101.9	(5.7)	
7	Seattle City Light	16.5	18.2	1.7	
8	Revenue from Deferral Rider	223.0	209.6	(13.4)	
9	Miscellaneous	126.6	138.7	12.0	
10		4,825.8	4,557.3	(268.4)	
11	Intersegment revenues	53.5	55.7	2.2	
12		4,879.3	4,613.1	(266.2)	
13	**EXPENSES**				
14	Domestic energy costs	1,391.7	1,475.6	83.8	Schedule C Line 19
15	Operating costs	1,146.6	1,251.6	105.0	
16	Depreciation and amortization	758.0	739.5	(18.5)	
17	Taxes	224.1	213.1	(11.0)	
18	Finance charges	838.3	746.6	(91.7)	
19		4,358.8	4,426.4	67.6	
20	**DOMESTIC INCOME (LOSS) BEFORE TRANSFER**				
21	**(TO)/FROM DEFERRAL ACCTS**	**520.5**	**186.7**	**(333.9)**	
22					
23	**POWEREX NET INCOME (LOSS)**	**110.0**	**58.7**	**(51.3)**	Schedule B Lines 20 - 22
24	**POWERTECH NET INCOME (LOSS)**	**5.1**	**4.2**	**(0.9)**	
25					
26	**TOTAL INCOME BEFORE TRANSFER (TO)/FROM**				
27	**DEFERRAL ACCOUNTS**	**635.6**	**249.5**	**(386.1)**	
28					
29	Heritage Deferral Account transfers	(15.8)	(188.5)	(172.7)	
30	Non- Heritage Deferral Account transfers	(93.6)	392.7	486.3	
31	Trade Income Deferral Account transfers	(89.7)	5.5	95.2	
32	Future Removal and Site Restoration Regulatory Account	31.2	24.2	(7.0)	
33	First Nation Costs & Provisions Regulatory Account	(15.3)	(22.9)	(7.5)	
34	Demand Side Management Regulatory Account	47.8	65.7	18.0	
35	Site C Clean Energy Project Regulatory Account	16.8	17.0	0.2	
36	Non-Current Pension Cost Regulatory Account	(15.5)	58.5	74.0	Note 1
37	Foreign Exchange Gains/Losses Regulatory Account	0.6	2.3	1.7	
38	Finance Charge Regulatory Account	25.5	(132.5)	(158.1)	
39	Environmental Compliance & Remediation Liability Provision	(8.2)	28.6	36.8	
40	Smart Metering and Infrastructure	(0.7)	(0.8)	(0.1)	
41	IFRS Property Plant & Equipment	114.6	114.6	(0.0)	
42	IFRS Pension	(38.2)	(38.2)	(0.0)	
43	Rate Smoothing	121.2	121.2	-	
44	Other Regulatory Accounts	(64.3)	(41.7)	22.6	Note 2
45	**TOTAL NET INCOME**	**651.9**	**655.0**	**3.2**	

Note 1: Included in the Net Income was a regulatory transfer of $58.5 million in the Non-Current Pension Cost regulatory account, which consists of ($15.5) million as amortization of the F11 - F14 balances, $17.2m million as variance on current service costs as approved per BCUC Order G-148-15, and $56.8 million as variance on non-current service costs in F16. Also deferred in the Non-Current Pension Cost regulatory account, but not reflected in the table above, was $68.5 million related to experience losses of non-current pension costs that flow through Other Comprehensive Income instead of the Net Income.

Note 2: Included in Other Regulatory Accounts are the following regulatory assets and liabilities: Pre-1996 Contributions in Aid of Construction, Storm Restoration Costs, Capital Project Investigation Costs, Amortization Variance on Capital Additions, Home Purchase Option Plan, Rock Bay Remediation Costs, Arrow Water Divestiture Costs & Provision, Asbestos Remediation, Real Property Sales, and Minimum Reconnection Charge.

British Columbia Hydro and Power Authority
Intersegment Revenues
For the Twelve Months Ended March 31, 2016
($ in million)

Line No.	Particulars	Approved	Actual	Variance	Reference
	(1)	(2)	(3)	(4) = (3) - (2)	(5)
1	Point-to-Point wheeling charge to Powerex	29.2	6.1	(23.1)	Note 1
2					
3	Point-to-Point wheeling charge to BCH	21.3	46.1	24.8	Note 2
4					
5	Allocation of BCH Corporate costs to Powerex	3.0	3.0	-	Note 3
6					
7	Mark to Market Gains	-	0.5	0.5	Schedule B Line 12
8					
9	Total	53.5	55.7	2.2	Appendix 1 Line 12

Note 1: These transmission revenues relate to an allocation of BC Hydro's cost of purchases of point-to-point transmission within BC for export and some import transactions. These revenues are eliminated against trade cost of energy on consolidation. The variance is deferred in the NHDA, please refer to Schedule B, Line 16 and Note 8.

Note 2: These transmission revenues relate to an allocation of BC Hydro's cost of purchases of point-to-point transmission relating to BC Hydro's Skagit Valley Treaty commitment, Canadian Entitlement Agreement (OATT Schedule 01) and Scheduling, System Control & Dispatch services (OATT Schedule 03). These Revenues are eliminated against domestic cost of energy on consolidation. The variance is deferred in the NHDA, please refer to Schedule B, Line 16 and Note 8.

Note 3: These revenues relate to an allocation of corporate overhead costs to Powerex and are eliminated against Trade Income.

Appendix 3

Deferral Account Rules

The following “rules” are used by BC Hydro for providing clarity in determining the deferral account transfers. These rules are derived from BC Hydro’s interpretation of the evidence and testimony provided during the F2005/F2006 Revenue Requirement Application (**RRA**) proceeding and in response to Commission Directive No. 19 of the October 29, 2004 Decision. These rules have been updated for the F07/F08 RRA Negotiated Settlement Agreement (**NSA**) and Directives included in the F09/F10 RRA Decision, the F11 RRA NSA, Commission’s Decision on the F12-F14 RRA as per Commission Order No. G-77-12A, and Commission’s issuance of Order No. G-48-14 related to Direction Nos. 6 and 7 issued from the Province to the Commission in regards to BC Hydro’s F15-F16 RRRA.

Where a footnote is shown, the referenced language is from the noted Commission decision. Where a footnote is not shown (e.g., the bullet points), the language represents BC Hydro’s interpretation of the evidence and testimony noted above.

Heritage Deferral Account (HDA)

Commission Decision, October 29, 2004, Page 41:

<u>Commission Findings</u>

The Commission Panel approves the HDA as proposed by BC Hydro, and approves BC Hydro's forecast of the cost components of the HPO for F2005 and F2006.

Variances between the forecast and the actual cost for the following components of the Heritage Payment Obligation will flow through the HDA:

1. Cost of energy[1]

   This item is expanded in greater detail below to provide clarification on the methodology used to determine variances:

   - Gains/losses on energy derivatives and financial instruments used to minimize energy costs are included as part of total energy costs;
   - The total Heritage Energy (including Skagit/Seattle City Light commitments) is limited to 49,000 GWh in terms of the Heritage contract. If the Heritage Energy including 100 per cent of market electricity purchases exceeds the Heritage Energy limit, the excess purchases are transferred to Non-Heritage Energy in order to reduce the Heritage Energy volumes to the Heritage Contract limit;
   - Variances resulting from changes to compensation and mitigation costs, water rental remissions, or Skagit energy transportation contracts are eligible for deferral. These are price variances as they do not vary with volume; and
   - All load curtailment costs are to be included as part of the Heritage Payment Obligation and variance between Actual and Plan is to be included in the HDA.[2]

2. Variable costs related to thermal generation.[1]
3. Significant unplanned major maintenance costs greater than $1 million related to single event equipment or infrastructure failure or caused by weather related events.[1]
4. Significant unplanned major capital expenditures having an incremental annual impact on the Income Statement greater than $1 million related to single event equipment or infrastructure failure or caused by weather related events.[1]
5. Amortization of unplanned deferred capital costs pursuant to Commission Order No. G-53-02.[1]
6. All net revenues from surplus hydro electricity sales.[3]

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1 Per F05/F06 RRA Decision Directive 11, amended by the F09F/10 RRA Decision, Directive 31, as confirmed by Direction 7, section 7(a).
2 Per F09/F10 RRA Decision, Directive 30.
3 Per F05/F06 RRA Decision, Directive 11.

7. Skagit Valley Treaty revenues and ancillary services revenues.[3]

8. An interest charge/credit[4] is to be calculated on the ending monthly balance in each deferral account. The interest rate used is BC Hydro's actual weighted cost of debt for its current fiscal year as approved effective April 1, 2011.[5]

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[4] Per F05/F06 RRA Decision Directive 18, amended by the F07/F08 RRA Negotiated Settlement Agreement.
[5] Per F12-F14 RRA Decision, Commission Order No. G-77-12A, Directive 1 (xxv).

Non-Heritage Deferral Account (NHDA)

Commission Decision, October 29, 2004, Page 41:

<u>Commission Findings</u>

The Commission Panel approves all elements of the NHDA, except the distribution emergency restoration costs elements, item 4, because it can be forecast with some confidence, unlike unplanned major capital expenditures and unplanned major maintenance expenditures, and because of risk/reward considerations. Given the denial of item 4 of the NHDA, item 3 of the NHDA is to be as set forth in Final Argument. The Commission Panel approves BC Hydro's forecast of the NHDA non-HPO cost of energy for F2005 and F2006.

Variances between the forecast and the actual cost for the following components of the Non-Heritage Cost of Energy will flow through the NHDA:

1. Cost of energy - all non-HPO energy costs.[6] This item is expanded in greater detail below to provide clarification on the methodology used to determine variances:

   - Any variances relating to fixed price gas transportation contracts would flow through the deferral accounts as they do not vary with volume;

   - Future Trade: when Powerex purchases energy for future trade the cost of the purchase from the external party and the sale to BC Hydro of this energy is recorded in Powerex and is included as part of Trade Income. The BC Hydro side of the entry is shown as part of domestic energy costs (on consolidation, the Powerex revenue from BC Hydro and the BC Hydro energy costs from Powerex are eliminated). The difference between Actual and Plan on the BC Hydro side relating to energy for future trade flows through the Non-Heritage Deferral Account. The Powerex side of the transaction, which is part of Trade Income, flows through the Trade Income Deferral Account. Similar treatment is made when the energy is returned to Powerex;

   - Future Trade: when Powerex purchases energy for future trade, the Heritage Payment Obligation (HPO) is charged with a notional water rental charge for the use of this energy. The other side of this entry is shown as part of Non-Heritage energy. These entries are eliminated on consolidation. The difference between the Actual and Plan notional water rentals that is part of the HPO flows through the Heritage Deferral Account. The opposite variance relating to the Non-Heritage side of the notional water rental transaction flows through the Non-Heritage Deferral Account; and

   - Gains/losses on energy derivatives and financial instruments used to minimize energy costs are included as part of total energy costs.

2. Significant unplanned major maintenance costs greater than $1 million related to single event equipment or infrastructure failure.[6]

3. Significant unplanned major capital expenditures having an incremental annual impact on the Income Statement greater than $1 million related to single event equipment or infrastructure failure or caused by weather related events.[6]

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6 Per F05/F06 RRA Decision, Directive 12, amended by F09F/10 RRA Decision, Directive 31, as confirmed by Direction 7, section 7 (c)(i).

4. Founding Partner Benefits and any CIS Credits under the ABS Contract.[6]

5. Impact of load variance.[7]

    - The Net Cost of Energy deferral amount is calculated by subtracting the Gross Load Variance and adding the Net Load Variance to the Gross Cost of Energy deferral amount. In practice, because Net Load Variance equals Gross Load Variance less Domestic Revenue Variance, the Net Cost of Energy Deferral simplifies to the Gross Cost of Energy Deferral minus the Domestic Revenue Variance.

6. Costs incurred by the authority in F2014 or a later fiscal year arising from the decommissioning of the Burrard Thermal Plant that are not required for transmission support services, including employee retention costs, penalties or damages that arise as a result of the decommissioning, and the net increase in amortization expense in F2015 and F2016.[8]

7. An interest charge/credit[9] is to be calculated on the ending monthly balance in each deferral account. The interest rate used is BC Hydro's actual weighted cost of debt for its current fiscal year as approved effective April 1, 2011.[10]

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7 F09/F10 RRA Decision, Directive 31 and F12-F14 RRA Decision, Commission Order No. G-77-12A, Directive 1 (ix).
8 Pursuant to Commission Order No. G-48-14 Directive 6 and Direction No. 7 to the Commission, section 7 (c)(ii).
9 Per F05/F06 RRA Decision Directive 18, amended by the F07/F08 RRA Negotiated Settlement Agreement.
10 Per F12-F14 RRA Decision, Commission Order No. G-77-12A, Directive 1 (xxv).

Trade Income Deferral Account (TIDA)

Commission Decision, October 29, 2004, Page 42, Section 4.6:

<u>Commission Findings</u>

The Commission Panel approves the TIDA as proposed by BC Hydro, and approves BC Hydro's forecast of Trade Income for F2005 and F2006.

- Under Direction No. 7 to the Commission, which continues the essential elements of the Heritage Contract framework formerly enshrined in Heritage Special Direction HC2, for F2015 and future years, any variance between the forecast Trade Income and the actual Trade Income will flow through the TIDA, except where Annual Trade Income is below zero;[11]

- Actual Trade Income is determined by excluding the impact on BC Hydro's consolidated net income due to foreign currency translation gains and losses on intercompany balances between BC Hydro and Powerex Corp. The "floor" of zero in the definition of Trade Income was removed for F2014 and reinstated for F2015 and future years;[11] and

- An interest charge/credit[12] is to be calculated on the ending monthly balance in each deferral account. The interest rate used is BC Hydro's actual weighted cost of debt for its current fiscal year as approved effective April 1, 2011.[13]

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11 Refer to Heritage Special Direction No. HC2 and Direction No. 7 to the Commission – definition of "Trade Income".
12 Per F05/F06 RRA Decision Directive 18, amended by the F07/F08 RRA Negotiated Settlement Agreement.
13 Per F12-F14 RRA Decision, Commission Order No. G-77-12A, Directive 1 (xxv).

Fiscal 2017 to Fiscal 2019

Revenue Requirements Application

Appendix M

Uniform Systems of Accounts

List of Attachments

The schedules in this appendix include the planned Operating and Maintenance expenses by BC Hydro Uniform System of Accounts (Attachment 1) and Property Plant and Equipment financial schedule by Uniform System of Accounts function; that is, hydraulic generation, transmission, distribution, etc. (Attachment 2).

BC Hydro plans Property Plant and Equipment expenditures at the functional level and not at the Uniform System of Accounts level. In addition, all substation expenditures are functionally classified as transmission for planning and are not split between transmission and distribution.

BC Hydro
Power smart

Fiscal 2017 to Fiscal 2019
Revenue Requirements Application

Appendix M

Attachment 1
Operations and Maintenance Costs Based on the Uniform System of Accounts

Gross Operations and Maintenance Costs Based on the Uniform System of Accounts

(in millions)

USoA Category	USoA	USoA Description	FY 2016 RRA	FY 2016 Actual	FY 2017 Plan	FY 2018 Plan	FY 2019 Plan
Steam Power Operations	500	Operation Supervision and Engineering	12.2	10.6	7.3	7.4	7.5
	501	Fuel and Fuel Handling	0.0	0.0	0.0	0.0	0.0
	502	Steam Expenses	0.0	0.0	0.0	0.0	0.0
	503	Steam from Other Sources	0.0	0.0	0.0	0.0	0.0
	505	Electric Expenses	0.0	0.0	0.0	0.0	0.0
	506	Other Steam Power Expenses	9.5	9.5	18.8	54.1	44.7
	507	Rents	0.0	0.0	0.0	0.0	0.0
			21.6	**20.0**	**26.1**	**61.5**	**52.2**
Steam Power Maintenance	510	Maintenance Supervision and Engineering	0.0	0.0	0.0	0.0	0.0
	511	Maintenance of Structures	0.0	0.0	0.0	0.0	0.0
	512	Maintenance of Boiler Plant	1.7	0.8	0.0	0.0	0.0
	513	Maintenance of Electric Plant	7.5	5.6	5.9	5.9	6.0
	514	Maintenance of Other Steam Plant	0.0	0.0	0.0	0.0	0.0
			9.2	**6.4**	**5.9**	**5.9**	**6.0**
Hydraulic Power Operations	535	Operation Supervision and Engineering	55.8	70.8	67.7	70.0	76.0
	536	Water for Power	0.0	0.0	0.0	0.0	0.0
	537	Hydraulic and Pumped Storage Expenses	25.6	28.1	24.2	24.3	24.6
	538	Electric Expenses	0.0	0.0	0.0	0.0	0.0
	539	Other Hydraulic and Pumped Storage Power Generation Expe	0.0	0.0	0.0	0.0	0.0
	540	Rents	0.0	0.0	0.0	0.0	0.0
			81.4	**98.9**	**91.8**	**94.3**	**100.7**
Hydraulic Power Maintenance	541	Maintenance Supervision and Engineering	0.0	0.0	0.0	0.0	0.0
	542	Maintenance of Structures	0.0	0.0	0.0	0.0	0.0
	543	Maintenance of Reservoirs, Dams and Waterways	9.8	8.2	10.2	10.3	10.5
	544	Maintenance of Electric Plant	31.0	33.3	31.0	31.3	31.7
	545	Maintenance of Other Hydraulic & Pumped Storage	2.5	3.3	2.8	2.8	2.8
			43.3	**44.8**	**44.0**	**44.5**	**45.0**
Other Power Generation Operation	546	Operation Supervision and Engineering	3.1	2.4	2.0	2.0	2.0
	547	Fuel	0.0	0.0	0.0	0.0	0.0
	548	Generation Expenses	0.0	0.0	0.0	0.0	0.0
	549	Miscellaneous Other Power Generation Expenses	24.3	9.2	9.3	9.5	9.7
	550	Rents	0.0	0.0	0.0	0.0	0.0
			27.4	**11.6**	**11.3**	**11.5**	**11.7**
Other Power Generation Maintenar	551	Maintenance Supervision and Engineering	0.0	0.0	0.0	0.0	0.0
	552	Maintenance of Structures	0.0	0.0	0.0	0.0	0.0
	553	Maintenance of Generating and Electric Plant	0.0	0.0	0.0	0.0	0.0
	554	Maintenance of Misc Other Power Generation Plant	7.4	7.3	8.5	8.5	8.5
	555	Purchased Power	0.0	0.0	0.0	0.0	0.0
	556	System Control and Load Dispatching	0.0	0.0	0.0	0.0	0.0
			7.4	**7.3**	**8.5**	**8.5**	**8.5**
Other Power Supply Expenses	557	Other Expenses	6.4	4.8	5.1	5.1	5.2
			6.4	**4.8**	**5.1**	**5.1**	**5.2**
Transmission Operations	560	Operation Supervision and Engineering	50.3	59.5	56.1	50.7	51.3
	561	Load Dispatching	39.3	43.9	43.3	44.0	44.6
	562	Station Expenses	0.0	0.0	0.0	0.0	0.0
	563	Overhead Line Expenses	0.0	0.0	0.0	0.0	0.0
	564	Underground Line Expenses	0.0	0.0	0.0	0.0	0.0
	565	Transmission of Electricity by Others	0.0	0.0	0.0	0.0	0.0
	566	Other Transmission Expenses	0.0	0.0	0.0	0.0	0.0
	567	Rents	0.0	0.0	0.0	0.0	0.0
			89.6	**103.4**	**99.4**	**94.7**	**95.9**
Transmission Maintenance	568	Maintenance Supervision and Engineering	0.0	0.0	0.0	0.0	0.0
	569	Maintenance of Structures	0.0	0.0	0.0	0.0	0.0
	570	Maintenance of Station Equipment	25.9	26.1	25.9	25.9	25.9
	571	Maintenance of Overhead Line	36.7	32.6	37.6	37.6	36.8
	572	Maintenance of Underground Lines	0.0	2.6	0.0	0.0	0.0
	573	Maintenance of Other Transmission Plant	0.0	0.0	0.0	0.0	0.0
			62.6	**61.3**	**63.5**	**63.5**	**62.8**

Gross Operations and Maintenance Costs Based on the Uniform System of Accounts

(in millions)

USoA Category	USoA	USoA Description	FY 2016 RRA	FY 2016 Actual	FY 2017 Plan	FY 2018 Plan	FY 2019 Plan
USoA Category	USoA	USoA Description	FY 2016 RRA	FY 2016 Actual	FY 2017 Plan	FY 2018 Plan	FY 2019 Plan
Distribution Operations	580	Operation Supervision and Engineering	92.8	92.0	73.5	75.1	76.5
	581	Load Dispatching	0.0	0.0	0.0	0.0	0.0
	582	Station Expenses	0.0	0.0	0.0	0.0	0.0
	583	Overhead Line Expenses	0.0	0.0	0.0	0.0	0.0
	584	Underground Line Expenses	0.0	0.0	0.0	0.0	0.0
	585	Street Lighting and Signal System Expenses	0.0	0.0	0.0	0.0	0.0
	586	Meter Expenses	0.0	0.0	0.0	0.0	0.0
	587	Customer Installations Expenses	0.0	0.0	0.0	0.0	0.0
	588	Other Distribution Expenses	0.0	0.0	0.0	0.0	0.0
	589	Rents	0.0	0.0	0.0	0.0	0.0
			92.8	**92.0**	**73.5**	**75.1**	**76.5**
Distribution Maintenance	590	Maintenance Supervision and Engineering	0.0	0.0	0.0	0.0	0.0
	591	Maintenance of Structures	0.0	0.0	0.0	0.0	0.0
	592	Maintenance of Station Equipment	0.0	0.0	0.0	0.0	0.0
	593	Maintenance of Overhead Lines	67.1	65.2	70.8	70.6	70.3
	594	Maintenance of Underground Lines	3.9	5.1	3.5	3.7	3.7
	595	Maintenance of Line Transformers	0.3	0.1	0.3	0.3	0.3
	596	Maintenance of Street Lighting and Signals	0.7	1.7	1.1	1.1	1.1
	597	Maintenance of Meters	2.9	1.6	3.9	3.9	3.9
	598	Maintenance of Other Distribution Plant	0.0	0.0	0.0	0.0	0.0
			74.9	**73.8**	**79.6**	**79.6**	**79.4**
Customer Accounts Operations	901	Support and Supervision	18.7	18.1	24.2	23.5	22.5
	902	Meter Reading & Bill Delivery	19.1	19.0	8.6	7.8	7.9
	903	Customer Records & Collection Expenses	26.4	31.1	26.5	26.7	27.6
	904	Uncollectible Accounts	7.6	6.9	8.6	8.6	8.6
	905	Other Customer Accounts Expenses	0.0	0.0	0.0	0.0	0.0
			71.8	**75.1**	**67.9**	**66.6**	**66.7**
Customer Service Operations	909	Supervision	0.0	0.0	0.0	0.0	0.0
	910	Customer Assistance Expenses	4.0	5.8	7.5	6.0	6.2
	912	Other Customer Service Expenses	0.0	0.0	0.0	0.0	0.0
			4.0	**5.8**	**7.5**	**6.0**	**6.2**
Sales Promotion Expenses	915	Supervision	0.0	0.0	0.0	0.0	0.0
	916	Demonstrating and Selling Expenses	0.0	0.0	0.0	0.0	0.0
	917	Advertising	0.0	0.0	0.0	0.0	0.0
	918	Other Sales Promotion Expenses	0.0	0.0	0.0	0.0	0.0
			0.0	**0.0**	**0.0**	**0.0**	**0.0**
Administrative Operations	920.05	Executive Team	8.0	8.1	7.1	7.2	7.3
	920.1	Finance	32.4	31.1	33.7	34.2	34.8
	920.15	Information Technology	105.4	102.6	135.6	135.7	134.9
	920.2	Regulatory	5.3	4.8	5.2	5.2	5.3
	920.25	Legal	11.0	10.2	11.2	11.3	11.4
	920.3	Human Resources	34.9	34.6	38.1	38.1	38.4
	920.35	Corporate Affairs	11.6	11.3	10.8	10.6	10.7
			208.5	**203.0**	**241.6**	**242.2**	**242.8**
General Operations	920.45	Procurement	20.4	21.0	25.5	25.1	25.4
	920.5	Fleet Services	23.1	20.7	19.4	19.5	19.6
	920.51	Materials Management	22.8	28.2	28.1	28.4	28.7
	920.55	Property Services	40.6	39.7	40.7	41.0	41.3
	920.6	Aboriginal Affairs	5.1	5.0	4.9	5.0	5.1
	920.65	Safety, Health and Environmental Support	25.8	32.8	34.2	34.6	34.6
	920.7	Engineering General & Support	20.9	21.7	25.0	25.9	26.3
	920.75	Business Technology	4.6	3.4	3.9	3.9	4.0
	920.8	Construction Services	13.8	11.5	12.6	12.8	12.9
	920.85	Corporate Cost	26.3	23.3	18.3	9.4	10.7
	924	Insurance	12.0	11.0	11.1	11.1	11.1
			215.4	**218.3**	**221.9**	**214.7**	**217.7**
General Maintenance	932.5	Fleet Services Maintenance	12.6	17.4	20.3	20.8	20.9
	932.55	Property Services Maintenance	0.0	0.1	0.0	0.0	0.0
			12.6	**17.5**	**20.3**	**20.8**	**20.9**
Operations & Maintenance Costs Before Transfers to Capital Overhead			1,026.8	1,052.3	1,067.9	1,094.7	1,098.0
Capitalized Overheads	922	Overheads Capitalized	(65.4)	(68.9)	(68.2)	(69.0)	(69.7)
Operations & Maintenance Costs After Transfers to Capital Overhead			961.3	983.4	999.7	1,025.7	1,028.3

NOTE: Due to minor computer rounding, some totals may not add.

Fiscal 2017 to Fiscal 2019
Revenue Requirements Application

Appendix M

Attachment 2
Assets in Service and Depreciation and Amortization Continuity Schedule

Appendix M - Attachment 2

BC Hydro
Electric Plant in Service
($ million)

			F2016 Actual				F2017 Plan				F2018 Plan				F2019 Plan			
USoA #	USoA Description	Actuals Balance as of March 31, 2015	Projects greater than $50M	Projects less than $50 M	Retire-ments	Actuals Balance as of March 31, 2016	Projects greater than $ 50M	Projects less than $50 M	Retire-ments	Balance March 31, 2017	Projects greater than $ 50M	Projects less than $50 M	Retire-ments	Balance March 31, 2018	Projects greater than $ 50M	Projects less than $50 M	Retire-ments	Balance March 31, 2019
	Total Intangible Plant	454.4		100.3	(0.7)	554.0		49.5	-	603.5	-	61.6	-	665.1		81.0	-	746.1
	Total Unclassified Plant													-				
	Total Steam Production	336.8		4.0	(0.7)	340.1	-	15.6	-	355.7	-	3.4	-	359.2		16.8	-	376.0
	Total Hydraulic and Pumped Storage Production	6,296.4	435.2	89.7	(5.3)	6,816.0	348.4	140.7	(3.7)	7,301.4	250.8	126.0	(3.8)	7,674.4	1,108.9	202.4	(3.6)	8,982.1
	Total Other Production	87.6		5.6	-	93.2	-	8.3	-	101.5	-	6.9	-	108.4		4.2	-	112.6
	Total Transmission Plant	5,755.8	1,149.2	356.8	(35.7)	7,226.1	211.8	435.5	(10.6)	7,862.8	96.1	352.0	(10.5)	8,300.5	74.6	384.2	(8.8)	8,750.5
	Total Distribution	5,344.3	149.5	262.9	(22.8)	5,733.8	-	372.1	(24.3)	6,081.6	-	399.3	(25.5)	6,455.4		413.0	(26.8)	6,841.6
	Total General Plant	1,277.4		227.0	(29.4)	1,475.0	-	155.7	(0.3)	1,630.5	-	193.8	(0.3)	1,823.9	71.0	31.7	(0.5)	1,926.2
101	TOTAL UTILITY PLANT IN SERVICE	19,552.7	1,733.8	1,046.3	(94.6)	22,238.3	560.2	1,177.4	(38.9)	23,937.0	346.9	1,143.0	(40.1)	25,386.8	1,254.5	1,133.3	(39.7)	27,735.0
115	TOTAL PLANT FOR INVESTMENT / RESALE	7.2		2.5	(2.6)	7.1				7.1				7.1				7.1
	TOTAL GROSS PLANT (Appendix A, sch 12.0, line 5)	**19,559.9**	**1,733.8**	**1,048.8**	**(97.2)**	**22,245.4**	**560.2**	**1,177.4**	**(38.9)**	**23,944.1**	**346.9**	**1,143.0**	**(40.1)**	**25,393.9**	**1,254.5**	**1,133.3**	**(39.7)**	**27,742.1**
108	TOTAL ACC DEPN (Appendix A, sch 12.0, line 16)	(2,309.3)				(2,962.7)				(3,722.5)				(4,518.8)				(5,351.6)
	NET PLANT (Appendix A, sch 12.0, line 17)	**17,250.6**				**19,282.7**				**20,221.6**				**20,875.1**				**22,390.5**
208	Net Contributions (Appendix A, sch 11.0, line 60)	(1,496.0)				(1,576.7)				(1,613.2)				(1,661.9)				(1,716.1)
186	Net DSM (Appendix A, sch 10.0, line 25)	841.4				907.2				931.8				995.7				990.9
	Pre 1996 Customer Contributions ((Appendix A, sch 9.0, line 37)	(87.4)				(92.1)				(91.4)				(88.2)				(83.3)
121	OTHER PLANT: Powerex & Powertech assets (Appendix A, sch 9.0, line 38)	50.7				41.2				42.4				43.2				43.6
	Allowance for Working Capital (Appendix A, sch 9.0 line 4(	250.0				250.0				250.0				250.0				250.0
	TOTAL (Appendix A, sch 9.0, line 41)	16,809.4				18,812.2				19,741.2				20,413.9				21,875.6
	TOTAL RATE BASE (Mid-Year)					17,810.8				19,276.7				20,077.6				21,144.8

BC Hydro
Depreciation and Amortization Continuity Schedule
($ million)

		F2016 Actual					F2017 Plan					F2018 Plan					F2019 Plan				
USoA #	USoA Description	Com-posite Depn %	Accum Balance @ March 31, 2015	Depn	Retire-ments	Balance March 31, 2016	Com-posite Depn %	Accum Balance @ March 31, 2016	Depn	Retire-ments	Balance March 31, 2017	Com-posite Depn %	Accum Balance @ March 31, 2017	Depn	Retire-ments	Balance March 31, 2018	Com-posite Depn %	Accum Balance @ March 31, 2018	Depn	Retire-ments	Balance March 31, 2019
	Total Intangible Plant	13%	(194.7)	(65.2)	0.7	(259.2)	12%	(259.2)	(71.8)		(331.0)	12%	(331.0)	(73.2)		(404.2)	10%	(404.2)	(73.7)		(477.9)
	Total Unclassified Plant																				
	Total Steam Production	9%	(97.9)	(30.3)	0.4	(127.8)	5%	(127.8)	(16.2)		(144.1)	5%	(144.1)	(16.2)		(160.2)	4%	(160.2)	(15.3)		(175.5)
	Total Hydraulic and Pumped Storage Production	2%	(576.3)	(163.6)	2.7	(737.2)	3%	(737.2)	(177.8)		(915.1)	3%	(915.1)	(187.9)		(1,102.9)	2%	(1,102.9)	(207.1)		(1,310.0)
	Total Other Production	4%	(11.8)	(3.7)	-	(15.5)	4%	(15.5)	(4.0)		(19.5)	4%	(19.5)	(4.2)		(23.7)	4%	(23.7)	(4.3)		(28.0)
	Total Transmission Plant	3%	(561.1)	(177.0)	7.5	(730.6)	3%	(730.6)	(208.0)		(938.6)	3%	(938.6)	(220.6)		(1,159.2)	3%	(1,159.2)	(230.3)		(1,38[illegible]
	Total Distribution	3%	(587.5)	(171.1)	8.2	(750.4)	3%	(750.4)	(185.3)		(935.8)	3%	(935.8)	(191.2)		(1,126.9)	3%	(1,126.9)	(197.8)		(1,324.7)
	Total General Plant	7%	(280.3)	(90.7)	29.1	(341.9)	6%	(341.9)	(96.7)		(438.5)	6%	(438.5)	(103.0)		(541.6)	6%	(541.6)	(104.3)		(645.9)
108	ACC DEPN - TOTAL UTILITY PLANT IN SERVICE - (Appendix A, sch 12.0, line 16)		(2,309.5)	(701.6)	48.5	(2,962.7)		(2,962.7)	(759.8)	-	(3,722.5)		(3,722.5)	(796.3)	-	(4,518.8)		(4,518.8)	(832.8)	-	(5,351.5)
122	ACC DEPN - TOTAL OTHER PLANT		(35.3)	(8.2)	3.8	(39.7)		(39.7)	(8.2)		(47.8)		(47.8)	(8.7)		(56.5)		(56.5)	(9.0)		(65.5)
	TOTAL ACC DEPN		**(2,344.8)**	**(709.8)**	**52.3**	**(3,002.3)**		**(3,002.3)**	**(768.0)**	**-**	**(3,770.3)**		**(3,770.3)**	**(805.0)**	**-**	**(4,575.3)**		**(4,575.3)**	**(841.8)**	**-**	**(5,417.0)**

Fiscal 2017 to Fiscal 2019
Revenue Requirements Application

Appendix N

Performance Measures

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List of Tables

1 Introduction

BC Hydro prepares and submits its Service Plan to government to meet requirements under the Budget Transparency and Accountability Act which provides the legislative framework for planning, reporting and accountability for the government. BC Hydro's Board of Directors is responsible for ensuring that the Service Plan aligns with and incorporates government's strategic priorities, including the mandate and policy expectations contained in the annual Mandate Letter and the Taxpayer Accountability Principles. BC Hydro's Service Plan is tabled in the legislature as part of the government's budget process and reports on the results to the government through submission and publication of an Annual Report. The Service Plan spans a three year horizon and is annually updated.

2 2016/17 to 2018/19 Service Plan

BC Hydro's mission is: **To provide our customers with reliable, affordable, clean electricity throughout B.C., safely.** In BC Hydro's 2016/17 to 2018/19 Service Plan strategic goals have been identified that guide our actions, each supported by corresponding strategies, 12 performance measures and corresponding targets.

3 Goals, Performance Measures and Targets

3.1 Goal 1: Set the Standard for Reliable and Responsive Service

BC Hydro will reliably meet the electricity requirements of customers and respond to their evolving expectations by planning and investing in the system to meet future needs and by consistently improving our service.

3.1.1 Strategies

- Ensure the reliability of the generation, transmission and distribution system by effectively implementing capital and maintenance programs to manage overall asset health and secure supply to meet customer load throughout the year;
- Identify and address vulnerabilities in our operating system and develop well practiced emergency response plans to improve overall system reliability;
- Through external benchmarking of North American transmission interconnection practices, review and implement appropriate recommendations to meet customer requirements as identified in the Industrial Electricity Policy Review;
- Make it easier for customers to do business with us through a series of internal and external improvements such as bills that are easier to read, access to critical information including outages, and customer-focussed training for our staff to enhance the overall customer service experience;
- Explore innovative energy conservation solutions such as load curtailment rates;
- Sustain gold-level certification under the Progressive Aboriginal Relations program by maintaining leading practices focused on Aboriginal employment, business development, community investment and community engagement; and
- Through early engagement and emphasizing collaboration, respect and mutually beneficial relationships with First Nations, BC Hydro will improve transparency into its operations and identify interests in the delivery of our capital projects.

Table N-1 Performance Measures 1 to 5[1]

Performance Measures	Four Year Avg.	Actual 2013/14	Actual 2014/15	Target 2015/16	Actual 2015/16	Target 2016/17	Target 2017/18	Target 2018/19
SAIDI (duration)[2] [total outage duration (in hours) experienced by an average customer in a year]	3.25	3.593	3.07	3.22	**3.01**	3.22	3.20	3.20
SAIFI (frequency)[2] [Number of sustained disruptions per year] (excluding major events)	1.43	1.56	1.30	1.40	**1.48**	1.40	1.35	1.35
Key Generating Facility Forced Outage Factor[4]	2.0	1.6	1.5[5]	NR[6]	**NR**	2.0	2.0	1.8
CSAT Index [Customer Satisfaction Index: % of customers satisfied or very satisfied]	86.8	85.0	86.0	85.0	**87.0**	85.0	85.0	85.0
Progressive Aboriginal Relations Designation[7]	Gold	Gold	Gold	Gold	**Gold**	Gold	Gold	Gold

[1] Performance Measure descriptions, rationale, data source information and benchmarking is available online at www.bchydro.com/performance.

[2] Annual targets are based on a number of factors including long-term historic reliability trending, current year performance, previous years investments and future years investment plans. The 2017/2018 target for SAIDI has been adjusted to reflect these factors but remains in line with historical performance. Note: Reliability targets are based on specific values, however performance within 10 per cent is considered acceptable given the wide range of variations in weather patterns and uncontrollable elements that can significantly disrupt the electrical system. BC Hydro measures reliability under normal circumstances, because major events are not predictable and largely uncontrollable. The reliability measure is therefore based on data that excludes major events. BC Hydro reviews performance during major events and takes the performance into consideration in reliability improvement initiatives.

[3] The 2013/2014 actuals have been calculated based on the latest available data and may be different than previously stated.

[4] A forced outage occurs when a generating unit is unable to start generating or doesn't stay on line as long as needed. Forced Outage Factor is defined as the total forced outage time in a period relative to the total number of hours in the same period (usually one year). Annually, the Forced Outage Factor can be relatively volatile and through applying the historical five-year rolling average it can smooth the range to provide a more stable measure for which targets can be set. Therefore, the strategy is to keep the Force Outage Factor below 2 per cent of the total number of hours per year. There are seven Key Generating Facilities, representing those plants with installed capacity greater than 200 MW. Together they provide 90 per cent of the average annual electricity generated by BC Hydro's facilities. This measurement will show the trend of how the assets are performing and aligns with how asset management investments decisions are made to maintain asset reliability that is reflected in a low forced outage factor.

[5] This is a new measure introduced for 2016/2017; however, historical information has been provided for context.

[6] NR (Not Reported) as this is a new measure, there were no targets set for the 2015/2016 year.

[7] BC Hydro attained a gold-level designation from the Canadian Council for Aboriginal Business in 2015/2016 which is valid for a three year period. In 2018/2019, BC Hydro will apply for the next certification.

New Measure - Key Generating Facility Forced Outage Factor replaces the previous Winter Generation Availability. With recent additions of capacity resources and long term planning criteria of capacity self-sufficiency, the risk to winter service reliability has decreased and in response, BC Hydro is removing the Winter Generation measure. Given the aging generating assets, BC Hydro is now refocussing on the performance of the Key Generating Facility units by measuring their Forced Outage Factor. This factor is one indicator of the units' health and provides both leading and lagging information on the effectiveness of BC Hydro's maintenance and capital investment programs. Forced Outage Factor is commonly used by electric utilities and industry benchmarks exist for comparative performance assessment. This new measure will allow for optimal outage planning throughout the year, including winter.

3.2 Goal 2: Ensure Rates are Among the Most Affordable in North America

BC Hydro customers will continue to have low, predictable rates while we efficiently manage our costs and make important investments to maintain and expand our system.

3.2.1 Strategies

- Prudently implement the Integrated Resource Plan recommendations and the 10 Year Capital Plan while keeping electricity rates low and predictable which will be reflected in the Revenue Requirements and Rate Design Applications to the BC Utilities Commission;
- Improve how we operate by focusing on safety, operational excellence, efficiency and reliability by enhancing work delivery methods as well as resourcing and supply chain strategies;

- Build Site C - a third dam and generating station on the Peace River, which is the most cost-effective way to meet the long–term need for energy and dependable capacity - on time and on budget; and
- Implement a scalable and consistent project delivery practice to actively manage project risks and apply industry best practices to deliver projects on time and on budget.

Table N-2 Performance Measure 6 to 7[1]

Performance Measures	Four Year Avg.	Actual 2013/14	Actual 2014/15	Target 2015/16	Actual 2015/16	Target 2016/17	Target 2017/18	Target 2018/19
Competitive Rates[2]	1st quartile	1st quartile	1st quartile	1st quartile	**1st quartile**	1st quartile	1st quartile	1st quartile
Project Budget to Actual Cost[3]	-1.8% on $3.94 billion[4]	-4.75% on $3.33 billion[5]	-1.8% on $3.94 billion[4]	Within +5% to -5% of budget excluding project reserve amounts	**-0.18% on $6.49 billion**	Within +5% to -5% of budget excluding project reserve amounts	Within +5% to -5% of budget excluding project reserve amounts	Within +5% to -5% of budget excluding project reserve amounts

1 Performance Measure definitions, rationales, data sources, and benchmarking information are available at www.bchydro.com/performance.
2 Based on BC Hydro's ranking in the residential category in the annual HydroQuebec Report on Electricity Rates in North America. BC Hydro calculates a relative index for each usage level within the residential category and then calculates an average of the index to create an overall ranking. The rankings of the 21 participating utilities are then divided into quartiles to determine BC Hydro's ranking. Based on this same methodology, BC Hydro's rates for commercial and industrial customers rank fourth and fifth lowest in the report.
3 The data includes Generation, Substation and Transmission Line projects managed by Project Delivery. Annually, BC Hydro reflects the past five years' performance in delivering capital projects. This is a five-year rolling data set of actual costs compared to original approved full scope implementation budgets not including project reserve amounts, for capital projects that were put into service during the period.
4 This is a five-year rolling average reflecting 2010/2011 to 2014/2015.
5 This is a five-year rolling average reflecting 2009/2010 to 2013/2014.

Discussion – Project Budget to Actual Cost is an important measure for evaluating financial performance in delivering large capital projects. The measure captures a five year rolling data set of actual costs compared to original approved full scope implementation budgets excluding project reserve funds for capital projects that were put into service during the period. The +/- 5 per cent target is the same over the plan period as it is the objective to have the entire project portfolio (Generaiton, Substation and Transmission Line) in-service within this financial range. Over the past five years, BC Hydro has delivered 563 capital projects at a total cost of $3.94 billion, which is 1.8 per cent under budget in aggregate.

3.3 Goal 3: Continue British Columbia's Leading Commitment to Renewable, Clean Power

BC Hydro will strengthen its legacy of renewable, clean power and energy conservation investments by implementing its energy conservation plan and by identifying and securing new competitively priced energy and capacity options to meet future customer needs.

3.3.1 Strategies

- Meet the *Clean Energy Act* objective that at least 93 per cent of electricity generation be from renewable, clean resources by implementing the Integrated Resource Plan recommendations, including renewing expiring electricity purchase agreements on a cost of service basis and by implementing the Memorandum of Understanding with Clean Energy BC which includes exploring opportunities to acquire dependable capacity resources through the Standing Offer Program;
- Implement the energy conservation plan, which will exceed the *Clean Energy Act* objective to meet at least two-thirds of future demand growth through conservation and other energy management measures by 2020; and
- Continue to provide opportunities for First Nations in non-integrated areas through established renewable energy programs.

Table N-3 Performance Measures 8 to 9[1]

Performance Measures	Four Year Avg.	Actual 2013/14	Actual 2014/15	Target 2015/16	Actual 2015/16	Target 2016/17	Target 2017/18	Target 2018/19
Energy Conservation Portfolio (New Incremental GWh/year)[2]	800	500	700[3]	NR[4]	**NR**	700	700	600
Clean Energy (%)[5]	97.8	97.1	97.9	93.0	**98.3**	93.0	93.0	93.0

[1] Performance Measure descriptions, rationale, data source information and benchmarking is available online at www.bchydro.com/performance.

[2] Reflects the annual new incremental electricity savings resulting from DSM portfolio results including programs, codes and standards and conservation rates. This metric is a reflection of performance within the current period and as such is not impacted by past performance and/or adjustments made to energy savings in prior years (e.g., persistence, evaluations, measurement and verification).

[3] This is a new measure introduced for 2016/2017; however, historical information has been provided for context.

[4] NR (Not Reported) as this is a new measure, there were no targets set for the 2015/2016 year.

[5] 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. BC Hydro's forecast is based on expected generation and is consistent with previous years.

New Measure - New Incremental Energy Conservation Portfolio Energy Savings (GWh/year) replaces the previous Cumulative Demand Side Management Energy Savings in prior Service Plans. BC Hydro continues to implement its plan to achieve or exceed the *Clean Energy Act* target to meet at least 66 per cent of incremental demand from 2008 to 2020 through conservation. This new metric is a better reflection of performance within the operating period because it is based on the new incremental energy savings from programs, codes and standards and conservation rates that are implemented within the period. In some cases, the implementation date for anticipated codes and standards can shift, which will cause actual incremental energy savings to vary from the targets that have been set for the period.

3.4 Goal 4: Safety Above All

BC Hydro's number one priority is ensuring its workforce goes home safely every day and that the public is safe around our system.

3.4.1 Strategies

- Implement the five-year safety strategy with key elements that include:
  - ▶ Maintaining a culture where safety is a core value through demonstrating seen and felt safety leadership; supporting the courage to intervene where anyone can stop unsafe work; improving safety awareness and communication; and, learning from injury and near miss incidents to prevent re-occurrence;
  - ▶ Enhance frontline accountability for safety by establishing clear roles and accountabilities; developing a leading-class safety management system; and, continuing to leverage the joint health and safety committees to identify hazards and risks;
  - ▶ Strengthening safety competencies for employees and contractors around our: Life Saving Rules, Arc flash, asbestos and confined space hazards; improving job planning, hazard identification and the use of multiple barriers; and providing frontline and crew leadership training; and
  - ▶ Incorporating safety into the strategy and planning process by reviewing and considering safety risks to our employees, contractors and the public in maintenance budgets and designs for capital projects.

Table N-4 Performance Measures 10 to 12[1]

Performance Measures	Four Year Avg.	Actual 2013/14	Actual 2014/15	Target 2015/16	Actuals 2015/16	Target 2016/17	Target 2017/18	Target 2018/19
Zero Fatality & Serious Injury[2] [Loss of life or the injury has resulted in a permanent disability]	0.75	0	1[3]	0	**0**	0	0	0
Lost Time Injury Frequency[2,4] [Number of employee injury incidents resulting in lost time (beyond the day of the injury) per 200,000 hours worked]	1.1	1.1[5]	1.0	1.0	**1.1**	1.0	0.9	0.8
Timely Completion of Corrective Actions (%)[6]	84	84	78[7]	NR[8]	**NR**	85	90	95

[1] Performance Measure descriptions, rationale, data source information and benchmarking is available online at www.bchydro.com/performance.
[2] BC Hydro's safety performance measures do not include contractor or public safety injuries or fatalities.
[3] The 2014/2015 actual reflects that a serious injury from an electrical contact occurred November 2014.
[4] Focusing on Lost Time Injury Frequency encourages managers to identify modified work duties for job categories and locations where workers experience injury, enabling injured workers to stay on the job while they recover. The earlier an injured worker is able to safely return to productive employment and maintain his or her positive connection to the workplace, the more likely he or she is of obtaining maximum recovery. With the increased granularity this metric provides, the organization is better able to focus its efforts on managing the hazards that can lead to Lost Time injuries.
[5] Prior years' results have been calculated based on the latest available data and may be different than previously stated.
[6] New Measure – defined as the percentage of safety corrective actions closed within 30 days of the original scheduled due date on an annual basis, with an aim to improve over time.
[7] This is a new measure introduced for 2016/2017; however, historical information has been provided for context.
[8] NR (Not Reported) as this is a new measure, there were no targets set for the 2015/2016 year.

New Measure – Timely Completion of Corrective Actions – The purpose of this measure is to track corrective actions that have been put in place from safety incidents (injuries and near misses) to improve our safety performance. It demonstrates that we are a learning organization with a focus on improving practices in a timely way from identified deficiencies that have a direct impact on the safety of our workforce. By implementing this measure, we will see systemic deficiencies corrected and our workforce will experience lower frequency of recurring issues.

This measure tracks the percentage of safety corrective actions closed within 30 days of the original scheduled due date on an annual basis. The target is to increase the percentage of corrective actions completed within 30 days of the original due date by 5 per cent per year for each of the next three years.

BC Hydro
Power smart

Fiscal 2017 to Fiscal 2019
Revenue Requirements Application

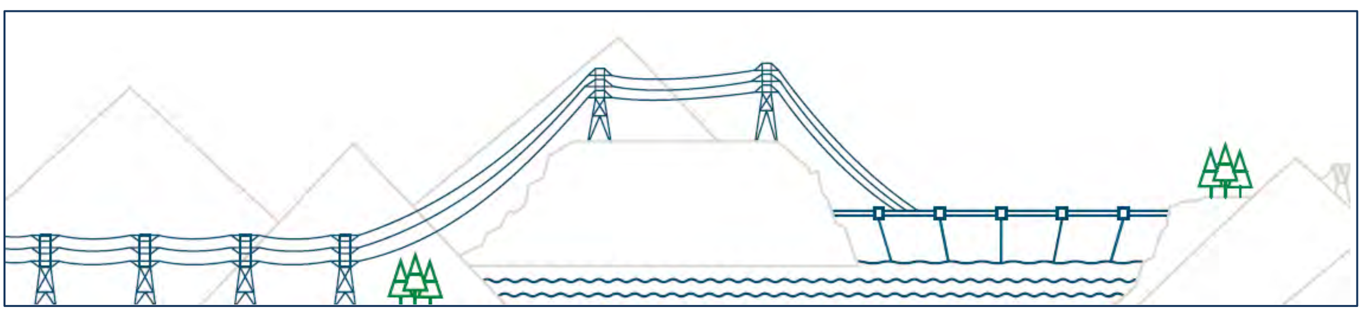
Appendix O

Technology Group
Five-Year Strategic Plan

Technology Group

Five-Year Strategic Plan F17- F21

March 2016



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.

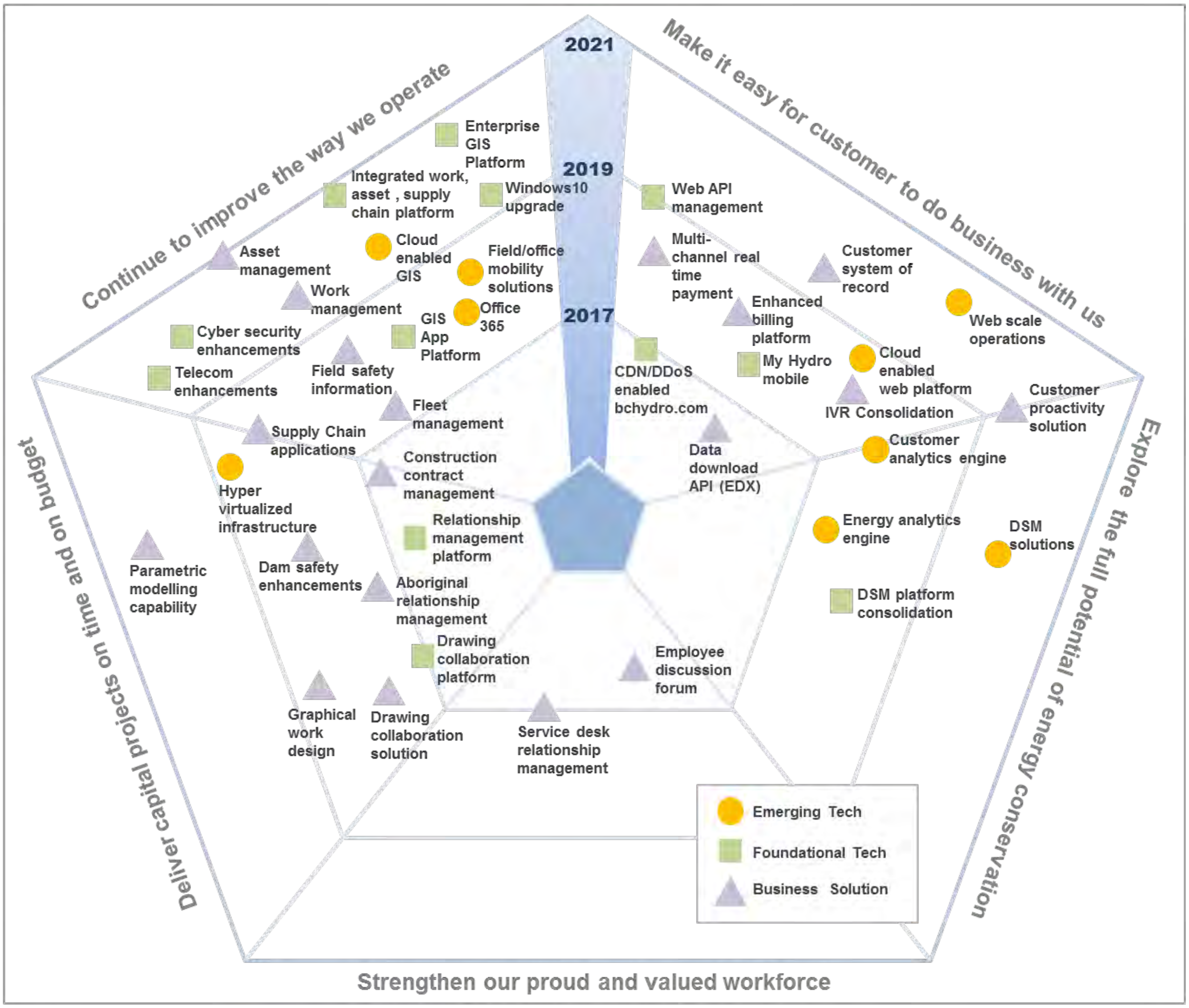


Figure: Roadmap for investment in information and communications technologies F17-F21

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.

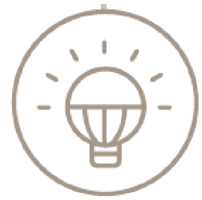
Choosing the right delivery approach

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

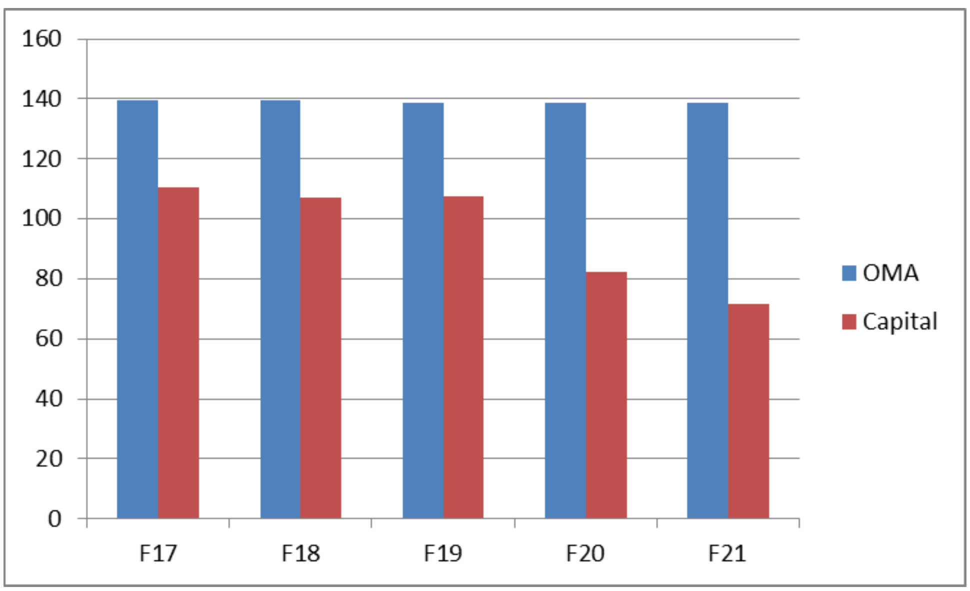
The Technology Group is in the process of developing new metrics that reflect our goal to work as a **team**, provide excellent **service**, be **efficient** in our operations and provide innovative, quality solutions.

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%.

Fiscal 2017 to Fiscal 2019

Revenue Requirements Application

Appendix P

Smart Metering and Infrastructure Completion Report

The Smart Metering and Infrastructure Completion Report will be provided upon its completion during the time period of this proceeding.

BC Hydro
Power smart

Fiscal 2017 to Fiscal 2019
Revenue Requirements Application

Appendix Q

Status of Outstanding Directives

Table of Contents

List of Tables

1 Outstanding BC Hydro Revenue Requirements Application Directives

The following tables set out the status of outstanding directives, commitments and provisions arising from British Columbia Utilities Commission Order No. G-148-05, BC Hydro's Fiscal 2012-Fiscal 2014 Amended Revenue Requirements Application, the Fiscal 2011 Revenue Requirement Application Negotiated Settlement Agreement, and the Commission's Decisions on BC Hydro's Fiscal 2009/Fiscal 2010 Revenue Requirements Application and Fiscal 2005/Fiscal 2006 Revenue Requirements Application.

Table Q-1 Status of the Commission Order No. G-148-05 Provisions

Provision		Action Taken, Relevant Filing Dates and Comments	Section in the Application
1.	The disposition of $17.2 million variance relegating to post-employment benefits current pension costs is to be addressed in BC Hydro's next revenue requirements application.	Requested Order related to Non-Current Pension Costs is outlined in Chapter 7 of the Application.	Section 7.5.12

Table Q-2 Status of the Fiscal 12-Fiscal 14 Revenue Requirements Application Provisions

Provision		Action Taken, Relevant Filing Dates and Comments	Section in the Application
1	BC Hydro is committed to providing a long-term capital plan	Complete	Appendix G
2	BC Hydro is committed to providing a long-term workforce plan	Complete	Appendix F

Table Q-3 Status of the Fiscal 2011 Revenue Requirement Application Negotiated Settlement Agreement Provisions

Provision		Action Taken, Relevant Filing Dates and Comments	Section in the Application
9(x)	BC Hydro shall report to the Commission IEEE 2.5 Beta and CEMI reliability metrics	Included in BC Hydro's Reliability Indices	Appendix U
9(xiii)	BC Hydro shall copy RRA interveners on BC Hydro's section 71 filings with the Commission of amended electricity purchase agreements.	Ongoing.	Not Applicable

Table Q-4 Status of the Fiscal 2009/Fiscal 20110 Revenue Requirements Application Directives

Directive		Action Taken, Relevant Filing Dates and Comments	Section in the Application
54	The Commission Panel directs BC Hydro to adopt the Commission USoA by no later than the F2012 reporting year. If certain plant accounts already in place cannot be coded to the proper Commission account, BC Hydro is to make an application for an exemption for these historical amounts.	BC Hydro will report its costs in accordance with the Commission USoA.	Appendix M
55	The Commission Panel further directs that if BC Hydro is to re-platform to a replacement financial system this replacement financial system is to fully incorporate the Commission USoA.	BC Hydro's financial systems will incorporate the Commission USoA.	Appendix M

Table Q-5 Status of the Fiscal 2005/Fiscal 2006 Revenue Requirements Application Directives

Directive		Action Taken, Relevant Filing Dates and Comments	Section in the Application
17	The Commission Panel directs BC Hydro to file quarterly and annual reports for the HDA and NHDA.	BC Hydro files a semi-annual deferral account report, with a copy included in this application. Commission Order No. G-12-14 adjusted the frequency of report distribution from quarterly to semi-annually.	Appendix L
26	The Commission Panel expects BC Hydro and BCTC to present their reliability indices (SAIFI, SAIDI, CAIDI, ASAI, SARI, MAIFI, generation forced outages, available, and the generation outage rates) both combined and disaggregated (where applicable) on an annual basis with comparison to CEA averages.	Included in BC Hydro's Reliability Indices	Appendix U

2 Outstanding British Columbia Transmission Corporation Directives

The following tables summarize the status of outstanding Commission directives to British Columbia Transmission Corporation, and provides resulting from the negotiated settlements of British Columbia Transmission Corporation's revenue requirements applications. Table Q-6 to Table Q-10 provides the status for or disposition of each directive arising from transmission system capital plan applications. All outstanding directives relative BCTC revenue requirements applications were sufficiently addressed in BC Hydro's Fiscal 2012-Fiscal 2014 Revenue Requirements Application.

Table Q-6 Status of the 2010 Transmission System Capital Plan Directives

Directive	Status	Action Taken, Relevant Filing Dates, and Comments	Section in the Application
The Commission Panel determines BCTC should continue to use the Sustainment Investment Model to suggest the expenditure level for the base Sustaining Capital portfolio for asset maintenance, and directs BCTC to provide separate and additional justification for exceptional projects within the Sustaining Capital portfolio driven by risk mitigation objectives, performance enhancement objectives, or Third-party requests. (Commission Order No. G-87-09, #20)	Ongoing.	BC Hydro continues to use the Sustainment Investment Model to inform the level of sustaining capital expenditures.	Section 6.3.6.2
The Commission Panel directs BCTC to provide a clear demonstration of how the expected effect of early replacement of assets resulting in a reduction in the forecast core Sustaining Capital budgets is adequately reflected within the operation of the Sustainment Investment Model in its next Capital Plan application. (Commission Order No. G-87-09, #28)	Ongoing.	BC Hydro identifies the level of sustaining capital expenditures needed along with supporting information in revenue requirement applications.	Section 6.3.6.2

Table Q-7 Status of the 2009 Transmission System Capital Plan Directives

Directive	Status	Action Taken, Relevant Filing Dates, and Comments	Section in the Application
The Commission Panel directs BCTC to continue identifying in future capital plans those projects that are being proposed to avoid generation shedding for first contingency events, and identify any transmission service or interconnection requests that trigger the need for upgraded facilities to avoid generation shedding for single contingency events. (Commission Order No. G-107-08, #1)	Ongoing.	Key drivers are identified, as applicable, in major capital project filings, and in capital project descriptions included in revenue requirement applications.	Appendix J
In future capital plans, and until directed otherwise, the Commission Panel directs BCTC to provide a thorough evaluation of options in situations where the cost of the preferred solution for an approved project changes by more than 100 per cent. (Commission Order No. G-107-08, #6)	Ongoing.	BC Hydro includes explanation of changes in project costs and project alternatives in revenue requirement applications.	Appendix J
The Commission Panel directs BCTC to report in future capital plans the specific instances where non-wires options have been considered in project option evaluations. (Commission Order No. G-107-08, #8)	Ongoing.	BC Hydro includes discussion of alternatives in major capital project filings, and in capital project descriptions included in revenue requirement applications.	Appendix J
The Commission Panel directs BCTC to continue to use an inflation adjustment equal to the BCCPI. (Commission Order No. G-107-08, #11)	Ongoing.	BC Hydro uses inflation adjustment consistent with BC Consumer Price Index.	Table 5-5
The Commission Panel directs BCTC to provide in future capital plans an estimate of all generation interconnection costs, except those which are 100 per cent third party funded and will remain owned by and the responsibility of the third party. (Commission Order No. G-107-08, #13)	Ongoing.	BC Hydro identifies interconnection related projects as applicable in revenue requirement applications.	Appendix I and Appendix J

Table Q-8 Status of the 2008 Transmission System Capital Plan Directives

Directive	Status	Action Taken, Relevant Filing Dates, and Comments	Section in the Application
For future capital plans, the Commission Panel directs BCTC to identify separately those projects and corresponding expenditures that are directly attributable to specific generation additions. (Commission Order No. G-69-07, #23)	Ongoing	Key drivers are identified in capital project descriptions included in revenue requirement applications.	Appendix J

Table Q-9 Status of the 2006 Transmission System Capital Plan Directives

Directive	Status	Action Taken, Relevant Filing Dates, and Comments	Section in the Application
The Commission Panel therefore directs BCTC to provide, in each future capital plan, a section describing its response to Commission directives from previous capital plans. The status of compliance with each directive is to be reported in each capital plan until such time as BCTC has complied with the directive. (Commission Order No. G-91-05, #7)	Ongoing.		Appendix Q
The Commission Panel directs BCTC to consider economics in its assessment of whether transmission upgrades should proceed. The Commission Panel does not consider that the simple existence of a NERC/WECC Planning Standards violation is sufficient justification for transmission upgrades in every case. (Commission Order No. G-91-05, #8)	Ongoing.	BC Hydro provides evaluation of alternatives in major capital project filings, and in capital project descriptions included in revenue requirement applications.	Appendix J
The Commission Panel considers the use of rigorous financial comparison of continued maintenance versus equipment replacement, including a comparison against options that were considered but not selected, to be a useful exercise when justifying a proposed program or project, and therefore determines this to be an ongoing obligation. (As affirmed from F2010 TSCP Decision, dated July 13, 2009, page 24.) (Commission Order No. G-91-05, #12)	Ongoing.	BC Hydro provides evaluation of alternatives in major capital project filings, and in capital project descriptions included in revenue requirement applications.	Appendix J

Directive	Status	Action Taken, Relevant Filing Dates, and Comments	Section in the Application
The Commission Panel directs BCTC to report future Sustaining Capital Portfolios in a manner that preserves the ability to track and trend annual Sustaining Capital spending as far back as F2001, and facilitates comparisons and identification of trends in spending for individual Sustaining Capital Programs. (Commission Order No. G-91-05, #28b)	Ongoing.	Table 6-5 provides Sustaining Capital Portfolio expenditures and allows for a comparison against previous years.	Figure 6-1, Table 6-5

Table Q-10 Status of the 2005 Transmission System Capital Plan Directives

Directive	Status	Action Taken, Relevant Filing Dates, and Comments	Section in the Application
The Commission Panel determines that tracking reliability-driven expenditures so that the effectiveness of such expenditures at reducing outages or otherwise increasing reliability can be assessed may still be useful in revealing longer-term trends, and therefore determines this to be an ongoing requirement. (As affirmed from F2010 TSCP Decision, dated July 13, 2009, page 24.) (Commission Order No. G-103-04, page 16)	Ongoing.	Projects driven by reliability (e.g., sustainment) are identified, as applicable, in revenue requirement applications.	Appendix I and Appendix J
However, the Commission Panel notes that rate impact information by project priority and capital portfolio would be useful, and directs BCTC to provide such information in future applications. (Commission Order No. G-103-04, page 20)	Addressed in future filings.	BC Hydro provides rate impact information for a project in the applicable major capital project filing.	
The Commission Panel accepts IPPBC's suggestion that the party funding a capital project and the amount it is paying should be identified, and it directs BCTC to provide such information in future Capital Plans, subject to confidentiality requirements. (Commission Order No. G-103-04, page 21)	Ongoing.	BC Hydro includes the gross cost and contributions in aid of projects with third party funding.	Appendix I and Appendix J

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Appendix R

Asset Health - Generation

Table of Contents

1 Introduction

Equipment health is assessed for Generation, Transmission and Distribution assets. The information is used for the life-cycle management of assets, including supporting the need for capital investments. The methodologies used provide a systematic, objective, repeatable, and transparent assessment of asset health. Summaries of the methodologies and asset health information are provided below.

2 Generation Equipment Health Ratings

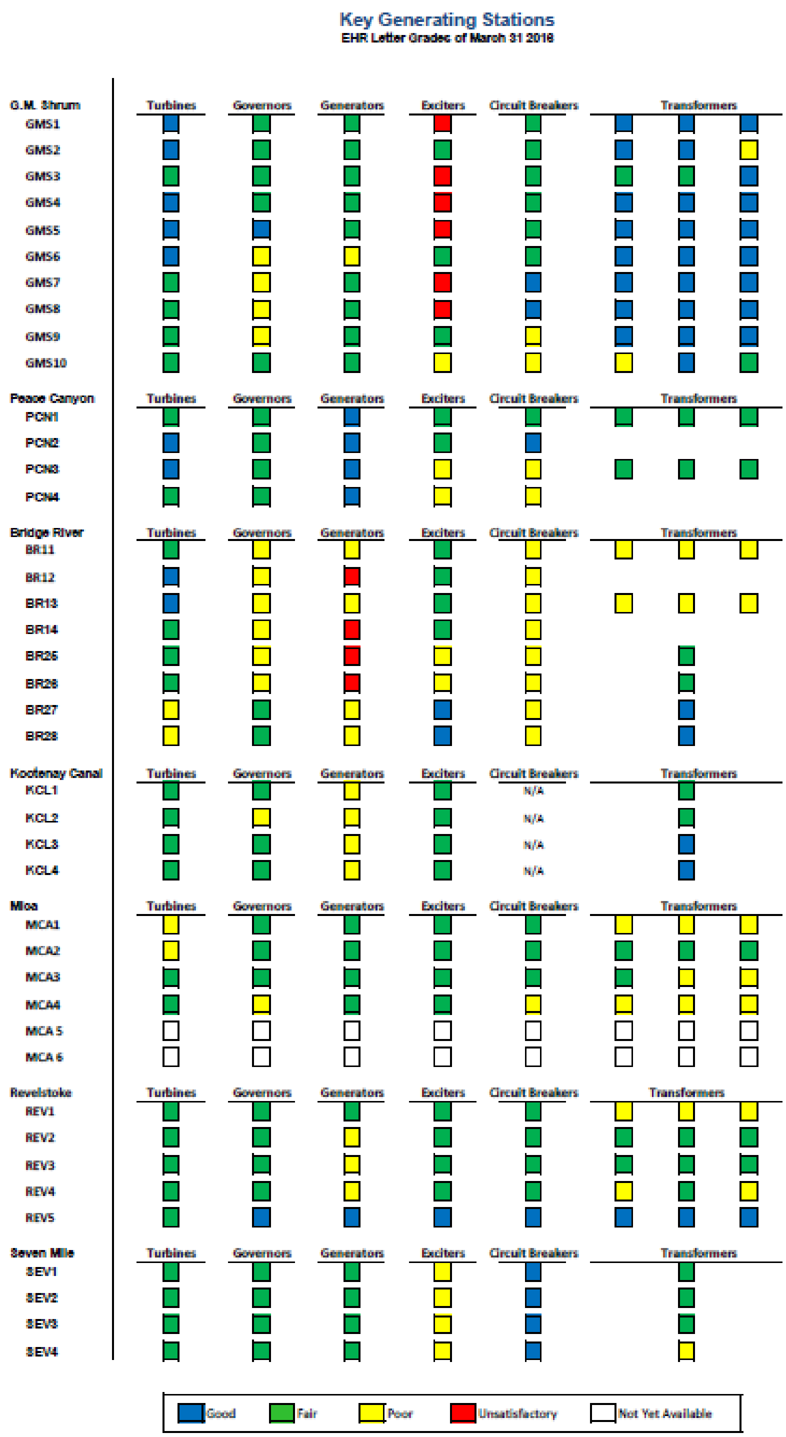
Generation periodically evaluates the condition of its major assets (turbines, generators, governors, exciters, transformers, and circuit breakers) based on the latest available maintenance test and inspection data. Health assessments are based primarily on asset condition but also consider safety and environmental issues, reliability, design deficiencies, asset age and industry expected life and availability of spare parts and technical expertise.

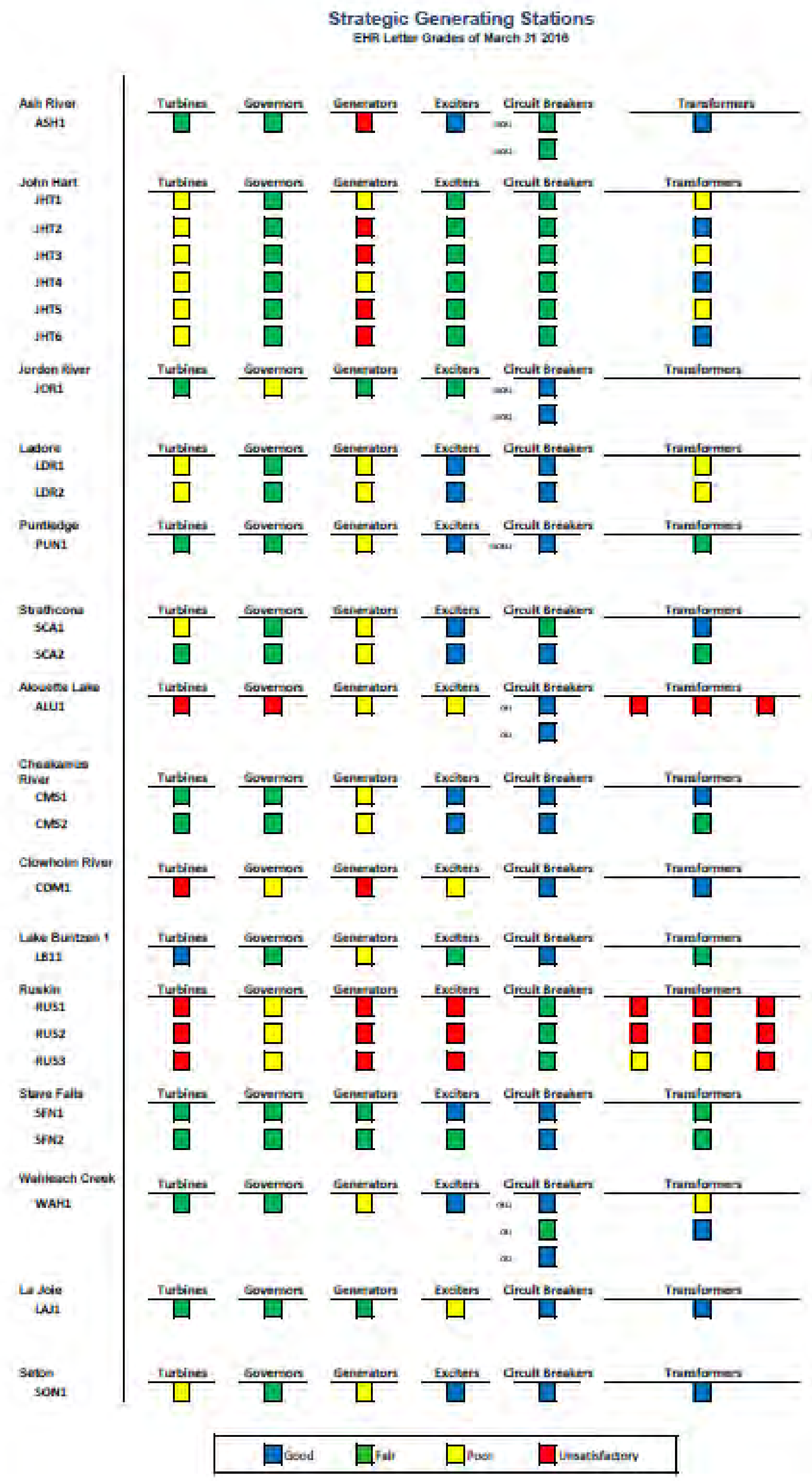
Each health assessment results in a rating of Good, Fair, Poor, or Unsatisfactory:

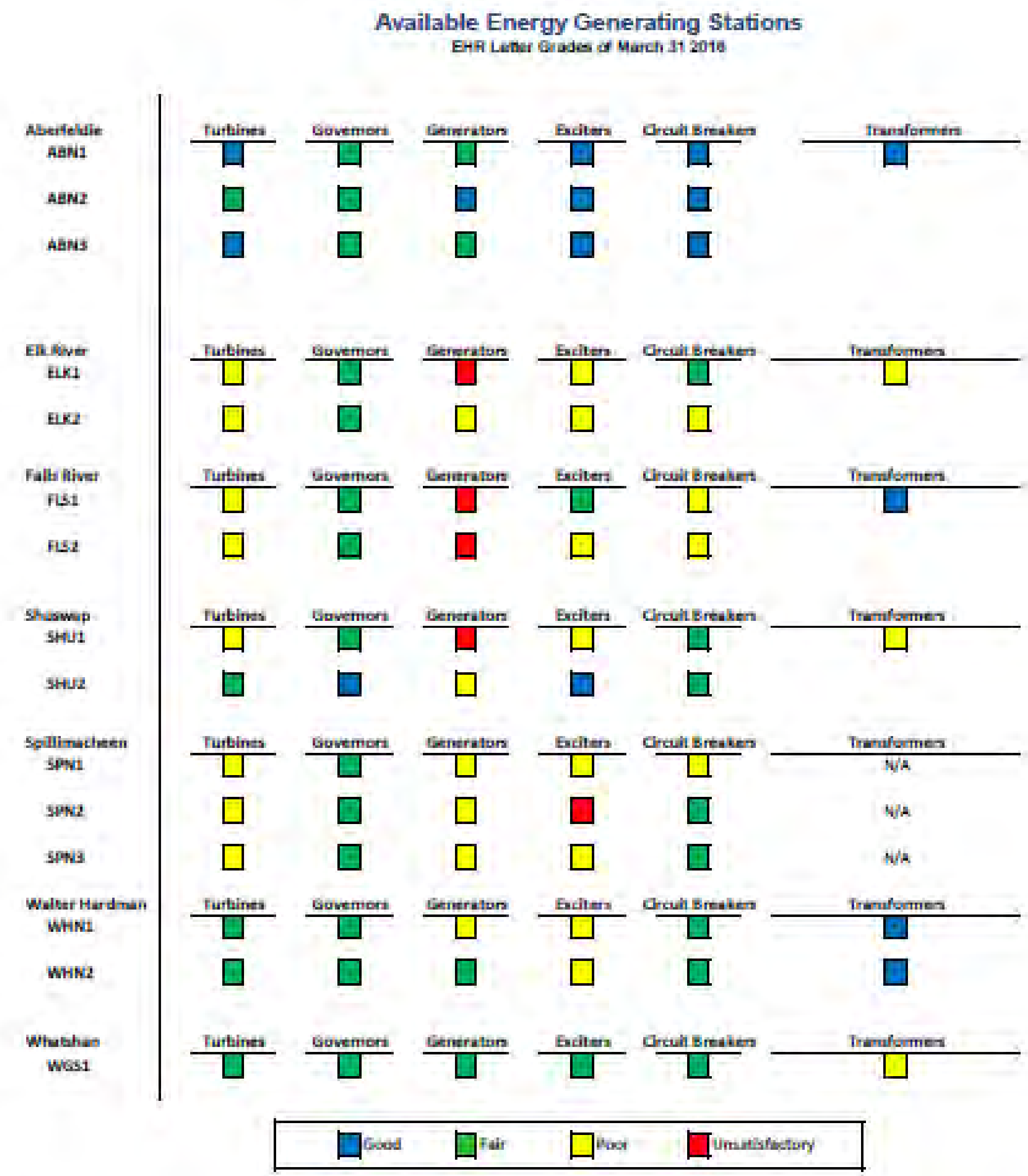
- **Good** - The asset is in as new condition, with no noticeable deterioration or defects.
- **Fair** - There is some normal deterioration of the asset with one or more minor defects; function is not affected.
- **Poor** - There is serious deterioration of the asset or serious defects in at least some portions of the asset; function is affected.
- **Unsatisfactory** - There is extensive deterioration of the asset and the asset no longer functions as designed.

Assets that have an Equipment Health Rating of Poor or Unsatisfactory are considered to have an increased likelihood of failure. Assets assessed as being in unsatisfactory condition are believed to have the highest likelihood of failure, with capital investment or replacement generally recommended within the next five to seven years. Investments in assets assessed as poor are generally considered with the next ten to 12 years.

Equipment Health Rating for Generation assets as of June 2015 are provided below.




Strategic Generating Stations
EHR Letter Grades of March 31 2016
Turbines
Governors
Generators
Exciters
Circuit Breakers
Transformers
Ash River
ASH1
John Hart
JHT1
JHT2
JHT3
JHT4
JHT5
JHT6
Jordan River
JOR1
Ladore
LDR1
LDR2
Puntledge
PUN1
Strathcona
SCA1
SCA2
Alouette Lake
ALU1
Cheakamus River
CMS1
CMS2
Clowhom River
COM1
Lake Buntzen 1
LB11
Ruskin
RUS1
RUS2
RUS3
Stave Falls
SFN1
SFN2
Wahleach Creek
WAH1
La Joie
LAJ1
Seton
SON1
Good
Fair
Poor
Unsatisfactory


Available Energy Generating Stations
EHR Letter Grades of March 31 2016
Aberfeldie
ABN1
ABN2
ABN3
Elk River
ELK1
ELK2
Falls River
FLS1
FLS2
Shuswap
SHU1
SHU2
Spillimacheen
SPN1
SPN2
SPN3
Walter Hardman
WHN1
WHN2
Whatshan
WGS1
Turbines
Governors
Generators
Exciters
Circuit Breakers
Transformers
N/A
Good
Fair
Poor
Unsatisfactory

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Appendix S

Asset Health – Transmission and Distribution

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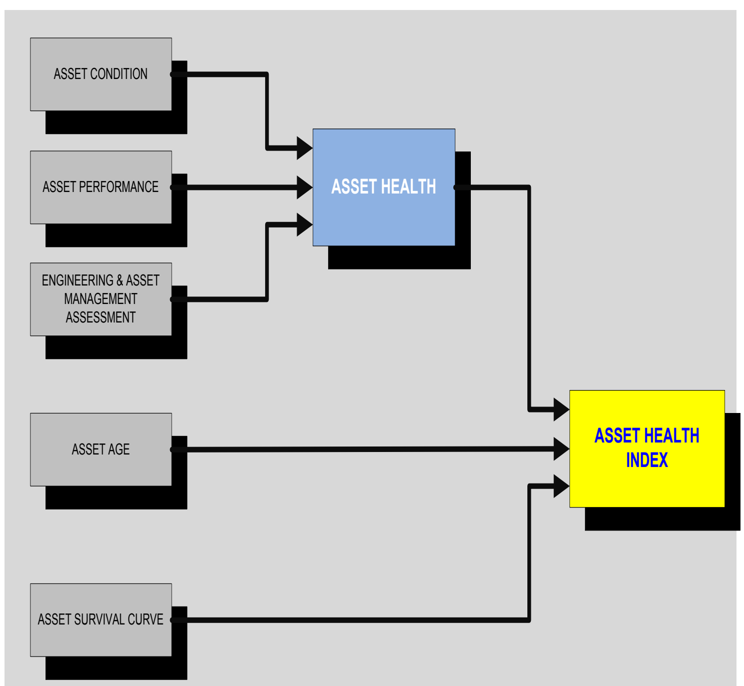
List of Tables

1 Introduction

Transmission, Distribution and Customer Service developed a methodology to evaluate the health of the Transmission and Distribution the assets. The information is used for the life-cycle management of assets, including supporting the need for capital investments. The methodology provides a systematic, objective, repeatable, and transparent assessment of asset health. Summaries of the methodology and asset health information are provided below.

2 Transmission and Distribution Asset Health Index

Asset Health Index is derived from operating, maintenance and asset management data. The inputs are described below.



The index is used to predict the asset’s future performance and investment needs. Asset Health Index ratings and possible investment needs are:

Very Good	Normal maintenance
Good	Normal maintenance
Satisfactory	May require increased diagnostics and component replacement
Poor	Overhaul or replacement may be required within four to ten years
Very Poor	Overhaul or replacement may be required within three years

Asset Health Index can be grouped and analysed by asset class and/or criticality. Below are Asset Health Index for Transmission and Distribution asset classes as of March 2016:

Table S-1 Asset Health Index Summary

T&D Assets	Number of Assets	% of Asset
T&D Assets	3,983,628	
- Transmission	125,271	
- Substation	48,122	
- Distribution	3,810,235	

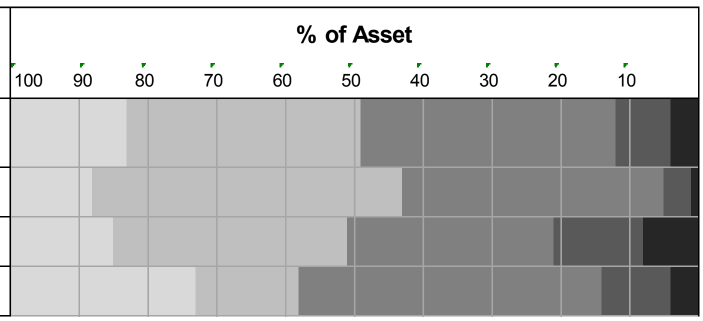


Table S-2 Asset Health Index for Transmission Lines Assets

All Transmission Assets	Number of Assets	% of Asset
All Transmission Assets	125,271	
1 - Metal Support Structures	23,084	
2 - Conductor Systems (km)	18,860	
3 - Wood Pole Structures	82,236	
4 - Underground Cables (km)	342	
5 - Line Disconnect Switches	430	
6 - Others	319	

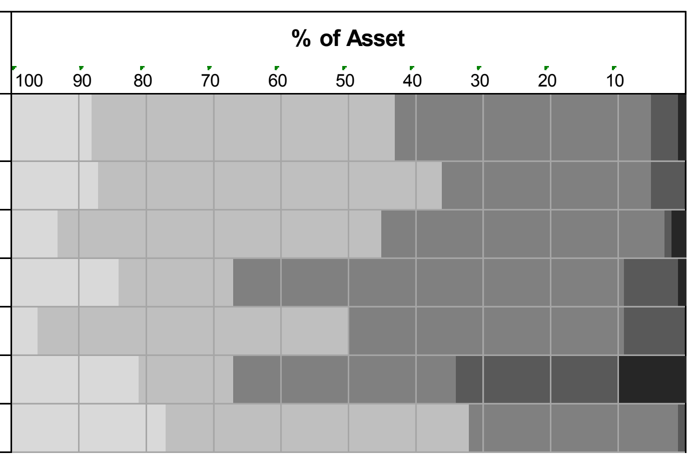


Table S-3 Asset Health Index for Substation Assets

All Substation Assets	Number of Assets
All Substation Assets	48,122
1 - Transformers	1,138
2 - Gas Insulated Switchgear	419
3 - Circuit Breakers	3,850
4 - Reactors	1,740
5 - Protection & Control Relay Systems	8,055
6 - Shunt Capacitors	417
7 - Disconnect Switches	13,722
8 - Instrument Transformers	8,343
9 - Series Capacitors	13
10 - HVDC Pole 2 (To be Obsolete)	1
11 - Surge Arrestors	5,840
12 - Synchronous Condensers	4
13 - Static VAR Compensator	5
14 - Station Insulators	435
15 - Standby Generators and Fuel Systems	76
16 - Batteries	325
17 - Mobile Transformers & Mobile Unit Substations	7
18 - Fire Protection Systems	132
19 - Voltage Regulators	375
20 - Others	3,225

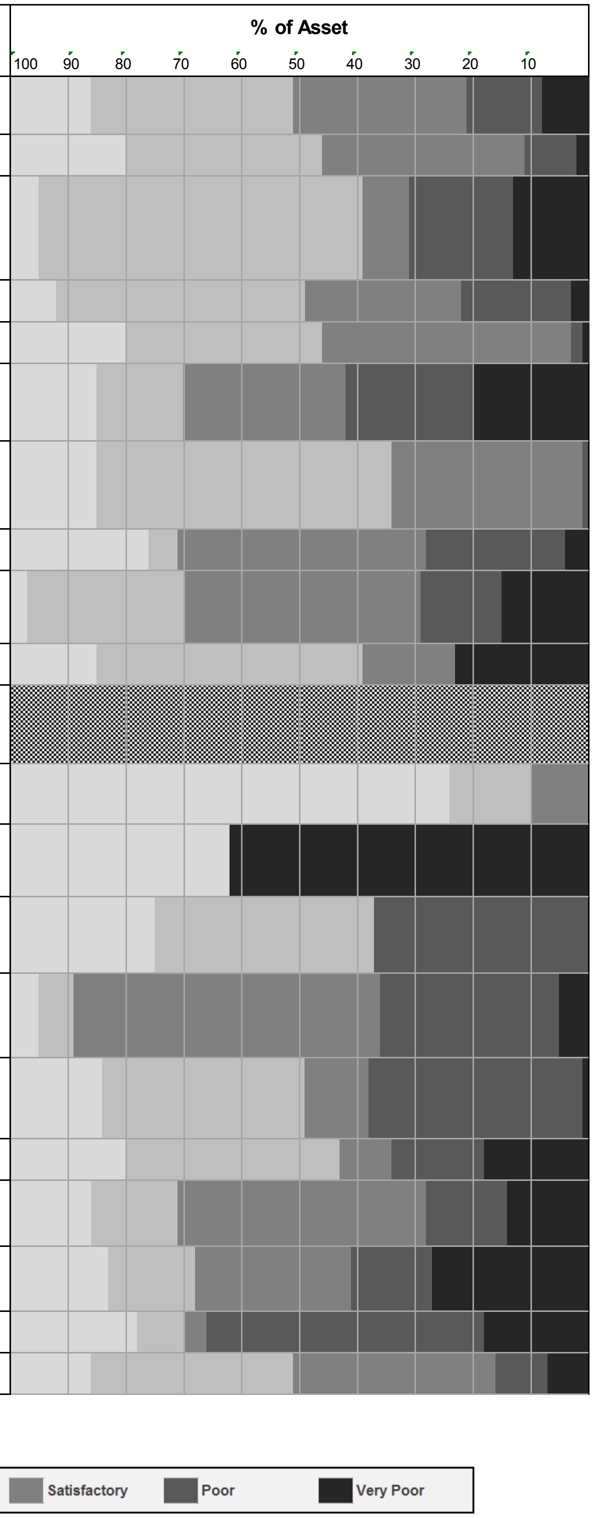
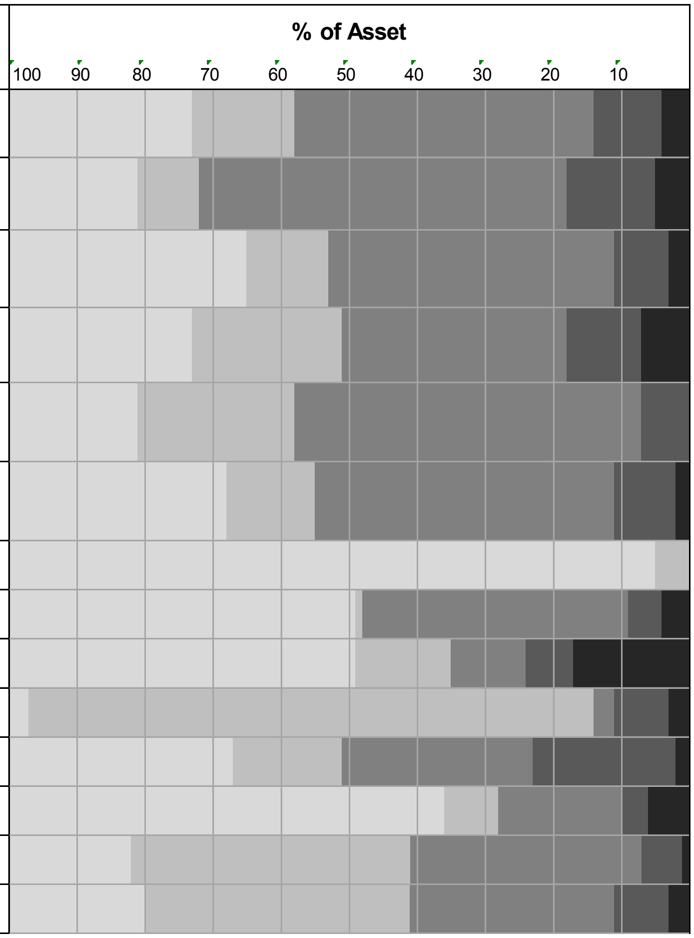


Table S-4 Asset Health Index for Distribution Assets

All Distribution Assets	Asset Count	% of Asset
All Distribution Assets	3,810,235	
1 - Distribution Poles	899,386	
2 - Underground Transformers	64,402	
3 - Overhead Transformers	280,751	
4 - Overhead Primary Conductors (km)	49,129	
5 - Underground Primary Cables (km)	10,489	
6 - Revenue Meters	1,956,750	
7 - Cutouts	403,383	
8 - Overhead Switches	11,007	
9 - Overhead Reclosers	2,152	
10 - Street Lights	91,493	
11 - Voltage Regulators	547	
12 - Capacitors	1,365	
13 - Others	39,381	



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Appendix T

Tariff Sheets

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List of Tables

Section 1 of this appendix provides a description of how the requested average rate increase will be applied to those customer rates in which the rate is not simply increased by the average rate increase, other than BC Hydro's Open Access Transmission Tariff rates which are the subject of Chapter 9 of the Application. Table 1 of section 2 of this appendix sets out the rates that will be applicable to each of the Rate Schedules in each rate class for fiscal 2017, and projections for fiscal 2018 and fiscal 2019. Attachments 1 and 2 provide clean and black-lined copies of the tariff pages with rates applicable as of April 1, 2016.

The requested average rate increases are 4.0 per cent in fiscal 2017, 3.5 per cent in fiscal 2018 and 3.0 per cent in fiscal 2019.

Section 2 contains fiscal 2017 rates which are effective April 1, 2016 on an interim and refundable basis. Rate changes shown in this section in regard to fiscal 2018 and fiscal 2019 are estimates and will be updated prior to April 1 for each applicable year. Fiscal 2016 rates are provided for reference.

Attachments 1 and 2 includes clean and black-lined copies of the tariff pages that will be applicable for fiscal 2017. BC Hydro has been granted approval of the fiscal 2017 rates on an interim and refundable basis by Commission Order No. G-40-16. The tariff pages assume that the interim fiscal 2017 rates are approved on a final basis. BC Hydro will be filing fiscal 2018 tariff sheets prior to April 1, 2017, and filing fiscal 2019 tariff sheets prior to April 1, 2018.

Attachment 3 explains and demonstrates in detail the calculation of the fiscal 2017 Residential Inclining Block (Rate Schedules 1101), Medium General Service (Rate Schedules 1500, 1501, 1510, 1511) and Large General Service (Rate Schedules 1600, 1601, 1610, 1611) rates in accordance with the applicable pricing principles.

1 Application of Rate Increases

1.1 Residential Rates

Rate Schedules 1101, 1121

Rate Schedules 1101 is the Residential Inclining Block rate, which is the default Residential rate. Rate Schedules 1121 is the Residential Inclining Block rate for Multiple Residential Service. The Residential Inclining Block rate structure is a two-step inclining block rate with the first step called the Step-1 energy rate and the amount above that the Step-2 energy rate. The Residential Inclining Block rate was implemented on October 1, 2008.

On September 24, 2015 BC Hydro filed its 2015 Rate Design Application which requested approval of ‘pricing principles’ for fiscal 2017 to fiscal 2019 for the Residential Inclining Block rate and that would be effective April 1, 2016. The term ‘pricing principles’ refers to how the revenue requirements application rate increases, which are set by the Commission through BC Hydro’s revenue requirements applications, are applied to each of the Residential Inclining Block rate’s pricing elements.

By Order No. G-13-14, the Commission approved pricing principles which uniformly increases the three pricing elements of the Residential Inclining Block rate by the amount of the approved Fiscal 2015/Fiscal 2016 Revenue Requirements Application rate increases. These Rate Schedules 1101 and Rate Schedules 1121 pricing principles expired on March 31, 2016. BC Hydro’s proposed Residential Inclining Block Pricing Principles for Rate Schedules 1101 and Rate Schedules 1121 for fiscal 2017 to fiscal 2019 is to continue with the Order No. G-13-14 pricing principles and accordingly is requesting approval of these pricing principles in the 2015 Rate Design Application Proceeding on a final basis.

BC Hydro uses its proposed 2015 Rate Design Application Residential Inclining Block Pricing Principles to derive the Residential Inclining Block rates shown in

Table 1 in section 2 below. Please refer to Attachment 3 which contains more detail on the Fiscal 2017 Residential Inclining Block rate calculation under the proposed pricing principle and also demonstrates that revenue neutrality is achieved.

Each of the three components of the Residential Inclining Block rate (Step-1 energy rate, Step-2 energy rate and Basic Charge) will increase by the amount of any approved general rate increase. The rates shown in Table 1 in section 2 and the tariff sheets in Attachments 1 and 2 have been calculated on the basis that the applied-for pricing principle is approved. The fiscal 2017 rates have been approved on an interim basis and if the Commission approves a different Residential Inclining Block pricing principle for fiscal 2017, BC Hydro will reflect this in final fiscal 2017 rates.

1.2 Commercial Rates

Rate Schedules 1300, 1301, 1310, 1311 (13XX) – Small General Service

The SGS rate includes a basic charge and a flat energy rate. BC Hydro has applied the requested average rate increases to both rate components to derive the fiscal 2017 to fiscal 2019 rates.

BC Hydro seeks approval in its 2015 Rate Design Application of a one-time increase to the Rate Schedules 13XX basic charge to 45 per cent recovery of customer-related costs attributable to the Small General Service class in the Fiscal 2016 Cost of Service study, and a one-time offsetting reduction of the energy rate, to maintain forecast revenue neutrality based on the Small General Service revenue target calculated using any applicable rate increases effective April 1, 2017. If approved by the Commission, BC Hydro will update fiscal 2018 Small General Service rates based on the new proposed rate design in its fiscal 2018 rate compliance filing.

Rate Schedules 1500, 1501, 1510, 1511 (15XX) – Medium General Service

The current Medium General Service rate is a two-part energy rate which was approved in 2010 pursuant to Commission Order No. G-110-10 as an outcome of the 2009 Large General Service Application Negotiated Settlement Agreement.

The Medium General Service demand charge, basic charge, and minimum energy rate are increased by the average rate increase.

The Medium General Service Part 1 energy rates comprise a higher Tier 1 rate applying to the last 14,800 kWh/month of baseline consumption and a lower Tier 2 rate applying to remaining baseline consumption.

Part 1 Energy Rates (Tier 1 and Tier 2):

The Medium General Service Part 1 Tier 1 rate is calculated residually in each year in order to maintain revenue neutrality for the class.

The calculations for the Medium General Service Part 1 Tier 1 and Tier 2 rates are based on prior years' billing data and forecast customer loads. The Part 1 rates shown for fiscal 2018 and fiscal 2019 are estimates that have been calculated for the 2015 Rate Design Application Status Quo Scenario. Please refer to BC Hydro's 2015 Rate Design Application Exhibit B-1, Appendix H-1A, Table H-1A-32 and Table H-1A-33 respectively. Updated Medium General Service rates for fiscal 2018 and fiscal 2019 will be provided in compliance filings prior to the start of the two fiscal years.[1]

[1] Note that the current rate structure could change starting in fiscal 2018. BC Hydro has applied in its 2015 Rate Design Application to amend rate structures for both Medium General Service and Large General Service rates. BC Hydro's proposed new Medium General Service and Large General Service rate structures consist of a flat energy rate, a flat demand charge, a basic charge and a monthly minimum charge effective April 1, 2017. BC Hydro also applied to eliminate Rate Schedules 26XX Large General Service for Distribution Utilities, effective at the same time. These rate design proposals are subject to Commission approval.

Part 2 Energy Rates:

In fiscal 2017, as per BCUC Order No. G-110-10, the long run marginal cost based Part 2 energy rate is increased by inflation, yielding a rate of 10.09 cents/kWh based on a 1.9 per cent inflation rate.

Please refer to the supporting Medium General Service documentation contained in Attachment 3 for the detailed derivation of the fiscal 2017 Medium General Service rates under the currently approved pricing principles and for demonstration that revenue neutrality is achieved.

Rate Schedules 1600, 1601, 1610, 1611 (16XX) – Large General Service

The current Large General Service rate is a two-part energy rate which was approved in 2010 pursuant to Commission Order No. G-110-10 as an outcome of the 2009 Large General Service Application Negotiated Settlement Agreement.

The Large General Service demand charge, basic charge and minimum energy rate are increased by the average rate increase.

The Large General Service energy rates have a two-part rate structure. The Part 1 rates have a declining block rate structure. The higher Tier 1 applies to the first 14,800 kWh/month of baseline consumption and the lower Tier 2 rate applies to all remaining monthly baseline consumption.

Part 1 Energy Rates (Tier 1 and Tier 2):

The Part 1 energy rates are calculated residually in order to maintain revenue neutrality for the class. The calculations for the Large General Service Part 1 Tier 1 and 2 rates are based on prior years' billing data and forecast customer loads. The Part 1 rates shown for fiscal 2018 and fiscal 2019 are estimates that have been calculated for the 2015 Rate Design Application Status Quo Scenario. Please refer to BC Hydro's 2015 Rate Design Application Exhibit B-1, Appendix H-1A, Table H-1A-20 and Table H-1A-21 respectively. Updated Large General Service rates for fiscal 2018 and fiscal 2019 will be provided in compliance filings prior to the start of the two fiscal years.[2]

Part 2 Energy Rate:

Please refer to Medium General Service Part 2 Energy Rate derivation explanation above, since the Large General Service and Medium General Service Part 2 Energy Rates are the same.

Please also refer to the supporting Large General Service documentation contained in Attachment 3 for the detailed derivation of the fiscal 2017 Large General Service rates under the currently approved pricing principles and for demonstration that revenue neutrality is achieved.

1.3 Transmission Service Rates

Rate Schedules 1823 – Transmission Service – Stepped Rate

The Rate Schedules 1823 pricing principles expired on March 31, 2016. BC Hydro applied for approval of Rate Schedules 1823 pricing principles for the period fiscal 2017 to fiscal 2019 in its 2015 Rate Design Application and uses these to derive the rates below. The fiscal 2017 Rate Schedules 1823 rates apply on an interim basis and if the Commission approves a different Rate Schedules 1823 pricing principle for fiscal 2017, BC Hydro will reflect this in final fiscal 2017 rates.

For fiscal 2017, the Tier 2 rate is set to the lower end of BC Hydro's energy long run marginal cost and the Tier 1 rate is set to reflect the 4.0 per cent RRA rate increase according to the bill neutrality approach i.e., 90 per cent of the Tier 1 rate plus 10 per cent of the Tier 2 rate is equal to the flat rate (Rate Schedules 1827 energy rate or the Rate Schedules 1823 Energy Charge A). The Tier 2 rate is 8.92 cents/kWh. The fiscal 2017 Tier 1 rate is calculated using the following formula,

[2] As noted in the previous footnote, the current Large General Service rate structure may change effective April 1, 2017 if BC Hydro's Medium General Service and Large General Service rate proposals in the 2015 Rate Design Application are approved by the Commission.

which uses the Rate Schedules 1827 – Transmission Service – Rate for Exempt Customers, as the “base rate”:

- The base rate in fiscal 2017 is the previous year rate increased by the average rate increase of 4.0 per cent = 4.475 cents/kWh
- Fiscal 2017 Tier 1 rate = (base rate - (10% x Tier 2 rate)) / 90%

  = (4.475 – (10% x 8.92)) / 90%

  = (4.475 – 0.892) / 90%

  = 3.981 cents/kWh

Other pricing elements (demand charge, energy rate applicable to Rate Schedules 1823 customers that do not have a Customer Baseline Load and monthly minimum charge) increase by the same applicable Fiscal 2017 Revenue Requirements Application rate increase.

For fiscal 2018 and fiscal 2019, each pricing element of Rate Schedules 1823 (Tier 1 energy rate, Tier 2 energy rate, demand charge, energy rate applicable to Rate Schedules 1823 customers that do not have a Customer Baseline Load and monthly minimum charge) will increase by the same RRA rate increase ordered by the Commission in regards to BC Hydro’s revenue requirements on April 1, 2017 and 2018. As noted above, the pricing principles for fiscal 2018 and fiscal 2019 are also subject to Commission approval as part of the 2015 Rate Design Application.

Rate Schedules 1825 – Transmission Service – Time of Use Rate

The Transmission Service – Time of Use Rate (Rate Schedules 1825) has four seasonal Customer Baseline Load pricing periods. The Rate Schedules 1825 Tier 2 rate is equal to the Rate Schedules 1823 Tier 2 rate on an annual weighted average basis. Seasonal prices for the Rate Schedules 1825 Tier 2 rate are shaped by month and weighted into High Load Hours and Low Load Hours periods to calculate the average price for each season. The Tier 1 rate is equal to the Rate Schedules 1823

Tier 1 rate for all seasonal Customer Baseline Load pricing periods. When the Tier 1 and Tier 2 rates are weighted by the number of hours in the year, and blended on a 90/10 basis, the annual overall weighted average energy price under Rate Schedules 1825 is equal to the Rate Schedules 1827 “base rate”.

Rate Schedules 1880 – Transmission Service – Standby and Maintenance

The Rate Schedules 1880 energy charge is tied to the Rate Schedules 1823 Tier 2 energy rate, which is based on the long run marginal cost. As described above, BC Hydro proposes the Rate Schedules 1823 Tier 2 energy rate to be 8.92 cents/kWh in fiscal 2017.

2 Summary of Fiscal 2017, Fiscal 2018 and Fiscal 2019 Rates

The following table provides the rates in each BC Hydro rate schedule for fiscal 2017, and illustrative rate projections for fiscal 2018 and fiscal 2019, assuming the requested rate increases in this revenue requirements application are approved as filed. As discussed above, some of these rates are subject to change as they are also dependent on the outcome of BC Hydro's 2015 Rate Design Application. Fiscal 2016 rates are provided for reference.

Table 1 Fiscal 2016 to Fiscal 2019 Rates

Rate Class	Rate Schedule	Rate	F2016	F2017	F2018	F2019
				Rate Increase 4.00%	Rate Increase 3.50%	Rate Increase 3.00%
Residential	1101/1121	Basic Charge ($/day)	0.1764	0.1835	0.1899	0.1956
		Step-1 energy rate ($/kWh)	0.0797	0.0829	0.0858	0.0884
		Step-2 energy rate ($/kWh)	0.1195	0.1243	0.1287	0.1326
Residential	1105 (closed)	Energy rate ($/kWh)	0.0522	0.0543	0.0562	0.0579
		Energy rate during period of interruption ($/kWh)	0.3037	0.3158	0.3269	0.3367
Residential Zone II	1107/1127	Basic Charge ($/day)	0.1882	0.1957	0.2025	0.2086
		Step-1 energy rate ($/kWh)	0.0955	0.0993	0.1028	0.1059
		Step-2 energy rate ($/kWh)	0.1641	0.1707	0.1767	0.182
Residential	1148 (closed)	Basic Charge ($/day)	0.1882	0.1957	0.2025	0.2086
		Energy rate $/kWh	0.0955	0.0993	0.1028	0.1059
Residential	1151/1161	Basic Charge ($/day)	0.1882	0.1957	0.2025	0.2086
		Energy rate $/kWh	0.0955	0.0993	0.1028	0.1059

Rate Class	Rate Schedule	Rate	F2016	F2017	F2018	F2019
				Rate Increase 4.00%	Rate Increase 3.50%	Rate Increase 3.00%
Exempt General Service	1200/1201/1210/1211	Basic Charge ($/day)	0.2257	0.2347	0.2429	0.2502
		Demand rate - Step-1 ($/kW)	0	0	0	0
		Demand rate - Step-2 ($/kW)	5.50	5.72	5.92	6.10
		Demand rate - Step-3 ($/kW)	10.55	10.97	11.35	11.69
		Energy Rate - Tier 1 ($/kWh)	0.1073	0.1116	0.1155	0.119
		Energy Rate - Tier 2 ($/kWh)	0.0515	0.0536	0.0555	0.0572
General Service	1205/1206/1207	Energy Rate - Tier 1 ($/kWh)	0.0522	0.0543	0.0562	0.0579
		Energy Rate - Tier 2 ($/kWh)	0.0342	0.0356	0.0368	0.0379
		Energy rate during period of interruption ($/kWh)	0.3037	0.3158	0.3269	0.3367
Small General Service Zone II	1234	Basic Charge ($/day)	0.2257	0.2347	0.2429	0.2502
		Energy Rate - Tier 1 ($/kWh)	0.1073	0.1116	0.1155	0.119
		Energy Rate - Tier 2 ($/kWh)	0.1787	0.1858	0.1923	0.1981
Distribution Service	1253	Monthly Minimum energy charge($/month)	41.37	43.02	44.53	45.87
Large General Service Zone II	1255/1256/1265/1266	Basic Charge ($/day)	0.2257	0.2347	0.2429	0.2502
		Energy Rate - Tier 1 ($/kWh)	0.1073	0.1116	0.1155	0.119
		Energy Rate - Tier 2 ($/kWh)	0.1787	0.1858	0.1923	0.1981

Rate Class	Rate Schedule	Rate	F2016	F2017	F2018	F2019
				Rate Increase 4.00%	Rate Increase 3.50%	Rate Increase 3.00%
Distribution Service	1268	Energy charge ($/kWh)	0.00166	0.00173	0.00179	0.00184
Power Service	1278 (closed)	$/kVA	2.678	2.785	2.882	2.968
		Energy charge $/kWh	0.07	0.0728	0.07535	0.07761
		Monthly minimum greater of $/kVa	5.23	5.44	5.63	5.80
		or ($)	10460.76	10879.19	11259.96	11597.76
Shore Power Service (Distribution)	1280	Monthly Charge ($/month)		150	150	150
		Energy Rate ($/kWh)		0.09227	0.09550	0.09836
Net Metering Service	1289	Energy Rate $/kWh	0.0999	0.0999	0.0999	0.0999
Small General Service	1300/1301/1310/1311	Basic Charge ($/day)	0.2257	0.2347	0.2429	0.2502
		Energy Rate $/kWh	0.1073	0.1116	0.1155	0.119
Irrigation	1401	Irrigation season energy rate ($/kWh)	0.0516	0.0537	0.0556	0.0573
		Non-irrigation season energy rate - Tier 1 ($/kWh)	0.0516	0.0537	0.0556	0.0573
		Non-irrigation season energy rate - Tier 2 ($/kWh)	0.4096	0.4260	0.4409	0.4541
		Minimum charge irrigation season $/kW	5.16	5.37	5.56	5.73
		Minimum charge non-irrigation season if consumption >500 kWh ($ per kW)	41.32	42.97	44.47	45.80

Rate Class	Rate Schedule	Rate	F2016	F2017	F2018	F2019
				Rate Increase 4.00%	Rate Increase 3.50%	Rate Increase 3.00%
Medium General Service	1500/1501/1510/1511	Basic Charge ($/day)	0.2257	0.2347	0.2429	0.2502
		Demand rate - Step-1 ($/kW)	0.00	0.00	0.00	0.00
		Demand rate - Step-2 ($/kW)	5.50	5.72	5.92	6.10
		Demand rate - Step-3 ($/kW)	10.55	10.97	11.35	11.69
		Part 1 Energy rate - Tier 1 ($/kWh)	0.0989	0.1030	0.1074	0.1112
		Part 1 Energy rate - Tier 2 ($/kWh)	0.0690	0.0719	0.0749	0.0776
		Part 2 Energy rate ($/kWh)	0.0990	0.1009	0.1030	0.1051
		Minimum Energy Rate ($/kWh)	0.0330	0.0343	0.0355	0.0366
Large General Service	1600/1601/1610/1611	Basic Charge ($/day)	0.2257	0.2347	0.2429	0.2502
		Demand rate - Step-1 ($/kW)	0.00	0.00	0.00	0.00
		Demand rate - Step-2 ($/kW)	5.50	5.72	5.92	6.10
		Demand rate - Step-3 ($/kW)	10.55	10.97	11.35	11.69
		Part 1 Energy rate - Tier 1 ($/kWh)	0.1066	0.1114	0.1164	0.1218
		Part 1 Energy rate - Tier 2 ($/kWh)	0.0513	0.0536	0.0560	0.0587
		Part 2 Energy rate ($/kWh)	0.0990	0.1009	0.1030	0.1051
		Minimum Energy rate ($/kWh)	0.0330	0.0343	0.0355	0.0366

Rate Class	Rate Schedule	Rate	F2016	F2017	F2018	F2019
				Rate Increase 4.00%	Rate Increase 3.50%	Rate Increase 3.00%
Large General Service (150 KW and over) for Distribution Utilities	2600/2601/2610/2611	Basic Charge ($/day)	0.2257	0.2347	0.2429	0.2502
		Demand rate - Step-1 ($/kW)	0.00	0.00	0.00	0.00
		Demand rate - Step-2 ($/kW)	5.50	5.72	5.92	6.10
		Demand rate - Step-3 ($/kW)	10.55	10.97	11.35	11.69
		Part 2 Energy Rate ($/kWh) (RS1600 rate)	0.0990	0.1009	0.1030	0.1051
		Embedded Cost Rate ($/kWh)	0.0531	0.0552	0.0571	0.0588
		Discount ($/kWh)	-0.0039	-0.0041	-0.0042	-0.0043
Street Lighting	1701	100 SV fixture rate ($/month)	16.55	17.21	17.81	18.34
		150 SV fixture ($/month)	19.73	20.52	21.24	21.88
		200 SV fixture ($/month)	22.78	23.69	24.52	25.26
		175 MV fixture ($/month)	18.18	18.91	19.57	20.16
		250 MV fixture ($/month)	20.95	21.79	22.55	23.23
		400 MV fixture ($/month)	27.01	28.09	29.07	29.94
Street Lighting	1702	Each Unmetered fixture ($/watt per month)	0.0318	0.0331	0.0343	0.0353
		Each Metered fixture ($/kWh)	0.0955	0.0993	0.1028	0.1059

Rate Class	Rate Schedule	Rate	F2016	F2017	F2018	F2019
				Rate Increase 4.00%	Rate Increase 3.50%	Rate Increase 3.00%
Street Lighting	1703	Energy rate ($/watt per month)	0.0318	0.0331	0.0343	0.0353
		Contact rate ($/contact per month)	0.96	0.9984	1.0333	1.0643
Street Lighting	1704	Energy rate $/kWh	0.0955	0.0993	0.1028	0.1059
Street Lighting	1755 (closed)	1. Pole owned by Customer				
		175 MV or 100 SV fixture charge ($ per month)	15.51	16.13	16.69	17.19
		400 MV or 150 SV fixture charge ($ per month)	26.73	27.80	28.77	29.63
		2. Pole on public property				
		175 MV or 100 SV fixture charge ($ per month)	16.47	17.13	17.73	18.26
		400 MV or 150 SV fixture charge ($ per month)	27.70	28.81	29.82	30.71
		3. Pole paid by BC Hydro				
		175 MV or 100 SV fixture charge ($ per month)	20.28	21.09	21.83	22.48
		400 MV or 150 SV fixture charge ($ per month)	31.92	33.20	34.36	35.39

Rate Class	Rate Schedule	Rate	F2016	F2017	F2018	F2019
				Rate Increase 4.00%	Rate Increase 3.50%	Rate Increase 3.00%
Transmission Service	1823	Demand rate ($/kVA)	7.341	7.635	7.902	8.139
		Energy rate A ($/kWh)	0.04303	0.04475	0.04632	0.04771
		Energy rate B - Tier 1 ($/kWh)	0.03836	0.03981	0.04120	0.04244
		Energy rate B - Tier 2 ($/kWh)	0.08503	0.0892	0.09232	0.09509
		Minimum demand ($/kVA)	7.341	7.635	7.902	8.139
Transmission Service	1825	Demand rate ($/kVA)	7.341	7.635	7.902	8.139
		Winter HLH energy rate (below 90%) ($/kWh)	0.03836	0.03981	0.04120	0.04244
		Winter HLH energy rate (above 90%) ($/kWh)	0.09489	0.09953	0.10299	0.10611
		Winter LLH energy rate (below 90%) ($/kWh)	0.03836	0.03981	0.04120	0.04244
		Winter LLH energy rate (above 90%) ($/kWh)	0.08600	0.09021	0.09334	0.09616
		Spring energy rate (below 90%) ($/kWh)	0.03836	0.03981	0.04120	0.04244
		Spring energy rate (above 90%) ($/kWh)	0.07660	0.08034	0.08313	0.08565
		Remaining energy rate (below 90%) ($/kWh)	0.03836	0.03981	0.04120	0.04244
		Remaining energy rate (above 90%) ($/kWh)	0.08398	0.08810	0.09116	0.09392

Rate Class	Rate Schedule	Rate	F2016	F2017	F2018	F2019
				Rate Increase 4.00%	Rate Increase 3.50%	Rate Increase 3.00%
Transmission Service	1827	Demand rate ($/kVA)	7.341	7.635	7.902	8.139
		Energy rate ($/kWh)	0.04303	0.04475	0.04632	0.04771
		Minimum demand ($/kVA)	7.341	7.635	7.902	8.139
Transmission Service	1852	Excess Demand rate ($/kVA)	7.341	7.635	7.902	8.139
Transmission Service	1853	Minimum Monthly Charge ($/month)	41.37	43.02	44.53	45.87
Transmission Service	1880	Administrative Charge per Period of Use ($)	150.00	150.00	150.00	150.00
		Energy Rate ($/kWh)	0.08503	0.0892	0.09232	0.09509
Shore Power Service (Transmission)	1891	Monthly Charge ($/month)		150	150	150
		Energy Rate ($/kWh)		0.0892	0.09232	0.09509
Transmission Service FortisBC	3808	Demand rate ($/kW)	7.341	7.635	7.902	8.139
		Energy rate - tranche 1 ($/kWh)	0.04303	0.04475	0.04632	0.04771
		Energy rate – tranche 2 ($/kWh)	0.12970	0.12970	0.12970	0.12970

OATT Rates **Refer to Chapter 9 for an Explanation of these Rates**			F2016	F2017	F2018	F2019
Network Integration Transmission Service Revenue Requirement	Attachment H	($)	744,750,000	~~823,300,000~~ 823,100,000	~~821,500,000~~ 823,000,000	~~842,000,000~~ 843,400,000

Rate Schedule		Rate	F2016	F2017	F2018	F2019
NITS Monthly Rate	RS 00	NITS monthly rate ($/month)	62,062,500	~~68,608,333~~ 68,591,667	~~68,458,333~~ 68,583,333	~~70,166,667~~ 70,283,333
Long-Term Firm Point-To-Point Transmission Service	RS 01	Yearly - $/MW of Reserved Capacity per year ($/MW/Year)	64,968	~~70,687~~ 70,993	~~71,738~~ 70,213	~~73,397~~ 72,032
Short-Term Firm and Non-Firm Point-To-Point Transmission Service	RS 01	Monthly - $/MW of Reserved Capacity per month ($/MW/month)	5,413.99	~~5,890.60~~ 5,916.10	~~5,978.14~~ 5,851.07	~~6,116.40~~ 6,002.66
		Weekly - $/MW of Reserved Capacity per week ($/MW/week)	1,249.38	~~1,359.37~~ 1,365.25	~~1,379.57~~ 1,350.25	~~1,411.48~~ 1,385.23
		Daily- $/MW of Reserved Capacity per day ($/MW/day)	177.99	~~193.66~~ 194.50	~~196.54~~ 192.36	~~201.09~~ 197.35
		Hourly - $/MW of Reserved Capacity per hour ($/MW/hour)	7.42	~~8.07~~ 8.10	~~8.19~~ 8.02	~~8.38~~ 8.22
Scheduling, System Control & Dispatch Service	RS 03	$ per MW of Reserved Capacity per hour	0.099	0.105	0.099	0.099

Fiscal F2017 to Fiscal 2019

Revenue Requirements Application

Appendix T

Attachment 1

Tariff Sheets

Clean

SCHEDULE 1101, 1121 – RESIDENTIAL SERVICE

Availability: For Residential Service. Service is normally single phase, 60 hertz at the secondary potential available. In BC Hydro's discretion, service may be three phase 120/208 or 240 volts.

Applicable in: Rate Zone I.

Rate: 1. Schedule 1101 - Residential Service

Basic Charge 18.35¢ per day

Energy Charge

A. For customers billed monthly

Step 1 – First 675 kW.h per month @ 8.29 cents/kW.h

Step 2 – Additional kW.h per month @ 12.43 cents/kW.h

B. For customers billed bi-monthly

Step 1 – First 1350 kW.h per two months @ 8.29 cents/kW.h

Step 2 – Additional kW.h per two months @ 12.43 cents/kW.h

Note: For billing purposes. Step 1 is pro-rated on a daily basis.

2. Schedule 1121 - Multiple Residential Service

Basic Charge 18.35¢ per Single-Family Dwelling per day

Energy Charge – Per Single Family Dwelling

A. For Customers billed monthly

Step 1 – First 675 kW.h. per month @ 8.29 cents/kW.h

Step 2 – Additional KW.h per month @ 12.43 cents/kW.h

B. For Customers billed bi-monthly

Step 1 – First 1350 kW.h per two months @ 8.29 cents/kW.h

Step 2 – Additional kW.h per two months @ 12.43 cents/kW.h

Note: For billing purposes, Step 1 is pro-rated on a daily basis

Minimum Charge: Schedule 1101 - The Basic Charge.

Schedule 1121 - The Basic Charge per Single-Family Dwelling.

ACCEPTED: April 6, 2016

ORDER NO. G-40-16

L Ross
ACTING COMMISSION SECRETARY

Special <u>Conditions:</u>	1. The maximum capacity of all heating elements energized at any one time in any water heater served under this schedule shall not exceed the greater of 1,500 watts or 45 watts per litre (200 watts per imperial gallon) of tank capacity, except with the written permission of BC Hydro. 2. Schedule 1121 applies if the Premises contain more than two Single-Family Dwellings. A discount of 25¢ per month per kW of maximum demand shall be applied to Schedule 1121 if a Customer supplies the transformation from a primary potential to a secondary potential. BC Hydro will install a demand meter in addition to a kilowatt hour meter. BC Hydro will install its meters at the secondary potential. The Billing Code for Schedule 1121 Customers eligible for the Discount for Ownership of Transformers shall be Schedule 1122.
<u>Rate Rider</u>:	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.
<u>Rate Increase</u>:	Effective April 1, 2016 the Rates and Minimum Charge under these schedules include an increase of 4.00% before rounding, approved by BCUC Order No. G-XX-XX.

SCHEDULE 1105 – RESIDENTIAL SERVICE – DUAL FUEL (CLOSED)

Availability:	For residential space heating and water heating upon an interruptible basis. Electricity purchased under this rate schedule will be separately metered. Service is single phase, 60 hertz, at 120/240 or 240 volts. This schedule is available only in Premises served under this schedule on 15 January 1990 and continuously thereafter, only with respect to equipment served under this schedule on 15 January 1990 and continuously thereafter, and only in Premises where there has been no change in Customer since April 1, 2008.
Applicable in:	Rate Zone I in areas where, in BC Hydro's opinion, BC Hydro's transmission, sub-transmission and distribution circuit feeders are or will be capable of handling the added load.
Rate:	Except as stated hereunder, the rate shall be: 5.43¢ per kW.h Exception: If during a Period of Interruption a customer has failed to comply with BC Hydro’s requirement to cease the use of electricity and BC Hydro, in its sole discretion, continues to supply electricity, the rate for such electricity shall be: 31.58¢ per kW.h
Period of Interruption:	A period during which a customer is required by BC Hydro to cease the use of electricity under this rate schedule.

ACCEPTED: April 6, 2016

ORDER NO. G-40-16

L Ross
ACTING COMMISSION SECRETARY

5. BC Hydro will upgrade an existing service connection supplying firm load to serve additional load under this rate schedule. The charge for upgrading will be the same as applicable to a new service connection.
6. No other load than that stipulated in the Availability clause is permitted under this rate schedule. Any unauthorized use of electricity or any refusal by a customer to permit Access to Premises in accordance with the Terms and Conditions of BC Hydro's Electric Tariff will result in the immediate disconnection of the service and all unauthorized consumption as estimated by BC Hydro shall be billed at the rate for electricity during a Period of Interruption as stated in this rate schedule.
7. In addition to and without restriction of any other limitations of liability of BC Hydro, BC Hydro shall specifically not be liable for any loss, damage, injury or expense occasioned to or suffered by any customer receiving service on this rate schedule, or by any other person, for or by reason of any interruption of electricity supply whatsoever for any reason whatsoever.
8. The maximum capacity of all heating elements energized at any one time in any water heater served under this schedule shall not exceed the greater of 1,500 watts or 45 watts per litre (200 watts per imperial gallon) of tank capacity, except with the written permission of BC Hydro
9. At the conclusion of any Period of Interruption, BC Hydro may terminate service under this rate schedule to any customer who used electricity during a Period of Interruption, unless it can be demonstrated to BC Hydro's satisfaction that adequate standby facilities exist.

<u>Rate Rider:</u> The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.

<u>Rate Increase</u>: Effective April 1, 2016 the Rates and Minimum Charge under these schedules include an increase of 4.00% before rounding, approved by BCUC Order No. G-XX-XX.

ACCEPTED:____________________________

ORDER NO.____________________________

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ACTING COMMISSION SECRETARY

SCHEDULE 1107, 1127 – RESIDENTIAL SERVICE – ZONE II

Availability: For Residential Service. Service is normally single phase, 60 hertz at the secondary potential available. In BC Hydro's discretion, service may be three phase 120/208 or 240 volts.

Applicable in: Rate Zone II.

Rate:

1. Schedule 1107 - Residential Service

   Basic Charge 19.57 ¢ per day

First 1500 kW.h	per month	@	9.93 ¢ per kW.h
All additional kW.h	per month	@	17.07 ¢ per kW.h.

2. Schedule 1127 - Multiple Residential Service

Basic Charge 19.57 ¢	per single-family dwelling per day		
First 1500 kW.h	per single-family dwelling per month		
		@	9.93 ¢ per kW.h
All additional kW.h	per month	@	17.07 ¢ per kW.h.

Minimum Charge: Schedule 1107 - The Basic Charge.

Schedule 1127 - The Basic Charge per Single-Family Dwelling.

Special Conditions:

1. The maximum capacity of all heating elements energized at any one time in any water heater served under this schedule shall not exceed the greater of 1,500 watts or 45 watts per litre (200 watts per imperial gallon) of tank capacity, except with the written permission of BC Hydro.
2. Schedule 1127 applies if the Premises contain more than two Single-Family Dwellings.

Discount for Ownership of Transformers: A discount of 25¢ per month per kW of maximum demand shall be applied to Schedule 1127 if a Customer supplies the transformation from a primary potential to a secondary potential. BC Hydro will install a demand meter in addition to a kilowatt hour meter. BC Hydro will install its meters at the secondary potential. The Billing Code for Schedule 1127 Customers eligible for the Discount for Ownership of Transformers shall be Schedule 1128.

Rate Rider: The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.

Rate Increase: Effective April 1, 2016 the Rates and Minimum Charge under these schedules include an increase of 4.00% before rounding, approved by BCUC Order No. G-XX-XX.

ACCEPTED:__________________________

ORDER NO.__________________________

ACTING COMMISSION SECRETARY

SCHEDULE 1148 – RESIDENTIAL SERVICE – ZONE II (CLOSED)

Availability: For Residential Service in Rate Zone II where a permanent electric space heating system is in use, providing the aforesaid system was installed prior to 10 October 1966.

This schedule is available only to a Customer and Premises served under this rate schedule on 24 April 1992 and continuously thereafter.

Applicable in: Rate Zone II.

Rate: Basic Charge 19.57 ¢ per day

All kW.h @ 9.93 ¢ per kW.h.

Minimum Charge: The Basic Charge.

Special Condition: The maximum capacity of all heating elements energized at any one time in any water heater served under this schedule shall not exceed the greater of 1,500 watts or 45 watts per litre (200 watts per imperial gallon) of tank capacity, except with the written permission of BC Hydro.

Rate Rider: The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.

Rate Increase: Effective April 1, 2016 the Rates and Minimum Charge under these schedules include an increase of 4.00% before rounding, approved by BCUC Order No. G-XX-XX.

ACCEPTED:______________________

ORDER NO.______________________

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ACTING COMMISSION SECRETARY

SCHEDULE 1151, 1161 - EXEMPT RESIDENTIAL SERVICE

Availability: For residential service and uses exempted from rate schedules 1101 and 1121, including:

1. Use upon farms as referenced in the definition of Residential Service.
2. Residential service Customers in Rate Zone IB.

Service is normally single phase, 60 hertz at the secondary potential available. In BC Hydro's discretion, service may be three phase 120/208 or 240 volts.

Applicable in: Rate Zone I and Rate Zone IB

Rate:

1. Schedule 1151 – Residential Service

   Basic Charge 19.57¢ per day

   All kW.h @ 9.93¢ per kW.h

2. Schedule 1161 – Multiple Residential Service

   Basic Charge 19.57¢ per day per Single-Family Dwelling per day

   All kW.h @ 9.93¢ per kW.h

Minimum Charge: Schedule 1151 - The Basic Charge.

Schedule 1161 – The Basic Charge per Single-Family Dwelling

Special Conditions: The maximum capacity of all heating elements energized at any one time in any water heater served under this schedule shall not exceed the greater of 1,500 watts or 45 watts per litre (200 watts per imperial gallon) of tank capacity, except with the written permission of BC Hydro.

ACCEPTED: April 6, 2016

ORDER NO. G-40-16

L Ross
ACTING COMMISSION SECRETARY

Discount for Ownership of Transformers: A discount of 25¢ per month per kW of maximum demand shall be applied to Schedule 1161 if a Customer supplies the transformation from a primary potential to a secondary potential. BC Hydro will install a demand meter in addition to a kilowatt hour meter. BC Hydro will install its meters at the secondary potential. The Billing Code for Schedule 1161 Customers eligible for the Discount for Ownership of Transformers shall be Schedule 1162.

Rate Rider: The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.

Rate Increase: Effective April 1, 2016 the Rates and Minimum Charge under these schedules include an increase of 4.00% before rounding, approved by BCUC Order No. G-XX-XX.

ACCEPTED:______________________

ORDER NO.______________________

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ACTING COMMISSION SECRETARY

SCHEDULE 1200, 1201, 1210, 1211 – EXEMPT GENERAL SERVICE (35 KW AND OVER)

Availability: For Customers who qualify for General Service and who are enrolled in BC Hydro's Medium General Service (MGS) or Large General Service (LGS) control groups and customers in Rate Zone 1B. A Customer who ceases to be enrolled in a MGS or the LGS control group shall revert to service under the applicable MGS rate schedule or LGS rate schedule. Supply is 60 hertz, single or three phase at secondary or primary potential. BC Hydro reserves the right to determine the potential of the service connection.

Applicable in: Rate Zone I and Rate Zone IB.

Rate: Basic Charge
23.47 ¢ per day

Demand Charge

First 35 kW of Billing Demand per Billing Period	@ $0.00 per kW
Next 115 kW of Billing Demand per Billing Period	@ $5.72 per kW
All additional kW of Billing Demand per Billing Period	@ $10.97 per kW

Energy Charge

First 14800 kW.h of energy consumption in the Billing Period
@ 11.16 ¢ per kW.h

All additional kW.h of energy consumption in the Billing Period
@ 5.36 ¢ per kW.h

Discounts

1. A discount of 1½% shall be applied to the above charges if a Customer's supply of electricity is metered at a primary potential.
2. A discount of 25¢ per billing period per kW of billing demand shall be applied to the above charges if a Customer supplies transformation from a primary potential to a secondary potential.
3. If a Customer is entitled to both of the above discounts, the discount for metering at a primary potential shall be applied first.

ACCEPTED: April 6, 2016

ORDER NO. G-40-16

L Ross
ACTING COMMISSION SECRETARY

Billing Codes:	Schedule 1200	applies if a Customer's supply of electricity is metered at a secondary potential and BC Hydro supplies transformation from a primary potential to a secondary potential.
	Schedule 1201	applies if a Customer's supply of electricity is metered at a primary potential and BC Hydro supplies transformation from a primary potential to a secondary potential.
	Schedule 1210	applies if a Customer's supply of electricity is metered at a secondary potential and the Customer supplies transformation from a primary potential to a secondary potential.
	Schedule 1211	applies if a Customer's supply of electricity is metered at a primary potential and the Customer supplies transformation from a primary potential to a secondary potential.

Billing Demand: The Billing Demand shall be the highest kW demand in the Billing Period.

Billing Period: "Billing Period" means a period of 27 to 33 consecutive days between regular meter readings, provided that in cases where meter readings are not available or are delayed for any reason BC Hydro may vary the number of days in the Billing Period.

Monthly Minimum Charge: 50% of the highest maximum demand charge billed in any billing period wholly within an on-peak period during the immediately preceding eleven billing periods. For the purpose of this provision an on-peak period commences on 1 November in any year and terminates on 31 March of the following year.

Special Condition:

1. A demand meter will normally be installed. Prior to the installation of such a meter, or if such a meter is not installed, the demand for billing purposes shall be the assessed demand estimated by BC Hydro.
2. Migration rule (between Exempt General Service and Small General Service): Customers taking service at Exempt General Service rates (Rate Schedules 1200, 1201, 1210 or 1211) will be moved to service at Small General Service rates (Rate Schedules 1300, 1301, 1310 or 1311) if the Customers' Billing Demand in each of the 12 most recent consecutive Billing Periods was less than 35 kW.

Rate Rider: The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.

Rate Increase: Effective April 1, 2016 the Rates and Minimum Charge under these schedules include an increase of 4.00% before rounding, approved by BCUC Order No. G-XX-XX.

ACCEPTED:____________________

ORDER NO.____________________

ACTING COMMISSION SECRETARY

SCHEDULE 1205, 1206, 1207 – GENERAL SERVICE – DUAL FUEL (CLOSED)

Availability: For general space heating, water heating and industrial process heating upon an interruptible basis.

Electricity purchased under these rate schedules will be separately metered. Service is 60 hertz single or three phase at the secondary or primary potential available. BC Hydro reserves the right to determine the potential of the service connection.

This schedule is available only in Premises served under this schedule on 15 January 1990 and continuously thereafter, only with respect to equipment served under this schedule on 15 January 1990 and continuously thereafter, and only in Premises where there has been no change in Customer since April 1, 2008.

Applicable in: Rate Zone I in areas where, in BC Hydro's opinion, BC Hydro's transmission, sub-transmission and distribution circuit feeders are or will be capable of handling the added load.

Rate: Except as stated hereunder the rate shall be:

First 8000	kW.h per month @ 5.43 ¢ per kW.h
All additional	kW.h per month @ 3.56 ¢ per kW.h

Exception: If during a Period of Interruption a customer has failed to comply with BC Hydro's requirement to cease the use of electricity and BC Hydro, in its sole discretion, continues to supply electricity, the rate for such electricity shall be:

31.58 ¢ per kW.h

Period of Interruption: A period during which a customer is required by BC Hydro to cease the use of electricity under these rate schedules.

ACCEPTED: April 6, 2016

ORDER NO. G-40-16

L Ross
ACTING COMMISSION SECRETARY

the Terms and Conditions of BC Hydro's Electric Tariff will result in the immediate disconnection of the service and all unauthorized consumption as estimated by BC Hydro shall be billed at the rate for electricity during a Period of Interruption as stated in these rate schedules.

9. In addition to and without restriction of any other limitations of liability of BC Hydro, BC Hydro shall specifically not be liable for any loss, damage, injury or expense occasioned to or suffered by any customer receiving service on these rate schedules, or by any other person, for or by reason of any interruption of electricity supply whatsoever for any reason whatsoever.
10. A customer who signs a contract with BC Hydro for the supply of electricity to new load under these rate schedules during the period commencing 1 July 1988 and ending 31 December 1988 shall be eligible to receive an incentive rebate on his electricity bills provided the customer begins taking service under these rate schedules no later than twelve months following the date the contract was signed.
11. A rebate shall be applied to reduce the effective rate to 1.1 ¢ per kW.h. Such rebate will apply only to an accumulated maximum of $30.00 per kW of connected new load in excess of 35 kW and only up to the first two years following connection. Bills for energy consumed shall be calculated and presented at full rates with the rebate for any given period applied to the following bill. The maximum two year period of billing rebates shall be extended by the equivalent of any Period of Interruption. Rebates shall not be applied to reduce the rate applicable for consumption during a Period of Interruption, nor shall rebates be applied to reduce power factor surcharges.
12. At the conclusion of any Period of Interruption, BC Hydro may terminate service under these rate schedules to any customer who used electricity during a Period of Interruption, unless it can be demonstrated to BC Hydro's satisfaction that adequate standby facilities exist.

Rate Rider: The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.

Rate Increase: Effective April 1, 2016 the Rates and Minimum Charge under these schedules include an increase of 4.00% before rounding, approved by BCUC Order No. G-XX-XX.

ACCEPTED:__________________________

ORDER NO.__________________________

ACTING COMMISSION SECRETARY

SCHEDULE 1234 – SMALL GENERAL SERVICE (UNDER 35 KW) – ZONE II

Availability:	For all purposes where a demand meter is not installed because the Customer's demand as estimated by BC Hydro is less than 35 kW. Supply is 60 hertz, single or three phase at an available secondary potential.
Applicable in:	Rate Zone II.
Rate:	Basic Charge 23.47 ¢ per day First 7000 kW.h per month @ 11.16 ¢ per kW.h All additional kW.h per month @ 18.58 ¢ per kW.h
Minimum Charge:	The Basic Charge.
Special Conditions for Unmetered Service:	Same as in Rate Schedules 1300, 1301, 1310 and 1311.
Rate Rider:	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.
Rate Increase:	Effective April 1, 2016 the Rates and Minimum Charge under these schedules include an increase of 4.00% before rounding, approved by BCUC Order No. G-XX-XX.

ACCEPTED:______________________________

ORDER NO.______________________________

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ACTING COMMISSION SECRETARY

SCHEDULE 1253 – DISTRIBUTION SERVICE – IPP STATION SERVICE

Availability: For Customers who are Independent Power Producers (IPPs) served at distribution voltage, subject to the Special Conditions below.

Applicable in: Rate Zone I excluding Districts of Kingsgate-Yahk and Lardeau-Shutty Bench.

Rate: Energy Charge: The sum, over the Billing Period, of the hourly energy consumed multiplied by the entry in the ICE Mid Columbia (Mid-C) Peak, and Mid-C Off-Peak weighted average index price as published by ICE in the ICE Day Ahead Power Price Report that corresponds to the time when consumption occurred, during that hour.

Monthly Minimum Charge: $43.02

Special Conditions:

1. BC Hydro agrees to provide Electricity under this Schedule to the extent that it has energy and capacity to do so.
2. BC Hydro may, without notice to the Customer, terminate the supply of Electricity under this Schedule if at any time BC Hydro does not have sufficient energy or capacity.
3. Prior to taking Electricity under this Schedule, the Customer may be required to obtain approval from BC Hydro. BC Hydro will advise the Customer of the need to obtain approval prior to the taking of energy under this Schedule.
4. Electricity taken under this Schedule is to be used solely for maintenance and black-start requirements and shall not displace Electricity that would normally be generated by the Customer.

Rate Rider: The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.

Rate Increase: Effective April 1, 2016 the Rates and Minimum Charge under these schedules include an increase of 4.00% before rounding, approved by BCUC Order No. G-XX-XX.

ACCEPTED:____________________

ORDER NO.____________________

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ACTING COMMISSION SECRETARY

SCHEDULE 1255, 1256, 1265, 1266 – GENERAL SERVICE (35 KW AND OVER) – ZONE II

Availability: For all purposes. Supply is 60 hertz, single or three phase at secondary or primary potential. BC Hydro reserves the right to determine the potential of the service connection.

Applicable in: Rate Zone II.

Rate: Basic Charge 23.47 ¢ per day

First 200 kW.h per kW of demand per month	@ 11.16 ¢ per kW.h
All additional kW.h per month	@ 18.58 ¢ per kW.h.

Discounts

1. A discount of 1½% shall be applied to the above rate if a Customer's supply of electricity is metered at a primary potential.
2. A discount of 25¢ per month per kW of billing demand shall be applied to the above rate if a Customer supplies transformation from a primary to a secondary potential.
3. If a Customer is entitled to both of the above discounts the discount for metering at a primary potential shall be applied first.

Billing Codes:

Schedule 1255 applies if a Customer's supply of electricity is metered at a secondary potential and BC Hydro supplies transformation from a primary potential to a secondary potential.

Schedule 1256 applies if a Customer's supply of electricity is metered at a primary potential and BC Hydro supplies transformation from a primary potential to a secondary potential.

Schedule 1265 applies if a Customer's supply of electricity is metered at a secondary potential and the Customer supplies transformation from a primary potential to a secondary potential.

Schedule 1266 applies if a Customer's supply of electricity is metered at a primary potential and the Customer supplies transformation from a primary potential to a secondary potential.

Monthly Minimum Charge:	The Monthly Minimum Charge paid by a Customer on Schedule 1255, or 1256, or 1265 or 1266 shall be the charge the Customer would have paid if he had been billed on Schedule 1200, or 1201, or 1210 or 1211 respectively.
Special Conditions:	1. A demand meter will normally be installed; prior to the installation of such a meter, or if such a meter is not installed, the demand for billing purposes shall be the assessed demand estimated by BC Hydro. 2. Where the Customer's demand is or is likely to be in excess of 45 kV.A, then BC Hydro may require that supply to such Customer be by special contract and that such supply be subject to such special conditions as BC Hydro, in its sole discretion, considers necessary to insert in the Customer's special contract.
Rate Rider:	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.
Rate Increase:	Effective April 1, 2016 the Rates and Minimum Charge under these schedules include an increase of 4.00% before rounding, approved by BCUC Order No. G-XX-XX.

ACCEPTED:__________________________

ORDER NO.__________________________

ACTING COMMISSION SECRETARY

SCHEDULE 1268 – DISTRIBUTION SERVICE – IPP DISTRIBUTION TRANSPORTATION ACCESS

Availability: For Customers who have generators connected to BC Hydro's distribution system and want access to BC Hydro's transmission system, the Wholesale Transmission Service Tariff (WTS), and Electric Tariff Supplement No. 30, subject to the Special Conditions below.

Applicable in: Rate Zone I excluding Districts of Kingsgate-Yahk and Lardeau-Shutty Bench.

Rate: Distribution Transportation Charge: 0.173 ¢ per kW.h

Special Conditions:

1. The Customer is required to pay the costs, including the cost of altering existing facilities, to connect the generator to B.C Hydro's distribution system in accordance with BC Hydro's Connection Requirements for Utility or Non-Utility Generation, 35 kV and Below.

2. For Customers with self-generation (i.e., with a Customer Baseline Load ("CBL") greater than zero), this Schedule is only applicable to sales of Surplus Energy. It may not be used by self-generating Customers who appear to have varied their demand for power from BC Hydro based on the actual or anticipated difference between BC Hydro's rate for providing service to them and the market price of power. For the purposes of this Schedule, "Surplus Energy" in any period is the energy made available from generation by the Customer calculated as the difference between the Customer's CBL and the Customer's actual consumption from BC Hydro in that period. The Customer's CBL is established, in general, by determining the Customer's electric energy consumption, on a monthly basis, for the past three years; in cases where inadequate history exists, alternative methods may be used to determine a Customer's CBL. Once established, the Customer's CBL will not be automatically adjusted for changes in the Customer's net metered consumption from BC Hydro. Any subsequent changes to the CBL must be due to changes in the Customer's load and not due to changes in its generation. The Customer must provide metered output from its generator which demonstrates an increase in generation output commensurate in time and amount with the Surplus Energy transported using this Schedule. Where it appears that the Customer has transported on this Schedule energy that is not Surplus Energy, BC Hydro will provide replacement energy to the Customer's load at market prices, subject to Commission approval for such sales.

ACCEPTED: April 6, 2016

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3. The metering point to determine the electricity being delivered to BC Hydro's distribution system will be determined by BC Hydro. The electricity delivered to BC Hydro's distribution system will also be deemed to be delivered to BC Hydro's transmission system (that is, no distribution loss adjustment will be applied to the electricity from an IPP or self-generator when determining capacity and energy delivered to BC Hydro's transmission system).

Rate Rider: The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.

Rate Increase: Effective April 1, 2016 the Rates and Minimum Charge under these schedules include an increase of 4.00% before rounding, approved by BCUC Order No. G-XX-XX.

SCHEDULE 1278 – POWER SERVICE (CLOSED)

Availability:	For power service when the demand is not less than 2000 kV.A for use in any one or more of electric steel making and the electric heating or melting of metals or other materials when such heating or melting is part of a continuous production process. This schedule is available only to a Customer served under this schedule on 1 April 1970 and continuously thereafter. Capacity in excess of that set out in a Customer's contract with BC Hydro, in effect on 1 April 1970, may be supplied at the sole discretion of BC Hydro. Service is three phase, 60 hertz at a nominal potential of 12,500 volts or higher as available
Applicable in:	Those parts of the Lower Mainland served by B.C. Electric Company Ltd. on 29 March 1962.
Rate:	\$2.785 per kV.A by which the maximum demand per month exceeds the capacity which BC Hydro had agreed to supply under this rate schedule on 1 April 1970; plus 7.280 ¢ per kW.h per month.
Monthly Minimum Charge:	The greater of: (i) \$5.44 per kV.A of maximum demand, or (ii) \$10,879.19
Special Condition:	A Customer taking electricity on this schedule for the operation of an electric arc furnace shall, as a condition of service, install such inductive reactance as BC Hydro may specify. A Customer who has installed reactance as specified shall not then be required to correct for lagging power factor occasioned by the operation of the said arc furnace.
Rate Rider:	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.
Rate Increase:	Effective April 1, 2016 the Rates and Minimum Charge under these schedules include an increase of 4.00% before rounding, approved by BCUC Order No. G-XX-XX.

ACCEPTED:______________________

ORDER NO.______________________ ______________________
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SCHEDULE 1280 – SHORE POWER SERVICE (DISTRIBUTION)

Availability: For the supply of Shore Power to Port Customers who qualify for General Service for use by Eligible Vessels while docked at the Port Customer's Port Facility.

Shore Power Service is supplied at 60 Hz, three phase at primary potential.

Applicable in: Rate Zone 1

Rate: Administrative Charge: $150.00 per month

Plus

Energy Charge: 9.227 ¢ per kW.h

Special Conditions:

1 BC Hydro agrees to provide Electricity under this Rate Schedule to the extent that it has energy and capacity to do so. BC Hydro may refuse or terminate service under this Rate Schedule in circumstances where BC Hydro does not have sufficient energy or capacity. For greater certainty, BC Hydro shall not be required to construct an Extension for the purpose of increasing the capacity of BC Hydro's distribution system to provide Shore Power Service under this Rate Schedule.

2 The terms and conditions under which Shore Power Service is supplied are contained in the Shore Power Service Agreement (Electric Tariff Supplement No. 86). The Port Customer shall pay to BC Hydro the charges set out in this Rate Schedule in addition to any charges set out in the Shore Power Service Agreement.

ACCEPTED: April 6, 2016

ORDER NO. G-40-16

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SCHEDULE 1300, 1301, 1310, 1311 SMALL GENERAL SERVICE (UNDER 35 KW)

Availability: For Customers who qualify for General Service and whose billing demand, metered or estimated by BC Hydro, as applicable, is less than 35 kW.

Supply is 60 hertz, single or three phase at a secondary or primary potential.

Applicable in: Rate Zone I and Rate Zone IB.

Rate: Basic Charge

23.47 ¢ per day

Energy Charge

All kW.h at 11.16 ¢ per kW.h

Discounts

1. A discount of 1½% shall be applied to the above charges if a Customer's supply of electricity is metered at a primary potential.
2. A discount of 25¢ per month per kW of maximum demand shall be applied if a Customer supplies transformation from a primary potential to a secondary potential. BC Hydro will install a demand meter in addition to a kilowatt hour meter.
3. If a Customer is entitled to both of the above discounts, the discount for metering at a primary potential shall be applied first.

ACCEPTED: April 6, 2016

ORDER NO. G-40-16

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Rate Rider: The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.

Rate Increase: Effective April 1, 2016 the Rates and Minimum Charge under these schedules include an increase of 4.00% before rounding, approved by BCUC Order No. G-XX-XX.

ACCEPTED:____________________________

ORDER NO.____________________________ ______________________________________

ACTING COMMISSION SECRETARY

SCHEDULE 1500, 1501, 1510, 1511 – MEDIUM GENERAL SERVICE (35 KW OR GREATER AND LESS THAN 150 KW)

Availability: For Customers who qualify for General Service and whose Billing Demand (determined under the Special Conditions below) is equal to or greater than 35 kW but less than 150 kW, or whose energy consumption in any 12-month period is equal to or less than 550,000 kW.h. Supply is 60 hertz, single or three phase at secondary or primary potential. BC Hydro reserves the right to determine the potential of the service connection.

Applicable in: Rate Zone I.

Charges: Basic Charge

23.47 ¢ per day

Demand Charge

First 35 kW of Billing Demand per Billing Period	@ $0.00 per kW
Next 115 kW of Billing Demand per Billing Period	@ $5.72 per kW
All additional kW of Billing Demand per Billing Period	@ $10.97 per kW

Energy Charge

1. Energy Charge – Customers who have not yet been transferred to the rate under Part 2

   Energy Charges will be determined under this part for Customers who have not yet been transferred to service at the rate under Part 2.

   First 14,800 kW.h of energy consumption in the Billing Period @ Tier 1 rate of 10.30 ¢ per kW.h.

   All additional kW.h of energy consumption in the Billing Period @ Tier 2 rate of 7.19 ¢ per kW.h.

2. Energy Charge – Customers who have been transferred to the rate under this part (see Special Condition 5 below).

Except for Customers being billed under "2.1 Energy Charge – Customers without HBLs", BC Hydro will determine monthly Historical Baselines ("HBLs") and related Billing Baselines ("BBLs") for use in calculating the Energy Charge payable by a Customer in a Billing Period.

2.1 Energy Charge - Customers without HBLs

Energy Charges will be determined under this part for Customers who do not have HBLs determined by BC Hydro under the Special Conditions below. The Energy Charges under this part will apply until HBLs can be determined by BC Hydro under the Special Conditions below.

Energy Charge:

First 14,800 kW.h of energy consumption in the Billing Period @ Tier 1 rate of 10.30 ¢ per kW.h.

All additional kW.h of energy consumption in the Billing Period @ Tier 2 rate of 7.19 ¢ per kW.h.

2.2 Energy Charge - Customers with HBLs

Energy Charges will be determined under this part for:

1. Customers who have been transferred to service at the rate under this part 2 for whom HBLs were determined by BC Hydro in accordance with the Special Conditions below, and
2. Customers who have been transferred to service at the rate under this part 2 for whom HBLs were determined by BC Hydro in accordance with the Special Conditions below after completion of 12 consecutive months of service under this rate schedule.

The Energy Charge is the Part 1 Energy Charge plus any additional charges or minus any credits determined under the Part 2 Energy Charge/Credit below.

Part 1 Energy Charge

The following rates are applied to the Customer's BBL for the Billing Period:

If the BBL is greater than 14,800 kW.h:

[BBL minus 14,800] kW.h of the BBL for the Billing period @ Tier 2 rate of 7.19 ¢ per kW.h.

Last 14,800 kW.h of the BBL for the Billing period @ Tier 1 rate of 10.30 ¢ per kW.h.

If the BBL is less than or equal to 14,800 kW.h:

BBL for the Billing Period @ Tier 1 rate of 10.30 ¢ per kW.h

Part 2 Energy Charge/Credit

The determination of the Part 2 Energy Charge/Credit depends on whether energy consumption in the Billing Period is greater or less than the Customer's BBL for the Billing Period. If energy consumption in the billing period is equal to the BBL there is no Part 2 Energy Charge/Credit.

Consumption greater than BBL

For purposes of the following calculations, the difference between the BBL and the energy consumption for the Billing Period is defined as the "Consumption Greater Than Baseline".

Charge is based on the following three steps:

1. The marginal cost based energy rate of 10.09 ¢ per kW.h is applied to the Consumption Greater Than Baseline subject to a maximum of 20% of the BBL.
2. Tier 1 rate of 10.30 ¢ per kW.h is applied to the lesser of:
   (a) the remaining portion of the Consumption Greater Than Baseline (if any) following step 1 above, and
   (b) that portion of the Consumption Greater than Baseline which is equal to 14,800 kW.h minus 120% of the BBL (but if 14,800 kW.h minus 120% of the BBL would produce a negative number, the result shall be deemed to be zero).
3. Tier 2 rate of 7.19 ¢ per kW.h is applied to the remaining portion of the Consumption Greater Than Baseline (if any) following steps 1 and 2 above.

Consumption less than BBL

For purposes of the following calculations, the difference between the BBL and the energy consumption for the Billing Period is defined as the "Consumption Less Than Baseline".

Credit is based on the following three steps:

1. The marginal cost based energy rate of 10.09 ¢ per kW.h is applied to the Consumption Less Than Baseline subject to a maximum of 20% of the BBL.
2. Tier 1 rate of 10.30 ¢ per kW.h is applied to the lesser of:
   (a) the remaining portion of the Consumption Less Than Baseline (if any) following step 1 above, and
   (b) that portion of the Consumption Less Than Baseline which is equal to 14,800 kW.h minus 20% of the BBL (but if 14,800 kW.h minus 20% of the BBL would produce a negative number, the result shall be deemed to be zero).
3. Tier 2 rate of 7.19 ¢ per kW.h is applied to the remaining portion of the Consumption Less Than Baseline (if any) following steps 1 and 2 above.

Minimum Energy Charge (Applicable to Energy Charge 2.2)

The Minimum Energy Charge is the minimum energy rate of 3.43 cents per kW.h multiplied by the total energy consumption in the Billing Period. The Minimum Energy Charge applies only when the average energy rate in a Billing Period (the Energy Charge 2.2 divided by total energy consumption in the Billing Period) is less than the minimum energy rate.

Discounts

1. A discount of 1½% shall be applied to the above charges if a Customer's supply of electricity is metered at a primary potential.
2. A discount of 25¢ per billing period per kW of billing demand shall be applied to the above charges if a Customer supplies transformation from a primary potential to a secondary potential.
3. If a Customer is entitled to both of the above discounts, the discount for metering at a primary potential shall be applied first.

Billing Codes: Schedule 1500 applies if a Customer's supply of electricity is metered at a secondary potential and BC Hydro supplies transformation from a primary potential to a secondary potential.

5. Transfer to the rate under Part 2

   Energy Charges under Part 2 will be applied progressively to groups of Customers according to their kW Billing Demand, as follows:

   a. Commencing on April 1, 2012, Customers whose Billing Demand is equal to or greater than 85 kW and less than 150 kW at least once in the twelve month period ending September 30 in the previous year.

   b. Commencing on April 1, 2013, all remaining Medium General Service Customers.

Rate Rider: The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.

Rate Increase: Effective April 1, 2016 the Rates and Minimum Charge under these schedules include an increase of 4.00% before rounding, approved by BCUC Order No. G-XX-XX.

SCHEDULE 1600, 1601, 1610, 1611 – LARGE GENERAL SERVICE (150 KW AND OVER)

Availability: For Customers who qualify for General Service and whose Billing Demand (determined under the Special Conditions below) is equal to or greater than 150 kW, or whose energy consumption in any 12 month period is greater than 550,000 kW.h. Supply is 60 hertz, single or three phase at secondary or primary potential. BC Hydro reserves the right to determine the potential of the service connection.

Applicable in: Rate Zone I.

Charges: Basic Charge

23.47 ¢ per day

Demand Charge

First 35 kW of Billing Demand per Billing Period	@ $0.00 per kW
Next 115 kW of Billing Demand per Billing Period	@ $5.72 per kW
All additional kW of Billing Demand per Billing Period	@ $10.97 per kW

Energy Charge

Except for Customers being billed under "1. Energy Charge – Customers without HBLs", BC Hydro will determine monthly Historical Baselines ("HBLs") and related Billing Baselines ("BBLs") for use in calculating the Energy Charge payable by a Customer in a Billing Period.

1. Energy Charge – Customers without HBLs

   Energy Charges will be determined under this part for Customers for whom no HBLs were determined by BC Hydro under the Special Conditions below at the time they commenced taking service under this rate schedule. The Energy Charges under this part will apply until they have taken service for a period of 12 consecutive months.

   Energy Charge:

   First 14,800 kW.h of energy consumption in the Billing Period
   @ Tier 1 rate of 11.14 ¢ per kW.h.

   All additional kW.h of energy consumption in the Billing period
   @ Tier 2 rate of 5.36 ¢ per kW.h.

ACCEPTED: April 6, 2016

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2. Energy Charge – Customers with HBLs

Energy Charges will be determined under this part for:

1. Customers for whom HBLs were determined by BC Hydro in accordance with the Special Conditions below at the time they commenced taking service under this rate schedule, and
2. Customers for whom HBLs were determined by BC Hydro in accordance with the Special Conditions below after completion of 12 consecutive months of service under this rate schedule.

The Energy Charge is the Part 1 Energy Charge plus any additional charges or minus any credits determined under the Part 2 Energy Charge/Credit below.

Part 1 Energy Charge

The following rates are applied to the Customer's BBL for the Billing Period:

First 14,800 kW.h of the BBL for the Billing Period @ the Tier 1 rate of 11.14 ¢ per kW.h.

Additional kW.h of BBL for the Billing Period @ the Tier 2 rate of 5.36 ¢ per kW.h.

Part 2 Energy Charge/Credit

The determination of the Part 2 Energy Charge/Credit depends on whether energy consumption in the Billing Period is greater or less than the Customer's BBL for the Billing Period.

Consumption greater than BBL

For purposes of the following calculations, the difference between the BBL and the energy consumption for the Billing Period is defined as the "Consumption Greater Than Baseline".

Charge is based on the following three steps:

1. The marginal cost based energy rate of 10.09 ¢ per kW.h is applied to Consumption Greater Than Baseline subject to a maximum of 20% of the BBL.

ACCEPTED: April 6, 2016

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2. Tier 1 rate of 11.14 ¢ per kW.h is applied to the lesser of:

   (a) the remaining portion of the Consumption Greater Than Baseline (if any) following step 1 above, and

   (b) that portion of the Consumption Greater Than Baseline which is equal to 14,800 kW.h minus 120% of the BBL (but if 14,800 kW.h minus 120% of the BBL would produce a negative number, the result shall be deemed to be zero).

3. Tier 2 rate of 5.36 ¢ per kW.h is applied to the remaining portion of the Consumption Greater Than Baseline (if any) following steps 1 and 2 above.

Consumption less than BBL

For purposes of the following calculations, the difference between the BBL and the energy consumption for the Billing Period is defined as the "Consumption Less Than Baseline".

Credit is based on the following three steps:

1. The marginal cost based energy rate of 10.09 ¢ per kW.h is applied to the Consumption Less Than Baseline subject to a maximum of 20% of the BBL.

2. Tier 2 rate of 5.36 ¢ per kW.h is applied to the lesser of:

   (a) the remaining portion of the Consumption Less Than Baseline (if any) following step 1 above, and

   (b) that portion of the Consumption Less Than Baseline which is equal to 80% of the BBL minus 14,800 kW.h (but if 80% of the BBL minus 14,800 kW.h would produce a negative number, the result shall be deemed to be zero).

3. Tier 1 rate of 11.14 ¢ per kW.h is applied to the remaining portion of the Consumption Less Than Baseline (if any) following steps 1 and 2 above.

Minimum Energy Charge (Applicable to Energy Charge 2.):

The Minimum Energy Charge is the minimum energy rate of 3.43 cents per kW.h multiplied by the total energy consumption in the Billing Period. The Minimum Energy Charge applies only when the average energy rate in a Billing Period (the Energy Charge 2. divided by total energy consumption in the Billing Period) is less than the minimum energy rate.

4. Migration Rule

4.1 Customers taking service at Medium General Service rates (rate schedules 1500, 1501, 1510 or 1511) will be moved to service at Large General Service rates (rate schedules 1600, 1601, 1610 or 1611) if the Customers' Billing Demand in any 6 of the most recent 12 Billing Periods was equal to or greater than 150 kW, or if the Customers' energy consumption was in excess of 550,000 kW.h in any 12 consecutive month period.

4.2 Customers taking service at Large General Service rates (rate schedules 1600, 1601, 1610 or 1611) will be moved to service at Medium General Service rates (rate schedules 1500, 1501, 1510 or 1511) if the Customers' Billing Demand in each of the 12 most recent consecutive Billing Periods was less than 100 kW and energy consumption in the 12 month period which corresponds to those Billing Periods was less than 400,000 kW.h.

5. Application for Prospective Growth

The rates prescribed in this schedule, in regard to a specific customer, are subject to Electric Tariff Supplement No. 82 – Rules for LGS Prospective Growth Applications.

Rate Rider: The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.

Rate Increase: Effective April 1, 2016 the Rates and Minimum Charge under these schedules include an increase of 4.00% before rounding, approved by BCUC Order No. G-XX-XX.

ACCEPTED:______________________

ORDER NO.______________________

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ACTING COMMISSION SECRETARY

SCHEDULE 1401 – IRRIGATION

Availability:	For motor loads of 746 watts or more used for irrigation and outdoor sprinkling where electricity will be used principally during the Irrigation Season as defined below. Supply is 60 hertz, single or three phase at the secondary or primary potential available. BC Hydro reserves the right to determine the potential of the service connection.
Applicable in:	Rate Zone I and Rate Zone IB.
Rate:	During the Irrigation Season 5.37 ¢ per kW.h. During the Non-Irrigation Season First 150 kW.h @ 5.37 ¢ per kW.h All additional kW.h @ 42.60 ¢ per kW.h.
Minimum Charge:	During the Irrigation Season $5.37 per kilowatt of connected load per month for a period of eight months commencing in March in any year whether consumption is registered or not. During the Non-Irrigation Season (i) Where the consumption is 500 kW.h or less, Nil. (ii) Where the consumption is more than 500 kW.h, $42.97 per kilowatt of connected load.
Discount for Ownership of Transformers:	A discount of 25¢ per month per kW of connected load shall be applied to the above rate if a Customer supplies the transformation from a primary potential to a secondary potential. The Billing Code for Schedule 1401 Customers eligible for the Discount for Ownership of Transformers shall be Schedule 1402.
Irrigation Season:	In respect of each service - the period commencing with a meter reading on or about 1 March in any year, with a mid-season meter reading on or about 31 July, and ending with a meter reading on or about 31 October in that same year. BC Hydro may, in its discretion extend the aforesaid period by postponing the termination date to any date not later than 30 November, for the sole purpose of permitting a Customer to fill reservoirs necessary for the operation of the irrigation or sprinkling system.

ACCEPTED: April 6, 2016

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Non-Irrigation Season: The period commencing at the end of one Irrigation Season and terminating at the beginning of the next Irrigation Season.

Special Conditions:

1. No equipment which has been served with electricity under this rate schedule shall be served with electricity under any other rate schedule while the Customer's agreement for service under this rate schedule is in force.
2. Normally the service will be energized during the Non-Irrigation Season, but will be disconnected if a Customer so requests.
3. The Minimum Charge during the Irrigation Season shall commence in March for an account which has not been terminated by the Customer, whether or not the service is energized and will be billed in two installments, at the end of July and at the end of October.

Billing:

1. For the Irrigation Season, a bill will be rendered following the July and October meter readings. The first bill will be the greater of the energy charge or the Minimum Charge for the period 1 March to 31 July. The second bill will be the greater of the energy charge for the season or the Minimum Charge for the season, less payment received for the first billing charges.
2. For the Non-Irrigation Season a bill will be rendered following the March meter reading provided that there is registered consumption.

Note: If a motor is rated in horsepower, the conversion factor from horsepower to kilowatts shall be:

1 horsepower = 0.746 kilowatts

Rate Rider: The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.

Rate Increase: Effective April 1, 2016 the Rates and Minimum Charge under these schedules include an increase of 4.00% before rounding, approved by BCUC Order No. G-XX-XX.

ACCEPTED:________________

ORDER NO.________________

ACTING COMMISSION SECRETARY

SCHEDULE 1701 – OVERHEAD STREET LIGHTING

Availability: For lighting of public highways, streets and lanes in cases where the BC Hydro owns, installs and maintains the fixtures, conductors, controls and poles.

Applicable in: Any area served by suitable overhead distribution lines.

Rate: Per fixture per month as hereunder:

100 watt H.P. Sodium Vapour Unit	$17.21
150 watt H.P. Sodium Vapour Unit	$20.52
200 watt H.P. Sodium Vapour Unit	$23.69
*175 watt Mercury Vapour Unit	$18.91
*250 watt Mercury Vapour Unit	$21.79
*400 watt Mercury Vapour Unit	$28.09

Wattages are lamp watts.

* Note Special Condition No. 2.

Special Terms and Conditions:

1. Connection Charge

   No charge will be made for Service Connections.

2. Mercury Vapour

   Mercury vapour fixtures are no longer available for new installations.

3. Extension Policy

   BC Hydro will construct a distribution extension if required by the applicant in accordance with the Terms and Conditions of the Electric Tariff as applicable.

   When, at the Customer's request, a new fixture replaces an existing fixture, the Customer shall pay to BC Hydro the original cost of the existing fixture, less any accumulated depreciation, and the cost of removing the existing fixture.

ACCEPTED: April 6, 2016

ORDER NO. G-40-16

L Ross
ACTING COMMISSION SECRETARY

4. Relocation and Redirection of Fixtures

   The Customer shall pay the full cost of relocating or redirecting fixtures when the change is made at the request of the Customer.

5. Design

   BC Hydro will design the installation of overhead street lighting fixtures.

6. Lamps Failing to Operate

   BC Hydro will, without charge, replace lamps or components which fail to operate, unless breakage is the reason for such failure in which case the Customer shall be charged the cost of the material required to make the fixture operate.

7. Contract Period

   The term of the initial contract shall be not more than five years, renewal periods shall be for five years.

Rate Rider: The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.

Rate Increase: Effective April 1, 2016 the Rates and Minimum Charge under these schedules include an increase of 4.00% before rounding, approved by BCUC Order No. G-XX-XX.

SCHEDULE 1702 – PUBLIC AREA ORNAMENTAL STREET LIGHTING

Availability: For lighting of public highways, streets and lanes and municipal pathways and for public area seasonal lighting displays, in those cases where the Customer owns, installs and maintains the standards, fixtures, conductors and controls.

Applicable in: All Rate Zones.

Rate:

For each unmetered fixture:	3.31¢ per watt per month.
For each metered fixture:	9.93¢ per kWh

For fixtures without dimming controls the number of watts per fixture include the wattage of the lamp and, where applicable, the ballast.

For fixtures with dimming controls the number of watts per fixture includes the wattage of the lamp and, where applicable, the wattage of the ballast multiplied by the ratio of Billable Wattage After Dimming to Billable Wattage Before Dimming.

The Billable Wattage is the sum of all wattage, on all fixtures, used by a customer. It depends both on the number of fixtures in use and the actual output wattages (bulb plus ballast) of each light. For a customer that has implemented dimming technology, the Billable Wattage will reflect the lower output wattages that result from dimming.

Special Terms and Conditions:

1. Service Connection

   Where necessary BC Hydro will provide an overhead or underground Service Connection in accordance with the Terms and Conditions of the Electric Tariff. No Service Connection shall be made to add any ornamental street lighting system which does not provide for eight or more street lighting fixtures except that, if the potential is 120/240 volts then, at B.C Hydro's discretion, a Service Connection may be made for a system of less than eight.

   Receptacle loads will be permitted for service under this rate schedule provided that such receptacles are used predominantly for seasonal lighting displays, meaning that no more than 10% of the usage may be for other purposes.

ACCEPTED: April 6, 2016

ORDER NO. G-40-16

L Ross
ACTING COMMISSION SECRETARY

6. Unmetered Service

   (a) BC Hydro may permit unmetered service under this rate schedule if it can estimate to its satisfaction the energy used in kilowatt hours over a period of one month based on the connected load and hours of use.

   (b) The Customer shall notify BC Hydro immediately of any proposed or actual change in load, or load characteristics, or hours of use.

   (c) BC Hydro, in its discretion, may at any time install a meter or meters and thereafter bill the Customer on the consumption registered.

Rate Rider: The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.

Rate Increase Effective April 1, 2016 the Rates and Minimum Charge under these schedules include an increase of 4.00% before rounding, approved by BCUC Order No. G-XX-XX.

SCHEDULE 1703 – STREET LIGHTING SERVICE

Availability: For lighting of public highways, streets and lanes in those cases where the Customer owns, installs and maintains the fixtures, conductors and controls on poles of BC Hydro. Available only to Customers formerly taking service on Rate Schedules 1755, 1756, 1757, 1758, 1759 or 1767, to the City of New Westminster in respect of a portion of D.L. 172, to the Municipality of Sparwood and to the City of Vancouver.

Applicable in: The Cities of Victoria and Prince Rupert, the Municipalities of Oak Bay, Esquimalt, Saanich and Central Saanich, the Village of Sidney, the unorganized areas of Port Renfrew and Shawnigan Lake, a portion of D.L. 172 in the City of New Westminster, Natal and the City of Vancouver.

Rate: The rate shall consist of two components:

(a) An energy charge of 3.31 ¢ per watt per month,

plus

(b) A contact charge of 99.84 ¢ per contact per month.

With respect to the Energy Charge - the number of watts per fixture include the wattage of the lamp and where applicable the ballast.

With respect to the Contact Charge - this is a charge per fixture for the use of pole space.

For fixtures without dimming controls the Billable Wattage is equal to the number of watts per fixture including the wattage of the lamp and, where applicable, the ballast.

For fixtures with dimming controls the number of watts per fixture includes the wattage of the lamp and, where applicable, the wattage of the ballast multiplied by the ratio of Billable Wattage After Dimming to Billable Wattage Before Dimming.

The Billable Wattage is the sum of all wattage, on all fixtures, used by a customer. It depends both on the number of fixtures in use and the actual output wattages (bulb plus ballast) of each light. For a customer that has implemented dimming technology, the Billable Wattage will reflect the lower output wattages that result from dimming.

Special Terms and Conditions:

1. Extension Policy

   No extensions will be made to serve street lights under this schedule.

2. Power Factor

   All installations of mercury vapour, sodium vapour or fluorescent lamps shall be equipped with the necessary auxiliaries to assure that a power factor of not less than 90% lagging shall be maintained.

3. Contract Period

   The term of the initial contract shall be not more than five years; renewal periods shall be for five years.

4. Fixtures with Automated Dimming Controls

The following special terms and conditions apply to lighting fixtures fitted with dimming controls:

a. For purposes of this part “dimming controls” means control units or fittings attached to or forming part of a street lighting fixture capable of being programmed or remotely operated so as to reduce the lumens output of the lamps during specified hours each day while the lamps are in operation. The reductions may vary according to the hours of the day, the days of the week, and the seasons of the year.

b. A Customer wishing to have fixtures with dimming controls separately rated under this rate schedule must submit a Dimming Schedule satisfactory to BC Hydro listing each light fixture fitted with dimming controls, the wattage of the fixture (including the lamp and, where applicable, the ballast), the dimming control setting or settings and the hours each day that the dimming control setting or settings will be in operation.

Whenever the Customer wishes to make changes in the lighting fixtures listed in the Dimming Schedule or in the dimming control settings or hours of operation, the Customer shall submit an updated Lighting Fixture Schedule to BC Hydro listing any changes. Changes will be permitted on a semi-annual basis (twice per year).

Rate Rider: The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.

Rate Increase: Effective April 1, 2016 the Rates and Minimum Charge under these schedules include an increase of 4.00% before rounding, approved by BCUC Order No. G-XX-XX.

ACCEPTED:______________________

ORDER NO.______________________

ACTING COMMISSION SECRETARY

SCHEDULE 1704 – TRAFFIC CONTROL EQUIPMENT

Availability: For traffic signals, traffic signs and traffic warning devices, and other equipment for controlling or directing vehicular or pedestrian traffic on public highways. For cases where the Customer installs, owns and maintains the standards, fixtures, wiring, controls and associated equipment.

Applicable in: All Rate Zones.

Rate: 9.93¢ per kW.h.

Special Terms and Conditions:

1. Service Connections

   Where necessary BC Hydro will provide an overhead or underground Service Connection in accordance with the Terms and Conditions of the Electric Tariff as applicable to "Service Connections".

2. Unmetered Service

   (a) BC Hydro may permit unmetered service under this rate schedule if it can estimate to its satisfaction the energy used in kilowatt hours over a period of one month based on the connected load and hours of use.

   (b) The Customer shall notify BC Hydro immediately of any proposed or actual change in load, or load characteristics, or hours of use.

   (c) BC Hydro, in its discretion, may at any time install a meter or meters and thereafter bill the Customer on the consumption registered.

3. Contract Period

   The term of the initial contract shall not be more than five years; renewal periods shall be for five years.

Rate Rider: The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.

Rate Increase: Effective April 1, 2016 the Rates and Minimum Charge under these schedules include an increase of 4.00% before rounding, approved by BCUC Order No. G-XX-XX.

ACCEPTED:______________________

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ACTING COMMISSION SECRETARY

SCHEDULE 1755 – PRIVATE OUTDOOR LIGHTING (CLOSED)

Availability: For outdoor lighting service to illuminate property other than public streets or lanes, herein referred to as private property, where service is provided from dusk to dawn and the supply is single phase, 60 hertz at the secondary potential available.

This schedule is available only in Premises served under this schedule on 1 January 1975 and only with respect to lights served under this rate schedule on 1 January 1975 and continuously thereafter, except BC Hydro may replace a Mercury Vapour Unit with a High Pressure Sodium Unit having approximately the same equivalent light output.

Applicable in: All Rate Zones.

Rate: Per fixture per month as hereunder:

1. Where a light is mounted on a pole which was installed by the Customer or by BC Hydro at the Customer's expense:

175 watt Mercury Vapour Unit or replacement 100 watt H.P. Sodium Vapour Unit	$16.13
400 watt Mercury Vapour Unit or replacement 150 watt H.P. Sodium Vapour Unit	$27.80

2. Where a light is mounted on a pole which is on public property, or an easement, and is part of BC Hydro's distribution system:

175 watt Mercury Vapour Unit or replacement 100 watt H.P. Sodium Vapour Unit	$17.13
400 watt Mercury Vapour Unit or replacement 150 watt H.P. Sodium Vapour Unit	$28.81

3. Where a light is mounted on a pole which was installed on the Customer’s property by BC Hydro, at its expense, solely for the purpose of supporting the light:

175 watt Mercury Vapour Unit or replacement 100 watt H.P. Sodium Vapour Unit	$21.09
400 watt Mercury Vapour Unit or replacement 150 watt H.P. Sodium Vapour Unit	$33.20

except that if two or more lights are mounted at one time on the same pole the rates for the additional light or lights shall be as set out under Item 1 above.

Special Conditions:

1. BC Hydro shall provide and install:
   (a) an outdoor light consisting of luminaire, mast arm, ballast, lamp and photo-electric control, and
   (b) not more than one span of overhead secondary conductors per light.
2. The Customer will be required to contribute the estimated cost of any plant required to make secondary potential available at a point not more than one span from the light; such contribution is not subject to refund.
3. BC Hydro reserves the sole right to determine whether or not a light shall be installed on a pole which is part of BC Hydro's distribution system.
4. The prior approval of BC Hydro is required if a Customer intends to install his own poles, and such poles shall be maintained to BC Hydro's satisfaction at the Customer's expense.
5. BC Hydro will maintain all equipment owned by BC Hydro and will replace lamps which have failed. Any breakage will be repaired by BC Hydro at the Customer's expense.
6. The initial contract period shall be three years and thereafter service shall be provided from month to month.

Rate Rider: The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.

Rate Increase: Effective April 1, 2016 the Rates and Minimum Charge under these schedules include an increase of 4.00% before rounding, approved by BCUC Order No. G-XX-XX.

ACCEPTED:____________________

ORDER NO.____________________

ACTING COMMISSION SECRETARY

SCHEDULE 1823 – TRANSMISSION SERVICE – STEPPED RATE

Availability: For all purposes. Supply is at 60,000 volts or higher. Customers being supplied with electricity under Schedule 1825 (Transmission Service Time-of-use) may only revert to service under this Schedule as permitted under Schedule 1825.

Transmission service, within the meaning of the Direction Respecting Liquefied Natural Gas Customers, may not be provided under this rate schedule.

Applicable in: Rate Zone 1 excluding the Districts of Kingsgate-Yahk and Lardeau-Shutty Bench.

Rate: Demand Charge: $7.635 per kV.A of Billing Demand per Billing Period.

Plus

Energy Charge:

A. For new Customers and Customers that do not have a CBL by Order of the British Columbia Utilities Commission:

4.475 ¢ per kW.h for all kW.h per Billing Period

This rate will apply until the Customer has been supplied with Electricity under this Schedule for 12 Billing Periods or other period with the approval of the British Columbia Utilities Commission, after which the Customer will be supplied with Electricity at the Rate specified in Part B below.

B. For Customers with a CBL:

3.981 ¢ per kW.h applied to all kW.h up to and including 90% of the Customer's CBL in each Billing Year.

8.920¢ per kW.h applied to all kW.h above 90% of the Customer's CBL in each Billing Year.

Note: Customers previously supplied with electricity under Schedule 1825 will be subject to the rates in Part B above from the time the Customer commences taking service under this Schedule.

Billing Year: The Billing Year is the 12 billing month period starting with the first day of the Billing Period which commences nearest to April 1st in each year, and ending on the last day of the 12th Billing Period thereafter.

ACCEPTED: June 30, 2016

ORDER NO. G-103-16

L Ross
ACTING COMMISSION SECRETARY

Billing Demand:

The Demand for billing purposes shall be:

1. the highest kV.A Demand during the High Load Hours (HLH) in the Billing Period; or
2. 75% of the highest Billing Demand for the Customer's Plant in the immediately preceding period of November to February, both months included; or
3. 50% of the Contract Demand stated in the Electricity Supply Agreement for the Customer's Plant,

whichever is the highest value, provided that for new Customers the Billing Demand for the initial 2 Billing Periods shall be the average of the daily highest kV.A Demands for the Customer's Plant.

The HLH period is defined as the hours from 06:00 to 22:00 Monday to Saturday, except for Statutory Holidays.

The LLH period is defined as all other hours.

Statutory Holidays for the purpose of this Schedule are New Year's Day, Family Day, Good Friday, Victoria Day, Canada Day, B.C. Day, Labour Day, Thanksgiving Day, Remembrance Day and Christmas Day.

Monthly Minimum Charge:

$7.635 per kV.A of Billing Demand

Customer Baseline Load:

The Customer Baseline Load (CBL) is the Customer's historic annual energy consumption in kW.h as approved by the British Columbia Utilities Commission. The Customer's CBL will initially be determined by BC Hydro, and be subject to revision from time to time, in accordance with the criteria and procedures set forth in BC Hydro's "Customer Baseline Load (CBL) Determination Guidelines". All CBLs will be subject to final approval of the British Columbia Utilities Commission.

Aggregation of Customer Baseline Load:

A Customer having two or more operating plants may elect to have a single aggregated CBL determined for all or any combination of its operating plants in accordance with the CBL Determination Guidelines. Thereafter, BC Hydro will issue a single bill for all operating plants included in the aggregation, and the energy charge payable will be determined on the basis of the aggregated CBL. However, the Demand Charge will continue to be determined separately for each operating plant.

ACCEPTED: April 6, 2016

ORDER NO. G-40-16

L Ross

ACTING COMMISSION SECRETARY

Special Conditions: The following Special Conditions are applicable to this Schedule:

1. If any initial, revised, or aggregate CBL for a Customer has not been determined by BC Hydro and approved by British Columbia Utilities Commission by the time the CBL would become effective, BC Hydro may determine the CBL on an interim basis, and apply the CBL so determined for purposes of any Billing Periods and bills rendered to the Customer until such time as the CBL has been finally determined and approved by the British Columbia Utilities Commission, whereupon BC Hydro will make any necessary billing adjustments.
2. If a Customer taking service at the rates in Part B of the Energy Charge rate section above terminates service under this Schedule prior to the end of a Billing Year, the Customer's CBL or aggregate CBL will be prorated for the portion of the Billing Year during which the Customer was taking service, and the prorated CBL or aggregate CBL will be used for purposes of applying the rates in Part B to all electricity consumption during the Billing Year up to the time of termination. BC Hydro will make any necessary billing adjustments and bill the Customer for the difference (if any) owing.

Taxes: The rates and minimum charge contained herein are exclusive of the Goods and Services tax and Social Services tax.

Note: The terms and conditions under which transmission service is supplied are contained in Electric Tariff Supplements 5 and 6, or Electric Tariff Supplements 87 and 88, as applicable.

Rate Rider: The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.

Rate Increase: Effective April 1, 2016 the Rates and Minimum Charge under these schedules include an increase of 4.00% before rounding, approved by BCUC Order No. G-XX-XX.

ACCEPTED:____________________________

ORDER NO.____________________________

ACTING COMMISSION SECRETARY

SCHEDULE 1825 – TRANSMISSION SERVICE – TIME-OF-USE (TOU) RATE

Availability: For Customers who provide notice by February 15th of each year and who at the time of application are eligible to take service under Schedule 1823 (Stepped Rate) at the energy charge rates set out in Part B of the Rate section of that Schedule, and who have entered into a TOU (Transmission Service) Agreement by March 15th of that year. Customers will start service under Schedule 1825 as of the Billing Period that starts closest to April 1st.

Transmission service, within the meaning of the Direction Respecting Liquefied Natural Gas Customers, may not be provided under this rate schedule.

Applicable in: Rate Zone 1 excluding the Districts of Kingsgate-Yahk and Lardeau-Shutty Bench.

Rate: Demand Charge: $7.635 per kV.A of Billing Demand per Billing Period

Billing Demand: The Demand for billing purposes shall be:

1. the highest kV.A Demand during the High Load Hours (HLH) in the Billing Period; or
2. 75% of the highest Billing Demand for the Customer's Plant in the immediately preceding period of November to February, both months included; or
3. 50% of the Contract Demand stated in the Electricity Supply Agreement for the Customer's Plant,

whichever is the highest value.

The HLH period is defined as the hours from 06:00 to 22:00 Monday to Saturday, except for Statutory Holidays.

The LLH period is defined as all other hours.

Statutory Holidays for the purpose of this Schedule are New Year’s Day, Family Day, Good Friday, Victoria Day, Canada Day, B.C. Day, Labour Day, Thanksgiving Day, Remembrance Day and Christmas Day.

Energy Charge: Winter HLH Period

3.981¢ per kW.h applied to all kW.h up to and including 90% of the Customer's Winter HLH Period CBL.

9.953¢ per kW.h applied to all kW.h above 90% of the Customer's Winter HLH Period CBL.

The Winter Period is the 4 Billing Periods starting with the first day of the Billing Period which commences nearest to November 1st each year and ending on the last day of the 4th Billing Period thereafter.

Winter LLH Period

3.981¢ per kW.h applied to all kW.h up to and including 90% of the Customer's Winter LLH Period CBL.

9.021¢ per kWh applied to all kW.h above 90% of the Customer's Winter LLH Period CBL.

The Winter Period is the 4 Billing Periods starting with the first day of the Billing Period which commences nearest to November 1st each year and ending on the last day of the 4th Billing Period thereafter.

Spring Period

3.981¢ per kW.h applied to all kW.h up to and including 90% of the Customer's Spring Period CBL.

8.034¢ per kW.h applied to all kW.h above 90% of the Customer's Spring Period CBL.

The Spring Period is the 2 Billing Periods starting with the first day of the Billing Period which commences nearest to May 1st each year and ending on the last day of the 2nd Billing Period thereafter.

Remaining Period

3.981¢ per kW.h applied to all kW.h up to and including 90% of the Customer's Remaining Period CBL applicable.

8.810¢ per kW.h applied to all kW.h above 90% of the Customer's Energy CBL applicable in the Billing Period.

ACCEPTED: April 6, 2016

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Utilities Commission by the time the CBL would become effective, BC Hydro may determine the CBL on an interim basis, and apply the CBL so determined for purposes of any Billing Periods and bills rendered to the Customer until such time as the CBL has been finally determined and approved by the British Columbia Utilities Commission, whereupon BC Hydro will make any necessary billing adjustments.

3. In accordance with the TOU (Transmission Service) Agreement, the Customer will have a period of 30 days following approval of the Customer's initial CBL by the British Columbia Utilities Commission within which the Customer may, by written notice to BC Hydro, withdraw from taking service under this Schedule, and revert to taking service under Schedule 1823 (Stepped Rate) instead. This right of withdrawal is available only when the Customer first subscribes to take service under this Schedule, and is applicable only in respect of the initial CBL determination. If the Customer exercises this right of withdrawal Schedule 1823 will apply from the commencement of the Billing Year, and BC Hydro will make any necessary billing adjustments.

Taxes:

4. Customers taking service under Schedule 1852 may not also take service under this Schedule.

Note: The rate charges contained herein are exclusive of the Goods and Services tax and Social Services tax.

The terms and conditions under which service is supplied are contained in the Electricity Supply Agreement (Electric Tariff Supplement 5 or Electric Tariff Supplement 87, as applicable) as amended by the TOU (Transmission Service) Agreement (Electric Tariff Supplement 72).

Rate Rider: The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.

Rate Increase: Effective April 1, 2016 the Rates and Minimum Charge under these schedules include an increase of 4.00% before rounding, approved by BCUC Order No. G-XX-XX.

ACCEPTED:______________________________

ORDER NO.______________________________

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ACTING COMMISSION SECRETARY

SCHEDULE 1827 – TRANSMISSION SERVICE – RATE FOR EXEMPT CUSTOMERS

Availability: For all purposes. Supply is at 60,000 volts or higher. Only for City of New Westminster and University of British Columbia and other Customers exempted from Rate Schedule 1823 by the British Columbia Utilities Commission.

Transmission service, within the meaning of the Direction Respecting Liquefied Natural Gas Customers, may not be provided under this rate schedule.

Applicable in: Rate Zone 1 excluding the Districts of Kingsgate-Yahk and Lardeau-Shutty Bench.

Rate: Demand Charge: $7.635 per kV.A of Billing Demand per Billing Period.

Plus

Energy Charge: 4.475 ¢ per kW.h for all kW.h in a Billing Period.

Billing Demand: The Demand for billing purposes shall be:

1. the highest kV.A Demand during the High Load Hours (HLH) in the Billing Period; or
2. 75% of the highest Billing Demand for the Customer's Plant in the immediately preceding period of November to February, both months included; or
3. 50% of the Contract Demand stated in the Electricity Supply Agreement for the Customer's Plant,

whichever is the highest value.

The HLH period is defined as the hours from 06:00 to 22:00 Monday to Saturday, except for Statutory Holidays.

The LLH period is defined as all other hours.

Statutory Holidays for the purpose of this Schedule are New Year's Day, Family Day, Good Friday, Victoria Day, Canada Day, B.C. Day, Labour Day, Thanksgiving Day, Remembrance Day and Christmas Day.

Monthly Minimum Charge: $7.635 per kV.A of Billing Demand

ACCEPTED: June 30, 2016

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Taxes:	The rates and minimum charge contained herein are exclusive of the Goods and Services tax and Social Service tax.
Note:	The terms and conditions under which transmission service is supplied are contained in Electric Tariff Supplements 5 and 6, or Electric Tariff Supplements 87 and 88, as applicable.
Rate Rider:	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.
Rate Increase:	Effective April 1, 2016 the Rates and Minimum Charge under these schedules include an increase of 4.00% before rounding, approved by BCUC Order No. G-XX-XX.

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ACTING COMMISSION SECRETARY

Excess Demand Charge

$7.635 per kV.A of metered kV.A Demand in excess of the Maximum Demand Level during the Low Load Hours is applicable to this Rate Schedule,

where:

“Maximum Demand Level” means the Maximum Demand Level(s) stated in the Modified Demand Agreement. For a Customer referred to in item (i) of the definition of High Load Hours, separate Maximum Demand Levels will be stated for (i) the Low Load Hours from 10:00 hours to 16:00 hours Monday to Friday, except for Statutory Holidays, and (ii) all other Low Load Hours. For a Customer referred to in item (ii) of the definition of Low Load Hours, a single Maximum Demand Level will be stated for all Low Load Hours.

The highest Maximum Demand Level will not exceed 95% of Contract Demand stated in the Customer’s Electricity Supply Agreement, and is subject to local transmission availability.

Special <u>Conditions:</u>

1. The provisions of Rate Schedule 1823 and the ESA continue to apply, except to the extent necessary to avoid conflict with this Rate Schedule and the Modified Demand Agreement. In the case of conflict between this Schedule or the Modified Demand Agreement and Rate Schedule 1823 and the ESA, the provisions of this Schedule and the Modified Demand Agreement shall govern.
2. Upon two occurrences of the following:

   If for any Billing Period the total energy consumed under RS1852, during the LLH, is greater than the LLH CBL Energy by 10% or more,

   The highest kV.A demand in the Billing Period during the High Load Hours (HLH) will be adjusted by a factor of the ratio of the average monthly LLH energy of the two Billing Periods which satisfied the condition above over the LLH CBL Energy. The adjustment of the highest kV.A demand will be in effect starting from the month immediately following the month of the second occurrence and continue for 12 months. The LLH CBL Energy will be recalculated using the consumption history of the most recent

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twelve Billing Periods,

where:

"LLH CBL Energy" means the highest monthly energy consumption during the LLH over the last twelve Billing Periods, or an estimate will be made if insufficient data is available.

3. For the purpose of determining the minimum amount of Minimum Reduction, as stated in the Modified Demand Agreement, the general guideline will be 50% of the difference between the Maximum Demand Level and the LLH CBL Demand, but shall be in all cases, no less than 10MW.
4. For the purpose of determining the Maximum Number of Demand Reduction Transactions, as stated in the Modified Demand Agreement, the Maximum Duration multiplied by the Maximum Number of Demand Reduction Transactions shall be at least 48 hours.

<u>Taxes:</u> The rates contained herein are exclusive of the Goods and Services tax and Social Services tax.

<u>Rate Rider</u>: The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.

<u>Rate Increase</u>: Effective April 1, 2016 the Rates and Minimum Charge under these schedules include an increase of 4.00% before rounding, approved by BCUC Order No. G-XX-XX.

ACCEPTED:______________________________

ORDER NO.______________________________

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ACTING COMMISSION SECRETARY

SCHEDULE 1853 – TRANSMISSION SERVICE – IPP STATION SERVICE

Availability:	For Customers who are Independent Power Producers (IPPs) served at transmission voltage subject to the Special Conditions below.
Applicable in:	Rate Zone I excluding Districts of Kingsgate-Yahk and Lardeau-Shutty Bench.
Rate:	Energy Charge: The sum, over the Billing Period, of the hourly energy consumed multiplied by the entry in the ICE Mid- Columbia (Mid-C) Peak, and Mid-C Off-Peak weighted average index price as published by ICE in the ICE Day Ahead Power Price Report that corresponds to the time when consumption occurred, during that hour.
Minimum Monthly Charge:	$43.02
Special Conditions:	BC Hydro agrees to provide Electricity under this Schedule to the extent that it has energy and capacity to do so. BC Hydro may, without notice to the Customer, terminate the supply of Electricity under this Schedule if at any time BC Hydro does not have sufficient energy or capacity. Prior to taking Electricity under this Schedule, the Customer may be required to obtain approval from BC Hydro. BC Hydro will advise the Customer of the need to obtain approval prior to the taking of energy under this Schedule. Electricity taken under this Schedule is to be used solely for maintenance and black-start requirements and shall not displace Electricity that would normally be generated by the Customer.
Taxes:	The rates and minimum charge contained herein are exclusive of the Goods and Services tax and the Social Services tax.
Rate Rider:	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.
Rate Increase:	Effective April 1, 2016 the Rates and Minimum Charge under these schedules include an increase of 4.00% before rounding, approved by BCUC Order No. G-XX-XX.

ACCEPTED:____________________________

ORDER NO.____________________________

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ACTING COMMISSION SECRETARY

SCHEDULE 1880 – TRANSMISSION SERVICE – STANDBY AND MAINTENANCE SUPPLY

Availability: For Customers supplied with Electricity under Schedules 1823, 1825, 1827, and 1852 subject to the Special Conditions below.

Applicable in: Rate Zone I excluding the Districts of Kingsgate-Yahk and Lardeau-Shutty Bench.

Rate: The Rate per Period of Use shall be:

Administrative Charge:

$150.00 per Period of Use

Energy Charge:

For each hour during the Period of Use the Energy Charge is the Schedule 1880 Energy metered consumption (in kW.h) multiplied by 8.920¢ per kW.

Period of Use: A period of consecutive hours during which Electricity is taken under this Schedule which may extend into subsequent Billing Periods. The Period of Use is as defined by the Customer when making the request to BC Hydro for service under Schedule 1880.

Reference Demand: The HLH Reference Demand is defined as the highest kV.A Demand in the HLH for the current Billing Period prior to the Period of Use excluding any prior Period of Use. If the Period of Use extends over an entire Billing Period, the highest kV.A Demand in the HLH from the prior Billing Period will be used in determining the HLH Reference Demand, excluding any Period of Use in the prior Billing Period.

For the purpose of the Reference Demand, the HLH periods are as defined per Schedule 1823, 1825, 1827 or 1852, whichever is applicable.

Schedule 1880 Energy Determination: During the HLH periods, on an hourly basis, the kW.h consumption which exceeds the HLH High kW.h/hr within the Period of Use, or portion thereof.

The HLH High kW.h/hr is defined as the product of the HLH Reference Demand multiplied by the Power Factor for the half hour when the HLH Reference Demand occurred.

5. In addition to the charges specifically set out in this Schedule, the Customer shall pay for any additional facilities required to deliver Electricity under this Schedule provided that BC Hydro obtains the prior consent of the Customer for construction of the additional facilities.
6. A Customer may be required to allow BC Hydro to install metering and communication equipment to measure the electricity output of the Customer's self-generation unit.
7. BC Hydro will bill for Electricity taken under Schedule 1880 at the same time it bills for Electricity taken under Schedule 1823, 1825, 1827 or 1852, whichever is applicable.

Taxes: The rates contained herein are exclusive of the Goods and Services tax and the Social Services tax.

Note: The terms and conditions under which transmission service is supplied are contained in Electric Tariff Supplements 5 and 6, or Electric Tariff Supplements 87 and 88, as applicable.

Rate Rider: The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.

Rate Increase: Effective April 1, 2016 the Energy Charge under these schedules includes an increase of 4.00% before rounding, approved by BCUC Order No. G-XX-XX.

ACCEPTED:____________________________

ORDER NO.____________________________

ACTING COMMISSION SECRETARY

SCHEDULE 1891 – SHORE POWER SERVICE (TRANSMISSION)

Availability	For the supply of Shore Power to Port Customers served at Transmission Service for use by Eligible Vessels while docked at the Port Customer's Port Facility. Shore Power Service is supplied at 60,000 volts or higher.
Applicable in:	Rate Zone 1
Rate:	Administrative Charge: $150.00 per month Plus Energy Charge: 8.920 ¢ per kW.h
Special Conditions:	1 BC Hydro agrees to provide Electricity under this Rate Schedule to the extent that it has energy and capacity to do so. BC Hydro may refuse service under this Rate Schedule in circumstances where BC Hydro does not have sufficient energy or capacity. For greater certainty, BC Hydro shall not be required to construct a System Reinforcement under Electric Tariff Supplement No. 6 to provide Shore Power Service under this Rate Schedule. 2 The terms and conditions under which Shore Power Service is supplied are contained in the Shore Power Service Agreement (Electric Tariff Supplement No. 86). The Port Customer shall pay to BC Hydro the charges set out in this Rate Schedule in addition to any charges set out in the Shore Power Service Agreement.

ACCEPTED: April 6, 2016

ORDER NO. G-40-16

L Ross
ACTING COMMISSION SECRETARY

SCHEDULE 2600, 2601, 2610, 2611 – LARGE GENERAL SERVICE (150 KW AND OVER) FOR DISTRIBUTION UTILITIES

Availability: For Customers who qualify for General Service and (i) whose Billing Demand (determined under the Special Conditions below) is equal to or greater than 150 kW, or whose energy consumption in any 12 month period is greater than 550,000 kWh; (ii) who re-sell the electricity purchased from BC Hydro under this rate schedule at rates that are designed to and will reduce the electricity consumption of the customers of the Customer; (iii) who are public utilities regulated by the British Columbia Utilities Commission in regard to the re-sale of electricity purchased under this rate schedule; and (iv) who elect service under this rate schedule. Supply is at 60 hertz, single or three phase at secondary or primary potential. BC Hydro reserves the right to determine the potential of the service connection.

Applicable in: Rate Zone I.

Charges: Basic Charge

23.47¢ per day

Demand Charge

First 35 kW of Billing Demand per Billing Period	@ $0.00 per kW
Next 115 kW of Billing Demand per Billing Period	@ $5.72 per kW
All additional kW of Billing Demand per Billing Period	@ $10.97 per kW

Energy Charge

All kWh of energy consumption in the Billing Period @ the rate equal to the sum of:

1. the product of the marginal cost-based energy rate prescribed in the Part 2 Energy Charge/Credit provision of Rate Schedule 1600/1601/1610/1611, and 0.05;

2. the product of 5.52¢ per kWh, and 0.95; and

3. –0.41¢ per kWh.

ACCEPTED: April 6, 2016

ORDER NO. G-40-16

L Ross
ACTING COMMISSION SECRETARY

Metering:	A demand meter will normally be installed. Prior to the installation of such a meter, or if such a meter is not installed, the Billing Demand shall be estimated by BC Hydro.
Rate Rider:	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.
Rate Increase:	Effective April 1, 2016 the Rates and Minimum Charge under these schedules include an increase of 4.00% before rounding, approved by BCUC Order No. G-XX-XX.

ACCEPTED:________________________

ORDER NO.________________________ ________________________

ACTING COMMISSION SECRETARY

SCHEDULE 3808 – TRANSMISSION SERVICE – FORTISBC

Availability:	This schedule is available to FortisBC in accordance with the terms and conditions of the Agreement between BC Hydro and FortisBC entered into and deemed effective the 1st day of July 2014 (the "Power Purchase Agreement"). The Contract Demand shall not exceed 200 MW in any hour.	
Applicable in:	For Electricity delivered to FortisBC at each Point of Delivery as defined in the Power Purchase Agreement.	
Rate:	Demand Charge:	\$7.635 per kW of Billing Demand per Billing Month plus
	Tranche 1 Energy Price:	4.475¢ per kW.h
	Tranche 2 Energy Price:	12.97¢ per kW.h

Billing Demand: The Demand for billing purposes in any Billing Month shall be the greatest of:

1. the maximum amount of Electricity (in kW) scheduled under the Power Purchase Agreement, for any hour of the Billing month;
2. 75% of the maximum amount of electricity (in kW) scheduled under the Power Purchase Agreement in any hour in the 11 months of the Term immediately prior to the Billing Month (or less than 11 months, if the Effective Date is less than 11 months prior to the Month); and
3. 50% of the Contract Demand (in kW) for the Billing Month.

If FortisBC has reduced the Contract Demand in accordance with the Power Purchase Agreement, the amount of Electricity specified in Section 2 above may not exceed an amount equal to 100% of the Contract Demand.

Maximum Tranche1 Amount: The Maximum Tranche 1 Amount for each Contract Year is 1,041 GW.h.

Scheduled Energy Less Than or Equal to Annual Energy Nomination: In any Contract Year, for the amount of the Scheduled Energy taken or deemed to be taken that is less than or equal to the Annual Energy Nomination, FortisBC shall pay:

(a) The Tranche 1 Energy Price for each kW.h of such Scheduled Energy taken or deemed taken that is less than or equal to the Maximum Tranche 1 Amount; and

(b) The Tranche 2 Energy Price for each kW.h of such Scheduled Energy taken that exceeds the Maximum Tranche 1 Amount.

ACCEPTED: April 6, 2016

ORDER NO. G-40-16

L Ross
ACTING COMMISSION SECRETARY

Scheduled Energy Exceeding the Annual Energy Nomination	In any Contract Year, for the amount of the Scheduled Energy taken or deemed to be taken that exceeds the Annual Energy Nomination, FortisBC shall pay: (a) 150% of the Tranche 1 Energy Price, for each kW.h of such Scheduled Energy taken or deemed taken that that exceeds the Annual Energy Nomination, but is less than or equal to the Maximum Tranche 1 Amount; and (b) 115% of the Tranche 2 Energy Price, for each kW.h of such Scheduled Energy taken that exceeds the Annual Energy Nomination and also exceeds the Maximum Tranche 1 Amount.
Annual Minimum Take	In any Contract Year, FortisBC shall schedule and take an amount of Electricity equal to at least 75% of the Annual Energy Nomination, and shall be responsible for any Annual Shortfall.
Note:	The terms and conditions under which service is supplied to FortisBC are contained in the Power Purchase Agreement.
Taxes:	The rates and charges contained herein are exclusive of the Goods and Services tax and the Social Services tax.
Rate Rider:	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.
Rate Increase:	The Tranche 1 Energy Price and Demand Charge are subject to the same rate adjustments as Schedule 1827. Tranche 2 Energy Price is subject to changes as provided for in the Power Purchase Agreement. Effective April 1, 2016 the Tranche 1 Energy Price and the Demand Charge under this schedule includes an increase of 4.00% before rounding, approved by BCUC Order No. G-XX-XX.

ACCEPTED:______________________________

ORDER NO.______________________________ ____
ACTING COMMISSION SECRETARY

ATTACHMENT H

Annual Transmission Revenue Requirement

for Network Integration Transmission Service

1. The Annual Transmission Revenue Requirement for purposes of the Network Integration Transmission Service shall be ~~$823,300,000~~$823,100,000.

2. The amount in (1) shall be effective until amended by the Transmission Provider or modified by the Commission.

Effective April 1, 2016, this Attachment H is approved as per BCUC Order No. G-XX-XX.

ACCEPTED:______________________________

ORDER NO.______________________________

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ACTING COMMISSION SECRETARY

BC Hydro
Open Access Transmission Tariff
Effective: April 1, 2016
OATT Schedule 00 – Tenth Revision of Page 1

Schedule 00

Network Integration Transmission Service

Availability	For wholesale transmission of electricity.
Rate	Monthly Transmission Revenue Requirement: Customers will be charged their load ratio share of one twelfth (1/12th) of the Network Transmission Revenue Requirement per month. The Transmission Revenue Requirement is shown in Attachment H. One-twelfth of the Transmission Revenue Requirement is ~~$68,608,333~~ $68,591,667.
Taxes	The Rate and Charges contained herein are exclusive of applicable taxes.
Note	The terms and conditions under which Network Integration Transmission Service is supplied are contained in BC Hydro's OATT. Capitalized terms appearing in this Schedule, unless otherwise noted, shall have the meaning ascribed to them therein.

Effective April 1, 2016, this rate schedule is approved as per BCUC Order No. G-XX-XX.

ACCEPTED:______________________________

ORDER NO.______________________________ ______________________________
ACTING COMMISSION SECRETARY

Schedule 01

Point-To-Point Transmission Service

Availability	For transmission of electricity on a firm and non-firm basis from one or more Point(s) of Receipt (POR) to one or more Point(s) of Delivery (POD).
Rate for Long-Term Firm Service	The Reserved Capacity Charge for the Long-Term Firm Service Rate will be up to a maximum price as set out below except where the POD is a point of interconnection between the Transmission System and the transmission system of FortisBC Inc., in which case the rate shall be zero ($0.00). The Maximum Reserved Capacity Charge is ~~$70,687~~$70,993/MW of reserved capacity per year to be invoiced monthly. Reserved Capacity Billing Demand The Reserved Capacity Billing Demand is determined for each POR(s), POD(s) pair. The Reserved Capacity for each pair of POR(s) and POD(s) will be the maximum non-coincident sum of the designated POR(s) and POD(s) included in the pair.

ACCEPTED:__________________________

ORDER NO.__________________________

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ACTING COMMISSION SECRETARY

Schedule 01 – Point-To-Point Transmission Service (continued)

Rate for Short-Term Firm and Non-Firm Service	The posted prices for Short-Term Firm and Non-Firm Service will be less than or equal to a maximum price ($/MWh) as set out below, except where the POD is a point of interconnection between the Transmission System and the transmission system of FortisBC Inc., in which case the rate shall be zero ($0.00). Maximum Price for: 1. Monthly delivery: ~~$5,890.60~~$5,916.10/MW of Reserved Capacity per month. 2. Weekly delivery: ~~$1,359.37~~$1,365.25/MW of Reserved Capacity per week. 3. Daily delivery: ~~$193.66~~194.50/MW of Reserved Capacity per day. 4. Hourly delivery: ~~$8.07~~$8.10/MW of Reserved Capacity per hour. Discount Rate: For discounted paths posted on the Transmission Provider's OASIS, the Transmission Customer shall pay each month for Reserved Capacity Billing Demand the greater of the rates set forth below and the rate offered by the Transmission Customer and accepted by the Transmission Provider up to the maximum rate for Short-Term Firm and Non-Firm Service: 1. Hourly delivery: $3/MW of Reserved Capacity per hour in the Heavy Load Hour period (06:00-22:00, Monday - Saturday, excluding NERC holidays) and $1/MW of Reserved Capacity per hour for the Light Load Hour period (remaining hours and days). 2. Daily delivery: sum of the hourly delivery charge in the 24 hour period in the day.
Reserved Capacity for Short-Term Firm and Non-Firm Services	The Reserved Capacity shall be the maximum of the sum of non-coincident POD(s) Capacity Reservations or sum of non-coincident POR(s) Capacity Reservations.

ACCEPTED:______________________________

ORDER NO.______________________________

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ACTING COMMISSION SECRETARY

Schedule 01 – Point-To-Point Transmission Service (continued)

Penalty Charge	In addition to the applicable rate for service and associated charges for Ancillary Services, a penalty charge will be applied to all unauthorized usage at a rate of 125 percent of the maximum hourly delivery charge.
Special Conditions	Discounts: The following conditions apply to discounts for transmission service: 1. any offer of a discount made by BC Hydro must be announced to all Eligible Customers solely by posting on the OASIS, 2 any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an affiliate's use) must occur solely by posting on the OASIS, 3. once a discount is negotiated, details must be immediately posted on the OASIS, and 4. for any discount agreed upon for service on a path, from POR(s) POD(s), BC Hydro must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same POD(s) on the Transmission System.
Taxes	The Rate and Charges contained herein are exclusive of applicable taxes.
Resales	The rates and rules governing charges and discounts stated above shall not apply to resales of transmission service, compensation for which shall be governed by section 23.1 of the Tariff.
Note	The terms and conditions under which Transmission Service is supplied are contained in BC hydro's Open Access Transmission Tariff. Capitalized terms appearing in this Rate Schedule, unless otherwise noted, shall have the meaning ascribed to them therein.

Effective April 1, 2016, this rate schedule is approved as per BCUC Order No. G-XX-XX.

ACCEPTED:________________________

ORDER NO.________________________

ACTING COMMISSION SECRETARY

Schedule 03

Scheduling, System Control, and Dispatch Service

Preamble	This service is required to schedule the movement of power through, out of, within, or into a Control Area. This service can be provided only by the operator of the Control Area in which the transmission facilities used for transmission service are located. Scheduling, System Control and Dispatch Service is to be provided directly by BC Hydro. The Transmission Customer must purchase this service from BC Hydro. The charges for Scheduling, System Control and Dispatch Service are to be based on the rates set forth below.
Availability	In support of Network Integration Transmission Service, Long and Short-Term Firm Point-to-Point Transmission Service, and Non-Firm Point-to-Point Transmission Service.
Rate	$0.105 per MW of Reserved Capacity per hour.
Taxes	The Rate and Charges contained herein are exclusive of applicable taxes.
Note	A description of the methodology for discounting Scheduling, System Control and Dispatch Services provided under this Schedule is contained in Section 3 of the BC Hydro OATT.

Effective April 1, 2016, this rate schedule is approved as per BCUC Order No. G-XX-XX.

ACCEPTED:______________________________

ORDER NO.______________________________

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ACTING COMMISSION SECRETARY

BC Hydro
Power smart

Fiscal F2017 to Fiscal 2019
Revenue Requirements Application

Appendix T

Attachment 2

Tariff Sheets
Black-lined

Special Conditions:

1. The maximum capacity of all heating elements energized at any one time in any water heater served under this schedule shall not exceed the greater of 1,500 watts or 45 watts per litre (200 watts per imperial gallon) of tank capacity, except with the written permission of BC Hydro.
2. Schedule 1121 applies if the Premises contain more than two Single-Family Dwellings.

A discount of 25¢ per month per kW of maximum demand shall be applied to Schedule 1121 if a Customer supplies the transformation from a primary potential to a secondary potential. BC Hydro will install a demand meter in addition to a kilowatt hour meter. BC Hydro will install its meters at the secondary potential. The Billing Code for Schedule 1121 Customers eligible for the Discount for Ownership of Transformers shall be Schedule 1122.

Rate Rider: The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.

~~Interim~~ Rate Increase: Effective April 1, 2016 the Rates and Minimum Charge under these schedules include an ~~interim~~ increase of 4.00% before rounding, approved by BCUC Order No. ~~G-40-16~~ G-XX-XX.

ACCEPTED:____________________

ORDER NO.____________________

ACTING COMMISSION SECRETARY

5. BC Hydro will upgrade an existing service connection supplying firm load to serve additional load under this rate schedule. The charge for upgrading will be the same as applicable to a new service connection.
6. No other load than that stipulated in the Availability clause is permitted under this rate schedule. Any unauthorized use of electricity or any refusal by a customer to permit Access to Premises in accordance with the Terms and Conditions of BC Hydro's Electric Tariff will result in the immediate disconnection of the service and all unauthorized consumption as estimated by BC Hydro shall be billed at the rate for electricity during a Period of Interruption as stated in this rate schedule.
7. In addition to and without restriction of any other limitations of liability of BC Hydro, BC Hydro shall specifically not be liable for any loss, damage, injury or expense occasioned to or suffered by any customer receiving service on this rate schedule, or by any other person, for or by reason of any interruption of electricity supply whatsoever for any reason whatsoever.
8. The maximum capacity of all heating elements energized at any one time in any water heater served under this schedule shall not exceed the greater of 1,500 watts or 45 watts per litre (200 watts per imperial gallon) of tank capacity, except with the written permission of BC Hydro
9. At the conclusion of any Period of Interruption, BC Hydro may terminate service under this rate schedule to any customer who used electricity during a Period of Interruption, unless it can be demonstrated to BC Hydro's satisfaction that adequate standby facilities exist.

Rate Rider: The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.

~~Interim~~ Rate Increase: Effective April 1, 2016 the Rates and Minimum Charge under these schedules include an ~~interim~~ increase of 4.00% before rounding, approved by BCUC Order No. ~~G-40-16~~G-XX-XX.

ACCEPTED:____________________

ORDER NO.____________________

ACTING COMMISSION SECRETARY

SCHEDULE 1107, 1127 – RESIDENTIAL SERVICE – ZONE II

Availability: For Residential Service. Service is normally single phase, 60 hertz at the secondary potential available. In BC Hydro's discretion, service may be three phase 120/208 or 240 volts.

Applicable in: Rate Zone II.

Rate:

1. Schedule 1107 - Residential Service

   Basic Charge 19.57 ¢ per day

   First 1500 kW.h per month @ 9.93 ¢ per kW.h

   All additional kW.h per month @ 17.07 ¢ per kW.h.

2. Schedule 1127 - Multiple Residential Service

   Basic Charge 19.57 ¢ per single-family dwelling per day

   First 1500 kW.h per single-family dwelling per month @ 9.93 ¢ per kW.h

   All additional kW.h per month @ 17.07 ¢ per kW.h.

Minimum Charge: Schedule 1107 - The Basic Charge.

Schedule 1127 - The Basic Charge per Single-Family Dwelling.

Special Conditions:

1. The maximum capacity of all heating elements energized at any one time in any water heater served under this schedule shall not exceed the greater of 1,500 watts or 45 watts per litre (200 watts per imperial gallon) of tank capacity, except with the written permission of BC Hydro.
2. Schedule 1127 applies if the Premises contain more than two Single-Family Dwellings.

Discount for Ownership of Transformers: A discount of 25¢ per month per kW of maximum demand shall be applied to Schedule 1127 if a Customer supplies the transformation from a primary potential to a secondary potential. BC Hydro will install a demand meter in addition to a kilowatt hour meter. BC Hydro will install its meters at the secondary potential. The Billing Code for Schedule 1127 Customers eligible for the Discount for Ownership of Transformers shall be Schedule 1128.

Rate Rider: The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.

~~Interim~~ Rate Increase: Effective April 1, 2016 the Rates and Minimum Charge under these schedules include an ~~interim~~ increase of 4.00% before rounding, approved by BCUC Order No. ~~G-40-16~~G-XX-XX.

ACCEPTED:______________________

ORDER NO.______________________

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ACTING COMMISSION SECRETARY

SCHEDULE 1148 – RESIDENTIAL SERVICE – ZONE II (CLOSED)

Availability:	For Residential Service in Rate Zone II where a permanent electric space heating system is in use, providing the aforesaid system was installed prior to 10 October 1966. This schedule is available only to a Customer and Premises served under this rate schedule on 24 April 1992 and continuously thereafter.
Applicable in:	Rate Zone II.
Rate:	Basic Charge 19.57 ¢ per day All kW.h @ 9.93 ¢ per kW.h.
Minimum Charge:	The Basic Charge.
Special Condition:	The maximum capacity of all heating elements energized at any one time in any water heater served under this schedule shall not exceed the greater of 1,500 watts or 45 watts per litre (200 watts per imperial gallon) of tank capacity, except with the written permission of BC Hydro.
Rate Rider:	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.
~~Interim~~ Rate Increase:	Effective April 1, 2016 the Rates and Minimum Charge under these schedules include an ~~interim~~ increase of 4.00% before rounding, approved by BCUC Order No. ~~G-40-16~~ G-XX-XX.

ACCEPTED:____________________________

ORDER NO.____________________________

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ACTING COMMISSION SECRETARY

Discount for Ownership of Transformers:	A discount of 25¢ per month per kW of maximum demand shall be applied to Schedule 1161 if a Customer supplies the transformation from a primary potential to a secondary potential. BC Hydro will install a demand meter in addition to a kilowatt hour meter. BC Hydro will install its meters at the secondary potential. The Billing Code for Schedule 1161 Customers eligible for the Discount for Ownership of Transformers shall be Schedule 1162.
Rate Rider:	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.
~~Interim~~ Rate Increase:	Effective April 1, 2016 the Rates and Minimum Charge under these schedules include an ~~interim~~ increase of 4.00% before rounding, approved by BCUC Order No. ~~G-40-16~~G-XX-XX.

Billing Codes:

Schedule 1200 applies if a Customer's supply of electricity is metered at a secondary potential and BC Hydro supplies transformation from a primary potential to a secondary potential.

Schedule 1201 applies if a Customer's supply of electricity is metered at a primary potential and BC Hydro supplies transformation from a primary potential to a secondary potential.

Schedule 1210 applies if a Customer's supply of electricity is metered at a secondary potential and the Customer supplies transformation from a primary potential to a secondary potential.

Schedule 1211 applies if a Customer's supply of electricity is metered at a primary potential and the Customer supplies transformation from a primary potential to a secondary potential.

Billing Demand: The Billing Demand shall be the highest kW demand in the Billing Period.

Billing Period: "Billing Period" means a period of 27 to 33 consecutive days between regular meter readings, provided that in cases where meter readings are not available or are delayed for any reason BC Hydro may vary the number of days in the Billing Period.

Monthly Minimum Charge: 50% of the highest maximum demand charge billed in any billing period wholly within an on-peak period during the immediately preceding eleven billing periods. For the purpose of this provision an on-peak period commences on 1 November in any year and terminates on 31 March of the following year.

Special Condition:

1. A demand meter will normally be installed. Prior to the installation of such a meter, or if such a meter is not installed, the demand for billing purposes shall be the assessed demand estimated by BC Hydro.
2. Migration rule (between Exempt General Service and Small General Service): Customers taking service at Exempt General Service rates (Rate Schedules 1200, 1201, 1210 or 1211) will be moved to service at Small General Service rates (Rate Schedules 1300, 1301, 1310 or 1311) if the Customers' Billing Demand in each of the 12 most recent consecutive Billing Periods was less than 35 kW.

Rate Rider: The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.

~~Interim~~ Rate Increase: Effective April 1, 2016 the Rates and Minimum Charge under these schedules include an ~~interim~~ increase of 4.00% before rounding, approved by BCUC Order No. ~~G-40-16~~ G-XX-XX.

ACCEPTED:____________________

ORDER NO.____________________

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ACTING COMMISSION SECRETARY

the Terms and Conditions of BC Hydro's Electric Tariff will result in the immediate disconnection of the service and all unauthorized consumption as estimated by BC Hydro shall be billed at the rate for electricity during a Period of Interruption as stated in these rate schedules.

9. In addition to and without restriction of any other limitations of liability of BC Hydro, BC Hydro shall specifically not be liable for any loss, damage, injury or expense occasioned to or suffered by any customer receiving service on these rate schedules, or by any other person, for or by reason of any interruption of electricity supply whatsoever for any reason whatsoever.

10. A customer who signs a contract with BC Hydro for the supply of electricity to new load under these rate schedules during the period commencing 1 July 1988 and ending 31 December 1988 shall be eligible to receive an incentive rebate on his electricity bills provided the customer begins taking service under these rate schedules no later than twelve months following the date the contract was signed.

11. A rebate shall be applied to reduce the effective rate to 1.1 ¢ per kW.h. Such rebate will apply only to an accumulated maximum of $30.00 per kW of connected new load in excess of 35 kW and only up to the first two years following connection. Bills for energy consumed shall be calculated and presented at full rates with the rebate for any given period applied to the following bill. The maximum two year period of billing rebates shall be extended by the equivalent of any Period of Interruption. Rebates shall not be applied to reduce the rate applicable for consumption during a Period of Interruption, nor shall rebates be applied to reduce power factor surcharges.

12. At the conclusion of any Period of Interruption, BC Hydro may terminate service under these rate schedules to any customer who used electricity during a Period of Interruption, unless it can be demonstrated to BC Hydro's satisfaction that adequate standby facilities exist.

Rate Rider: The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.

~~Interim~~ Rate Increase: Effective April 1, 2016 the Rates and Minimum Charge under these schedules include an ~~interim~~ increase of 4.00% before rounding, approved by BCUC Order No. ~~G-40-16~~ G-XX-XX.

ACCEPTED:____________________

ORDER NO.____________________

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ACTING COMMISSION SECRETARY

SCHEDULE 1234 – SMALL GENERAL SERVICE (UNDER 35 KW) – ZONE II

Availability:	For all purposes where a demand meter is not installed because the Customer's demand as estimated by BC Hydro is less than 35 kW. Supply is 60 hertz, single or three phase at an available secondary potential.
Applicable in:	Rate Zone II.
Rate:	Basic Charge 23.47 ¢ per day First 7000 kW.h per month @ 11.16 ¢ per kW.h All additional kW.h per month @ 18.58 ¢ per kW.h
Minimum Charge:	The Basic Charge.
Special Conditions for Unmetered Service:	Same as in Rate Schedules 1300, 1301, 1310 and 1311.
Rate Rider:	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.
~~Interim~~ Rate Increase:	Effective April 1, 2016 the Rates and Minimum Charge under these schedules include an ~~interim~~ increase of 4.00% before rounding, approved by BCUC Order No. ~~G-40-16~~G-XX-XX.

ACCEPTED:____________________

ORDER NO.____________________

ACTING COMMISSION SECRETARY

SCHEDULE 1253 – DISTRIBUTION SERVICE – IPP STATION SERVICE

Availability:	For Customers who are Independent Power Producers (IPPs) served at distribution voltage, subject to the Special Conditions below.	
Applicable in:	Rate Zone I excluding Districts of Kingsgate-Yahk and Lardeau-Shutty Bench.	
Rate:	Energy Charge:	The sum, over the Billing Period, of the hourly energy consumed multiplied by the entry in the ICE Mid Columbia (Mid-C) Peak, and Mid-C Off-Peak weighted average index price as published by ICE in the ICE Day Ahead Power Price Report that corresponds to the time when consumption occurred, during that hour.
Monthly Minimum Charge:	$43.02	

Special Conditions:

1. BC Hydro agrees to provide Electricity under this Schedule to the extent that it has energy and capacity to do so.
2. BC Hydro may, without notice to the Customer, terminate the supply of Electricity under this Schedule if at any time BC Hydro does not have sufficient energy or capacity.
3. Prior to taking Electricity under this Schedule, the Customer may be required to obtain approval from BC Hydro. BC Hydro will advise the Customer of the need to obtain approval prior to the taking of energy under this Schedule.
4. Electricity taken under this Schedule is to be used solely for maintenance and black-start requirements and shall not displace Electricity that would normally be generated by the Customer.

Rate Rider: The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.

~~Interim~~ Rate Increase: Effective April 1, 2016 the Rates and Minimum Charge under these schedules include an ~~interim~~ increase of 4.00% before rounding, approved by BCUC Order No. ~~G-40-16~~G-XX-XX.

ACCEPTED:____________________

ORDER NO.____________________

ACTING COMMISSION SECRETARY

Monthly Minimum Charge:	The Monthly Minimum Charge paid by a Customer on Schedule 1255, or 1256, or 1265 or 1266 shall be the charge the Customer would have paid if he had been billed on Schedule 1200, or 1201, or 1210 or 1211 respectively.
Special Conditions:	1. A demand meter will normally be installed; prior to the installation of such a meter, or if such a meter is not installed, the demand for billing purposes shall be the assessed demand estimated by BC Hydro. 2. Where the Customer's demand is or is likely to be in excess of 45 kV.A, then BC Hydro may require that supply to such Customer be by special contract and that such supply be subject to such special conditions as BC Hydro, in its sole discretion, considers necessary to insert in the Customer's special contract.
Rate Rider:	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.
~~Interim~~ Rate Increase:	Effective April 1, 2016 the Rates and Minimum Charge under these schedules include an ~~interim~~ increase of 4.00% before rounding, approved by BCUC Order No. ~~G-40-16~~G-XX-XX.

3. The metering point to determine the electricity being delivered to BC Hydro's distribution system will be determined by BC Hydro. The electricity delivered to BC Hydro's distribution system will also be deemed to be delivered to BC Hydro's transmission system (that is, no distribution loss adjustment will be applied to the electricity from an IPP or self-generator when determining capacity and energy delivered to BC Hydro's transmission system).

Rate Rider: The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.

~~Interim~~ Rate Increase: Effective April 1, 2016 the Rates and Minimum Charge under these schedules include an ~~interim~~ increase of 4.00% before rounding, approved by BCUC Order No. ~~G-40-16~~G-XX-XX.

SCHEDULE 1278 – POWER SERVICE (CLOSED)

Availability: For power service when the demand is not less than 2000 kV.A for use in any one or more of electric steel making and the electric heating or melting of metals or other materials when such heating or melting is part of a continuous production process.

This schedule is available only to a Customer served under this schedule on 1 April 1970 and continuously thereafter.

Capacity in excess of that set out in a Customer's contract with BC Hydro, in effect on 1 April 1970, may be supplied at the sole discretion of BC Hydro.

Service is three phase, 60 hertz at a nominal potential of 12,500 volts or higher as available

Applicable in: Those parts of the Lower Mainland served by B.C. Electric Company Ltd. on 29 March 1962.

Rate: $2.785 per kV.A by which the maximum demand per month exceeds the capacity which BC Hydro had agreed to supply under this rate schedule on 1 April 1970;

plus

7.280 ¢ per kW.h per month.

Monthly Minimum Charge: The greater of:

(i) $5.44 per kV.A of maximum demand, or

(ii) $10,879.19

Special Condition: A Customer taking electricity on this schedule for the operation of an electric arc furnace shall, as a condition of service, install such inductive reactance as BC Hydro may specify. A Customer who has installed reactance as specified shall not then be required to correct for lagging power factor occasioned by the operation of the said arc furnace.

Rate Rider: The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.

~~Interim~~ Rate Increase: Effective April 1, 2016 the Rates and Minimum Charge under these schedules include an ~~interim~~ increase of 4.00% before rounding, approved by BCUC Order No. ~~G-40-16~~G-XX-XX.

ACCEPTED:____________________

ORDER NO.____________________

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ACTING COMMISSION SECRETARY

Rate Rider:	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.
~~Interim~~ Rate Increase:	Effective April 1, 2016 the Rates and Minimum Charge under these schedules include an ~~interim~~ increase of 4.00% before rounding, approved by BCUC Order No. ~~G-40-16~~G-XX-XX.

ACCEPTED:____________________________

ORDER NO.____________________________

ACTING COMMISSION SECRETARY

5. Transfer to the rate under Part 2

Energy Charges under Part 2 will be applied progressively to groups of Customers according to their kW Billing Demand, as follows:

a. Commencing on April 1, 2012, Customers whose Billing Demand is equal to or greater than 85 kW and less than 150 kW at least once in the twelve month period ending September 30 in the previous year.

b. Commencing on April 1, 2013, all remaining Medium General Service Customers.

Rate Rider: The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.

~~Interim~~ Rate Increase: Effective April 1, 2016 the Rates and Minimum Charge under these schedules include an ~~interim~~ increase of 4.00% before rounding, approved by BCUC Order No. ~~G-40-16~~G-XX-XX.

4. Migration Rule

4.1 Customers taking service at Medium General Service rates (rate schedules 1500, 1501, 1510 or 1511) will be moved to service at Large General Service rates (rate schedules 1600, 1601, 1610 or 1611) if the Customers' Billing Demand in any 6 of the most recent 12 Billing Periods was equal to or greater than 150 kW, or if the Customers' energy consumption was in excess of 550,000 kW.h in any 12 consecutive month period.

4.2 Customers taking service at Large General Service rates (rate schedules 1600, 1601, 1610 or 1611) will be moved to service at Medium General Service rates (rate schedules 1500, 1501, 1510 or 1511) if the Customers' Billing Demand in each of the 12 most recent consecutive Billing Periods was less than 100 kW and energy consumption in the 12 month period which corresponds to those Billing Periods was less than 400,000 kW.h.

5. Application for Prospective Growth

The rates prescribed in this schedule, in regard to a specific customer, are subject to Electric Tariff Supplement No. 82 – Rules for LGS Prospective Growth Applications.

Rate Rider: The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.

~~Interim~~ Rate Increase: Effective April 1, 2016 the Rates and Minimum Charge under these schedules include an ~~interim~~ increase of 4.00% before rounding, approved by BCUC Order No. ~~G-40-16~~G-XX-XX.

ACCEPTED:______________________________

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ACTING COMMISSION SECRETARY

Non-Irrigation Season:	The period commencing at the end of one Irrigation Season and terminating at the beginning of the next Irrigation Season.
Special Conditions:	1. No equipment which has been served with electricity under this rate schedule shall be served with electricity under any other rate schedule while the Customer's agreement for service under this rate schedule is in force. 2. Normally the service will be energized during the Non-Irrigation Season, but will be disconnected if a Customer so requests. 3. The Minimum Charge during the Irrigation Season shall commence in March for an account which has not been terminated by the Customer, whether or not the service is energized and will be billed in two installments, at the end of July and at the end of October.
Billing:	1. For the Irrigation Season, a bill will be rendered following the July and October meter readings. The first bill will be the greater of the energy charge or the Minimum Charge for the period 1 March to 31 July. The second bill will be the greater of the energy charge for the season or the Minimum Charge for the season, less payment received for the first billing charges. 2. For the Non-Irrigation Season a bill will be rendered following the March meter reading provided that there is registered consumption.
Note:	If a motor is rated in horsepower, the conversion factor from horsepower to kilowatts shall be: 1 horsepower = 0.746 kilowatts
Rate Rider:	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.
~~Interim~~ Rate Increase:	Effective April 1, 2016 the Rates and Minimum Charge under these schedules include an ~~interim~~ increase of 4.00% before rounding, approved by BCUC Order No. ~~G-40-16~~G-XX-XX.

ACCEPTED:________________________

ORDER NO.________________________

ACTING COMMISSION SECRETARY

4. Relocation and Redirection of Fixtures

   The Customer shall pay the full cost of relocating or redirecting fixtures when the change is made at the request of the Customer.

5. Design

   BC Hydro will design the installation of overhead street lighting fixtures.

6. Lamps Failing to Operate

   BC Hydro will, without charge, replace lamps or components which fail to operate, unless breakage is the reason for such failure in which case the Customer shall be charged the cost of the material required to make the fixture operate.

7. Contract Period

   The term of the initial contract shall be not more than five years, renewal periods shall be for five years.

Rate Rider: The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.

~~Interim~~ Rate Increase: Effective April 1, 2016 the Rates and Minimum Charge under these schedules include an ~~interim~~ increase of 4.00% before rounding, approved by BCUC Order No. ~~G-40-16~~G-XX-XX.

6. Unmetered Service

(a) BC Hydro may permit unmetered service under this rate schedule if it can estimate to its satisfaction the energy used in kilowatt hours over a period of one month based on the connected load and hours of use.

(b) The Customer shall notify BC Hydro immediately of any proposed or actual change in load, or load characteristics, or hours of use.

(c) BC Hydro, in its discretion, may at any time install a meter or meters and thereafter bill the Customer on the consumption registered.

Rate Rider: The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.

~~Interim~~ Rate Increase: Effective April 1, 2016 the Rates and Minimum Charge under these schedules include an ~~interim~~ increase of 4.00% before rounding, approved by BCUC Order No. ~~G-40-16~~G-XX-XX.

ACCEPTED:______________________________

ORDER NO.______________________________

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ACTING COMMISSION SECRETARY

Special Terms and Conditions:

1. Extension Policy

   No extensions will be made to serve street lights under this schedule.

2. Power Factor

   All installations of mercury vapour, sodium vapour or fluorescent lamps shall be equipped with the necessary auxiliaries to assure that a power factor of not less than 90% lagging shall be maintained.

3. Contract Period

   The term of the initial contract shall be not more than five years; renewal periods shall be for five years.

4. Fixtures with Automated Dimming Controls

The following special terms and conditions apply to lighting fixtures fitted with dimming controls:

a. For purposes of this part "dimming controls" means control units or fittings attached to or forming part of a street lighting fixture capable of being programmed or remotely operated so as to reduce the lumens output of the lamps during specified hours each day while the lamps are in operation. The reductions may vary according to the hours of the day, the days of the week, and the seasons of the year.

b. A Customer wishing to have fixtures with dimming controls separately rated under this rate schedule must submit a Dimming Schedule satisfactory to BC Hydro listing each light fixture fitted with dimming controls, the wattage of the fixture (including the lamp and, where applicable, the ballast), the dimming control setting or settings and the hours each day that the dimming control setting or settings will be in operation.

Whenever the Customer wishes to make changes in the lighting fixtures listed in the Dimming Schedule or in the dimming control settings or hours of operation, the Customer shall submit an updated Lighting Fixture Schedule to BC Hydro listing any changes. Changes will be permitted on a semi-annual basis (twice per year).

Rate Rider: The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.

~~Interim~~ Rate Increase: Effective April 1, 2016 the Rates and Minimum Charge under these schedules include an ~~interim~~ increase of 4.00% before rounding, approved by BCUC Order No. ~~G-40-16~~G-XX-XX.

ACCEPTED:________________________

ORDER NO.________________________

ACTING COMMISSION SECRETARY

SCHEDULE 1704 – TRAFFIC CONTROL EQUIPMENT

Availability: For traffic signals, traffic signs and traffic warning devices, and other equipment for controlling or directing vehicular or pedestrian traffic on public highways. For cases where the Customer installs, owns and maintains the standards, fixtures, wiring, controls and associated equipment.

Applicable in: All Rate Zones.

Rate: 9.93¢ per kW.h.

Special Terms and Conditions:

1. Service Connections

   Where necessary BC Hydro will provide an overhead or underground Service Connection in accordance with the Terms and Conditions of the Electric Tariff as applicable to "Service Connections".

2. Unmetered Service

   (a) BC Hydro may permit unmetered service under this rate schedule if it can estimate to its satisfaction the energy used in kilowatt hours over a period of one month based on the connected load and hours of use.

   (b) The Customer shall notify BC Hydro immediately of any proposed or actual change in load, or load characteristics, or hours of use.

   (c) BC Hydro, in its discretion, may at any time install a meter or meters and thereafter bill the Customer on the consumption registered.

3. Contract Period

   The term of the initial contract shall not be more than five years; renewal periods shall be for five years.

Rate Rider: The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.

~~Interim~~ Rate Increase: Effective April 1, 2016 the Rates and Minimum Charge under these schedules include an ~~interim~~ increase of 4.00% before rounding, approved by BCUC Order No. ~~G-40-16~~G-XX-XX.

ACCEPTED:______________________________

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175 watt Mercury Vapour Unit or replacement 100 watt H.P. Sodium Vapour Unit	$21.09
400 watt Mercury Vapour Unit or replacement 150 watt H.P. Sodium Vapour Unit	$33.20

except that if two or more lights are mounted at one time on the same pole the rates for the additional light or lights shall be as set out under Item 1 above.

Special Conditions:

1. BC Hydro shall provide and install:
   (a) an outdoor light consisting of luminaire, mast arm, ballast, lamp and photo-electric control, and
   (b) not more than one span of overhead secondary conductors per light.
2. The Customer will be required to contribute the estimated cost of any plant required to make secondary potential available at a point not more than one span from the light; such contribution is not subject to refund.
3. BC Hydro reserves the sole right to determine whether or not a light shall be installed on a pole which is part of BC Hydro's distribution system.
4. The prior approval of BC Hydro is required if a Customer intends to install his own poles, and such poles shall be maintained to BC Hydro's satisfaction at the Customer's expense.
5. BC Hydro will maintain all equipment owned by BC Hydro and will replace lamps which have failed. Any breakage will be repaired by BC Hydro at the Customer's expense.
6. The initial contract period shall be three years and thereafter service shall be provided from month to month.

Rate Rider: The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.

~~Interim~~ Rate Increase: Effective April 1, 2016 the Rates and Minimum Charge under these schedules include an ~~interim~~ increase of 4.00% before rounding, approved by BCUC Order No. ~~G-40-16~~G-XX-XX.

ACCEPTED:____________________

ORDER NO.____________________

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ACTING COMMISSION SECRETARY

Special Conditions: The following Special Conditions are applicable to this Schedule:

1. If any initial, revised, or aggregate CBL for a Customer has not been determined by BC Hydro and approved by British Columbia Utilities Commission by the time the CBL would become effective, BC Hydro may determine the CBL on an interim basis, and apply the CBL so determined for purposes of any Billing Periods and bills rendered to the Customer until such time as the CBL has been finally determined and approved by the British Columbia Utilities Commission, whereupon BC Hydro will make any necessary billing adjustments.
2. If a Customer taking service at the rates in Part B of the Energy Charge rate section above terminates service under this Schedule prior to the end of a Billing Year, the Customer's CBL or aggregate CBL will be prorated for the portion of the Billing Year during which the Customer was taking service, and the prorated CBL or aggregate CBL will be used for purposes of applying the rates in Part B to all electricity consumption during the Billing Year up to the time of termination. BC Hydro will make any necessary billing adjustments and bill the Customer for the difference (if any) owing.

Taxes: The rates and minimum charge contained herein are exclusive of the Goods and Services tax and Social Services tax.

Note: The terms and conditions under which transmission service is supplied are contained in Electric Tariff Supplements 5 and 6, or Electric Tariff Supplements 87 and 88, as applicable.

Rate Rider: The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.

~~Interim~~ Rate Increase: Effective April 1, 2016 the Rates and Minimum Charge under these schedules include an ~~interim~~ increase of 4.00% before rounding, approved by BCUC Order No. ~~G-40-16~~G-XX-XX.

ACCEPTED:______________________________

ORDER NO.______________________________

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ACTING COMMISSION SECRETARY

Utilities Commission by the time the CBL would become effective, BC Hydro may determine the CBL on an interim basis, and apply the CBL so determined for purposes of any Billing Periods and bills rendered to the Customer until such time as the CBL has been finally determined and approved by the British Columbia Utilities Commission, whereupon BC Hydro will make any necessary billing adjustments.

3. In accordance with the TOU (Transmission Service) Agreement, the Customer will have a period of 30 days following approval of the Customer's initial CBL by the British Columbia Utilities Commission within which the Customer may, by written notice to BC Hydro, withdraw from taking service under this Schedule, and revert to taking service under Schedule 1823 (Stepped Rate) instead. This right of withdrawal is available only when the Customer first subscribes to take service under this Schedule, and is applicable only in respect of the initial CBL determination. If the Customer exercises this right of withdrawal Schedule 1823 will apply from the commencement of the Billing Year, and BC Hydro will make any necessary billing adjustments.

Taxes:

4. Customers taking service under Schedule 1852 may not also take service under this Schedule.

Note: The rate charges contained herein are exclusive of the Goods and Services tax and Social Services tax.

The terms and conditions under which service is supplied are contained in the Electricity Supply Agreement (Electric Tariff Supplement 5 or Electric Tariff Supplement 87, as applicable) as amended by the TOU (Transmission Service) Agreement (Electric Tariff Supplement 72).

Rate Rider: The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.

~~Interim~~ Rate Increase: Effective April 1, 2016 the Rates and Minimum Charge under these schedules include an ~~interim~~ increase of 4.00% before rounding, approved by BCUC Order No. ~~G-40-16~~G-XX-XX.

ACCEPTED:____________________________

ORDER NO.____________________________

ACTING COMMISSION SECRETARY

Taxes: The rates and minimum charge contained herein are exclusive of the Goods and Services tax and Social Service tax.

Note: The terms and conditions under which transmission service is supplied are contained in Electric Tariff Supplements 5 and 6, or Electric Tariff Supplements 87 and 88, as applicable.

Rate Rider: The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.

~~Interim~~ Rate Increase: Effective April 1, 2016 the Rates and Minimum Charge under these schedules include an ~~interim~~ increase of 4.00% before rounding, approved by BCUC Order No. ~~G-40-16~~G-XX-XX.

twelve Billing Periods,

where:

"LLH CBL Energy" means the highest monthly energy consumption during the LLH over the last twelve Billing Periods, or an estimate will be made if insufficient data is available.

3. For the purpose of determining the minimum amount of Minimum Reduction, as stated in the Modified Demand Agreement, the general guideline will be 50% of the difference between the Maximum Demand Level and the LLH CBL Demand, but shall be in all cases, no less than 10MW.
4. For the purpose of determining the Maximum Number of Demand Reduction Transactions, as stated in the Modified Demand Agreement, the Maximum Duration multiplied by the Maximum Number of Demand Reduction Transactions shall be at least 48 hours.

Taxes:	The rates contained herein are exclusive of the Goods and Services tax and Social Services tax.
Rate Rider:	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.
~~Interim~~ Rate Increase:	Effective April 1, 2016 the Rates and Minimum Charge under these schedules include an ~~interim~~ increase of 4.00% before rounding, approved by BCUC Order No. ~~G-40-16~~G-XX-XX.

SCHEDULE 1853 – TRANSMISSION SERVICE – IPP STATION SERVICE

Availability: For Customers who are Independent Power Producers (IPPs) served at transmission voltage subject to the Special Conditions below.

Applicable in: Rate Zone I excluding Districts of Kingsgate-Yahk and Lardeau-Shutty Bench.

Rate: Energy Charge: The sum, over the Billing Period, of the hourly energy consumed multiplied by the entry in the ICE Mid- Columbia (Mid-C) Peak, and Mid-C Off-Peak weighted average index price as published by ICE in the ICE Day Ahead Power Price Report that corresponds to the time when consumption occurred, during that hour.

Minimum Monthly Charge: $43.02

Special Conditions: BC Hydro agrees to provide Electricity under this Schedule to the extent that it has energy and capacity to do so.

BC Hydro may, without notice to the Customer, terminate the supply of Electricity under this Schedule if at any time BC Hydro does not have sufficient energy or capacity.

Prior to taking Electricity under this Schedule, the Customer may be required to obtain approval from BC Hydro. BC Hydro will advise the Customer of the need to obtain approval prior to the taking of energy under this Schedule.

Electricity taken under this Schedule is to be used solely for maintenance and black-start requirements and shall not displace Electricity that would normally be generated by the Customer.

Taxes: The rates and minimum charge contained herein are exclusive of the Goods and Services tax and the Social Services tax.

Rate Rider: The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.

~~Interim~~ Rate Increase: Effective April 1, 2016 the Rates and Minimum Charge under these schedules include an ~~interim~~ increase of 4.00% before rounding, approved by BCUC Order No. ~~G-40-16~~G-XX-XX.

ACCEPTED:________________________

ORDER NO.________________________

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5. In addition to the charges specifically set out in this Schedule, the Customer shall pay for any additional facilities required to deliver Electricity under this Schedule provided that BC Hydro obtains the prior consent of the Customer for construction of the additional facilities.
6. A Customer may be required to allow BC Hydro to install metering and communication equipment to measure the electricity output of the Customer's self-generation unit.
7. BC Hydro will bill for Electricity taken under Schedule 1880 at the same time it bills for Electricity taken under Schedule 1823, 1825, 1827 or 1852, whichever is applicable.

Taxes: The rates contained herein are exclusive of the Goods and Services tax and the Social Services tax.

Note: The terms and conditions under which transmission service is supplied are contained in Electric Tariff Supplements 5 and 6, or Electric Tariff Supplements 87 and 88, as applicable.

Rate Rider: The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.

~~Interim~~ Rate Increase: Effective April 1, 2016 the Energy Charge under these schedules includes an ~~interim~~ increase of 4.00% before rounding, approved by BCUC Order No. ~~G-40-16~~G-XX-XX.

Metering: A demand meter will normally be installed. Prior to the installation of such a meter, or if such a meter is not installed, the Billing Demand shall be estimated by BC Hydro.

Rate Rider: The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.

~~Interim~~ Rate Increase: Effective April 1, 2016 the Rates and Minimum Charge under these schedules include an ~~interim~~ increase of 4.00% before rounding, approved by BCUC Order No. ~~G-40-16~~G-XX-XX.

ACCEPTED:______________________________

ORDER NO.______________________________

ACTING COMMISSION SECRETARY

Scheduled Energy Exceeding the Annual Energy Nomination

In any Contract Year, for the amount of the Scheduled Energy taken or deemed to be taken that exceeds the Annual Energy Nomination, FortisBC shall pay:

(a) 150% of the Tranche 1 Energy Price, for each kW.h of such Scheduled Energy taken or deemed taken that that exceeds the Annual Energy Nomination, but is less than or equal to the Maximum Tranche 1 Amount; and

(b) 115% of the Tranche 2 Energy Price, for each kW.h of such Scheduled Energy taken that exceeds the Annual Energy Nomination and also exceeds the Maximum Tranche 1 Amount.

Annual Minimum Take

In any Contract Year, FortisBC shall schedule and take an amount of Electricity equal to at least 75% of the Annual Energy Nomination, and shall be responsible for any Annual Shortfall.

Note:

The terms and conditions under which service is supplied to FortisBC are contained in the Power Purchase Agreement.

Taxes:

The rates and charges contained herein are exclusive of the Goods and Services tax and the Social Services tax.

Rate Rider:

The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.

~~Interim~~ Rate Increase:

The Tranche 1 Energy Price and Demand Charge are subject to the same rate adjustments as Schedule 1827. Tranche 2 Energy Price is subject to changes as provided for in the Power Purchase Agreement.

Effective April 1, 2016 the Tranche 1 Energy Price and the Demand Charge under this schedule includes an ~~interim~~ increase of 4.00% before rounding, approved by BCUC Order No. ~~G-40-16~~G-XX-XX.

ACCEPTED:______________________________

ORDER NO.______________________________

ACTING COMMISSION SECRETARY

ATTACHMENT H

Annual Transmission Revenue Requirement
for Network Integration Transmission Service

1. The Annual Transmission Revenue Requirement for purposes of the Network Integration Transmission Service shall be $~~805,500,000~~~~823,300,000~~823,100,000.

2. The amount in (1) shall be effective until amended by the Transmission Provider or modified by the Commission.

Effective April 1, 2016, this ~~rate schedule~~Attachment H is ~~interim~~ approved as per BCUC Order No. ~~G-40-16~~ G-XX-XX.

ACCEPTED:____________________________

ORDER NO.____________________________

ACTING COMMISSION SECRETARY

Schedule 00

Network Integration Transmission Service

Availability	For wholesale transmission of electricity.
Rate	Monthly Transmission Revenue Requirement: Customers will be charged their load ratio share of one twelfth (1/12th) of the Network Transmission Revenue Requirement per month. The Transmission Revenue Requirement is shown in Attachment H. One-twelfth of the Transmission Revenue Requirement is $~~67,125,000~~~~68,608,333~~68,591,667.
Taxes	The Rate and Charges contained herein are exclusive of applicable taxes.
Note	The terms and conditions under which Network Integration Transmission Service is supplied are contained in BC Hydro's OATT. Capitalized terms appearing in this Schedule, unless otherwise noted, shall have the meaning ascribed to them therein.

Effective April 1, 2016, this rate schedule is approved ~~interim~~ as per ~~by~~ BCUC Order No. ~~G-40-16~~G-XX-XX.

ACCEPTED:______________________________

ORDER NO.______________________________

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ACTING COMMISSION SECRETARY

Schedule 01

Point-To-Point Transmission Service

Availability	For transmission of electricity on a firm and non-firm basis from one or more Point(s) of Receipt (POR) to one or more Point(s) of Delivery (POD).
Rate for Long-Term Firm Service	The Reserved Capacity Charge for the Long-Term Firm Service Rate will be up to a maximum price as set out below except where the POD is a point of interconnection between the Transmission System and the transmission system of FortisBC Inc., in which case the rate shall be zero ($0.00). The Maximum Reserved Capacity Charge is $~~69,455~~70,68770,993/MW of reserved capacity per year to be invoiced monthly. Reserved Capacity Billing Demand The Reserved Capacity Billing Demand is determined for each POR(s), POD(s) pair. The Reserved Capacity for each pair of POR(s) and POD(s) will be the maximum non-coincident sum of the designated POR(s) and POD(s) included in the pair.

Schedule 01 – Point-To-Point Transmission Service (continued)

Rate for Short-Term Firm and Non-Firm Service	The posted prices for Short-Term Firm and Non-Firm Service will be less than or equal to a maximum price ($/MWh) as set out below, except where the POD is a point of interconnection between the Transmission System and the transmission system of FortisBC Inc., in which case the rate shall be zero ($0.00). Maximum Price for: 1. Monthly delivery: $~~5,787.91~~~~5,890.60~~5,916.10/MW of Reserved Capacity per month. 2. Weekly delivery: $~~1,335.67~~~~1,359.37~~1,365.25/MW of Reserved Capacity per week. 3. Daily delivery: $~~190.29~~~~193.66~~194.50/MW of Reserved Capacity per day. 4. Hourly delivery: $~~7.93~~~~8.07~~8.10/MW of Reserved Capacity per hour. Discount Rate: For discounted paths posted on the Transmission Provider's OASIS, the Transmission Customer shall pay each month for Reserved Capacity Billing Demand the greater of the rates set forth below and the rate offered by the Transmission Customer and accepted by the Transmission Provider up to the maximum rate for Short-Term Firm and Non-Firm Service: 1. Hourly delivery: $3/MW of Reserved Capacity per hour in the Heavy Load Hour period (06:00-22:00, Monday - Saturday, excluding NERC holidays) and $1/MW of Reserved Capacity per hour for the Light Load Hour period (remaining hours and days). 2. Daily delivery: sum of the hourly delivery charge in the 24 hour period in the day.
Reserved Capacity for Short-Term Firm and Non-Firm Services	The Reserved Capacity shall be the maximum of the sum of non-coincident POD(s) Capacity Reservations or sum of non-coincident POR(s) Capacity Reservations.

ACCEPTED:______________________________

ORDER NO.______________________________ ______________________________
ACTING COMMISSION SECRETARY

Schedule 01 – Point-To-Point Transmission Service (continued)

Penalty Charge	In addition to the applicable rate for service and associated charges for Ancillary Services, a penalty charge will be applied to all unauthorized usage at a rate of 125 percent of the maximum hourly delivery charge.
Special Conditions	Discounts: The following conditions apply to discounts for transmission service: 1. any offer of a discount made by BC Hydro must be announced to all Eligible Customers solely by posting on the OASIS, 2 any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an affiliate's use) must occur solely by posting on the OASIS, 3. once a discount is negotiated, details must be immediately posted on the OASIS, and 4. for any discount agreed upon for service on a path, from POR(s) POD(s), BC Hydro must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same POD(s) on the Transmission System.
Taxes	The Rate and Charges contained herein are exclusive of applicable taxes.
Resales	The rates and rules governing charges and discounts stated above shall not apply to resales of transmission service, compensation for which shall be governed by section 23.1 of the Tariff.
Note	The terms and conditions under which Transmission Service is supplied are contained in BC hydro's Open Access Transmission Tariff. Capitalized terms appearing in this Rate Schedule, unless otherwise noted, shall have the meaning ascribed to them therein.

Effective April 1, 2016, this rate schedule is ~~interim~~ approved as per BCUC Order No. ~~G-40-16~~G-XX-XX.

ACCEPTED:__________________________

ORDER NO.__________________________ ______________________________

ACTING COMMISSION SECRETARY

Schedule 03

Scheduling, System Control, and Dispatch Service

Preamble	This service is required to schedule the movement of power through, out of, within, or into a Control Area. This service can be provided only by the operator of the Control Area in which the transmission facilities used for transmission service are located. Scheduling, System Control and Dispatch Service is to be provided directly by BC Hydro. The Transmission Customer must purchase this service from BC Hydro. The charges for Scheduling, System Control and Dispatch Service are to be based on the rates set forth below.
Availability	In support of Network Integration Transmission Service, Long and Short-Term Firm Point-to-Point Transmission Service, and Non-Firm Point-to-Point Transmission Service.
Rate	$~~0.099~~0.105 per MW of Reserved Capacity per hour.
Taxes	The Rate and Charges contained herein are exclusive of applicable taxes.
Note	A description of the methodology for discounting Scheduling, System Control and Dispatch Services provided under this Schedule is contained in Section 3 of the BC Hydro OATT.

Effective April 1, 2016, this rate schedule is ~~interim~~ approved as per BCUC Order No. ~~G-40-16~~G-XX-XX.

ACCEPTED:______________________________

ORDER NO.______________________________ ______________________________
ACTING COMMISSION SECRETARY

Fiscal 2017 to Fiscal 2019
Revenue Requirements Application

Appendix T

Attachment 3

Fiscal 2017 Residential Inclining Block Rate, Medium General Service Rate and Large General Service Rate Calculation Methodology

Table of Contents

List of Tables

1 Fiscal 2017 RIB Rate Calculation Methodology

1.1 Executive Summary

This document describes the methodology used to calculate the Fiscal 2017 Residential Inclining Block (**RIB**) rate which BC Hydro is applying to be effective April 1, 2016 on an interim basis. The rate is computed based on a 4.00 per cent rate increase as applied for in the Fiscal 2017-Fiscal 2019 Revenue Requirements Application (**RRA**). The pricing principles used for the calculation of these interim rates follow the RIB rate pricing principles as approved by Commission Order No. G-13-14. BC Hydro has requested approval of 'pricing principles' for fiscal 2017-fiscal 2019 for the RIB rate that would be effective April 1, 2016 in its 2015 Rate Design Application (**RDA**).

The Fiscal 2017 RIB rate is shown in Table T-1 as follows:

Table T-1 Fiscal 2017 RIB Rate

Rate Component	Rate
Basic Charge ($/day)	0.1835
Energy Charge	
Step-1 rate (cents/kWh)	8.29
Step-2 rate (cents/kWh)	12.43

Section 1 describes the methodology used to calculate the RIB rate for fiscal 2017. It also demonstrates that the calculated RIB rate is revenue neutral on a forecast basis in fiscal 2017.

1.2 Pricing Principles

The term 'pricing principles' refers to how the RRA rate increases, which are set by the Commission through BC Hydro's RRAs, are applied to each of the RIB rate's pricing elements. The Fiscal 2017 RIB rate is derived following the pricing principles as approved previously by Commission Order No. G-13-14, which is consistent with that proposed by BC Hydro in its 2015 RDA. That is, each of the Step-1 rate, Step-2 rate, and the Basic Charge is increased by BC Hydro’s RRA rate increase.

1.3 Billing Determinants

The forecasted fiscal 2017 residential kWh sales net of demand-side management under the RIB rate by step is based on BC Hydro’s October 2015 Energy Sales Load forecast, which is consistent with the load forecast filed in the Fiscal 2017-Fiscal 2019 RRA, as follows:

Total kWh: 17,629 GWh
kWh in Step-1: 10,388 GWh
kWh in Step-2: 7,241 GWh

The ratio used for allocating kWh sales to Step-1 and Step-2 is 1.43 (Step-1 kWh/Step-2 kWh). This ratio is a five-year average of the fiscal 2010 to Fiscal 2015 Step-1 and Step-2 kWh energy sales since the RIB rate has been in effect. This is consistent with the methodology of using historical averages used for BC Hydro’s fiscal 2015 and fiscal 2016 RIB rate calculation.

1.4 RRA Increase

The Fiscal 2017 RRA increase is based on BC Hydro’s applied for rate increase in the Fiscal 2017-Fiscal 2019 RRA and the Fiscal 2017 Rate Rider is based on that set out in the Order in Council No. 097, Direction No. 7 to the Commission, section 10.

The values are as follows:

Fiscal 2017 RRA increase: 4.00 per cent
Fiscal 2017 Rate Rider: 5.00 per cent

1.5 Target Revenue

Target revenue is determined by the same general methodology used to determine forecast domestic revenue described in previous years.

Fiscal 2017 target revenue is computed using the fiscal 2016 RIB rate approved by Commission Order No. G-48-14 as the base, the fiscal 2017 rate increase as proposed in the Fiscal 2017-Fiscal 2019 RRA, and the approved Fiscal 2017 Rate Rider as per Direction No. 7 to the Commission and the October 2015 load forecast used in the Fiscal 2017-Fiscal 2019 RRA.

The steps are as follows:

(i) "Total revenue under fiscal 2016 rates" is equal to the sum of (a) forecast fiscal 2017 RIB kWh load for Step-1 and Step-2, multiplied by the Fiscal 2016 RIB Step-1 and Step-2 rates and (b) forecast fiscal 2017 number of RIB rate customer accounts multiplied by the Fiscal 2016 RIB Basic Charge multiplied by 365 days.

(ii) The annual RRA increases for fiscal 2017 is applied to the "Total revenue under fiscal 2016 rates" calculated in (i).

(iii) The annual Rate Rider for fiscal 2017 of 5.00 per cent is applied to the outcome of (ii), resulting in the fiscal 2017 target revenue. These calculations are shown in Table T-2.

1 **Table T-2 Target Revenue Calculation**

Line	Description	Value	Unit	Source
A	Forecast F2017 RIB Step-2 Load	7,241,499,076	kWh	October 2015 Load Forecast (refer to section 1.3)
B	Forecast F2017 RIB Step-1 Load	10,388,354,114	kWh	October 2015 Load Forecast (refer to section 1.3)
C	Forecast F2017 Customer Accounts	1,742,798	Accounts	October 2015 Load Forecast
D	April 1, 2015 RIB Step-1 Rate (F2016)	7.97	cents/kWh	RS1101, Electric Tariff. Approved by Commission Order No. G-48-14
E	April 1, 2015 RIB Step-2 Rate (F2016)	11.95	cents/kWh	RS1101, Electric Tariff. Approved by Commission Order No. G-48-14
F	April 1, 2015 RIB Basic Charge (F2016)	0.1764	$/day	RS1101, Electric Tariff. Approved by Commission Order No. G-48-14
G	Step-1 Revenue under F2016 RIB Rate	827,951,823	$	D * B / 100
H	Step-2 Revenue under F2016 RIB Rate	865,359,140	$	E * A / 100
I	Basic Charge Revenue under F2016 RIB Rate	112,211,792	$	C * F * 365
J	Total Revenue under F2016 RIB Rate Excluding Rate Rider	1,805,522,754	$	G + H + I
K	F2017 RRA increase	4.00	%	Chapter 1, BC Hydro F2017-F2019 RRA
L	Total Revenue under F2016 RIB Rate Escalated by F2017 RRA increase	1,877,743,665	$	J * (1 + K)
M	F2017 Rate Rider	5.00	%	Order in Council No. 097, Direction No. 7, section 10
N	F2017 Total Rate Rider Revenue	93,887,183	$	L * M
O	**Total F2017 Target Revenue**	**1,971,630,848**	**$**	**L + N**

1.6 Rate Computation

1.6.1 Basic Charge

The Basic Charge computation follows the pricing principles outlined in section 1.2.

Basic Charge = Fiscal 2016 Basic Charge * (Fiscal 2017 RRA % + 100%)
= $0.1764 / day * (4.00% + 100%)
= $0.1835 / day

1.6.2 Step-1 and Step-2 Rates

The Step-1 and Step-2 rate computations follow the pricing principles outlined in section 1.2.

Step-1 rate = Fiscal 2016 Step-1 rate * (Fiscal 2017 RRA % + 100%)
= $0.0797 * (4.00% + 100%)
= $0.0829 / kWh

Step-2 rate = Fiscal 2016 Step-2 rate * (Fiscal 2017 RRA % + 100%)
= $0.1195 * (4.00% + 100%)
= $0.1243 / kWh

Outcome:

The resulting Fiscal 2017 RIB rate (excluding Rate Rider) is as follows:

Step-1 rate: 8.29 cents/kWh
Step-2 rate: 12.43 cents/kWh

The computation details are shown in Table T-3.

Table T-3 Computation of Fiscal 2017 RIB Rate

Line	Description	Value	Unit	Source
A	F2017 RRA increase	4.00	%	Chapter 1, BC Hydro F2017-F2019 RRA
B	April 1, 2015 RIB Step-1 Rate (F2016)	7.97	cents/kWh	Commission Order No. G-48-14
C	April 1, 2015 RIB Step-2 Rate (F2016)	11.95	cents/kWh	Commission Order No. G-48-14
D	April 1, 2015 RIB Rate Basic Charge (F2016)	0.1764	$/day	Commission Order No. G-48-14
	Resulting F2017 RIB Rate*			
E	**F2017 RIB Step-1 Rate**	**8.29**	**cents/kWh**	**B * (100% + A)**
F	**F2017 RIB Step-2 Rate**	**12.43**	**cents/kWh**	**C * (100% + A)**
G	**F2017 RIB Rate Basic Charge**	**0.1835**	**$/day**	**D * (100% + A)**

* Fiscal 2017 RIB Rate excludes Rate Rider and is rounded to 1/100 of a cent/kWh. Refer to section 1.2 and section 1.6.2 for a description of the pricing methodology.

1.7 Revenue Neutrality

Using the rates calculated via the rate calculation methodology described above, this section shows that the rates are revenue neutral on a forecast basis using the fiscal 2017 forecast load. This is done by comparing the revenue under the Fiscal 2017 RIB rate and the revenue target, as shown in Table T-4.

1 **Table T-4 Revenue Neutrality**

Line	**Description**	**Value**	Unit	**Source**
A	Forecast F2017 RIB Step-2 Load	7,241,499,076	kWh	October 2015 Load Forecast
B	Forecast F2017 RIB Step-1 Load	10,388,354,114	kWh	October 2015 Load Forecast
C	Forecast F2017 Customer Accounts	1,742,798	Accounts	October 2015 Load Forecast
	F2017 RIB Rate			
D	RIB Step-1 Rate (rounded to 1/100 of a cent)	8.29	cents/kWh	Table T-3, Line E
E	RIB Step-2 Rate (rounded to 1/100 of a cent)	12.43	cents/kWh	Table T-3, Line F
F	RIB Rate Basic Charge (rounded to 1/100 of a cent)	0.1835	$/day	Table T-3, Line G
G	Rate Rider	5.00	%	Order No. in Council No. 097, Direction No. 7, section 9
H	RIB Step-1 Rate Revenue	861,194,556	$	D * B / 100
I	RIB Step-2 Rate Revenue	900,118,335	$	E * A / 100
J	RIB Rate Basic Charge Revenue	116,728,253	$	F * C * 365
K	Rate Rider Revenue	93,902,057	$	(H + I + J) * G
L	Total F2017 Revenue forecasted from the RIB Rate and Rate Rider	1,971,943,201	$	H + I + J + K
M	F2017 Target Revenue	1,971,630,848	$	Table T-2, Line P
N	Variance due to rounding at the 3rd decimal place	(312,354)	$	M – L
O	**Variance %**	**-0.016**	**%**	**N / M * 100%**

2 Fiscal 2017 Medium General Service (MGS) Rate Calculation

2.1 Executive Summary

This document describes the methodology BC Hydro used to calculate the Fiscal 2017 MGS rate (Rate Schedule 1500, 1501, 1510, and 1511 (**15XX**)) effective April 1, 2016, which BC Hydro is applying to be effective on an interim basis. The rate is computed based on a 4.00 per cent rate increase as applied for by BC Hydro in the Fiscal 2017-Fiscal 2019 RRA.

The Fiscal 2017 MGS rate is shown in Table T-5.

Table T-5 Fiscal 2017 MGS Rate

Rate Component	Amount
Basic Charge ($/day)	0.2347
Demand Charge	
Tier 1 ($/kW)	0
Tier 2 ($/kW)	5.72
Tier 3 ($/kW)	10.97
Energy charge	
Tier 1 (cents /kwh)	10.30
Tier 2 (cents /kwh)	7.19
Part 2 LRMC [Note 1] based Rate (cents/kwh)	10.09
Minimum Energy Charge (cents/kwh)	3.43

Note 1: "**LRMC**" denotes Long Run Marginal Cost

The rate calculation methodology is consistent with the LGS pricing methodology outlined in Appendix O of BC Hydro's LGS Rate Application filed on October 16, 2009 and approved by Commission Order No. G-110-10.

The calculation shows that this rate recovers the target revenue based on forecasted kWh energy sales, with a variance of 0.028 per cent that is attributable to rounding (demand charges are rounded to the nearest $0.01/kW and energy charges are rounded to the nearest 0.01 cents/kWh).

2.2 Methodology

BC Hydro's methodology used to calculate the Fiscal 2017 LGS rate reflects the 4.00 per cent rate increase as applied for by BC Hydro in the Fiscal 2017-Fiscal 2019 RRA. The rate calculation methodology is consistent with the LGS pricing methodology approved by Commission Order No. G-110-10. The MGS pricing methodology is embedded in BC Hydro's MGS Rate Model which calculates the rates for Rate Schedules 15XX.

2.2.1 Pricing Methodology

The following steps are used to calculate the MGS rates that arise from the pricing methodology:

(a) The basic charge is increased at the rate of the general BC Hydro rate increase;

(b) The demand charges, based on peak usage at Tier 1 (35 kW and under), Tier 2 (35 kW up to but not including 150 kW), and Tier 3 (150 kW and up) are increased at the rate of the general BC Hydro rate increase;

(c) The Fiscal 2017 Part-2 LRMC-based energy rate is the fiscal 2016 rate (9.90 c/ kWh) increased at the rate of inflation;

(d) The minimum energy charge is increased at the rate of the general BC Hydro rate increase;

(e) The forecast revenue determined from applying the rates from (a), (b), (c), and (d) to the forecast billing determinants is subtracted from the target revenue, and this residual amount is recovered by the Tier 1 and Tier 2 energy rates; and

(f) Tier-1 and Tier-2 are determined by maintaining T2 and T1 at the rate ratio in fiscal 2016.

2.2.2 Billing Determinants

The billing determinants used for rate modelling are based on a sample constructed from a subset of fiscal 2017 forecasted sales of the MGS rate class by account (column 3, Table T-6).

Table T-6 Fiscal 2017 MGS Billing Determinants

Line	Rate Component	F2017 MGS Sample Forecast Sales	F2017 MGS Total Forecast Sales	
A	Energy Sales, MGS Class (kWh)	2,940,155,316	3,378,219,450	Note 1
B	Total Accounts	14,139	16,246	Note 2
C	Demand Tier 1 (kW)	5,734,249	6,588,615	Note 2
D	Demand Tier 2 (kW)	3,416,425	3,925,450	Note 2
E	Demand Tier 3 (kW)	6,838	7,857	Note 2
F	Part 1 Tier 1 (HBL kWh Note 3)	2,076,213,548	2,385,555,944	Note 2
G	Part 1 Tier 2 (HBL kWh)	910,099,347	1,045,698,266	Note 2
H	Part 2 LRMC-based (kWh)	(36,908,321)	(42,407,422)	Note 2
I	Part 2 Tier 1 (kWh)	(13,207,542)	(15,175,381)	Note 2
J	Part 2 Tier 2 (kWh)	3,958,284	4,548,043	Note 2
K	Minimum Energy Charge (kWh)	–	–	Note 2

Note 1: Forecast is estimated by first calculating the proportion of Fiscal 2015 MGS sales to total Fiscal 2015 Existing Large General Service (**ELGS**) sales. This proportion is then applied to the Fiscal 2017 ELGS forecast of 14,874.5 GWh from the October 2015 Load Forecast.

Note 2: Forecast based on applying a calibration factor of 1.1490 to the Fiscal 2017 MGS modelling subset billing determinants. This factor is constructed by dividing the Fiscal 2017 MGS class energy forecast (3,378.2 GWh) by the Fiscal 2017 MGS modelling subset energy forecast (2,940.2 GWh) (refer to section 2.2.2.4).

Note 3: "**HBL**" denotes Historical Baseline

2.2.2.1 Subset of Billing Data used for Rate Modelling

Fiscal 2015 MGS billing data (April 2014 through March 2015) is used for modelling and rate-setting. Accompanying this billing data are forecasted Fiscal 2017 HBLs as described in section 2.2.2.3.

This data consists of billing kW and kWh, calendarized on a monthly basis, by account. The rate modelling is based on a subset of the billing data, which is created by excluding accounts that meet the general criteria below, as established in the previous compliance filing:

(a) Missing kWh consumption or demand in any month of fiscal 2015;

(b) Have no HBL available for any month in fiscal 2016 (which are used to forecast Fiscal 2017 HBLs);

(c) Have non-zero kWh consumption coincident with zero kW demand in any month of fiscal 2015;

(d) Have negative kW demand in any demand tier in any month of fiscal 2015;

(e) Have non-zero kW demand coincident with zero kW demand in a lower tier in any month of fiscal 2015;

(f) “New” accounts with service commencement dates in fiscal 2015 or later; and

(g) Accounts that closed before fiscal year end.

2.2.2.2 Forecasting modelling subset’s billing determinants for the test year

The modelling subset’s number of accounts, and each account’s specific monthly demand and energy consumption are scaled by a common factor to forecast the respective quantities in the modelling subset for fiscal 2017, the test year. The scaling factor is constructed using the actual and forecasted sales of ELGS accounts, which currently would consist of Rate Schedules 1200, 1201, 1210, 1211, 15XX, and 16XX:

Scaling factor = (Fiscal 2017 ELGS Forecast sales) / (Fiscal 2015 ELGS sales)
= 14,874.5 GWh / 14,630.3 GWh
= 1.0167

BC Hydro does not currently have enough information to estimate a precise scaling factor specific to the MGS class (accounts taking service under Rate Schedules 15XX) as the rate was implemented in January 2011.

The key assumptions and specifications regarding the billing determinants used in the MGS rate model are specified by rate components below:

Basic Charge	The billing determinant for the basic charge is the sum of the number of forecasted accounts in the rate design subset, multiplied by 365 days in a year.
Demand Charge	The forecasted fiscal 2017 peak demand for each tier is estimated by adjusting the fiscal 2015 demand sales by the energy consumption scaling factor (1.0167) to ensure that the revenue forecasted from demand charges are representative and consistent with forecasted account and energy growth of the class.
Part-1 and Part-2 Tier 1 and Tier 2 Energy Rates	Part-1 Tier 1 HBL energy consists of all baseline consumption (HBL) that is at or below 14,800 kWh in a given monthly billing period. Part-1 Tier 2 HBL energy consists of remaining baseline consumption. Part-2 Tier 1 and Tier 2 HBL energy is then determined for forecast fiscal 2017 consumption outside the price limit band i.e., 80 per cent of HBL to 120 per cent of HBL (or -20%/+20% of HBL).
Part-2 LRMC-based Energy Charge/Credit	This is calculated based on the difference between the forecasted HBL and forecasted fiscal 2017 consumption and the price limit band.

Part-2 Tier 1 and Tier 2 Energy Charge/Credit

The model computes the forecasted energy consumption at each tier in Part 2, using the following steps:

For forecasted consumption higher than the HBL:

1. The amount of energy charged at the Part-2 LRMC rate is computed.
2. The amount of Part-2 energy allocated to Tier 1 is the lesser of:
   (a) The remaining portion of the consumption greater than baseline (if any) following step 1 above, and
   (b) The portion of consumption greater than Baseline which is equal to 14,800 kWh minus 120 per cent of the HBL (but if 14,800 kWh minus 120 per cent of the HBL would produce a negative number, the result is zero)
3. The remaining portion of the consumption greater than Baseline (if any) is allocated to Part 2, Tier 2.

For forecasted consumption lower than the HBL:

1. The amount of energy credited at the Part 2 LRMC rate is computed
2. The amount of Part-2 energy credited at Tier 1 is the lesser of:
   (a) The remaining portion of the consumption less than Baseline (if any) following step 1 above, and
   (b) The portion of the consumption less than Baseline

which is equal to 14,800 kWh minus 20 per cent of the HBL (but if 14,800 minus 20 per cent of the HBL would produce a negative number, the result is zero).

3. The remaining portion of the credit is applied to Part 2, Tier 2.

Fiscal 2017 MGS Class Forecast Sales	The most recently available Fiscal 2017 ELGS forecast sales based on BC Hydro's October 2015 Load Forecast is used. The MGS class-specific load forecast is estimated by first calculating the proportion of Fiscal 2015 MGS sales to total Fiscal 2015 ELGS sales. This proportion is then applied to the Fiscal 2017 ELGS forecast sales of 14,874.5 GWh. (see Table T-6, Note 1)

2.2.2.3 Forecasting Baselines (HBLs)

The fiscal 2017 baselines are forecasted by scaling up the fiscal 2016 baselines by the difference between the three-year moving average consumption for years leading up to fiscal 2016 (which informs fiscal 2016 baselines) and the three-year moving average consumption for years leading up to fiscal 2017 (which informs fiscal 2017 baselines). This best preserves the variations between forecast consumption and baseline.

2.2.2.4 Model Calibration

A calibration step is applied to the model to extrapolate the billing determinants in the modelling subset to the entire class. A calibration factor (1.1490) is constructed by dividing the Fiscal 2017 MGS class energy forecast (3,378.2 GWh) by the fiscal 2017 modelling subset energy forecast (2,940.2 GWh). This factor is applied to each component of the billing determinants in the fiscal 2017 modelling subset to obtain the calibrated quantities for the class.

Although the rate model uses the modelling subset for the computations, the outcomes are identical if the calibrated billing determinants are used instead. Therefore, for the purposes of this report, the calibrated class forecast is used from section 2.3 and onwards in this document.

2.3 General Rate Increases

The fiscal 2017 general rate increase used is 4.00 per cent, as applied for by BC Hydro in the Fiscal 2017-Fiscal 2019 RRA. The rate rider used in the fiscal 2017 pricing is that set out in the Order in Council No. 097, Direction No. 7, section 10 to the Commission. In summary, the rate increases used are as follows:

Fiscal 2017 general rate increase: 4.00 per cent
Fiscal 2017 Rate Rider: 5.00 per cent

Inflation projection for fiscal 2017 is 1.90 per cent, as set by the Treasury board of the Province of B.C. in October 2015.

2.4 Target Revenue

Fiscal 2017 MGS class target revenue is determined using same general methodology used to determine forecast domestic revenue described in previous years. The computation uses MGS revenue based on fiscal 2016 rates, scaled up by the BC Hydro requested general rate increase for fiscal 2017 in the Fiscal 2017-Fiscal 2019 RRA.

The steps for computation of the target revenue are as follows:

Table T-7 MGS Target Revenue Computation Steps

Line	Description	Value	Unit	Source
A	Forecast F2017 sales	3,378.2	GWh	October 2015 Load Forecast
B	Revenue under F2016 rates	326.2	$ million	Calculated MGS Revenue Forecast @ F2016 Tariff Rates
C	F2017 RRA increase	4.00	%	Chapter 1, BC Hydro F2017-F2019 RRA.
D	F2017 Target Revenue (Total Revenue at F2016 Rates Escalated by F2017 RRA increases)	339.3	$ million	B * (1 + C)
E	F2017 Rate Rider	5.00	%	Order in Council No. 097, Direction No. 7, section 10
F	F2017 Rate Rider Revenue	17.0	$ million	D * (1 + E)
G	F2017 Target Revenue including Rate Rider	356.2	$ million	D + F

Note: The computation of each result takes into account all decimal places from its components before rounding, and the precision is to 1/10 of a million dollars.

2.5 Rate Computation

A summary of the computed rates are outlined in Table T-8.

Table T-8 Fiscal 2017 MGS Rates (Excluding Rate Rider)

Line	Rate Component	Amount	Reference
A	Basic Charge ($/day)	0.2347	Section 2.5.1
	Demand Charge		
B	Tier 1 ($/kW)	0	Section 2.5.2
C	Tier 2 ($/kW)	5.72	Section 2.5.2
D	Tier 3 ($/kW)	10.97	Section 2.5.2
	Energy charge		
E	Tier 1 (cents /kwh)	10.30	Section 2.5.6
F	Tier 2 (cents /kwh)	7.19	Section 2.5.6
G	Part 2 LRMC based Rate (cents /kwh)	10.09	Section 2.5.3
H	Minimum Energy Charge (cents /kwh)	3.43	Section 2.5.4

2.5.1 Basic Charge

The basic charge computation follows the pricing principles as outlined in section 2.2.1 above to increase by the general rate increase.

Basic Charge = Fiscal 2016 Basic Charge * (Fiscal 2017 RRA % + 100%)
Basic Charge = $0.2257 / day * (4.00% + 100%) = $0.2347 / day

2.5.2 Demand Charge

The demand charge computation follows the pricing principles as outlined in section 2.2.1 above, and the demand charge is increased by the general rate increase.

Demand Charge = Fiscal 2016 Demand Charge * (Fiscal 2017 RRA % + 100%)
Demand Tier 1 = $0 / kW * (4.00% + 100%) = $0 / kW
Demand Tier 2 = $5.50 / kW * (4.00% + 100%) = $5.72 / kW
Demand Tier 3 = $10.55 / kW * (4.00% + 100%) = $10.97 / kW

2.5.3 Part-2 LRMC Based Energy Rate

The Fiscal 2017 Part-2 LRMC based energy rate is set to increase by the rate of inflation:

Fiscal 2017 Part-2 LRMC based energy rate = Fiscal 2016 Part-2 LRMC based energy rate x (Inflation Rate % + 100%)
Fiscal 2017 Part-2 LRMC based energy rate = 9.90 cents/kWh x (1.90% + 100%) = 10.09 cents/kWh

2.5.4 Minimum Energy Charge

The Minimum Energy Charge follows the pricing principles as outlined in section 2.2.1 above, and is increased by the general BC Hydro rate increase.

Fiscal 2017 Minimum Energy Charge = Fiscal 2016 Minimum energy Charge * (Fiscal 2017 RRA % + 100%)

Fiscal 2017 Minimum Energy Charge = 3.30 cents/ kWh * (4.00% + 100%) = 3.43 cents/kWh

2.5.5 Discounts

The discounts are not affected by the rate increase.

Primary discount of 1.5 per cent applies to all charges for accounts under Rate Schedules 1501 and 1511.

A discount of 25 cents per billing period per kW of billing demand is applied to accounts under Rate Schedules 1510 and 1511.

The total discount amount for eligible customers is estimated to be $131,850. This amount is entered in the model as an adjustment to forecasted revenue (Table T-9, Line V).

2.5.6 Tier 1 and Tier 2 Energy Rates

The Tier 1 and Tier 2 energy rates are set to collect the residual forecast revenue in the MGS rates model. The model first computes the forecast revenue to be collected for each of the respective rate components outlined in sections 2.5.1 to 2.5.5. This quantity is then subtracted from the target revenue to determine the remaining forecast revenue to be collected under the Tier 1 and Tier 2 energy rates.

Table T-9 Computation of Forecast Revenue to be Collected under the Tier 1 and Tier 2 MGS Energy Rates

Line	Description	Value	Unit	Source
A	Forecast F2017 Part 2 LRMC rate component energy	(42,407,422)	kWh	Table T-6, Line H
B	Forecast F2017 Minimum Energy Charge energy	-	kWh	Table T-6, Line K
C	Forecast F2017 Tier 1 demand	6,588,615	kW	Table T-6, Line C
D	Forecast F2017 Tier 2 demand	3,925,450	kW	Table T-6, Line D
E	Forecast F2017 Tier 3 demand	7,857	kW	Table T-6, Line E
F	Forecast F2017 number of accounts	16,246		Table T-6, Line B
G	Part 2 LRMC Rate	10.09	cents/kwh	Table T-8, Line G
H	Tier 1 Energy Rate	10.30	cents/kwh	Estimated through iterations Note 1
I	Tier 2 Energy Rate	7.19	cents/kwh	Estimated through iterations Note 1
J	Tier 1 Demand Rate	–	$/kW	Table T-8, Line B
K	Tier 2 Demand Rate	5.72	$/kW	Table T-8, Line C
L	Tier 3 Demand Rate	10.97	$/kW	Table T-8, Line D
M	MGS basic charge	23.47	cents/day	Table T-8, Line A
N	Minimum Energy Charge	3.43	cents/kwh	Table T-8, Line H
O	Forecast Revenue by rate component, excluding rate rider:			
P	Part 2 LRMC Forecast Revenue	(4,278,103)	$	A * G / 100 Note 2
Q	MGS Tier 1 Demand Forecast Revenue	-	$	C * J Note 2
R	MGS Tier 2 Demand Forecast Revenue	22,453,572	$	D * K Note 2
S	MGS Tier 3 Demand Forecast Revenue	86,209	$	E * L Note 2
T	MGS basic charge Forecast Revenue	1,395,683	$	M * F * 365 / 100 Note 2
U	MEC Bills Forecast Revenue	–	$	N * B / 100 Note 2
V	Transformation and Primary Potential Discounts	(131,850)	$	Estimated using the rates in Line G, H, I, J , K, L, M, N Note 2
W	Total forecast Revenue from rate components excluding Tier 1 and Tier 2 Energy	19,525,511	$	Sum (P thru V)

Line	Description	Value	Unit	Source
X	F2017 Total Target Revenue	339,276,642	$	Table T-7, Line D
Y	**Forecast Revenue to be collected from Tier 1 and Tier 2 energy rates**	319,751,131	**$**	**X - W**

Note 1: The Tier 1 and Tier 2 energy rates in Table T-9 lines H and I are used as inputs for computing discounts only. These estimates are derived iteratively with the rate outcomes in Table T-9 lines H and I, to a variance of 0.001 cent/kWh.

Note 2: No rounding has been applied to the calculations to compute the outcomes, as this is an intermediate step in the rate model.

The calculation of Tier 1 and Tier 2 energy rates are designed to collect the revenue referenced in Table T-9, Line Y, while maintaining a T2/T1 ratio of 1.4333 which is the T2/T1 ratio in fiscal 2016 rates.

The computation of Tier 1 and Tier 2 energy rates are detailed in Table T-10 and the final rates are as follows:

Tier 1 energy rate: 10.30 cents/kWh

Tier 2 energy rate: 7.19 cents/kWh

Table T-10 Computation of Tier 1 and Tier 2 MGS Energy Rates

Line	Description	Value	Unit	Source
A	Tier 1 forecasted billed consumption, from both Part 1 and Part 2	2,370,380,563	kWh	Table T-6, Line F and Line I
B	Tier 2 forecasted billed consumption, from both Part 1 and Part 2	1,050,246,309	kWh	Table T-6, Line G and Line J
C	**Revenue to be recovered from Tier 1 and Tier 2 Tariff Rates**	319,751,131	$	Table T-9, Line Y
D	F16 Tier 1 Rate	9.89		F2016 Tariff Approved by Commission Order No. G-48-14
E	F16 Tier 2 Rate	6.90		F2016 Tariff Approved by Commission Order No. G-48-14
F	F16 Tier 1 / Tier 2 Ratio	1.43		D / E
G	F17 Tier 1 / Tier 2	1.43		I / H
H	**F2017 Tier 2 Energy Rate**	**7.19**	**cents/kWh**	**Determined so that F is as close to G as possible, without exceeding G.**
I	**F2017 Tier 1 Energy Rate**	**10.30**	**cents/kWh**	**[C – (B*H/100)] /A*100**

2.6 Revenue Neutrality

The rates calculated in section 2.5 above are revenue neutral on a forecast basis and are verified to ensure that they recover the target revenue on a forecast basis by applying the rates computed in section 2.5.6 above (Table T-10, Lines H and I) to the Fiscal 2017 MGS class forecast, and then comparing the resulting forecast revenue to the Fiscal 2017 MGS class revenue target. The results in Table T-11, Lines AF to AI show that the rates recover the target revenue on a forecast basis, with a variance of 0.028 per cent, which is attributable to rounding (demand charge to the $0.01/kW and Energy charge to the 0.01 cent/kWh).

1 **Table T-11 Revenue Neutrality**

Line	Description	Value	Unit	Source
A	Forecast Part 1, Tier 1 Class Load	2,385,555,944	kWh	Table T-6, Line F
B	Forecast Part 1, Tier 2 Class Load	1,045,698,266	kWh	Table T-6, Line G
C	Forecast Part 2 LRMC Class Load	(42,407,422)	kWh	Table T-6, Line H
D	Forecast Part 2 Tier 1 Class Load	(15,175,381)	kWh	Table T-6, Line I
E	Forecast Part 2 Tier 2 Class Load	4,548,043	kWh	Table T-6, Line J
F	Forecast Minimum energy charge Class load	-	kWh	Table T-6, Line K
G	Forecast Energy, MGS Class	3,378,219,450	kWh	Table T-6, Line A
H	Forecast Number of Accounts, MGS Class	16,246		Table T-6, Line B
I	Forecast Class Demand Tier 1	6,588,615	kW	Table T-6, Line C
J	Forecast Class Demand Tier 2	3,925,450	KW	Table T-6, Line D
K	Forecast Class Demand Tier 3	7,857	kW	Table T-6, Line E
L	Tier 1 Energy Rate	10.30	cents/kWh	Table T-10, Line I
M	Tier 2 Energy Rate	7.19	cents/kWh	Table T-10, Line H
N	Part 2 LRMC Energy Rate	10.09	cents/kWh	Table T-9, Line G
O	Minimum Energy Charge	3.43	cents/kWh	Table T-9, Line N
P	Basic Charge	0.2347	$ / Day	Table T-9, Line M
Q	Tier 1 Demand Rate	-	$/kW	Table T-9, Line J
R	Tier 2 Demand Rate	5.72	$/kW	Table T-9, Line K
S	Tier 3 Demand Rate	10.97	$/kW	Table T-9, Line L
T	Forecast primary potential and transformation discounts	(131,850)	$	Table T-9, Line V
U	Tier 1 Energy Revenue	245,712,262	$	A * L / 100
V	Tier 2 Energy Revenue	75,185,705	$	B * M / 100
W	Part 2 LRMC Energy Revenue	(4,278,909)	$	C * N / 100
X	Part 2 Tier 1 Energy Revenue	(1,563,064)	$	D * L / 100

Line	Description	Value	Unit	Source
Y	Part 2 Tier 2 Energy Revenue	327,004	$	E * M / 100
Z	Minimum Energy Charge Revenue	-	$	F * O / 100
AA	Tier 1 Demand Revenue	-	$	I * Q
AB	Tier 2 Demand Revenue	22,453,572	$	J * R
AC	Tier 3 Demand Revenue	86,193	$	K * S
AD	Basic Charge Revenue	1,391,722	$	H * P * 365
AE	Rate Rider	5%		Order in Council No. 097, Direction No. 7, section 9
AF	Total Forecasted Revenue (including rate rider)	356,141,767	$	Sum (T to AD)* (1+ AE)
AG	Target Revenue (including rate rider)	356,240,474	$	Table T-7, Line G
AH	Variance due to rates rounding	(98,707)	$	AF - AG
AI	Variance %	-0.028%		AH / AG

1 **Note:** Results displayed in Table T-11 are calculated before any of the inputs are rounded.

3 Fiscal 2017 Large General Service (LGS) Rate Calculation

3.1 Executive Summary

This document describes the methodology BC Hydro used to calculate the Fiscal 2017 LGS rate (Rate Schedules 1600, 1601, 1610, and 1611 (**16XX**)) effective April 1, 2016, which BC Hydro is applying to be effective on an interim basis. The rate is computed based on a 4.00 per cent rate increase as applied for by BC Hydro in the Fiscal 2017-Fiscal 2019 RRA.

The Fiscal 2017 LGS rate is shown in Table T-12.

Table T-12 Fiscal 2017 LGS Rate

Rate Component	Amount
Basic Charge ($/day)	0.2347
Demand Charge	
Tier 1 ($/kW)	0
Tier 2 ($/kW)	5.72
Tier 3 ($/kW)	10.97
Energy charge	
Tier 1 (cents /kwh)	11.14
Tier 2 (cents /kwh)	5.36
Part 2 LRMC [Note 1] based Rate (cents /kwh)	10.09
Minimum Energy Charge (cents /kwh)	3.43

Note 1: "**LRMC**" denotes Long Run Marginal Cost

The rate calculation methodology is consistent with the LGS pricing methodology outlined in Appendix O of BC Hydro's LGS Rate Application filed on October 16, 2009 and approved by Commission Order No.G-110-10.

The calculation shows that this rate recovers the target revenue based on forecasted kWh energy sales, with a variance of 0.011 per cent that is attributable to rounding (demand charges are rounded to the nearest \$0.01/kW and energy charges are rounded to the nearest 0.01 cents/kWh).

3.2 Methodology

BC Hydro's methodology used to calculate the Fiscal 2017 LGS rate reflects the 4.00 per cent rate increase as applied for by BC Hydro in the Fiscal 2017-Fiscal 2019 RRA. The rate calculation methodology is consistent with the LGS pricing methodology approved by Commission Order No.G-110-10 and is embedded in BC Hydro's LGS Rate Model which calculates the rates for Rate Schedules 16XX.

3.2.1 Pricing Methodology

The following steps are used to calculate the LGS rates that arise from the pricing methodology as approved by Commission Order No. G-110-10:

(a) The basic charge is increased at the rate of the general BC Hydro rate increase;

(b) The demand charges, based on peak usage at Tier 1 (35 kW and under), Tier 2 (35 kW up to but not including 150 kW), and Tier 3 (150 kW and up) are increased at the rate of the general BC Hydro rate increase;

(c) The Fiscal 2017 Part-2 LRMC-based energy rate is the fiscal 2016 rate (9.90 c/ kWh) increased at the rate of inflation;

(d) The minimum energy charge is increased at the rate of the general BC Hydro rate increase;

(e) The forecast revenue from applying the rates from (a), (b), (c), and (d) to their respective forecast billing determinants is subtracted from the target revenue, and this residual amount is recovered by the Tier 1 and Tier 2 energy rates; and

(f) Part-1 rates are determined so that the ratio of Tier 2 rates to Tier 1 rates is 2.08, as explained in Appendix O, page 16, of the LGS Rate Application.

3.2.2 Billing Determinants

The billing determinants are based on a modelling sample constructed from a subset of fiscal 2017 forecasted sales of the LGS Class by account (Column 3, Table T-13).

Table T-13 LGS Fiscal 2017 Billing Determinants

Line	Rate Component	F2017 LGS Sample Forecast Sales	F2017 LGS Total Forecast Sales
A	Energy Sales, LGS Class (kWh)	10,499,241,978	11,117,924,209 Note 1
B	Number of Accounts	6,266	6,635 Note 2
C	Demand Tier 1 (kW)	2,613,192	2,767,178 Note 2
D	Demand Tier 2 (kW)	7,476,517	7,917,082 Note 2
E	Demand Tier 3 (kW)	15,819,994	16,752,208 Note 2
F	Part 1 Tier 1 (HBL kWh Note 3)	1,080,985,298	1,144,683,839 Note 2
G	Part 1 Tier 2 (HBL kWh)	9,414,582,510	9,969,349,694 Note 2
H	Part 2 LRMC-based (kWh)	924,657	979,144 Note 2
I	Part 2 Tier 2 (kWh)	(8,826,041)	(9,346,128) Note 2
J	Minimum Energy Charge (kWh)	11,575,554	12,257,659 Note 2

Note 1: Forecast is estimated by first calculating the proportion of Fiscal 2015 LGS sales to total Fiscal 2015 ELGS sales. This proportion is then applied to the Fiscal 2017 ELGS forecast of 14,874.5 GWh from the October 2015 Load Forecast.

Note 2: Forecast based on applying a calibration factor of 1.0589 to the Fiscal 2017 LGS modelling subset billing determinant. This factor is constructed by dividing the Fiscal 2017 LGS Class energy forecast (11,117.9 GWh) by the Fiscal 2017 LGS modelling subset energy forecast (10,499.2 GWh) (see section 3.2.4 below).

Note 3: "**HBL**" denotes Historical Baseline

3.2.2.1 Subset of Billing Data used for Rate Modelling

Fiscal 2015 LGS billing data (April 2014 through March 2015) is used for modelling and rate-setting. Accompanying this billing data are forecasted Fiscal 2017 HBLs as described in section 3.2.3.

This data consists of billing kW and kWh, calendarized on a monthly basis, by account. The rate modelling is based on a subset of the billing data, which is created by excluding accounts that meet the general criteria below, as established in the previous compliance filing:

(a) Missing kWh consumption or demand in any month of fiscal 2015;

(b) Have no HBL available for any month for fiscal 2016 (which are used to forecast Fiscal 2017 HBLs);

(c) Have non-zero kWh consumption coincident with zero kW demand in any month of fiscal 2015;

(d) Have negative kW demand in any demand tier in any month of fiscal 2015;

(e) Have non-zero kW demand coincident with zero kW demand in a lower tier in any month of fiscal 2015;

(f) "New" accounts with service commencement dates in fiscal 2015 or later; and

(g) Accounts that closed before fiscal year end.

3.2.2.2 Forecasting the modelling subset's billing determinants for the test year

The modelling subset's number of accounts, and each account's specific monthly demand and energy consumption are scaled by a common factor to forecast the respective quantities in the modelling subset for fiscal 2017, the test year. The scaling factor is constructed using the actual and forecasted sales of ELGS accounts, which currently would consist of Rate Schedules 1200, 1201, 1210, 1211, 15XX, and 16XX:

Scaling factor = (Fiscal 2017 ELGS Forecast sales) / (Fiscal 2015 ELGS sales)
= 14,874.5 GWh / 14,630.3 GWh
= 1.0167

BC Hydro does not currently have enough information to estimate a precise scaling factor specific to the LGS Class (accounts taking service under Rate Schedules 16XX) as the rate was implemented in January 2011.

The key assumptions and specifications regarding the billing determinants used in the LGS rate model are specified by rate components below:

Basic Charge	The billing determinant for the basic charge is the sum of the number of forecasted accounts in the rate design subset, multiplied by 365 days in a year.
Demand Charge	The forecasted fiscal 2017 peak demand for each tier are estimated by adjusting the fiscal 2015 demand sales by the energy consumption scale factor (1.0167) to ensure that the revenue forecasted from demand charges are representative and consistent with forecasted account and energy growth of the class.
Part-1 and Part-2 Tier 1 and Tier 2 energy rates	Part-1 Tier 1 HBL energy consists of all baseline consumption (HBL) that is at or below 14,800 kWh in a given monthly billing period. Part-1 Tier 2 HBL energy consists of remaining baseline consumption. Part-2 Tier 1 and Tier 2 billing determinants are the allocated Tier 1 and Tier 2 HBL energy adjusted for forecast fiscal 2017 consumption outside the price limit band i.e., 80 per cent of HBL to 120 per cent of HBL (or -20%/+20% of HBL) .
Part-2 LRMC-based energy charge/credit	This is calculated based on the difference between the forecasted HBL and forecasted fiscal 2017 consumption and the price limit band.

Part-2 Tier 2 and Tier 1 energy charge/credit	The model assumes that the forecasted energy consumption for accounts that exceed the price limit bands falls into the Tier 2 energy rate component. This is because most LGS accounts greatly exceed the Tier 1 consumption threshold of 14,800 kWh. This assumption simplifies the model without substantive impact on the outcome.
Fiscal 2017 LGS Class Forecast Sales	The most recently available Fiscal 2017 ELGS forecast sales based on BC Hydro's October 2015 Load Forecast is used. The LGS class-specific load forecast is estimated by first calculating the proportion of Fiscal 2015 LGS sales to total Fiscal 2015 ELGS sales. This proportion is then applied to the Fiscal 2017 ELGS forecast sales of 14,874.5 GWh. (see Table T-13, Note 1)

3.2.3 Forecasting Baselines (HBLs)

Fiscal 2017 baselines are forecasted by scaling the fiscal 2016 baselines up by the difference between the three-year moving average consumption for years leading up to fiscal 2016 (which informs fiscal 2016 baselines) and the three-year moving average consumption for years leading up to fiscal 2017 (which informs fiscal 2017 baselines). This best preserves the variations between forecast consumption and baseline.

3.2.4 Model Calibration

While the LGS class energy load forecast is an external input as described in section 3.2.2.2, the LGS class billing determinants for each rate component are determined by applying a calibration factor of 1.0589 to the respective components of the billing determinants in the fiscal 2017 modelling subset. This calibration factor is constructed based on dividing the fiscal 2017 LGS Class energy forecast

(11,117.9 GWh) by the fiscal 2017 modelling subset energy forecast (10,499.2 GWh). The calculations described in section 3.3 and onwards are based on calibrated quantities for the class.

3.3 General Rate Increases

The general rate increase used is 4.00 per cent, as applied for by BC Hydro in the Fiscal 2017-Fiscal 2019 RRA. The rate rider used in the fiscal 2017 pricing is that set out in the Order in Council No. 097, Direction No. 7, section 10 to the Commission. In summary, the rate increases used are as follows:

Fiscal 2017 general rate increase: 4.00 per cent
Fiscal 2017 Rate Rider: 5.00 per cent

Inflation projection for F2017 is 1.90 per cent, as set by the Treasury board of the Province of B.C. in October 2015.

3.4 Target Revenue

Fiscal 2017 LGS class target revenue is determined using same general methodology used to determine forecast domestic revenue described in previous years. The computation uses LGS revenue calculated at fiscal 2016 rates scaled up by the BC Hydro requested general rate increase for fiscal 2017 in the Fiscal 2017-Fiscal 2019 RRA.

The steps for computation for the target revenue are as follows:

Table T-14 LGS Target Revenue Computation Steps

Line	Description	Value	Unit	Source
A	Forecast F2017 sales	11,117.9	GWh	October 2015 BC Hydro Load Forecast
B	Revenue under F2016 rates	847.2	$ million	Calculated LGS Revenue Forecast at F2016 Tariff Rates
C	F2017 RRA increase	4.00	%	Chapter 1, BC Hydro F2017-F2019 RRA.
D	F2017 Target Revenue (Total Revenue at F2016 Rates Escalated by F2017 RRA increases)	881.1	$ million	B * (1 + C)
E	F2017 Rate Rider	5.00	%	Order in Council No. 097, Direction No. 7, section 10
F	F2017 Rate Rider Revenue	44.1	$ million	D * E
G	F2016 Target Revenue including Rate Rider	925.2	$ million	D + F

3.5 Rate Computation

A summary of the computed rates is provided in Table T-15.

Table T-15 Fiscal 2017 LGS Rates (Excluding Rate Rider)

Line	Rate Component	Amount	Reference
A	Basic Charge ($/day)	0.2347	Section 3.5.1
	Demand Charge		
B	Tier 1 ($/kW)	0	Section 3.5.2
C	Tier 2 ($/kW)	5.72	Section 3.5.2
D	Tier 3 ($/kW)	10.97	Section 3.5.2
	Energy charge		
E	Tier 1 (cents /kwh)	11.14	Section 3.5.6
F	Tier 2 (cents /kwh)	5.36	Section 3.5.6
G	Part 2 LRMC based Rate (cents /kwh)	10.09	Section 3.5.3
H	Minimum Energy Charge (cents /kwh)	3.43	Section 3.5.4

3.5.1 Basic Charge

The basic charge computation follows the pricing principles as outlined in section 3.2.1 above, which is to increase by the general rate increase.

Basic Charge = Fiscal 2016 Basic Charge * (Fiscal 2017 RRA % + 100%)

Basic Charge = $0.2257 / day * (4.00% + 100%) = $0.2347 / day

3.5.2 Demand Charge

The demand charge computation follows the pricing principles as outlined in section 3.2.1 above, and the demand charge is increased by the general rate increase.

Demand Charge = Fiscal 2016 Demand Charge * (Fiscal 2017 RRA % + 100%)

Demand Tier 1 = $0 / kW * (4.00% + 100%) = $0 / kW

Demand Tier 2 = $5.50 / kW * (4.00% + 100%) = $5.72 / kW

Demand Tier 3 = $10.55 / kW * (4.00% + 100%) = $10.97 / kW

3.5.3 Part-2 LRMC Based Energy Rate

The Fiscal 2017 Part-2 LRMC based energy rate is set to increase by the rate of inflation:

Fiscal 2017 Part-2 LRMC based energy rate = Fiscal 2016 Part-2 LRMC based energy rate x (Inflation Rate % + 100%)

Fiscal 2017 Part-2 LRMC based energy rate = 9.90 cents/kWh x (1.90% + 100%) = 10.09 cents/kWh

3.5.4 Minimum Energy Charge

The Minimum Energy Charge follows the pricing principles as outlined in section 3.2.1 above, and is increased by the general BC Hydro rate increase.

Fiscal 2017 Minimum Energy Charge = Fiscal 2016 Minimum energy Charge * (Fiscal 2017 RRA % + 100%)

Fiscal 2017 Minimum Energy Charge = 3.30 cents/ kWh * (4.00% + 100%) = 3.43 cents/kWh

3.5.5 Discounts

The discount rates are not affected by the rate increase.

Primary discount of 1.5 per cent applies to all charges for customers under Rate Schedules 1601 and 1611.

A discount of 25 cents per billing period per kW of billing demand is applied to customers under Rate Schedules 1610 and 1611.

The total discount amount for eligible customers is estimated to be $10,312,082. This amount is entered in the model as an adjustment to forecasted revenue (Table T-16, Line U).

3.5.6 Tier 1 and Tier 2 Energy Rates

The Tier 1 and Tier 2 energy rates are set to collect the residual forecast revenue in the LGS rates model. The model first computes the forecast revenues to be collected for each of the respective rate components outlined in sections 3.5.1 to 3.5.5 above. This quantity is then subtracted from the target revenue to determine the remaining forecast revenue to be collected under the Tier 1 and Tier 2 energy rates.

Table T-16 Computation of Forecast Revenue to be Collected under the Tier 1 and Tier 2 LGS Energy Rates

Line	Description	Value	Unit	Source
A	Forecast F2017 Part 2 LRMC rate component energy	979,144	kWh	Table T-13, Line H
B	Forecast F2017 Minimum Energy Charge energy	12,257,659	kWh	Table T-13, Line J
C	Forecast F2017 Tier 1 demand	2,767,178	kW	Table T-13, Line C

Line	Description	Value	Unit	Source
D	Forecast F2017 Tier 2 demand	7,917,082	kW	Table T-13, Line D
E	Forecast F2017 Tier 3 demand	16,752,208	kW	Table T-13, Line E
F	Forecast F2017 Number of accounts	6,635		Table T-13, Line B
G	Part 2 LRMC Rate	10.09	cents/kwh	Table T-15, Line G
H	Tier 1 Energy Rate	11.14	cents/kwh	Estimated through iterations Note 1
I	Tier 2 Energy Rate	5.36	cents/kwh	Estimated through iterations Note 1
J	Tier 1 Demand Rate	-	$/kW	Table T-15, Line B
K	Tier 2 Demand Rate	5.72	$/kW	Table T-15, Line C
L	Tier 3 Demand Rate	10.97	$/kW	Table T-15, Line D
M	LGS basic charge	23.47	cents/day	Table T-15, Line A
N	Minimum Energy Charge (**MEC**)	3.43	cents/kwh	Table T-15, Line H
	Forecast Revenue by rate component, excluding rate rider:			
O	Part 2 LRMC Forecast Revenue	98,777	$	A * G / 100 Note 2
P	LGS Tier 1 Demand Forecast Revenue	-	$	C * J Note 2
Q	LGS Tier 2 Demand Forecast Revenue	45,285,706	$	D * K Note 2
R	LGS Tier 3 Demand Forecast Revenue	183,805,231	$	E * L Note 2
S	LGS basic charge Forecast Revenue	570,024.89	$	M * F * 365 / 100 Note 2
T	MEC Bills Forecast Revenue	420,682.86	$	N * B / 100 Note 2
U	Transformation and Primary Potential Discounts	(10,312,082)	$	Estimated, using the rates in Line G, H, I, J , K, L, M, N Note 2
V	Total forecast Revenue from rate components excluding Tier 1 and Tier 2 energy	219,868,340	$	Sum (O thru U)
W	F2017 Total Target Revenue	881,107,347	$	Table T-14, Line E
X	**Forecast Revenue to be collected from Tier 1 and Tier 2 Energy rates**	**661,239,007**	**$**	**W - V**

Note 1: The Tier 1 and Tier 2 Energy rates in Table T-16, lines H and I are used as inputs for computing discounts only. These estimates are derived iteratively with the rate outcomes in Table T-17, lines G and H, to a variance of 0.001 cents/kWh.

Note 2: No rounding has been applied to the calculations to compute the outcomes, as this is an intermediate step in the rate model.

The calculation of Tier 1 and Tier 2 Energy rates are designed to collect the revenue referenced in Table T-16, Line Y. The design of these rates maintains the rate ratio of 2.08:1 (Tier 1: Tier 2 rates) per BC Hydro's LGS Rate Application and approved by Commission Order No. G-110-10, and is verified by dividing the Fiscal 2017 Tier 2 energy rate by the Tier 1 energy rate. This ratio allows the Tier 2 rate to be derived directly, and the Tier 1 rate to be calculated as the Tier 2 rate multiplied by the rate ratio. The formula used to derive Tier 1 and Tier 2 energy rates is described below:

Beta = Ratio of Fiscal 2017 Tier 1 / Fiscal 2017 Tier 2 energy rates = 2.08

R = Forecast revenue to be recovered from Tier 1 and Tier 2 energy rates
= Tier 1 kWh *(Beta) * Tier 2 rate + Tier 2 kWh * Tier 2 rate

Rearranging above formula yields:

Tier 2 rate = R / (Tier 1 kWh * (Beta) + Tier 2 kWh)

The rate derivation is described in Table T-17.

Table T-17 Computation of Tier 1 and Tier 2 Energy Rates

Line	Description	Value	Unit	Source
A	Tier 1 forecasted billed consumption	1,144,683,839	kWh	Table T-13, Line F
B	Tier 2 forecasted billed consumption	9,960,003,566	kWh	Table T-13, Line G and Table T-13, Line I
C	Revenue to be recovered from Tier 1 and Tier 2 energy rates	661,239,007	$	Table T-16, Line X
D	F2016 Tier 1 Energy Rate	10.66	cents/kWh	F2016 Tariff Approved by Commission Order No. G-48-14
E	F2016 Tier 2 Energy Rate	5.13	cents/kWh	F2016 Tariff Approved by Commission Order No. G-48-14
F	Beta	2.08		LGS Rate Application and approved by Commission Order No. G-110-10; verified by D/E
G	F2017 Tier 2 Energy Rate	5.36	cents/kWh	C / (A*F + B) *100
H	F2017 Tier 1 Energy Rate	11.14	cents/kWh	G*F

3.6 Revenue Neutrality

Using the rates calculated via the rate calculation methodology described above, this section shows that the rates are class revenue neutral on a forecast basis using the fiscal 2017 forecast load. This is done by comparing the revenue under the Fiscal 2017 LGS rate and the revenue target, as shown in Table T-18.

The rates calculated in section 3.5 above are verified to ensure that they recover the target revenue on a forecast basis by applying the rates computed in section 3.5.6 above (Table T-17, Lines G and H) to the Fiscal 2017 LGS class forecast, and then comparing the resulting forecast revenue to the Fiscal 2017 LGS class revenue target. The results in Table T-18, lines AD to AG, show that the rates recover the target revenue on a forecast basis, with a variance of 0.011 per cent, which is attributable to rounding (demand charge to the $0.01/kW and Energy charge to the 0.01 cent/kWh).

Table T-18 Revenue Neutrality

Line	Description	Value	Unit	Source
A	Forecast Part 1, Tier 1 Class Load	1,144,683,839	kWh	Table T-13, Line F
B	Forecast Part 1, Tier 2 Class Load	9,969,349,694	kWh	Table T-13, Line G
C	Forecast Part 2 LRMC Class Load	979,144	kWh	Table T-13, Line H
D	Forecast Part 2 Tier 2 Class Load	(9,346,128)	kWh	Table T-13, Line I
E	Forecast Minimum Energy Charge Class Load	12,257,659	kWh	Table T-13, Line J
F	Forecast Energy, LGS Class	11,117,924,209	kWh	Table T-13, Line A
G	Forecast Number of Accounts, LGS Class	6,635		Table T-13, Line B
H	Forecast Class Demand Tier 1	2,767,178	kW	Table T-13, Line C
I	Forecast Class Demand Tier 2	7,917,082	KW	Table T-13, Line D
J	Forecast Class Demand Tier 3	16,752,208	kW	Table T-13, Line E
K	Tier 1 Energy Rate	11.14	cents/kWh	Table T-17, Line H
L	Tier 2 Energy Rate	5.36	cents/kWh	Table T-17, Line G
M	Part 2 LRMC Energy Rate	10.09	cents/kWh	Table T-15, Line G
N	Minimum Energy Charge	3.43	cents/kWh	Table T-15, Line H
O	Basic Charge	23.47	$ / Day	Table T-15, Line A
P	Tier 1 Demand Rate	-	$/kW	Table T-15, Line B
Q	Tier 2 Demand Rate	5.72	$/kW	Table T-15, Line C
R	Tier 3 Demand Rate	10.97	$/kW	Table T-15, Line D
S	Forecast primary potential and transformation discounts	(10,312,082)	$	Table T-16, Line U
T	Tier 1 Energy Revenue	127,517,780	$	A * K / 100
U	Tier 2 Energy Revenue	534,357,144	$	B * L / 100
V	Part 2 LRMC Energy Revenue	98,796	$	C * M / 100
W	Part 2 Tier 2 Energy Revenue	(500,952)	$	D * L / 100
X	Minimum Energy Charge Revenue	420,438	$	E * N / 100
Y	Tier 1 Demand Revenue	-	$	H * P

Line	Description	Value	Unit	Source
Z	Tier 2 Demand Revenue	45,285,706	$	I * Q
AA	Tier 3 Demand Revenue	183,771,726	$	J * R
AB	Basic Charge Revenue	568,391	$	G * O * 365
AC	Rate Rider	5	%	Order in Council No. 097, Direction No. 7, section 10
AD	Total Forecasted Revenue (including rate rider)	925,267,292	$	Sum (S to AB) * (1+AC)
AE	Target Revenue (including rate rider)	925,162,714	$	Table T-14, Line G
AF	Variance due to rates rounding	104,578	$	AD – AE
AG	Variance %	0.011	%	AF / AE

BC Hydro
Power smart

Fiscal 2017 to Fiscal 2019
Revenue Requirements Application

Appendix U

BC Hydro Reliability Indices

BC Hydro
Power smart

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May 11, 2016

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)
Annual Reporting of Reliability Indices
Annual Response to Directive 26 of Commission Decision on F2005/F2006 Revenue Requirements Application (F05/F06 RRA)

BC Hydro writes in compliance with Directive 26 of the Commission's decision on BC Hydro's F05/F06 RRA to provide its annual reporting of reliability indices.

BC Hydro submitted its initial distribution and generation reliability indices compliance filing in September 2005, and subsequently reported the available reliability indices in May 2006 as part of the F2007/F2008 RRA. BC Hydro has since filed annual reports to the Commission on these reliability indices for each year starting in May 2007. Transmission system reliability indices for years prior to F2012 were provided separately by the British Columbia Transmission Corporation (**BCTC**) in its Transmission System Capital Plan filings. BC Hydro provided the transmission system reliability indices starting in F2012, subsequent to the integration of BC Hydro and BCTC in F2011.

In this filing, BC Hydro is providing reliability indices for distribution, transmission and generation performance through F2016.

Directive 26 of the F05/F06 RRA Decision

"The Commission Panel expects BC Hydro and BCTC to present their reliability indices (SAIFI, SAIDI, CAIDI, ASAI, SARI, MAIFI, generation forced outages, availability, and generation outage rates) both combined and disaggregated (where applicable) on an annual basis with comparisons to CEA averages."

Distribution and Transmission Update

The most recent annual Canadian Electricity Association (**CEA**) reports for distribution and transmission include the 2014 Annual Service Continuity data on Distribution System Performance in Electrical Utilities and the 2014 Bulk Electricity System. The comparative information for BC Hydro is provided in Attachment 1 in tabular and graphical form, both overall and disaggregated for the distribution and transmission system.

Generation Performance Update

As in previous years, BC Hydro generation reliability statistics are provided on a fiscal year basis. CEA calendar year data is provided for comparison, as is done with BC Hydro distribution and transmission reliability statistics.

The most recent annual CEA report on generation performance is the 2014 Generation Equipment Status Annual Report. CEA data on generation performance for the 2015 calendar year are not yet available. BC Hydro's generation reliability indices are presented for the ten-year period ending F2016, along with CEA generation data through 2014, in tabular and graphical form in Attachment 2.

For further information, please contact Fred James at 604-623-4317 or by email at bchydroregulatorygroup@bchydro.com.

Yours sincerely,

Tom Loski
Chief Regulatory Officer

ls/ma

Enclosures (2)

F05/F06 Revenue Requirements Application
Annual Response to Directive 26 of BCUC Decision

F2016 Annual Reporting of Reliability Indices

Attachment 1

Distribution and Transmission Reliability Indices

This section includes the following distribution and transmission indices:

SAIFI	a measure of the number of sustained interruptions (longer than one minute) an average distribution customer will experience over the course of a year
T-SAIFI-MI	a measure of transmission interruptions of less than one minute in duration that a delivery point experiences during a given period
T-SAIFI-SI	a measure of transmission interruptions of one minute or more that a delivery point experiences during a given period
T-SAIDI	a measure of the average total interruption duration, in hours that a delivery point experiences during a given period
SAIDI	a measure of the amount of time, in hours, an average distribution customer is without power in a year
CAIDI	a measure of the average interruption, in hours, per interrupted distribution customer
%ASAI	a measure of the percentage of time service is available in the year
CEMI-4	percentage of customers experiencing four or more outages during a 12-month period
MAIFI	a measure of the frequency of momentary (less than one minute) interruptions per distribution customer served
DPUI	a measure of overall bulk electricity system performance in terms of a composite index of unreliability expressed in system minutes during a year. It takes into account all forced and planned outages except interruptions attributed to generators
SARI	a measure of the average restoration time, in hours, for each transmission delivery point

As noted in Provision 9x of the F2011 Revenue Requirements Application Negotiated Settlement Agreement, BC Hydro is also reporting its CEMI-4 reliability metric, and SAIFI, SAIDI, CAIDI, ASAI, and CEMI-4 metrics normalized using the IEEE 2.5 Beta method. CEMI-4 is not benchmarked externally as utilities are at varying stages in their development of this metric.

Table 1 Reliability Indices – BC Hydro Overall and CEA Overall (All-Event Indices, Not Normalized)

	BC Hydro Overall				CEA Overall			
Year	SAIFI	SAIDI	CAIDI	%ASAI	SAIFI	SAIDI	CAIDI	%ASAI
F1996	1.40	3.04	2.17	99.965	2.80	3.06	1.09	99.965
F1997	1.43	2.95	2.03	99.966	2.39	2.86	1.20	99.967
F1998	1.13	2.00	1.76	99.977	2.35	3.70	1.57	99.958
F1999	1.50	4.23	2.82	99.952	2.40	3.32	1.38	99.962
F2000	1.21	2.28	1.88	99.974	2.59	4.31	1.67	99.951
F2001	1.18	2.51	2.13	99.971	2.26	3.23	1.43	99.963
F2002	1.41	3.60	2.55	99.959	2.41	3.67	1.52	99.958
F2003	1.45	3.77	2.60	99.957	2.33	4.06	1.74	99.954
F2004	1.63	4.51	2.77	99.949	2.67	10.65	3.99	99.878
F2005	1.47	3.96	2.69	99.955	1.98	3.95	2.00	99.955
F2006	1.78	3.82	2.15	99.956	2.13	4.80	2.26	99.945
F2007	2.78	11.40	4.09	99.870	2.53	7.85	3.11	99.910
F2008	1.90	5.68	2.99	99.935	2.32	5.47	2.36	99.938
F2009	1.92	5.24	2.73	99.940	2.34	6.29	2.69	99.928
F2010	1.71	4.25	2.49	99.952	2.01	4.20	2.09	99.952
F2011	1.89	5.28	2.80	99.940	2.20	5.17	2.35	99.941
F2012	1.92	5.08	2.65	99.942	2.63	6.16	2.34	99.930
F2013	1.59	3.70	2.33	99.958	2.54	4.66	1.83	99.947
F2014	1.83	5.19	2.83	99.941	2.72	9.49	3.49	99.892
F2015	1.72	5.11	2.97	99.942	2.39	6.38	2.67	99.927
F2016	2.29	10.69	4.66	99.878	n/a	n/a	n/a	n/a

Table 2 Reliability Indices – BC Hydro (Distribution) and CEA (Distribution) (All-Event Indices, Not Normalized)

Year	BC Hydro (Distribution)				CEA (Distribution)			
	SAIFI	SAIDI	CAIDI	%ASAI	SAIFI	SAIDI	CAIDI	%ASAI
F1996	0.95	2.66	2.78	99.970	1.85	2.51	1.35	99.971
F1997	0.88	2.35	2.64	99.973	1.74	2.39	1.38	99.973
F1998	0.70	1.60	2.28	99.982	1.70	3.21	1.87	99.963
F1999	1.02	3.61	3.54	99.959	1.69	2.82	1.67	99.968
F2000	0.65	1.80	2.78	99.979	1.93	3.80	1.97	99.957
F2001	0.73	1.98	2.72	99.977	1.77	2.83	1.60	99.968
F2002	0.86	2.94	3.43	99.966	1.86	3.19	1.71	99.964
F2003	0.89	3.18	3.59	99.964	1.74	3.55	2.03	99.960
F2004	1.21	3.50	2.89	99.960	1.89	5.69	3.01	99.935
F2005	1.06	3.57	3.35	99.959	1.56	3.49	2.24	99.960
F2006	1.25	3.27	2.61	99.963	1.74	4.33	2.49	99.951
F2007	2.29	10.49	4.58	99.880	2.11	7.35	3.49	99.916
F2008	1.45	5.01	3.44	99.943	1.86	4.94	2.66	99.944
F2009	1.42	4.54	3.21	99.948	1.88	5.65	3.01	99.936
F2010	1.21	3.61	2.98	99.959	1.59	3.63	2.28	99.959
F2011	1.43	4.77	3.34	99.946	1.74	4.65	2.67	99.947
F2012	1.37	4.40	3.22	99.950	2.09	5.59	2.68	99.936
F2013	1.06	3.08	2.92	99.965	1.86	4.13	2.22	99.953
F2014	1.45	4.66	3.20	99.947	2.05	8.59	4.19	99.902
F2015	1.34	4.44	3.31	99.949	1.79	5.67	3.16	99.935
F2016	1.91	10.13	5.30	99.884	n/a	n/a	n/a	n/a

Table 3 Reliability Indices – BC Hydro Overall – Normalized using IEEE 2.5 Beta Method

Year	BC Hydro Overall – Normalized using IEEE 2.5 Beta Method				
	SAIFI	SAIDI	CAIDI	CEMI-4 %	%ASAI
F2010	1.52	3.50	2.29	13.18	99.960
F2011	1.61	3.83	2.38	15.26	99.956
F2012	1.67	3.89	2.34	15.37	99.956
F2013	1.46	3.33	2.28	10.45	99.962
F2014	1.68	4.14	2.46	12.52	99.953
F2015	1.35	3.37	2.49	10.13	99.962
F2016	1.60	3.42	2.14	14.00	99.961

Table 4 Reliability Indices – BC Hydro CEMI-4 Overall

(All-Event Indices, Not Normalized)

Year	**BC Hydro Overall**
	CEMI-4 %
F2010	15.22
F2011	19.26
F2012	17.43
F2013	12.88
F2014	15.10
F2015	15.15
F2016	23.77

Note: CEA does not survey for CEMI-4 or IEEE 2.5 Beta.

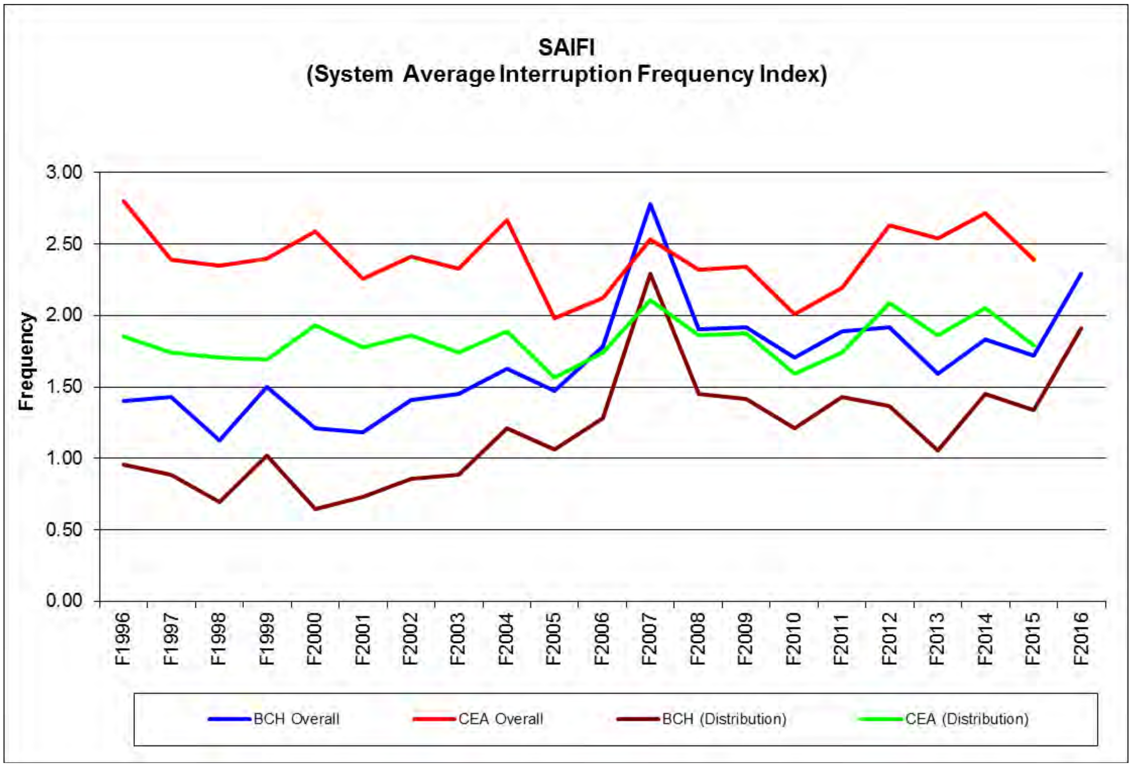
Table 5 Reliability Indices – BC Hydro (Transmission) and CEA (Transmission) (Forced Data)

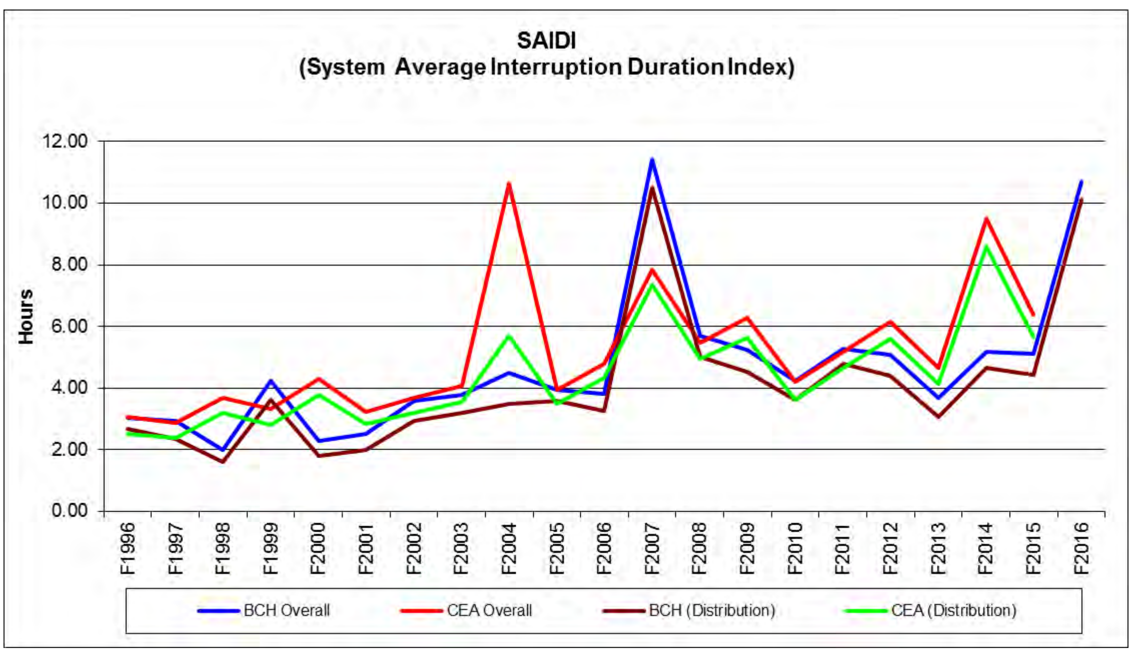
(All-Event Indices, Not Normalized)

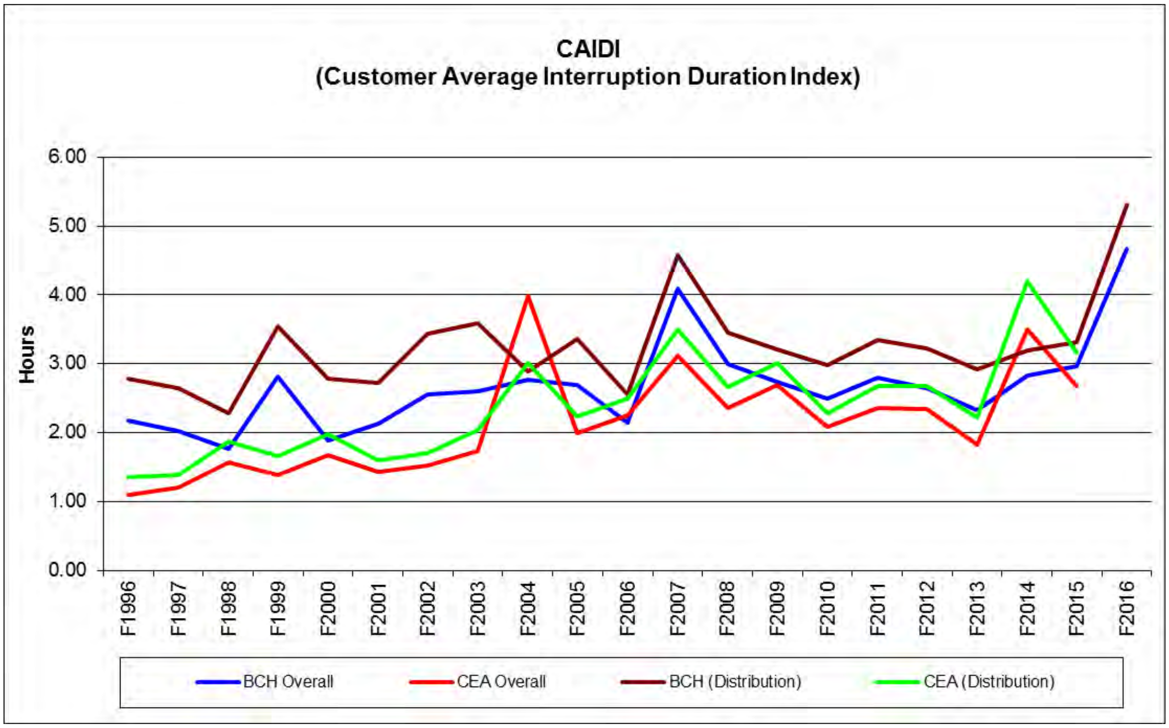
Year	BC Hydro (Transmission) (Forced)					CEA (Transmission) (Forced)				
	T-SAIFI-MI	T-SAIFI-SI	T-SAIDI	DPUI	SARI	T-SAIFI-MI	T-SAIFI-SI	T-SAIDI	DPUI	SARI
F2005	0.90	0.82	1.68	18.02	1.96	0.67	0.85	1.51	21.00	1.65
F2006	0.75	0.91	1.73	25.31	1.87	0.81	0.85	1.29	32.00	1.52
F2007	1.26	1.11	3.80	47.16	1.87	0.91	0.79	1.54	25.51	1.52
F2008	0.87	0.83	2.11	50.54	3.40	0.87	0.74	1.30	18.82	1.94
F2009	0.65	0.72	1.93	35.13	2.42	0.64	0.75	1.23	21.48	1.64
F2010	0.72	1.02	2.31	26.99	2.44	1.01	0.71	1.41	24.98	1.98
F2011	0.38	0.71	1.30	11.31	1.83	0.54	0.64	1.39	13.22	2.16
F2012	0.43	0.86	1.55	19.39	1.81	0.84	0.81	1.73	23.35	2.13
F2013	0.56	0.74	1.64	17.16	2.19	0.84	0.90	4.48	51.18	4.98
F2014	0.74	0.87	2.57	25.18	3.01	0.86	0.83	2.59	27.07	3.11
F2015	0.83	0.74	2.11	26.41	2.86	0.72	0.83	2.56	19.24	3.10
F2016	0.79	0.63	2.46	27.77	3.90	n/a	n/a	n/a	n/a	n/a

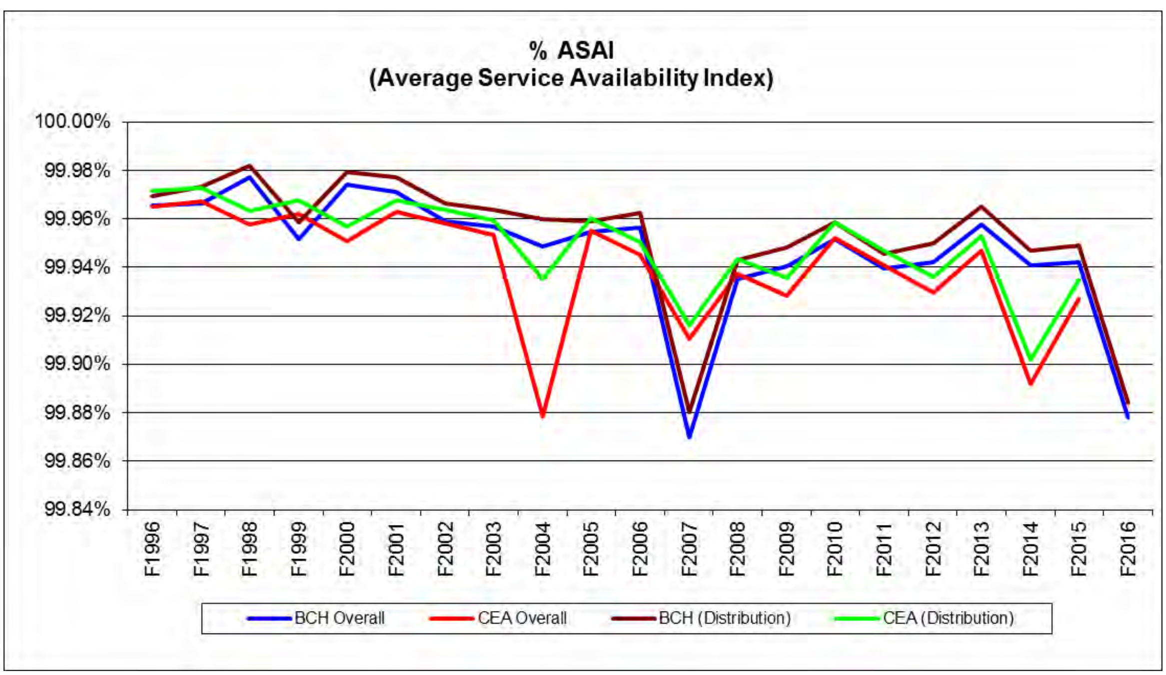
Note: The CEA Bulk Electricity Study program reports only on forced outage results as not all the participating utilities report planned outages.

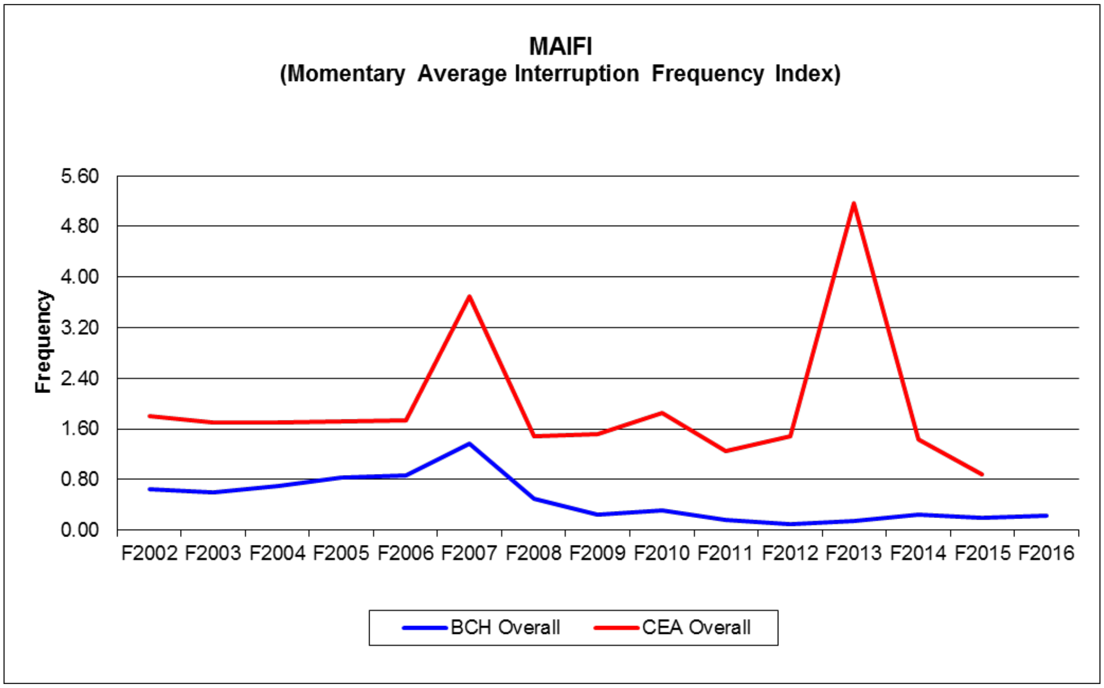
Distribution Graphs





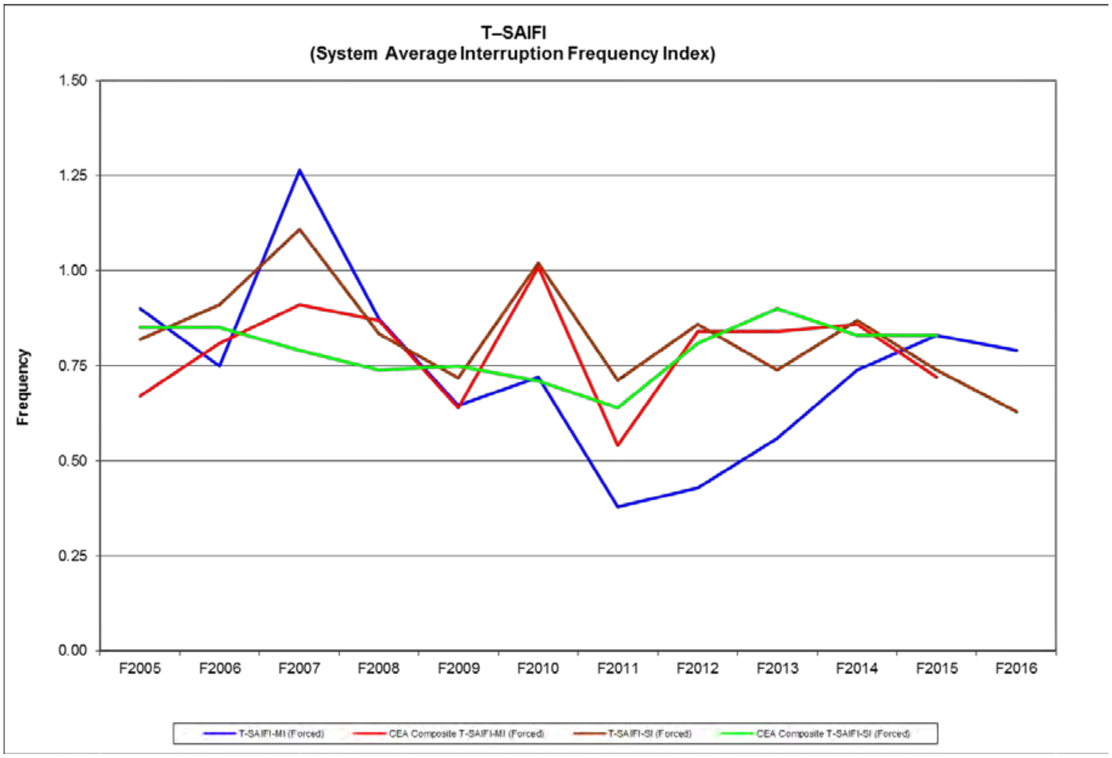

CAIDI
(Customer Average Interruption Duration Index)
Hours
6.00
5.00
4.00
3.00
2.00
1.00
0.00
F1996
F1997
F1998
F1999
F2000
F2001
F2002
F2003
F2004
F2005
F2006
F2007
F2008
F2009
F2010
F2011
F2012
F2013
F2014
F2015
F2016
BCH Overall
CEA Overall
BCH (Distribution)
CEA (Distribution)

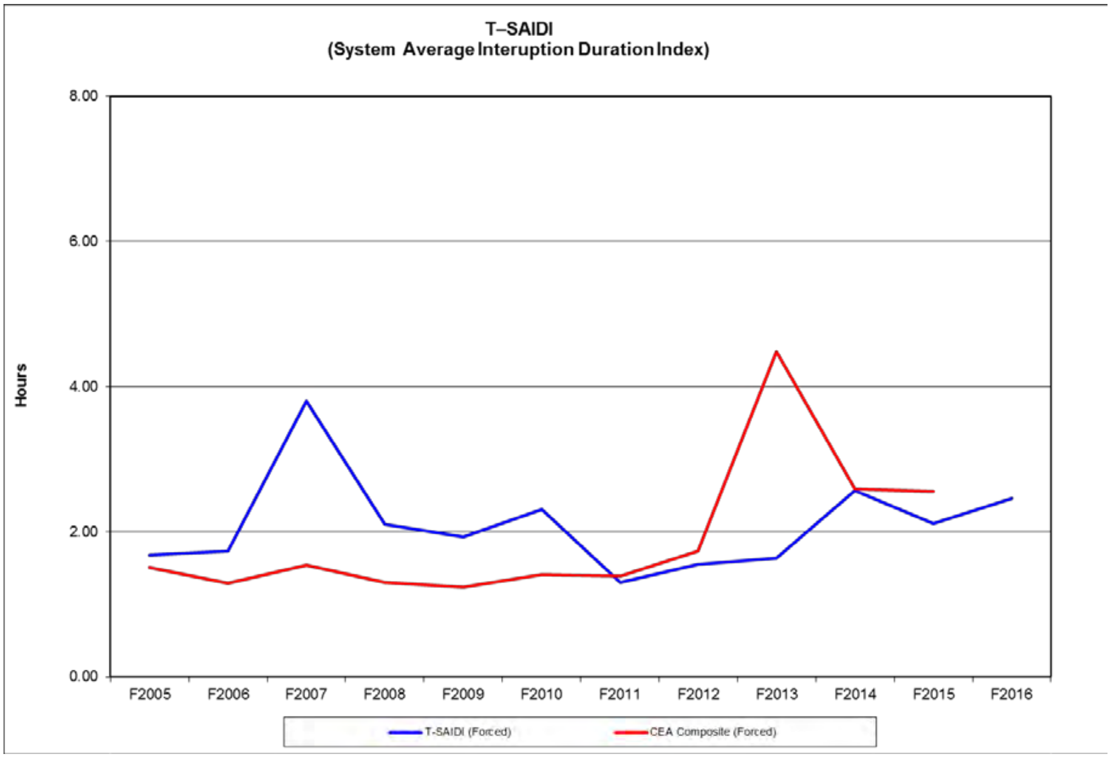

% ASAI
(Average Service Availability Index)
100.00%
99.98%
99.96%
99.94%
99.92%
99.90%
99.88%
99.86%
99.84%
F1996
F1997
F1998
F1999
F2000
F2001
F2002
F2003
F2004
F2005
F2006
F2007
F2008
F2009
F2010
F2011
F2012
F2013
F2014
F2015
F2016
BCH Overall
CEA Overall
BCH (Distribution)
CEA (Distribution)

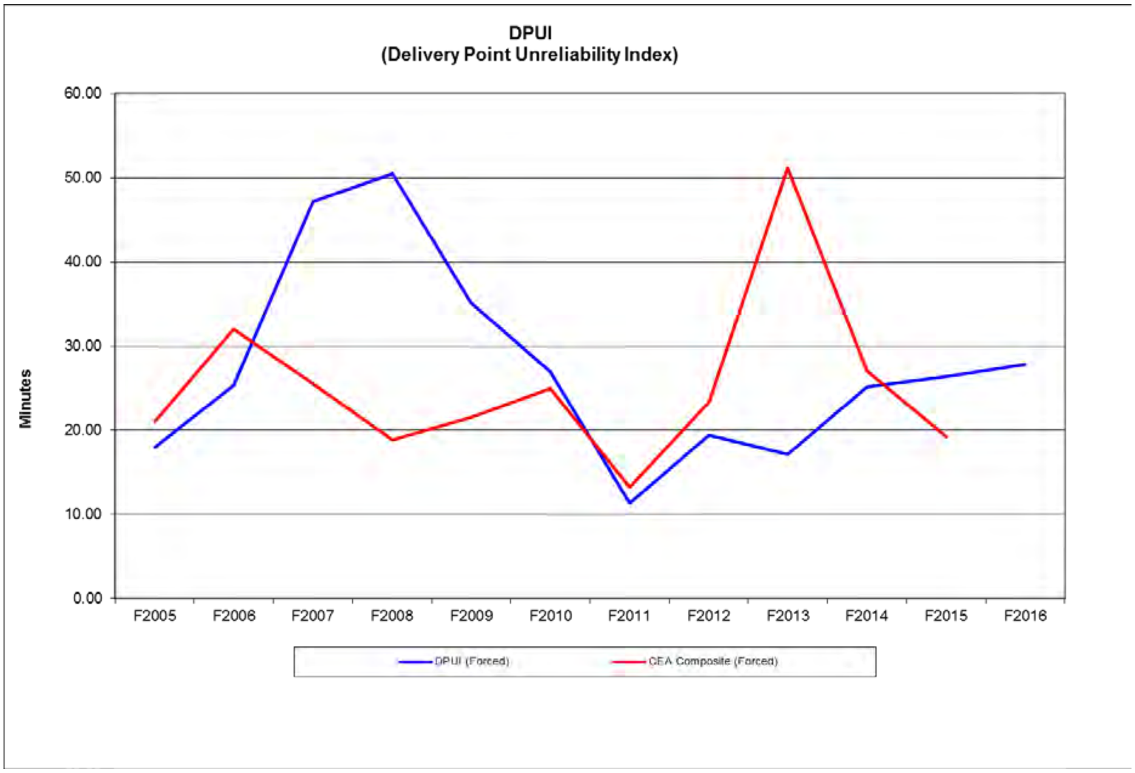


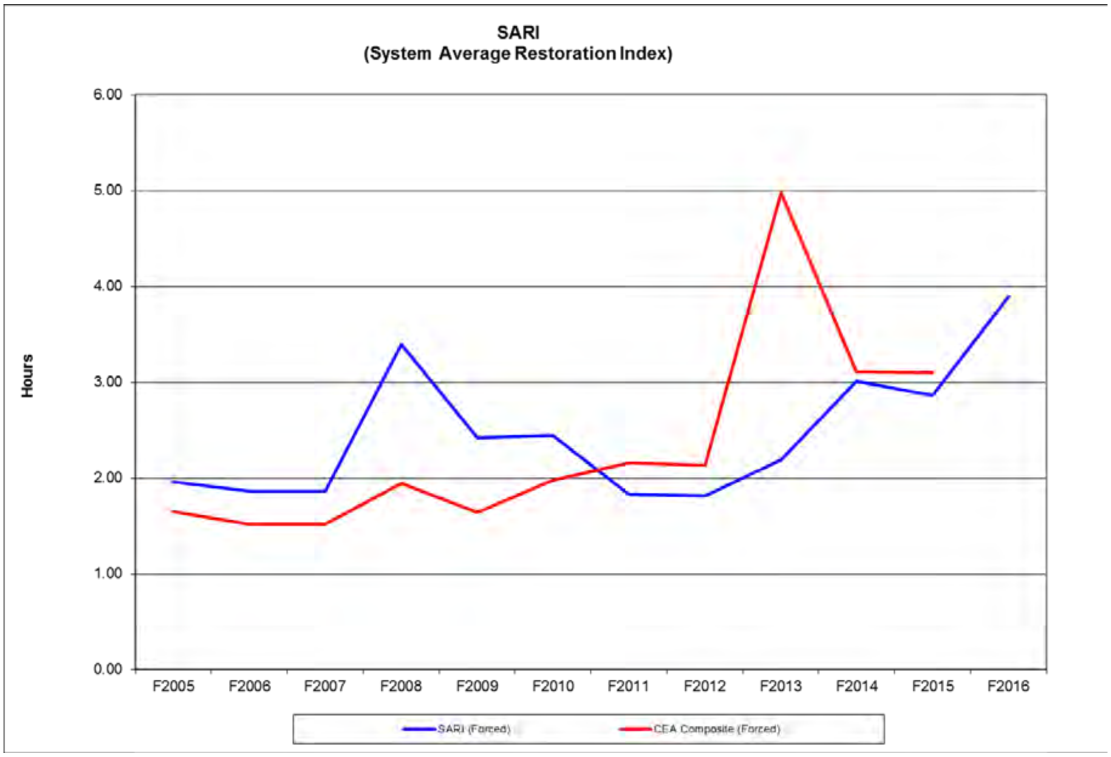
Note: The customer momentary interruptions and the resulting MAIFI may not apply to the utility's total customer population in the CEA comparison. Momentary outages are any interruptions on the feeders of less than one minute duration, caused by disturbance on the distribution, substation or transmission system.

Transmission Graphs




T–SAIDI
(System Average Interuption Duration Index)
Hours
8.00
6.00
4.00
2.00
0.00
F2005
F2006
F2007
F2008
F2009
F2010
F2011
F2012
F2013
F2014
F2015
F2016
T-SAIDI (Forced)
CEA Composite (Forced)


DPUI
(Delivery Point Unreliability Index)
Minutes
60.00
50.00
40.00
30.00
20.00
10.00
0.00
F2005
F2006
F2007
F2008
F2009
F2010
F2011
F2012
F2013
F2014
F2015
F2016
DPUI (Forced)
CEA Composite (Forced)


SARI
(System Average Restoration Index)
Hours
6.00
5.00
4.00
3.00
2.00
1.00
0.00
F2005
F2006
F2007
F2008
F2009
F2010
F2011
F2012
F2013
F2014
F2015
F2016
SARI (Forced)
CEA Composite (Forced)

F05/F06 Revenue Requirements Application
Annual Response to Directive 26 of BCUC Decision

F2016 Annual Reporting of Reliability Indices

Attachment 2

Generation Reliability Indices

	BC Hydro Hydroelectric Units						CEA Hydroelectric Units				
Fiscal Year	Average Availability Factor (%)	Average Operating Factor (%)	Average Forced Outage Count (Including starting failures) (Internal) Note 1	Average Forced Outage Factor (%) (Including starting failures) (Internal) Note 1	Failure Rate	Calendar Year	Average Availability Factor (%)	Average Operating Factor (%)	Average Forced Outage Count (Including starting failures) (Internal) Note 1	Average Forced Outage Factor (%) (Including starting failures) (Internal) Note 1	Failure Rate
F2007	88.6	73.6	2.1	1.6	2.0	C2006	90.2	73.0	2.8	1.8	2.1
F2008	85.8	74.8	2.2	2.9	2.1	C2007	92.2	74.2	2.5	1.8	2.0
F2009	85.6	71.3	2.0	5.2	2.1	C2008	93.5	80.0	2.5	2.0	2.1
F2010	84.7	68.7	2.1	2.2	2.3	C2009	91.8	77.1	2.4	1.4	2.0
F2011	81.9	68.0	2.0	5.1	1.9	C2010	90.4	70.3	2.2	3.0	1.9
F2012	82.2	69.8	2.4	5.0	2.7	C2011	88.4	72.5	2.5	3.9	2.2
F2013	82.7	72.6	2.0	3.4	2.3	C2012	89.2	72.0	2.5	3.8	2.3
F2014 Note 2	80.5	64.7	2.5	4.7	2.7	C2013	87.9	74.0	2.4	3.9	2.1
F2015 Note 3	81.1	65.1	2.4	3.7	2.9	C2014	87.5	73.5	2.4	5.0	2.1
F2016 Note 3	82.2	65.9	2.0	4.1	2.4	C2015	n/a	n/a	n/a	n/a	n/a

Definitions

Availability Factor = Operating Time + Available-But-Not-Operating Time / In Commercial Service Time Note 4

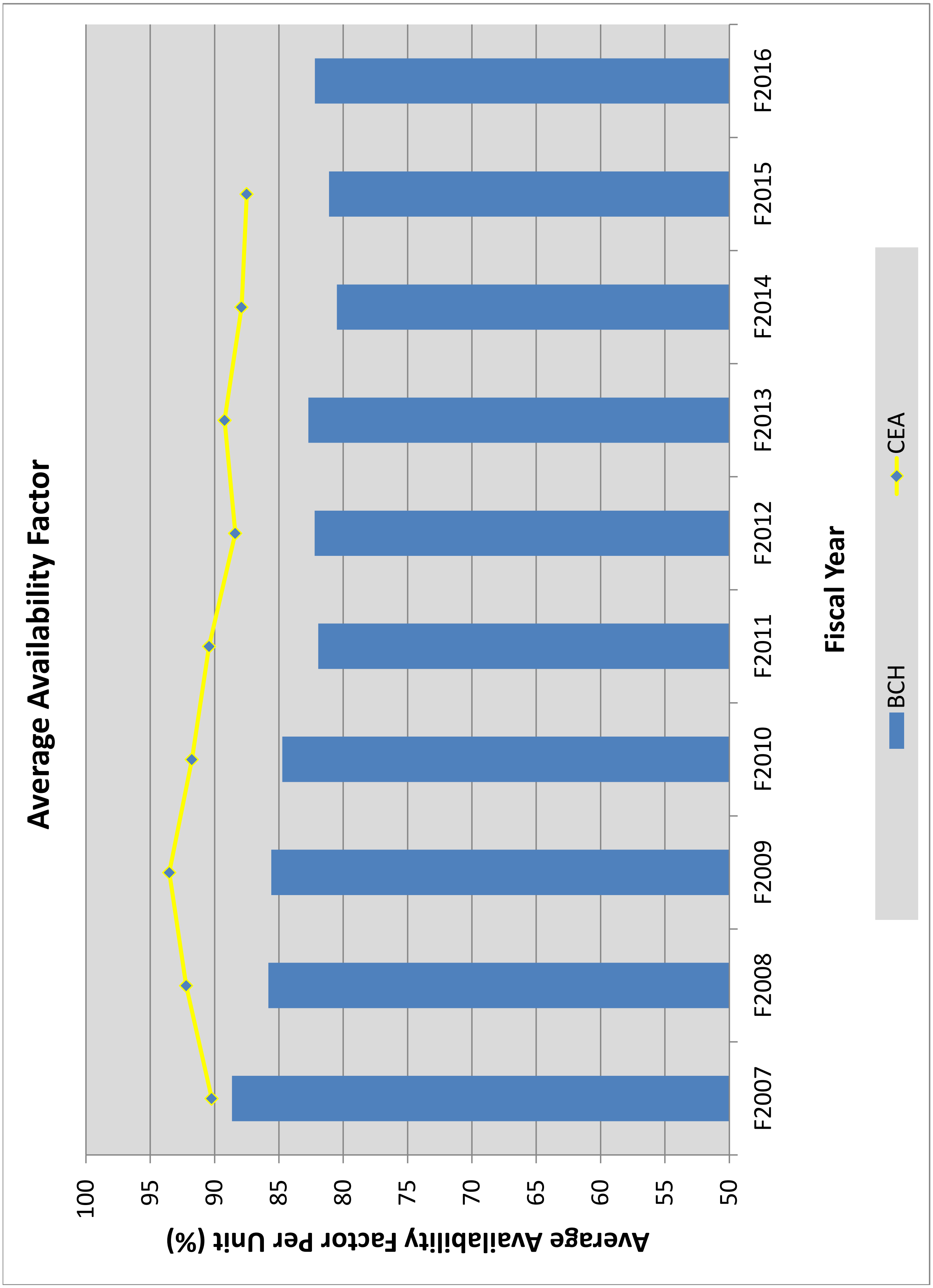
Forced Outage Count = Average Number of Forced Outages / Unit / Year (including Starting Failures)(Internal)

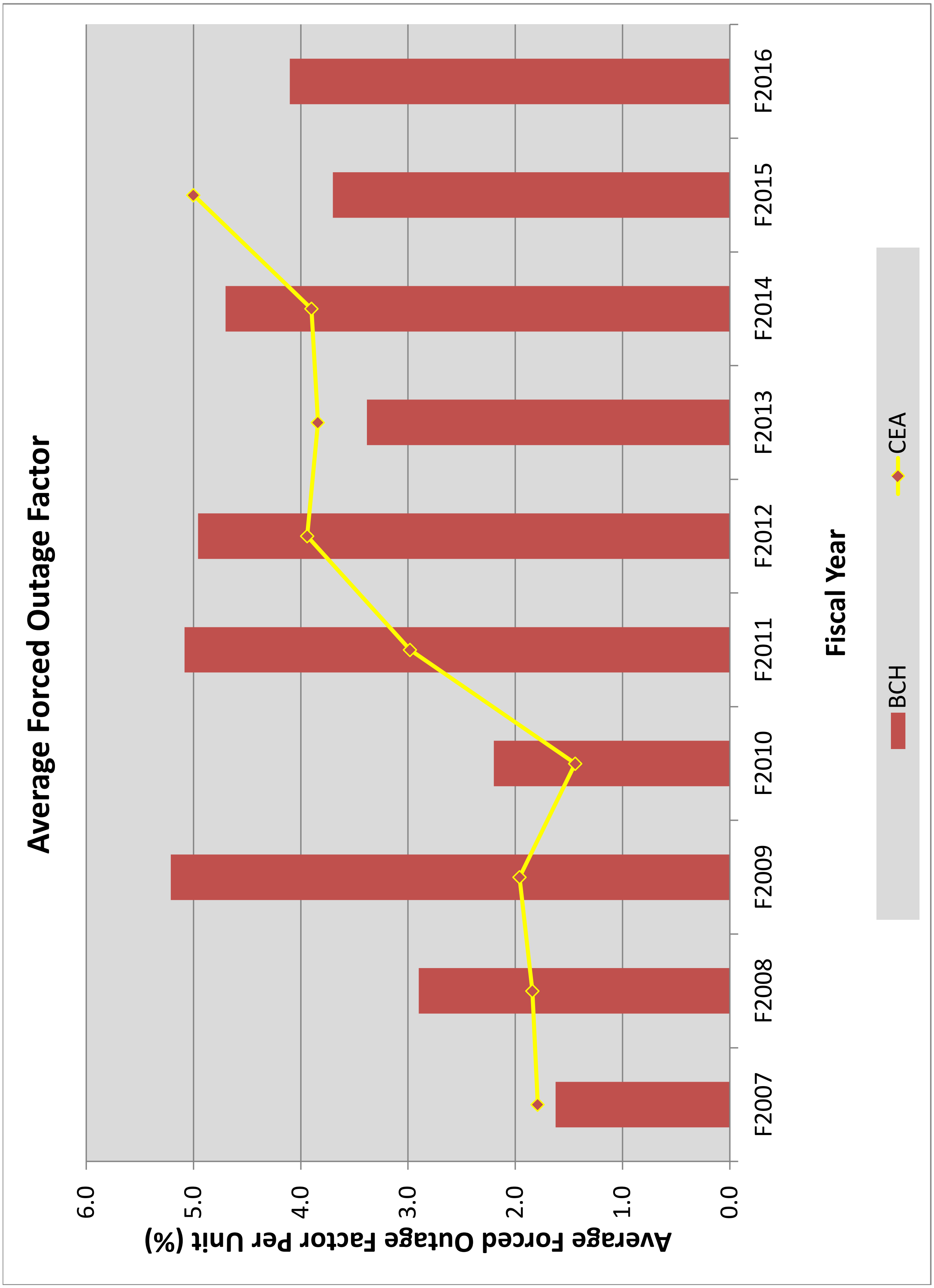
Forced Outage Factor = Forced Outage Time (including Starting Failures)(Internal) / In Commercial Service Time Note 4

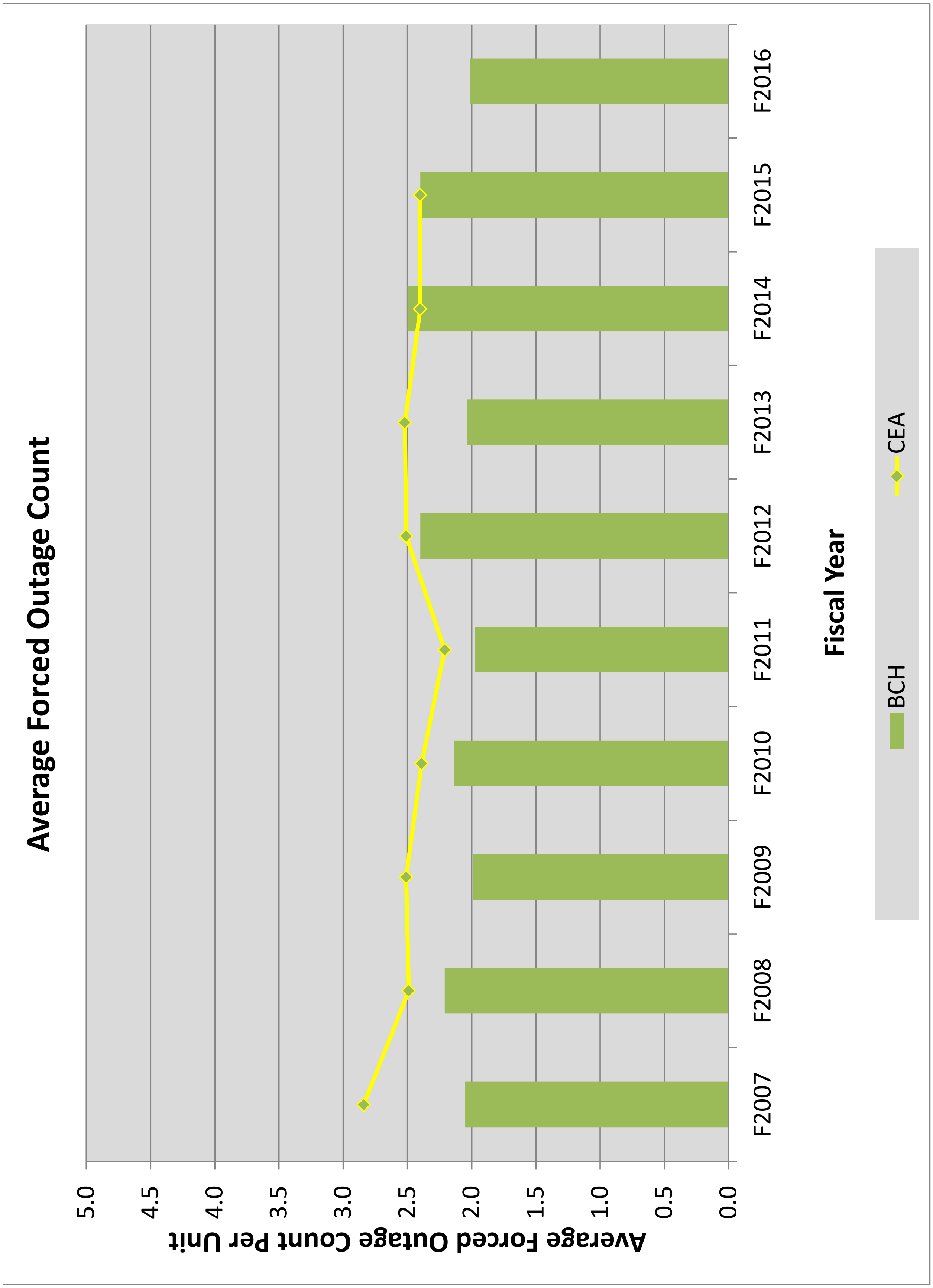
Failure Rate = Forced Outage Count (excluding Starting Failures)(Internal) / Operating Time X In Commercial Service Time Note 4

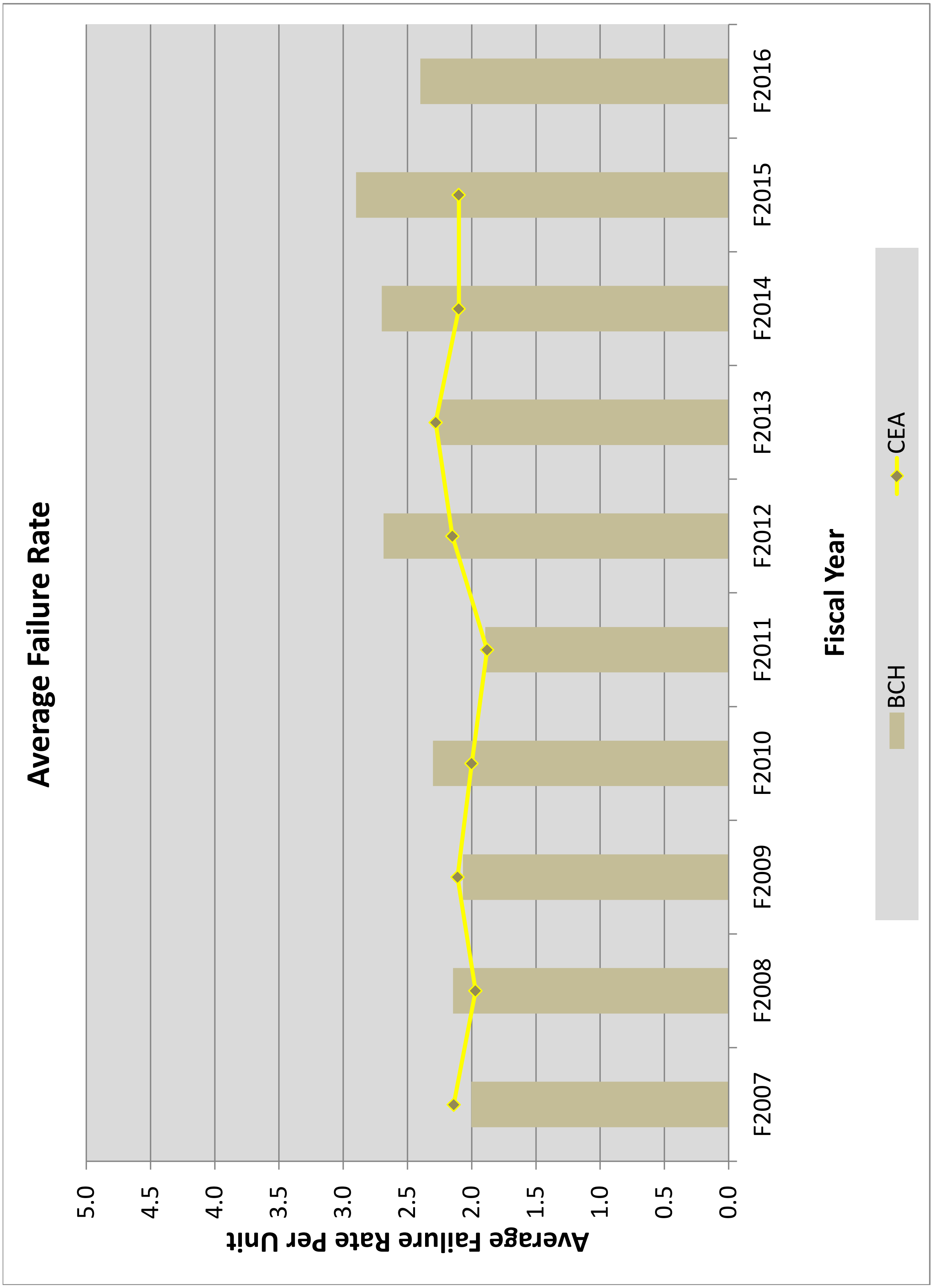
Notes

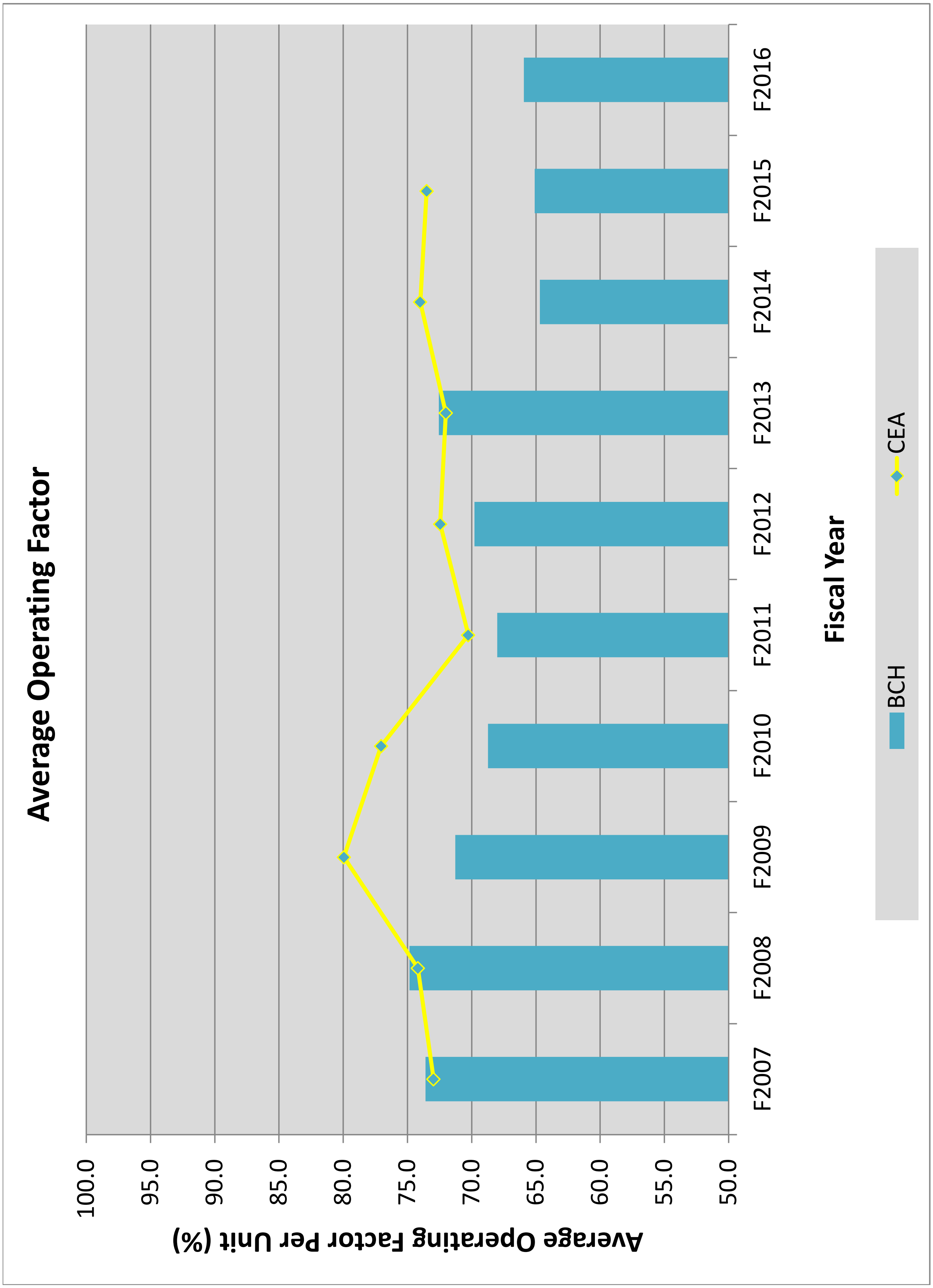
1. Outages with causes that were external to Generation, such as Transmission System forced outages, are excluded from this measure.
2. Data excludes ALU Unit 1 and SHU Unit 1, which have been forced out of service for an extended period.
3. Data excludes ALU Unit 1, SHU Unit 1 and ELK Units 1 and 2 which have been forced out of service for an extended period.
4. In Commercial Service Time represents the number of hours in the measurement period that the unit(s) were considered part of the active fleet.


Average Availability Factor
Average Availability Factor Per Unit (%)
100
95
90
85
80
75
70
65
60
55
50
F2007
F2008
F2009
F2010
F2011
F2012
F2013
F2014
F2015
F2016
Fiscal Year
BCH
CEA


Average Forced Outage Factor
Average Forced Outage Factor Per Unit (%)
6.0
5.0
4.0
3.0
2.0
1.0
0.0
F2007
F2008
F2009
F2010
F2011
F2012
F2013
F2014
F2015
F2016
Fiscal Year
BCH
CEA


Average Forced Outage Count
Average Forced Outage Count Per Unit
0.0
0.5
1.0
1.5
2.0
2.5
3.0
3.5
4.0
4.5
5.0
F2007
F2008
F2009
F2010
F2011
F2012
F2013
F2014
F2015
F2016
Fiscal Year
BCH
CEA


Average Failure Rate
Average Failure Rate Per Unit
5.0
4.5
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
F2007
F2008
F2009
F2010
F2011
F2012
F2013
F2014
F2015
F2016
Fiscal Year
BCH
CEA


Average Operating Factor
Average Operating Factor Per Unit (%)
100.0
95.0
90.0
85.0
80.0
75.0
70.0
65.0
60.0
55.0
50.0
F2007
F2008
F2009
F2010
F2011
F2012
F2013
F2014
F2015
F2016
Fiscal Year
BCH
CEA

Fiscal 2017 to Fiscal 2019

Revenue Requirements Application

Appendix V

Demand-Side Management Initiatives Descriptions

Table of Contents

1 Codes and Standards

1.1 Initiative Description

This initiative provides a focus on transforming the marketplace to energy efficient practices and products, by working with all levels of government. BC Hydro supports and relies on government implementation of a suite of changes to energy efficiency requirements in building codes and product and equipment standards. Regulations can mandate a minimum level of energy efficiency, thereby eliminating the worst performing building practices and electrical products from the market.

1.2 Savings Estimates

	Building Codes	Product and Equipment Standards	Total
Projected Annual Energy Savings by F2021 (GWh)	310	2,000	2,310
Projected Capacity Savings by F2021 (MW)	62	377	439

Note: The energy savings are cumulative since fiscal 2016 as measured at the customer meter.

1.3 Assumptions

Savings Assumptions		Building Codes	Product and Equipment Standards
	Savings Persistence (years)	30	30
	Compliance Rate (%)	63 - 100	70 - 95
	Direct Rebound Effect (%)	0 - 1	0 – 1
	Cross Effects (%)	0	0 - 5

1.4 Financial Information

UC (F2017-F2019, Nominal $1000s)	14,500
Gross Levelized TRC (F2016 $/MWh)	20
Net Levelized TRC (F2016 $/MWh)	-5
TRC Benefit-Cost Ratio vs LRMC	6.4
UC Benefit-Cost Ratio vs LRMC	149[1]
UC Benefit-Cost Ratio vs Market Price	77.3

1.5 Initiative Strategy – Codes and Standards

Technology Innovation	This initiative maintains a line-of-sight into the state of technology development, and maintains relationships with manufacturers to develop a current selection of energy conservation measures to be adopted through programs as needed. This supporting initiative maintains contacts and connections with other utilities in order to identify promising technologies that may become available to customers in B.C.
Sustainable Communities	Local governments can exercise influence over energy use in a community through land use controls, bylaws, regulations and compliance tools. This initiative provides financial support and technical guidance to local governments to encourage them to use the specific powers available to them in order to embed energy conservation and efficiency into community planning and development and to support the adoption of new codes and standards. Targeted outcomes of this initiative include enhanced customer awareness of and participation in demand-side management programs, increased compliance with energy codes, adoption and promotion of stretch codes at the local level, and adoption of enabling policies such as energy benchmarking and building labeling.

[1] BC Hydro acknowledges that there are many influence factors and participants which affect the development and introduction of new codes and standards. BC Hydro is not claiming that its efforts solely result in all of the incremental savings, or that no codes and standards development would occur in BC Hydro’s absence. Only a small portion of the identified savings need to be attributed to BC Hydro activities for the Codes and Standards initiative to be cost-effective.

Codes and Standards Investigation	This initiative seeks to address the market barriers that are holding back the development of new codes and standards, and the adoption of more energy efficient building practices and energy efficient products. Other BC Hydro demand-side management initiatives are designed to increase the market penetration of the most efficient products and practices to set the stage for changes to energy efficient regulation. BC Hydro works with government agencies and other utilities in order to support the introduction of new building practices and energy efficiency product standards. Funding is provided to support specific building codes and standards development, and compliance activities. Marketplace awareness and trades training is undertaken to advance building codes and product standards introduction, and subsequent compliance. Both the Federal and B.C. Governments have stated that BC Hydro plays a critical role in enabling changes to codes and standards. The potential for enhanced codes and standards is also being explored in response to Integrated Resource Plan Recommended Action 3. In this investigation area, BC Hydro is: • developing building technology roadmaps; • building capacity and acceptance for enhanced codes and standards; and • leading the initial stages to develop the next wave of improvements to codes and standards.
First Nations Strategies	There are unique geographic and market barriers that affect First Nations and remote communities. In order to address these unique barriers, BC Hydro is focusing on activities that will: • support education and skills training to build energy literacy in the community, empower community members to manage energy use and reduce energy costs, and foster local economic development opportunities related to energy; • facilitate access to opportunity assessments and energy efficient upgrades for homes and community buildings in order to generate energy savings and reduce electricity bills; • support the development and implementation of energy efficient housing policy to ensure that new homes on reserve are built to higher energy performance standards and that existing homes are upgraded to improve energy performance over time; • support the development of community energy plans that articulate both short and long-term opportunities and priorities for community energy management; and • pilot a targeted Low Income program offer to First Nations communities.
Residential New Construction	BC Hydro works with builders and developers, industry partners and government to create demand for and construct homes that are more energy-efficient than the B.C. Building Code minimum requirements. Recognizing the need to move beyond influencing individual projects, this initiative focuses on activities that leverage changes to transform the construction industry. These activities include workshops with the building industry aimed at raising energy literacy and acceptance of new cost-effective technologies and construction practices, showcase building projects that will demonstrate energy efficient designs, construction practices and integration of new approaches to home construction, and continued training initiatives to build capacity and foster the development of a home energy performance industry in B.C.

1.6 Activity Highlights – Building Codes

BC Hydro continues to play an instrumental role in influencing long and short term priorities for the development of National Energy Code of Canada for Buildings, B.C. Building Code and City of Vancouver’s Building Bylaw regarding energy efficiency requirements. In particular, BC Hydro's activities ensure that builders can easily access energy-efficiency training and education, including on-site training and one-on-one coaching, and set the stage for changes to the B.C. Building Code and the City of Vancouver’s Building Bylaw. With support from BC Hydro, the B.C. Building Code and the City of Vancouver’s Building Bylaw was upgraded to reference higher energy efficiency standards – National Energy Code for Buildings 2011 and ASHRAE Std. 90.1-2010 which represented an estimated 20 per cent improvement over the previous codes. In addition, BC Hydro staff is involved in updating the energy efficiency requirement to higher levels as in the newly published National Energy Code for Buildings 2015.

BC Hydro’s energy efficiency codes and standards activities have produced cost-effective electrical energy savings through governmental measures, such as product/equipment regulations, building energy codes and other energy efficiency policies. Some of the on-going and planned activities related to energy code development and implementation include:

Provincial and local governments’ levels:

- Support development and Implementation of B.C. Building Code and the City of Vancouver’s Building Bylaw energy efficiency requirements upgrades;
- Support code compliance enhancement - perform gap analysis, facilitate establishment of code compliance working group, develop common checklist templates for access by building design professionals, industry code compliance survey with designers and building officials, etc.;

- Develop and implement energy code training/education with stakeholder organizations for design professionals and building officials;
- Participate in the development of a Professional Practice Guideline of Energy Modelling with the Association of Professional Engineers and Geoscientists of B.C., Architectural Institute of B.C. and City of Vancouver for building modellers; and
- Provide technical and financial support for provincial Compliance Advisor and City of Vancouver's Building Policy Specialist positions.

National level:

- Support upgrade of the National Energy Codes of Canada for Buildings:
  - Member of the Standing Committee on Energy Efficiency in Buildings; and
  - Chair of the Task Group on Lighting and Electrical Power.

BC Hydro continues to take a lead role in researching and identifying top priorities for changes to the B.C. Building Code and the City of Vancouver's Building Bylaw and provides expert technical support. For example, BC Hydro is currently working with the City of Vancouver, the Ministry of Energy and Mines and Building and Safety Standards Branch to enhance code compliance levels and exploring the opportunity of addressing the energy efficiency in the existing building market.

1.7 Activity Highlights – Product and Equipment Standards

BC Hydro has played a leading role in influencing the development of Federal and Provincial energy efficiency performance standards for energy consuming products and equipment. In particular, BC Hydro's demand-side management programs increase the market share of energy efficient products and set the stage for changes to B.C. and Federal energy efficiency regulations. Examples of products where BC Hydro has helped to transform the market include residential windows, high efficiency motors, residential lighting and televisions. BC Hydro also actively builds coalitions to support market transformation through joint funding and collaboration on priorities with other utilities and government agencies. BC Hydro is currently coordinating with other government organizations and utilities in advocating, prioritizing and funding changes to upgrade energy performance standards issued by the Canadian Standards Association. BC Hydro staff is also involved in the development of energy efficiency standards through participation in Canadian Standards Association technical committees and introducing proposals for new standards.

BC Hydro continues to take a lead role in identifying top priorities for changes to regulations under the B.C. Energy Efficiency Act and provides expert technical and market analytical support on standards development through its involvement in Canadian Standards Association technical committees.

In addition to providing technical and marketing intelligence support to both the provincial and federal governments in the development of new energy efficiency regulations, BC Hydro also provides support to both agencies on regulation compliance in B.C. in terms of market survey activities, etc.

2 Residential Inclining Block Rate

2.1 Initiative Description

BC Hydro introduced its Residential Inclining Block rate structure in October 2008. Customers are charged for electricity consumption at two rates, an initial Step 1 threshold of 1350 kWh per two-month billing period charges at a lower rate (as of April 1, 2016, 8.29 cents per kWh); and a higher rate for Step 2 consumption above that threshold (as of April 1, 2016, 12.43 cents per kWh). This provides customers with a price signal that encourages conservation.

2.2 Savings Estimates

Projected Annual Energy Savings by F2021 (GWh)	63
Projected Capacity Savings by F2021 (MW)	13

Note: The energy savings are cumulative since fiscal 2016 as measured at the customer meter.

2.3 Assumptions

Savings Assumptions	Savings Persistence	The rate structure is assumed to be ongoing, providing a price signal for continuous demand-side management savings

2.4 Financial Information

UC (F2017-F2019, Nominal $1000s)	1,500
Gross Levelized TRC (F2016 $/MWh)	6
Net Levelized TRC (F2016 $/MWh)	-17
TRC Benefit-Cost Ratio vs LRMC	19.9
UC Benefit-Cost Ratio vs LRMC	19.9
UC Benefit-Cost Ratio vs Market Price	10.2

2.5 Activity Highlights

Fiscal 2017 to fiscal 2019 planned activities are primarily for the completion of the 2015 Rate Design Application.

3 Rate Schedule (RS) 1823, Stepped Rate

3.1 Initiative Description

The Stepped Rate, also referred to as the Transmission Service Rate, applies to most large customers that are supplied with electricity at transmission voltages (60,000 volts or more). The rate has been in place since April 2006. There are approximately 140 transmission customer sites taking electricity service under the Transmission Service Rate.

The Transmission Service Rate is a two-tier (Tier 1 and Tier 2) inclining block conservation rate where annual energy consumption above a threshold is charged at a higher Tier 2 rate. The consumption threshold is set at 90 per cent of the plant's historical annual energy consumption (called the Customer Baseline). The result is a 90:10 split in energy pricing. The Tier 2 price was established to provide a conservation price signal. The Tier 1 price is derived from the Tier 2 price and the 90:10 Tier 1/Tier 2 pricing split to achieve revenue neutrality with the former flat rate structure, at 100 per cent of the plant's historical Customer Baseline consumption.

As of April 1, 2016, the Tier 1 price was 3.981 cents per kWh, and Tier 2 was priced at 8.920 cents per kWh. Customers are also charged for electricity demand at a flat rate $7.635 per kVA.

3.2 Savings Estimates

Projected Annual Energy Savings by F2021 (GWh)	142
Projected Capacity Savings by F2021 (MW)	17

Note: The energy savings are cumulative since fiscal 2016 as measured at the customer meter.

3.3 Assumptions

Savings Assumptions	Savings Persistence	1 - 3 years

3.4 Financial Information

UC (F2017-F2019, Nominal $1000s)	2,000
Gross Levelized TRC Cost (F2016 $/MWh)	35
Net Levelized TRC Cost (F2016 $/MWh)	27
TRC Benefit-Cost Ratio vs LRMC	3.1
UC Benefit-Cost Ratio vs LRMC	21.5
UC Benefit-Cost Ratio vs Market Price	7.5

3.5 Activity Highlights

Fiscal 2017 to fiscal 2019 planned activities are primarily for the completion of the 2015 Rate Design Application, and ongoing maintenance and review of customer baselines.

4 Behaviour Program

4.1 Initiative Description

The Behaviour program, known as Team Power Smart, encourages BC Hydro's residential customers to adopt more energy efficient behaviours in their everyday life with the intent of transforming those behaviours into new energy management habits, resulting in energy savings and reduced bills. The program addresses the market barriers that are holding back the adoption of more energy efficient behaviours by raising customers' awareness about their energy consuming behaviours and patterns and educating them on what drives high consumption and the energy management changes that they can make while providing feedback, guidance and rewards for changing their behaviour.

4.2 Savings Estimates

Projected Annual Energy Savings by F2021 (GWh)	85
Projected Capacity Savings by F2021 (MW)	17

Note: The energy savings are cumulative since fiscal 2016 as measured at the customer meter.

4.3 Assumptions

Savings Assumptions[2]		Behaviour
	Savings Persistence (years)	1
	Free Riders (%)	0
	Spillover (%)	0
	Market Effects (%)	0
	Direct Rebound Effect (%)	0
	Cross Effects (%)	0

Note: The energy savings are renewed on an annual basis as long as the customer continues to participate in the program.

2 The Behaviour program has been evaluated by comparing electricity consumption before and after each fiscal year among participant households and a group of comparison households. With this evaluation method, net savings are directly determined, so assumptions for free riders and other factors are already included in the calculation.

4.4 Financial Information

UC (F2017-F2019, Nominal $1000s)	11,100
Gross Levelized TRC Cost (F2016 $/MWh)	31
Net Levelized TRC Cost (F2016 $/MWh)	9
TRC Benefit-Cost Ratio vs LRMC	4.0
UC Benefit-Cost Ratio vs LRMC	3.7
UC Benefit-Cost Ratio vs Market Price	1.9

4.5 Initiative Strategy

Market Barriers	The program seeks to address the awareness and acceptance market barriers that are holding back the adoption of more energy efficient behaviours.
Delivery	The program leverages energy management information and relies on the key elements of social marketing best practices, including setting a target, gaining commitments and providing feedback. The power of norms is used through comparing participants' consumption to similar households and through testimonial statements and storytelling of existing members. This encourages consumers to take action to improve efficiency and reduce their bills.
Incentives	A $50 'reward' is offered to customers who complete a one year reduction challenge and successfully reduce their annual consumption by 10 per cent or more from the preceding year. This incentive is a catalyst for customers to take action and to remain focused on their target over the duration of the year.
Promotion	The program uses BC Hydro owned channels as well as market channels such as online ads and newspaper to drive customers to the program on the BC Hydro website.

4.6 Activity Highlights

The program utilizes social marketing concepts to engage customers, present them with information on electricity consumption, and encourage them to undertake Consumption Reduction Challenges to reduce their consumption by at least 10 per cent. Customers can track their progress and compare themselves to relevant groups over time. Customers can take successive Reduction Challenges, or enter into a Maintenance Challenge as their savings potential becomes exhausted. Participation is free and customers can implement behaviour measures at low or no cost.

The program provides an ideal platform to respond to evolving customer needs for more digital information and interactions. BC Hydro provides this program to reach residential customers and provide them with energy management information and insight to assist them in leveraging new technologies.

5 Low Income Program

5.1 Initiative Description

The Low Income program reduces energy consumption and lowers bills for low income customers. BC Hydro accomplishes this by addressing the capital, awareness, education and other unique barriers that often prevent these customers from participating in other conservation programs. The program has two components; Energy Savings Kits and the Energy Conservation Assistance Program.

5.2 Savings Estimates

Projected Annual Energy Savings by F2021 (GWh)	11
Projected Capacity Savings by F2021 (MW)	3

Note: The energy savings are cumulative since fiscal 2016 as measured at the customer meter.

5.3 Assumptions

Savings Assumptions		**Low Income**
	Savings Persistence (years)	1 - 25
	Free Riders (%)	0 - 44
	Spillover (%)	0 - 17
	Market Effects (%)	0
	Direct Rebound Effect (%)	0 - 6
	Cross Effects (%)	0 – 12

5.4 Financial Information

UC (F2017-F2019, Nominal $1000s)	7,800
Gross Levelized TRC Cost (F2016 $/MWh)	156
Net Levelized TRC Cost (F2016 $/MWh)	88
TRC Benefit-Cost Ratio vs LRMC	1.1
UC Benefit-Cost Ratio vs LRMC	0.8
UC Benefit-Cost Ratio vs Market Price	0.3

5.5 Initiative Strategy

Market Barriers	The program seeks to address the market barriers that are holding back the adoption of more energy efficient products, particularly affordability issues.
Delivery	Since 2010, BC Hydro has partnered with FortisBC Energy Inc. to reduce costs and improve the effectiveness of providing this program to low income customers across the province. FortisBC Inc. is running a similar program modelled after the BC Hydro Low Income program. BC Hydro is also coordinating with Pacific Northern Gas in their service territory on delivery of the Low Income program
Energy Savings Kits	The Energy Savings Kit is a package of basic energy saving measures provided at no charge that can be installed by most homeowners or tenants with limited or basic tools. Energy Savings Kits contain lighting-related products, water saving products (e.g., faucet aerators and a low flow showerhead), heat-loss products (e.g., water heater pipe wrap, draft proofing material, and window film) and general energy savings tips and brochures. As of December 2015, 90,000 low-income houses have received energy savings kits from BC Hydro since the Energy Savings Kit launched in April 2008.
Energy Conservation Assistance Program	The Energy Conservation Assistance Program provides eligible BC Hydro low income Residential customers at no charge with a home evaluation, installation of energy saving products and education on what customers can do around their homes to save energy. Some of the energy saving products that may be installed include energy saving light bulbs , low-flow showerheads and faucet aerators, pipe wrap, draft proofing (e.g., door sweeps), an Energy Star refrigerator, a high-efficiency gas furnace (in conjunction with FortisBC Energy Inc.), and insulation for attics, walls and crawlspaces.

5.6 Activity Highlights

One of the biggest challenges facing the program has been finding participants. To address this, BC Hydro is coordinating with agencies and non-profit organizations already working within the Low Income community in order to identify qualifying low-income customers.

A targeted offer for First Nations is also being designed, which will include energy conservation education for community members, band staff and businesses and will extend free energy savings assessments and installation of measures to commercial and community building(s).

6 Retail Program

6.1 Initiative Description

The Retail program provides rebate offers to residential customers for lighting, appliances, consumer electronics and home improvement and water saving products. The program establishes relationships with key manufacturers and retailers, and leverages the potential for low-cost and far-reaching public exposure through partner's flyers and promotion.

6.2 Savings Estimates

Projected Annual Energy Savings by F2021 (GWh)	42
Projected Capacity Savings by F2021 (MW)	14

Note: The energy savings are cumulative since fiscal 2016 as measured at the customer meter.

6.3 Assumptions

Savings Assumptions		Retail Program
	Savings Persistence (years)	4 - 20
	Free Riders (%)	5 - 33
	Spillover (%)	0 - 15
	Market Effects (%)	0
	Direct Rebound Effect (%)	0
	Cross Effects (%)	0 - 6

6.4 Financial Information

UC (F2017-F2019, Nominal $1000s)	8,100
Gross Levelized TRC Cost (F2016 $/MWh)	19
Net Levelized TRC Cost (F2016 $/MWh)	-10
TRC Benefit-Cost Ratio vs LRMC	7.1
UC Benefit-Cost Ratio vs LRMC	3.8
UC Benefit-Cost Ratio vs Market Price	2.0

6.5 Initiative Strategy

Overall Strategy	The program aims to advance the adoption of more energy efficient products by working with market partners to have energy efficient products available on store shelves throughout B.C. at affordable price points, supported by knowledgeable sales staff.
Market Barriers	The program seeks to address the awareness, affordability, accessibility, availability and acceptability market barriers that impede the adoption of more energy efficient products.
Delivery	The program works with retailers and manufacturers in order to address market barriers to purchasing the most efficient products on the market. BC Hydro is partnering with FortisBC Energy Inc. on promoting clothes washers to reduce program costs and increase customer incentives and participation. FortisBC Inc. often aligns its retail offers to those of BC Hydro to leverage the negotiations that BC Hydro undertakes with partners around product price, positioning and promotion prior to each campaign. BC Hydro runs campaigns through the year that target various end-use categories. This approach to campaign management provides operational efficiencies while maximizing the time that offers are in market and available to assist customers.
Incentives	In addition to customer incentives, select products have incentives provided to retailers to improve stocking patterns and encourage active promotion of the most efficient products in the stores.
Promotion	BC Hydro provides advertising funding to engage retailers. By supporting retailers through advertising, promotions and program collateral, the program leverages flyer exposure and additional incentives from retailers to customers.
Regulation	The program is designed to increase the market penetration of the most efficient products and sets the stage for changes to energy efficient regulation.

6.6 Activity Highlights

BC Hydro plans to run four major campaigns per year, along with a number of smaller campaigns. BC Hydro will continue to engage and influence channel partners (retailers and manufacturers) which will allow adjustments to the program offering based on the introduction of new energy efficient products to the marketplace.

7 Home Energy Rebate Offer

7.1 Initiative Description

The Home Energy Rebate Offer focuses on customers with electric heat, who typically have the high electric bills and seeks to motivate them to undertake energy efficiency upgrades to their existing homes, primarily focused on lowering their space heating load. Incentives are provided for the installation of energy efficient equipment and building envelope measures. The Home Energy Rebate Offer is jointly administered with FortisBC Energy Inc. and FortisBC Inc., allowing customers to access a single offer regardless of whether their homes are electric or gas heated.

In addition to direct incentives, the program communications are aimed at program awareness and participation, and educating consumers on energy efficient home renovations. The program works with contractors, providing program details, sales support and recommendations on installation best practices in home energy retrofits to improve the availability and quality of home energy retrofit services in B.C.

7.2 Savings Estimates

Projected Annual Energy Savings by F2021 (GWh)	31
Projected Capacity Savings by F2021 (MW)	11

Note: The energy savings are cumulative since fiscal 2016 as measured at the customer meter.

7.3 Assumptions

Savings Assumptions		**HERO**
	Savings Persistence (years)	9 - 23
	Free Riders (%)	38 - 45
	Spillover (%)	0 - 31
	Market Effects (%)	0
	Direct Rebound Effect (%)	0 - 6
	Cross Effects (%)	0

7.4 Financial Information

UC (F2017-F2019, Nominal $1000s)	8,300
Gross Levelized TRC Cost (F2016 $/MWh)	107
Net Levelized TRC Cost (F2016 $/MWh)	54
TRC Benefit-Cost Ratio vs LRMC	1.5
UC Benefit-Cost Ratio vs LRMC	3.8
UC Benefit-Cost Ratio vs Market Price	2.1

7.5 Initiative Strategy

Market Barriers	The program seeks to address the awareness, accessibility, affordability and acceptability market barriers that are holding back upgrades to more energy efficient homes, by providing financial incentives for building envelope improvements for B.C. residents living in single family dwellings and row/townhouses.
Delivery	The program is delivered directly through contractors. The program has been jointly offered by BC Hydro, FortisBC Energy Inc. and FortisBC Inc. since 2008. This has provided internal efficiencies and improved the customer experience in dealing with the program.

7.6 Activity Highlights

BC Hydro will be working to strengthen ties with the contractor community, through the BC Hydro Alliance of Energy Professionals, newsletters, and direct engagement. This will also allow for the potential inclusion of new program components in the future to address changing customer expectations.

8 Residential Sector Enabling Initiative

8.1 Initiative Description

The residential sector enabling activities support BC Hydro's residential demand-side management programs by providing energy education, partner training, and the development of industry capacity to undertake energy efficiency projects. Although these activities do not achieve direct energy savings, they are critical success drivers for securing energy savings through programs, rates, and codes and standards.

8.2 Savings Estimates

Projected Annual Energy Savings by F2021 (GWh)	n/a
Projected Capacity Savings by F2021 (MW)	n/a

8.3 Financial Information

UC (F2017-F2019, Nominal $1000s)	2,600
Gross Levelized TRC Cost (F2016 $/MWh)	n/a
Net Levelized TRC Cost (F2016 $/MWh)	n/a
TRC Benefit-Cost Ratio vs LRMC	n/a
UC Benefit-Cost Ratio vs LRMC	n/a
UC Benefit-Cost Ratio vs Market Price	n/a

8.4 Initiative Strategy

Strategy	Enabling activities motivate customers and supply-chain partners to participate in BC Hydro demand-side management programs and stimulate market transformation towards energy efficiency through training, education and awareness. Customer interest generates market pull, while supply-chain partnerships can lead to market push, ultimately resulting in increased penetration of energy-efficient technologies.
Energy Information Support	BC Hydro enables the provision of support for our customers to resolve their energy related inquiries and become more educated on how to access our programs and energy saving opportunities. The Customer Support Centre – ABSU call centre provides a first call/email option for our customers to find out more about their specific energy inquiries.

Partner Training	A critical success factor in the realization of the Demand-Side Management Plan is that there is an available and accessible "energy efficiency skilled" workforce in place in B.C. BC Hydro plays an important role in identifying and filling skill gaps in the workforce by partnering with post-secondary institutions and industry associations who develop and deliver new training and educational programs. BC Hydro has partnered with FortisBC Energy Inc., FortisBC Inc. and the B.C. Government in support of the development of a Home Performance Stakeholder Council. This council will identify and support the implementation of long-term strategies to facilitate the growth of a self-sustainable home energy performance industry in the province.
BC Hydro Alliance of Energy Professionals	The BC Hydro Alliance of Energy Professionals is a network of contractors, consulting engineers, distributors and registered experts that will promote the use of energy efficiency solutions to our customers. BC Hydro leverages the Alliance members' ability to sell and promote energy efficient products, services and programs to our customers within the context of demand-side management programs which is a cost-effective approach to minimize program marketing expenditures. BC Hydro delivers training to Alliance members to ensure they are educated on conservation and energy management and trained on the details of the available BC Hydro programs. This goal is achieved in part through partnerships with associations for development and delivery of courses and workshops. The BC Hydro Alliance of Energy Professionals also allows BC Hydro to monitor and assess the quality of work that customers receive from Alliance members, and take remedial action if deficiencies are identified.

8.5 Activity Highlights

In fiscal 2017, contractor outreach through the BC Hydro Alliance of Energy Professionals will expand to include contractors who are active in supporting a broad spectrum of residential energy-efficiency upgrades.

9 Leaders in Energy Management – Commercial

9.1 Initiative Description

The Leaders in Energy Management – Commercial program provides strategic energy management to assist customers with managing their energy bills. This is achieved through operational and maintenance changes, energy efficiency retrofits of existing buildings, behavioural change, and assisting customers in integrating a strategic energy management model into their ongoing business practices and corporate culture.

9.2 Savings Estimates

Projected Annual Energy Savings by F2021 (GWh)	346
Projected Capacity Savings by F2021 (MW)	48

Note: The energy savings are cumulative since fiscal 2016 as measured at the customer meter.

9.3 Assumptions

Savings Assumptions		Leaders in Energy Management
	Savings Persistence (years)	2 - 16
	Free Riders (%)	0 - 25
	Spillover (Free Drivers) (%)	0 – 22
	Market Effects (%)	0
	Direct Rebound Effect (%)	0
	Cross Effects (%)	0 - 4

9.4 Financial Information

UC (F2017-F2019, Nominal $1000s)	71,100
Gross Levelized TRC Cost (F2016 $/MWh)	65
Net Levelized TRC Cost (F2016 $/MWh)	48
TRC Benefit-Cost Ratio vs LRMC	1.8
UC Benefit-Cost Ratio vs LRMC	2.8
UC Benefit-Cost Ratio vs Market Price	1.2

9.5 Initiative Strategy

Market Barriers	The program seeks to address the affordability, availability, accessibility, awareness and acceptance market barriers that are preventing the adoption of a strategic energy management approach, energy efficient projects, improving and sustaining building performance, and behavioural change.
Strategy	The program provides strategic energy management to assist customers with optimizing their energy bills. These improvements are achieved through operational and maintenance changes, incentives to facilitate energy efficiency retrofits of existing buildings, behavioural change, and assisting customers in integrating a strategic energy management model into their ongoing business practices and corporate culture. This program targets BC Hydro's commercial segment, including small medium business to key account managed large commercial customers. The program's strategic integrated approach to energy management includes four principal components: (1) Energy Manager; (2) Business Management; (3) Asset Management; and (4) Change Management.
Energy Manager	The Energy Manager represents the critical first step to secure a dedicated energy efficiency champion within an organization that can work with the company's senior management team to help create and implement the integrated energy management program, energy efficiency targets and instill a conservation culture. The Energy Manager utilizes program tools and resources such as energy study funding, project incentives, energy information and behavioural/operational initiatives to ensure the company's energy policies and long term goals are met through energy savings initiatives.
Business Management	The Business Management component provides customers with the ability to determine the current energy situation, both from an end use and business management perspective, and identify areas of opportunities for improvement. This is in line with changing customer expectations around technologies and energy information. Examples of tools to support organizations include energy studies, an Energy Management Assessment (a diagnostic workshop with an organization's senior management to review practices and procedures regarding energy management) and a Strategic Energy Management Plan (i.e. a one to three year plan that captures energy savings opportunities and aligns with corporate budgets and targets).
Asset Management	The Asset Management component provides customers the ability to track energy consumption within their portfolio of buildings. By using tools, such as energy use intensity reporting, and energy management information systems, customers have the ability to focus on areas of opportunities to optimize their capital expenditures and leverage BC Hydro incentives to overcome capital barrriers preventing projects from being implemented.

Change Management	Once energy efficiency projects have been implemented, focus is required to ensure the equipment is operated at the highest efficiency level and that operators appropriately use/maintain the energy efficiency equipment. Energy information is available to customers to enable them to gain energy insights to better manage their portfolio of buildings. Training is also a key component with regular workshops to address education gaps and targeted building operator activities. Change management includes social marketing techniques to target end users to ensure a culture of conservation is embedded within the organization which helps to change the behaviours of employees.

9.6 Activity Highlights

Leaders in Energy Management – Commercial continues to provide a foundation of energy efficiency initiatives for commercial customers, while at the same time evolving to place more emphasis on strategic energy management. This allows customers to leverage new information and technology to provide better insights on their electricity consumption and enable them to develop organizational energy management policies and targets.

The evolution will include the introduction of the Energy Associates models for customers who don't have a BC Hydro supported Energy Manager. The Energy Associates model will provide customers with access to educational and training events, resources and tools to develop Strategic Energy Management Plans, tracking and reporting templates, diagnostic workshops, and mentoring from BC Hydro funded Energy Managers.

The strategic energy management model will also introduce a multi-organizational Energy Wise Network to support commercial customers to engage people at their organization in energy conservation. This network provides customers with education, campaign toolkits, diagnostic tools, mentoring support, and funding to implement campaigns to engage employees in their organization to use energy wisely. The Energy Wise Network will broaden the support available to more customers and will help customers improve their employee engagement efforts.

10 New Construction Program

10.1 Initiative Description

The New Construction program provides industry and customer training, financial support for the design and implementation of new high performing buildings, partnering with other organizations such as FortisBC Energy Inc. and Leadership in Energy and Environmental Design (a rating system that is recognized as the international mark of excellence for green buildings). The program sets the stage for changes to energy efficiency requirements in the B.C. Building Code.

10.2 Savings Estimates

Projected Annual Energy Savings by F2021 (GWh)	70
Projected Capacity Savings by F2021 (MW)	9

Note: The energy savings are cumulative since fiscal 2016 as measured at the customer meter.

10.3 Assumptions

Savings Assumptions		New Construction
	Savings Persistence (years)	15 - 20
	Free Riders (%)	22
	Spillover (Free Drivers) (%)	7.6
	Market Effects (%)	0
	Direct Rebound Effect (%)	0
	Cross Effects (%)	1

10.4 Financial Information

UC (F2017-F2019, Nominal $1000s)	25,300
Gross Levelized TRC Cost (F2016 $/MWh)	80
Net Levelized TRC Cost (F2016 $/MWh)	47
TRC Benefit-Cost Ratio vs LRMC	1.9
UC Benefit-Cost Ratio vs LRMC	2.9
UC Benefit-Cost Ratio vs Market Price	1.3

10.5 Initiative Strategy

Market Barriers	The program seeks to address the following market barriers that are preventing the adoption of designing and constructing more energy efficient buildings: affordability, availability, awareness and acceptance.
Strategy	The program will overcome these barriers through an integrated approach that utilizes incentives, industry and customer training, technical support and recognition. The program's strategic approach to more efficient design and construction of buildings includes the principal component of Whole Building Design.
Whole Building Design	Targeted at buildings over 50,000 square feet that can deliver over 50,000 kWh of electricity savings per year. BC Hydro will fund an energy study of the whole building to analyze the energy savings of various bundles of energy efficiency measures. Participants can qualify for an incentive for the implemented bundle of energy saving measures.
Delivery	BC Hydro works directly with customers and members of the BC Hydro Alliance of Energy Professionals (further described under the Commercial Sector Enabling Initiative) to deliver the New Construction program. These industry members work with customers to identify and implement energy management projects and practices.

10.6 Activity Highlights

Over the next three years, ongoing program activities will include project funding, completion of energy studies and support of new codes and standards.

The focus will be on Whole Building Design which is a customized building approach that looks at a building as a single, highly integrated system to create a high-performance building.

BC Hydro has not included in this application expenditures for Commercial New Construction in its outlook for demand-side management beyond fiscal 2022. Decisions on whether to proceed beyond this point would need to be informed by potential changes within this period in the commercial building code.

11 Commercial Sector Enabling Initiative

11.1 Initiative Description

The commercial sector enabling activities support commercial demand-side management programs by providing education, training and information, building customer and industry capacity to undertake energy efficiency projects and further motivating customers to participate in programs. These activities will enable customers to integrate energy efficiency into their on-going business practices, support customers in pursuing energy management objectives in their operations.

11.2 Savings Estimates

Projected Annual Energy Savings by F2021 (GWh)	n/a
Projected Capacity Savings by F2021 (MW)	n/a

11.3 Financial Information

UC (F2017-F2019, Nominal $1000s)	3,100
Gross Levelized TRC Cost (F2016 $/MWh)	n/a
Net Levelized TRC Cost (F2016 $/MWh)	n/a
TRC Benefit-Cost Ratio vs LRMC	n/a
UC Benefit-Cost Ratio vs LRMC	n/a
UC Benefit-Cost Ratio vs Market Price	n/a

11.4 Initiative Strategy

Strategy	There are three key commercial sector enabling activities: (1) BC Hydro Alliance of Energy Professionals (which supports industrial and residential customers as well); (2) e.Catalog; and (3) Education and Training.
BC Hydro Alliance of Energy Professionals	The BC Hydro Alliance of Energy Professionals is a network of contractors, consulting engineers, distributors and registered experts that will promote the use of energy efficiency solutions to our customers. BC Hydro leverages the Alliance members' ability to sell and promote energy efficient products, services and programs to our customers within the context of demand-side management programs which is a cost-effective approach to minimize program marketing expenditures. BC Hydro delivers training to Alliance members to ensure they are educated on conservation and energy management and trained on the details of the available BC Hydro programs. This goal is achieved in part through partnerships with associations for development and delivery of courses and workshops. The BC Hydro Alliance of Energy Professionals also allows BC Hydro to monitor and assess the quality of work that customers receive from Alliance members, and take remedial action if deficiencies are identified.
Energy Information Support	BC Hydro enables the provision of support for our customers to resolve their energy related inquiries and become more educated on how to access our programs and energy saving opportunities. The Customer Support Centre – ABSU call centre provides a first call/email option for our customers to find out more about their specific energy inquiries. Additionally they provide, through the Business Help Desk, a channel of support for specific conservation and energy management program inquiries.
e.Catalog	e.Catalog is an online catalogue of energy efficient products that provides customers, contractors, distributors and manufacturers with easily accessible specifications of products that are supported within BC Hydro programs. The catalogue is a resource not only for customers but for Alliance members in their efforts to provide energy management solutions to commercial customers. Expenditures for e.Catalog support the maintenance and evolution of its self-serve online functionality.
Education and Training	A critical success factor for the Demand-Side Management Plan is that there is an available and accessible “energy efficiency skilled” workforce in place in B.C. BC Hydro plays an important role in identifying and filling skill gaps in the workforce by partnering with post-secondary institutions and industry associations who develop and deliver new training and educational programs. The objective of education and training is to develop and build market capacity of individuals that will be qualified to become energy managers and energy conservation champions within customer and industry organizations as well as to grow the pool of qualified individuals who can join trade ally firms. This will support program participation, increase conservation awareness and action and ultimately integrate efficiency into ongoing business processes. This initiative includes integrating energy efficiency and conservation modules within targeted disciplines of academic and training institutions as well as the development of case studies and other materials to educate customers and trade allies.

11.5 Activity Highlights

Updates are being made to e.Catalog to ensure that energy saving technologies which are supported in BC Hydro's demand-side management programs are listed in the catalog.

Ongoing partnerships with the Electrical Joint Training Committee and BCIT will develop new training and certificate programs for the trades and energy professionals.

12 Leaders in Energy Management – Transmission

12.1 Initiative Description

The Leaders in Energy Management – Transmission program captures energy savings at these large industrial facilities through energy efficiency retrofits, operational and maintenance changes, and behavioural change. The program addresses the market barriers that prevent the adoption of more energy efficient projects by encouraging and assisting these customers in integrating energy efficiency into their ongoing business practices and corporate culture. Sectors are large customer segments with common interests and energy opportunities, including Pulp and Paper, Wood Products, Mining, Oil and Gas, Chemical, and Cement.

The Leaders in Energy Management – Transmission program provides strategic energy management training and resources (including Industrial Energy Managers), audits, studies and resources required to enable the customer to implement facility changes and benefit from the Transmission Service Rate or leverage capital incentives.

12.2 Savings Estimates

Projected Annual Energy Savings by F2021 (GWh)	435
Projected Capacity Savings by F2021 (MW)	48

Note: The energy savings are cumulative since fiscal 2016 as measured at the customer meter.

1 ## 12.3 Assumptions

Savings Assumptions		Transmission
	Savings Persistence (years)	5 - 16
	Free Riders (%)	28
	Spillover (%)	19
	Market Effects (%)	0
	Direct Rebound Effect (%)	0
	Cross Effects (%)	0

2 ## 12.4 Financial Information

UC (F2017-F2019, Nominal $1000s)	51,000
Gross Levelized TRC Cost (F2016$/MWh)	52
Net Levelized TRC Cost (F2016 $/MWh)	41
TRC Benefit-Cost Ratio vs LRMC	2.2
UC Benefit-Cost Ratio vs LRMC	3.8
UC Benefit-Cost Ratio vs Market Price	1.6

3 ## 12.5 Initiative Strategy

Market Barriers	The program seeks to address the market barriers preventing customer implementation of energy efficiency upgrades and improved energy management practices by providing tools, education and incentives.
Strategy	The approach to the industrial energy-efficiency market is structured to support the customer through four stages of energy management: Plan, Discover, Upgrade and Support.
Plan	Integrate energy management into long-term business vision. These initiatives supply funding and resources to make it easier to integrate energy management and efficient design into the customer's long-term business vision. These initiatives are recommended to achieve continuous energy improvement at industrial facilities. • Energy Management Assessment: an assessment of a customer's energy management practices. • Development of a Strategic Energy Management Plan to build executive support and guide multi-year efficiency plans. • Training and support for an energy management resource that will utilize energy data to drive business decisions related to policy, processes, and capital changes with a positive impact on the customer energy use.
Discover	Find and study opportunities to save electricity. This initiative offers funding to help build a solid business case for efficiency upgrades. Energy study findings (i.e., a high-level assessment of an entire facility or plant or of a specific system, or an in-depth investigation of solutions of a single system) are used to drive customer-funded projects or to access upgrade funding.

Upgrade	Build efficiency into existing facilities. This initiative provides support for customers to fund their own operational initiatives or hard-wired projects, or may provide funding for energy efficiency retrofit projects to help improve the economics of the projects.
Support	Grow energy savings with smart monitoring of energy use and awareness. Customers are provided with the tools and training and funding to: • Build an Energy Monitoring and Targeting model to monitor facility energy use and identify areas of improvement. • Develop an awareness program around efficiency to grow savings through employee and management-led initiatives.

12.6 Activity Highlights

Building on the success of the industrial energy managers, Leaders in Energy Management – Transmission is expanding efforts in strategic energy management and industrial operational efficiencies. The addition of the Strategic Energy Management Cohort offer will bring together groups of medium to large sized industrial customers for a two year engagement to work together and share knowledge related to building energy management in their business. This offer will focus on providing customers with energy data in order to allow them to make choices that will increase their energy efficiency.

In addition, an expansion of the Energy Monitoring and Targeting offer will provide customers with the energy information required to both identify capital projects as well as implement low and no-cost operational changes to their processes.

13 Thermo-Mechanical Pulp Program[3]

13.1 Initiative Description

The Thermo-Mechanical Pulp Program assists BC Hydro's thermo-mechanical pulp customers to manage their electricity consumption and complete projects at their facilities. The program targets the six thermo-mechanical pulp sites and provides incentives for projects that help to manage their energy consumption.

13.2 Savings Estimates

Projected Annual Energy Savings by F2021 (GWh)	293
Projected Capacity Savings by F2021 (MW)	35

Note: The energy savings are cumulative since fiscal 2016 as measured at the customer meter.

13.3 Assumptions

Savings Assumptions		TMP
	Savings Persistence (years)	15 - 20
	Free Riders (%)	0
	Spillover (%)	0
	Market Effects (%)	0
	Direct Rebound Effect (%)	0
	Cross Effects (%)	0

13.4 Financial Information

UC (F2017-F2019, Nominal $1000s)	55,800
Gross Levelized TRC Cost (F2016 $/MWh)	37
Net Levelized TRC Cost (F2016 $/MWh)	26
TRC Benefit-Cost Ratio vs LRMC	3.0
UC Benefit-Cost Ratio vs LRMC	4.4
UC Benefit-Cost Ratio vs Market Price	1.9

[3] The Thermo-Mechanical Pulp program is covered by the Direction to the BC Utilities Commission Respecting the Authority's TMP Program (B.C. Reg. 139/2015). A copy of this Direction is provided in Appendix CC.

13.5 Initiative Strategy

Market Barriers	The program helps to overcome market barriers preventing customer projects by providing study funding and access to experts to address awareness and availability of resources to quantify energy savings. By providing incentives, the program helps customers overcome financial barriers to implementing energy efficiency upgrades.
Approach	Funding for this program has been allocated to customers based on their TMP capacity. As a first step, an energy study was required for each facility, and reviewed by BC Hydro. Customers are then required to submit an incentive application, and undertake approved projects.

13.6 Activity Highlights

Energy studies to investigate the feasibility of proposed projects and to quantify potential energy savings and project costs have all been completed.

In fiscal 2017 through fiscal 2019, four project completions are planned. A project at the first thermo-mechanical pulp site was completed in fiscal 2016.

14 Leaders in Energy Management – Distribution

14.1 Initiative Description

The Leaders in Energy Management – Distribution program provides offers for industrial customers served under a distribution rate. The program's objective is to capture energy savings through energy efficiency retrofits of existing facilities, operational and maintenance changes, and behavioural change. The program seeks to address the access to capital, lack of internal and external resources, and knowledge of energy-efficiency market barriers that are holding back the adoption of more energy efficient projects and behaviours and to transform the market to higher levels of energy efficiency by encouraging and assisting customers in integrating energy efficiency into their ongoing business practices and corporate culture. Sectors are customer segments with common interests and energy opportunities, including Wood Products, Food and Beverage, Transportation, and Manufacturing.

The Leaders in Energy Management – Distribution program provides strategic energy management training and resources (such as including industrial Energy Managers), audits, studies and resources required to enable Distribution customers to implement facility changes and benefit from bill savings and/or leverage capital incentives.

14.2 Savings Estimates

Projected Annual Energy Savings by F2021 (GWh)	143
Projected Capacity Savings by F2021 (MW)	18

Note: The energy savings are cumulative since fiscal 2016 as measured at the customer meter.

14.3 Assumptions

Savings Assumptions		Distribution
	Savings Persistence (years)	5 - 16
	Free Riders (%)	26
	Spillover (%)	13
	Market Effects (%)	0
	Direct Rebound Effect (%)	0
	Cross Effects (%)	0

14.4 Financial Information

UC (F2017-F2019, Nominal $1000s)	29,400
Gross Levelized TRC Cost (F2016 $/MWh)	60
Net Levelized TRC Cost (F2016 $/MWh)	47
TRC Benefit-Cost Ratio vs LRMC	1.9
UC Benefit-Cost Ratio vs LRMC	2.5
UC Benefit-Cost Ratio vs Market Price	1.1

14.5 Initiative Strategy

Market Barriers	The program seeks to address the market barriers preventing customer implementation of energy efficiency upgrades and improved energy management practices by providing tools, education and incentives.
Approach	The approach to the industrial energy-efficiency market is structured to support the customer through four stages of energy management: Plan, Discover, Upgrade and Support.
Plan	Integrate energy management into long-term business vision. These initiatives supply funding and expert resources to make it easier to integrate energy management and efficient design into the customer's long-term business vision. These initiatives are recommended to achieve continuous energy improvement at industrial facilities. • Energy Management Assessment: an assessment of a customer's energy management practices. • Development of a Strategic Energy Management Plan to build executive support and guide multi-year efficiency plans. • Training and support for an energy management resource that will utilize energy data to drive business decisions related to policy, processes, and capital changes with a positive impact on the customer energy use.
Discover	Find and study opportunities to save electricity. This initiative offers funding to help build a solid business case for efficiency upgrades. Energy studies findings (a high-level assessment of an entire facility or plant or of a specific system, or an in-depth investigation of solutions of a single system) are used to access major upgrade funding.
Upgrade	Build efficiency into existing facilities. This initiative provides funding for energy efficiency retrofit projects to help improve the economics of the projects.
Support	Grow energy savings with smart monitoring of energy use and awareness. Customers are provided with the tools and training and funding to: • Build an Energy Monitoring and Targeting model to monitor facility energy use and identify areas of improvement. • Develop an awareness program around efficiency to grow savings through employee and management-led initiatives.

14.6 Activity Highlights

Building on the success of the industrial energy managers, Leaders in Energy Management – Distribution is expanding efforts in strategic energy management and industrial operational efficiencies by providing two new strategic energy management offers available to industrial customers.

The first of these offers, the Strategic Energy Management Cohort offer, will bring together groups of medium to large sized industrial customers for a two year engagement to work together and share knowledge related to building energy management in their business. The second offer, the Operational Energy Analytics offer, will bring strategic energy management fundamentals to the small and medium industrial customer and will focus on making operational changes in their facility. Each of these offers provide customers with energy data that allows them to make low or no cost choices in the way they operate that will increase their energy efficiency.

15 Industrial Sector Enabling Initiative

15.1 Initiative Description

Industrial sector enabling activities support industrial demand-side management programs by building industry capacity to undertake energy efficiency projects.

15.2 Savings Estimates

Projected Annual Energy Savings by F2021 (GWh)	n/a
Projected Capacity Savings by F2021 (MW)	n/a

15.3 Financial Information

UC (F2017-F2019, Nominal $1000s)	2,500
Gross Levelized TRC Cost (F2016 $/MWh)	n/a
Net Levelized TRC Cost (F2016 $/MWh)	n/a
TRC Benefit-Cost Ratio vs LRMC	n/a
UC Benefit-Cost Ratio vs LRMC	n/a
UC Benefit-Cost Ratio vs Market Price	n/a

15.4 Initiative Strategy

Strategy	There is one key industrial sector enabling activity: BC Hydro Alliance of Energy Professionals (which supports commercial and residential customers as well).
BC Hydro Alliance of Energy Professionals	The BC Hydro Alliance of Energy Professionals is a network of contractors, consulting engineers, distributors and registered experts that will promote the use of energy efficiency solutions to our customers. BC Hydro leverages the Alliance members' ability to sell and promote energy efficient products, services and programs to our customers within the context of demand-side management programs which is a cost-effective approach to minimize program marketing expenditures. BC Hydro delivers training to Alliance members to ensure they are educated on conservation and energy management and trained on the details of the available BC Hydro programs. This goal is achieved in part through partnerships with associations for development and delivery of courses and workshops. The BC Hydro Alliance of Energy Professionals also allows BC Hydro to monitor and assess the quality of work that customers receive from Alliance members, and take remedial action if deficiencies are identified.

15.5 Activity Highlights

BC Hydro will be delivering ongoing training and development, and certificate programs for the trades and energy professionals in the Alliance. This will be accomplished through partnerships with the Electrical Joint Training Committee and BCIT.

16 Capacity Focused Pilots

16.1 Initiative Description

Load curtailment and demand response initiatives are pilot initiatives which were identified in the 2013 Integrated Resource Plan and are currently in the market, to understand the dependability of the capacity savings for inclusion in BC Hydro's planning. These pilots are also reflective of BC Hydro's shift to a broader energy management framework as shown in Figure 10-1 of Chapter 10.This initiative work includes:

- Load Curtailment pilot activities that are designed to provide an understanding of the amount of available demand reduction that is available based on the ability of large industrials to respond to calls for demand reduction over a substantial duration; and

- Demand response activities intended to test various residential, commercial and industrial technologies and the effect of implementing these technologies on the end user and the BC Hydro system.

16.2 Savings Estimates

Projected Annual Energy Savings by F2021 (GWh)	n/a
Projected Capacity Savings by F2021 (MW)	0

16.3 Assumptions

Savings Assumptions		Capacity Pilots
	Savings Persistence	n/a
	Free Riders	n/a
	Spillover	n/a
	Market Effects	n/a
	Direct Rebound Effect	n/a
	Cross Effects	n/a

16.4 Financial Information

UC (F2017-F2019, Nominal $1000s)	38,600
Gross Levelized TRC Cost (F2016 $/MWh)	n/a
Net Levelized TRC Cost (F2016 $/MWh)	n/a
TRC Benefit-Cost Ratio vs LRMC	n/a
UC Benefit-Cost Ratio vs LRMC	n/a
UC Benefit-Cost Ratio vs Market Price	n/a

16.5 Initiative Strategy

Market Barriers	Pilot testing for capacity-focused activities are intended to identify the market barriers and BC Hydro issues associated with implementing Load Curtailment and Demand Response programs.
Approach	Delivery of these pilots and investigation is through a combination of internal resources and specialized external parties with expertise in load curtailment and demand response.

16.6 Activity Highlights

The planned activities for Capacity Focused demand-side management programs for fiscal 2017 to fiscal 2019 have been informed by the results of the pilots in fiscal 2015 through fiscal 2016, with the goal of addressing gaps in market potential and/or learning.

BC Hydro plans to deliver the following activities in fiscal 2017 through fiscal 2019 and will adjust these activities based on planning direction or market conditions, and results of learnings through the pilots:

Load Curtailment:	• Execute year 2 of the pilot with transmission customers in F2017 • Analyze the results of year 1 and 2 to inform the design of any potential future program
Commercial/Industrial Demand Response	• Continue testing existing participants from F2016 and expand target technologies and sectors • Investigate opportunities for future connected buildings • Leverage existing energy efficiency programs
Residential Demand Response	• Continue testing water heater participants from F2016 and expand target technologies (such as smart thermostats, electric vehicle smart charging and connected home) • Leverage existing energy efficiency programs • Investigate opportunities for behavioral demand response

17 Public Awareness Supporting Initiative

17.1 Initiative Description

The public awareness initiative is a set of foundational activities that increase customers' energy literacy and receptiveness to the concept of conservation and energy efficiency. This increased awareness and acceptance ultimately sets the stage for improved participation in a variety of behaviors and programs and support of codes and standards, leading to increased energy conservation and energy efficiency. These activities cover a variety of channels designed to most effectively reach a wide cross-section of customers and align with the Demand-Side Measures Regulation.

17.2 Savings Estimates

Projected Annual Energy Savings by F2021 (GWh)	n/a
Projected Capacity Savings by F2021 (MW)	n/a

17.3 Financial Information

UC (F2017-F2019, Nominal $1000s)	20,900
Gross Levelized TRC Cost (F2016 $/MWh)	n/a
Net Levelized TRC Cost (F2016 $/MWh)	n/a
TRC Benefit-Cost Ratio vs LRMC	n/a
UC Benefit-Cost Ratio vs LRMC	n/a
UC Benefit-Cost Ratio vs Market Price	n/a

17.4 Initiative Strategy

Market Barriers	Activities are designed to address two specific barriers to demand-side management participation: awareness of demand-side management programs, and acceptance of these programs in order to increase participation and seek out energy savings opportunities.
Public Awareness	By using a combination of paid, owned, and earned communications strategies, BC Hydro is able to reach customers with messages intended to elevate awareness of efficiency and conservation, and encourage residential and business customers to undertake energy conservation and energy efficiency actions. Strategies and messages target a range of demographics including multicultural, age, region and gender. Efforts will focus on maintaining awareness through traditional channels while driving customers to bchydro.com for in-depth information about tips and programs. Digital activities include the use of mobile platforms, digital advertising, social media channels, and subscriber newsletters.
Public Engagement	Engaging with customers directly helps build awareness and gain support for energy conservation activities. This initiative includes both BC Hydro Outreach and school programs. Outreach reaches customers primarily at home shows and retail stores, as well as work locations, to provide information on energy conservation tips, products, and programs. The goal through these interactions is to act as a personal energy coach to help encourage the adoption of energy efficient products, services and behaviours. School activities target and engage teachers and students (under the age of 18) to foster a conservation culture in B.C. through comprehensive, relevant school programs and initiatives.

17.5 Activity Highlights

In previous years, community engagement was a separate supporting initiative from public awareness. By combining and operating these activities as a single initiative, efficiencies will be achieved while ensuring that conservation awareness remains prominent in the marketplace for customers. Outreach operates with one team of employees year-round, and the flexibility to peak up as required for retail and home show campaigns.

17.6 Public Awareness

Over the next three years, paid, owned and earned strategies are expected to maintain conservation awareness at current levels. Messaging will continue to be targeted through research, and activities will become more prominent in the digital space where traffic can be efficiently driven to bchydro.com. Conservation awareness efforts are expected to drive over 2.5 million visitors to bchydro.com and maintain page views to conservation content at approximately 4.5 million per year. In addition, website visits from mobile is expected to increase to 45 per cent, due to enhancements to the mobile experience. Email subscriptions will maintain at 215,000, where conservation content is a prominent message.

17.6.1 Public Engagement

Community Outreach provides support for retail and home show campaigns. Over the next three years, Community Outreach expects to educate 150,000 customers across B.C., attending 900 events.

School education will focus on aligning classroom resources to the Ministry of Education’s curriculum transformation. Program delivery to schools and teachers will continue to follow a blended delivery model of in-service workshops for teachers and online support via FirstWave, BC Hydro’s online platform for teachers and students. The focus will be on increasing teacher registration and interaction on FirstWave. This will result in a cumulative participation of 6,500 teachers, 150,000 students and 550,000 student hours over three years.

18 Indirect and Portfolio Enabling Supporting Initiative

18.1 Initiative Description

The indirect and portfolio enabling activities are an important component of the Demand-Side Management Plan in that they provide general management and infrastructure that is critical to the effectiveness and integrity of demand-side management initiatives. This encompasses a wide range of activities that are not specific to individual programs or sectors and that are important in delivering the demand-side management goals in both the short term and long term.

18.2 Savings Estimates

Projected Annual Energy Savings by F2021 (GWh)	n/a
Projected Capacity Savings by F2021 (MW)	n/a

18.3 Financial Information

UC (F2017-F2019, Nominal $1000s)	21,500
Gross Levelized TRC Cost (F2016 $/MWh)	n/a
Net Levelized TRC Cost (F2016 $/MWh)	n/a
TRC Benefit-Cost Ratio vs LRMC	n/a
UC Benefit-Cost Ratio vs LRMC	n/a
UC Benefit-Cost Ratio vs Market Price	n/a

18.4 Initiative Description

General	A portion of the Conservation and Energy Management business unit's general management of people and resources.
Support and Administration	A portion of the Conservation and Energy Management business unit's general administrative functions, including costs associated with administrative support, office equipment and supplies, as well as a portion of labour for individual timesheets, expense reporting and benefits administration.
Regulatory	Activities that support regulatory filings and reporting.
Strategy and Policy	The development, updating and review of demand-side management strategy and policies
Planning	The development, updating and review of both long-term and operational Demand-Side Management plans, including demand-side management modelling and cost-effectiveness analysis.
Processes and Documentation	Support activities related to the development, administration and review of general processes and procedures related to the effectiveness, quality and integrity of demand-side management activities.
Demand-Side Management-related Training and Education	Individual employee training related to demand-side management.

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Revenue Requirements Application

Appendix W

Demand-Side Management Data Tables

Table 1. Cumulative Energy Savings at Customer Meter (GWh/yr)

	Actual F2016	Forecast F2017	Forecast F2018	Forecast F2019	Forecast F2020	Forecast F2021	Forecast F2022	Forecast F2023	Forecast F2024
Codes and Standards									
Residential	420	632	807	1,003	1,192	1,568	1,755	1,899	2,018
Commercial	118	181	256	366	502	674	798	913	1,001
Industrial	18	25	32	41	51	68	79	88	97
Total Codes and Standards	**557**	**838**	**1,096**	**1,410**	**1,744**	**2,310**	**2,631**	**2,901**	**3,115**
Rate Structures									
Residential Inclining Block Rate	29	37	49	58	60	63	74	87	103
General Service Rate	0	0	0	0	0	0	0	0	0
Transmission Service Rate	115	129	143	142	142	142	142	141	141
Total Rate Structures	**143**	**166**	**192**	**200**	**202**	**205**	**216**	**228**	**244**
DSM Programs									
Residential Sector									
Behaviour	15	31	45	61	73	85	95	102	110
Refrigerator Buy-back	3	3	3	3	3	3	3	0	0
Low Income	3	6	8	11	12	11	12	13	13
New Home	1	1	1	1	1	1	1	1	1
Retail	18	33	37	41	44	42	44	46	47
Home Energy Retrofit Offer	6	10	15	20	26	31	37	42	48
Residential Sector Total	*46*	*83*	*108*	*137*	*158*	*173*	*191*	*203*	*218*
Commercial Sector									
Leaders in Energy Management - Commercial	71	177	213	252	316	346	374	402	434
New Construction	17	37	52	57	65	70	78	78	77
Commercial Sector Total	*87*	*214*	*265*	*310*	*381*	*416*	*452*	*481*	*511*
Industrial Sector									
Leaders in Energy Management - Transmission	94	200	250	308	372	435	476	540	602
Thermo-Mechanical Pulp	66	66	293	293	293	293	293	293	293
Leaders in Energy Management - Distribution	27	52	74	98	120	143	163	182	199
Load Displacement	49	49	49	49	49	49	49	49	49
Industrial Sector Total	*237*	*367*	*666*	*748*	*834*	*920*	*981*	*1,064*	*1,143*
Total Programs	**369**	**664**	**1,040**	**1,194**	**1,373**	**1,509**	**1,624**	**1,748**	**1,872**
PORTFOLIO TOTAL	**1,069**	**1,668**	**2,327**	**2,804**	**3,319**	**4,024**	**4,471**	**4,877**	**5,231**

Table 2. Cumulative Associated Capacity Savings at Customer Meter (MW)

	Actual F2016	Forecast F2017	Forecast F2018	Forecast F2019	Forecast F2020	Forecast F2021	Forecast F2022	Forecast F2023	Forecast F2024
Codes and Standards									
Residential	71	158	200	236	275	353	427	462	489
Commercial	9	21	30	43	59	80	99	114	127
Industrial	1	2	3	4	5	7	8	10	11
Total Codes and Standards	**81**	**182**	**234**	**283**	**339**	**439**	**534**	**586**	**627**
Rate Structures									
Residential Inclining Block Rate	6	8	11	12	13	13	16	19	22
General Service Rate	0	0	0	0	0	0	0	0	0
Transmission Service Rate	14	9	16	16	17	17	17	17	17
Total Rate Structures	**20**	**17**	**27**	**29**	**30**	**30**	**33**	**35**	**39**
DSM Programs									
Residential Sector									
Behaviour	2	5	8	12	14	17	19	21	23
Refrigerator Buy-back	0	0	0	0	0	0	0	0	0
Low Income	1	1	2	2	3	3	3	3	3
New Home	0	0	0	0	0	0	0	0	0
Retail	4	9	12	13	15	14	15	15	16
Home Energy Retrofit Offer	1	3	5	7	9	11	13	15	17
Residential Sector Total	*8*	*19*	*28*	*35*	*41*	*45*	*50*	*55*	*59*
Commercial Sector									
Leaders in Energy Management - Commercial	4	17	27	33	41	48	53	57	61
New Construction	1	4	6	8	9	9	10	11	11
Commercial Sector Total	*5*	*21*	*34*	*41*	*49*	*58*	*63*	*68*	*72*
Industrial Sector									
Leaders in Energy Management - Transmission	7	17	27	33	41	48	55	61	68
Thermo-Mechanical Pulp	3	8	10	35	35	35	35	35	35
Leaders in Energy Management - Distribution	2	5	8	11	15	18	21	23	26
Load Displacement	4	6	6	6	6	6	6	6	6
Industrial Sector Total	*16*	*37*	*51*	*86*	*96*	*107*	*117*	*125*	*135*
Total Programs	**29**	**77**	**113**	**161**	**187**	**210**	**230**	**248**	**266**
PORTFOLIO TOTAL	**130**	**276**	**373**	**473**	**556**	**680**	**797**	**869**	**932**

Table 3. BC Hydro Non-Incentive Costs ($ Million)

	Actual F2016	Forecast F2017	Forecast F2018	Forecast F2019	Forecast F2020	Forecast F2021	Forecast F2022	Forecast F2023	Forecast F2024	Total: F2016-F2024
Codes and Standards										
Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Codes and Standards	4.7	4.7	4.8	4.9	5.0	5.1	5.2	5.3	5.4	45.1
Rate Structures										
Residential Inclining Block Rate	0.5	0.5	0.3	0.7	0.8	0.3	0.3	0.5	0.7	4.6
General Service Rate	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.5
Transmission Service Rate	0.3	0.7	0.7	0.5	0.5	0.5	0.5	0.5	0.6	4.9
Total Rate Structures	**1.3**	**1.2**	**1.0**	**1.2**	**1.3**	**0.8**	**0.8**	**1.0**	**1.3**	**10.0**
DSM Programs										
Residential Sector										
Behaviour	2.6	3.4	2.6	3.4	3.4	3.6	3.6	4.2	3.8	30.7
Refrigerator Buy-back	0.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.6
Low Income	0.7	1.1	1.2	1.2	1.2	1.2	1.2	1.3	1.3	10.5
New Home	0.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.6
Retail	2.1	1.7	1.6	1.6	1.6	1.5	1.5	1.6	1.3	14.5
Home Energy Retrofit Offer	0.8	0.9	1.0	0.9	1.0	1.0	1.0	1.0	1.0	8.5
Sector Enabling Activities	1.0	0.8	0.9	0.9	0.9	0.9	0.9	0.9	1.0	8.1
Residential Sector Total	*8.4*	*8.0*	*7.2*	*8.0*	*8.1*	*8.2*	*8.3*	*9.0*	*8.4*	*73.5*
Commercial Sector										
Leaders in Energy Management - Commercial	8.2	6.8	6.9	7.2	7.3	7.4	7.5	7.7	7.8	66.7
New Construction	1.7	1.5	1.4	1.4	0.8	0.7	0.5	0.4	0.0	8.4
Sector Enabling Activities	1.1	1.0	1.0	1.0	1.1	1.1	1.1	1.1	1.1	9.7
Commercial Sector Total	*11.1*	*9.2*	*9.3*	*9.6*	*9.1*	*9.2*	*9.2*	*9.1*	*8.9*	*84.7*
Industrial Sector										
Leaders in Energy Management - Transmission	4.5	3.0	3.3	3.3	3.4	3.5	3.5	3.6	3.7	31.9
Thermo-Mechanical Pulp	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Leaders in Energy Management - Distribution	3.6	2.6	2.8	2.8	2.9	3.0	3.1	3.2	3.2	27.3
Load Displacement	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2
Sector Enabling Activities	1.0	0.8	0.8	0.8	0.8	0.9	0.9	0.9	0.9	7.8
Industrial Sector Total	*9.2*	*6.5*	*6.9*	*7.0*	*7.2*	*7.4*	*7.5*	*7.7*	*7.9*	*67.2*
Total Programs	**28.7**	**23.6**	**23.3**	**24.6**	**24.4**	**24.7**	**25.0**	**25.8**	**25.2**	**225.4**
Supporting Initiatives										
Public Awareness	8.8	6.9	6.9	7.1	7.1	7.2	7.3	7.4	7.6	66.4
Indirect and Portfolio Enabling	7.3	7.2	7.3	7.1	7.2	7.4	7.6	8.1	8.0	67.2
Supporting Initiatives Total	**16.1**	**14.0**	**14.2**	**14.2**	**14.4**	**14.6**	**14.9**	**15.6**	**15.5**	**133.6**
ENERGY EFFICIENCY PORTFOLIO TOTAL	**50.8**	**43.7**	**43.4**	**44.9**	**45.1**	**45.2**	**45.9**	**47.7**	**47.4**	**414.1**
Capacity Focused DSM	**1.2**	**3.3**	**4.6**	**4.7**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**13.8**
PORTFOLIO TOTAL, EE & CF DSM	**52.0**	**47.0**	**48.0**	**49.6**	**45.1**	**45.2**	**45.9**	**47.7**	**47.4**	**427.9**

Note:
Codes and Standards costs are provided as a total value, since they are not allocated between the three sectors

Table 4. BC Hydro Incentive Costs ($ Million)

	Actual F2016	Forecast F2017	Forecast F2018	Forecast F2019	Forecast F2020	Forecast F2021	Forecast F2022	Forecast F2023	Forecast F2024	Total: F2016-F2024
Codes and Standards										
Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Codes and Standards	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Rate Structures										
Residential Inclining Block Rate	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
General Service Rate	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Transmission Service Rate	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Rate Structures	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
DSM Programs										
Residential Sector										
Behaviour	0.6	0.5	0.6	0.6	0.5	0.5	0.4	0.4	0.4	4.5
Refrigerator Buy-back	0.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.6
Low Income	1.7	1.4	1.4	1.5	1.2	1.2	1.0	1.0	1.0	11.4
New Home	0.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.6
Retail	2.6	1.7	0.8	0.8	0.7	0.4	0.4	0.4	0.4	8.1
Home Energy Retrofit Offer	1.5	1.6	1.8	2.1	2.2	2.2	2.3	2.3	2.4	18.4
Sector Enabling Activities	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Residential Sector Total	*7.6*	*5.2*	*4.6*	*5.0*	*4.7*	*4.4*	*4.0*	*4.1*	*4.1*	*43.7*
Commercial Sector										
Leaders in Energy Management - Commercial	16.9	24.6	13.5	12.3	12.3	12.5	12.5	12.7	12.9	130.1
New Construction	5.6	10.1	7.1	3.8	3.1	2.3	2.5	0.0	0.0	34.5
Sector Enabling Activities	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Commercial Sector Total	*22.6*	*34.7*	*20.6*	*16.0*	*15.4*	*14.8*	*15.0*	*12.7*	*12.9*	*164.6*
Industrial Sector										
Leaders in Energy Management - Transmission	14.3	13.0	14.9	13.4	13.7	14.0	14.3	14.6	14.8	127.0
Thermo-Mechanical Pulp	19.6	0.0	55.8	0.0	0.0	0.0	0.0	0.0	0.0	75.4
Leaders in Energy Management - Distribution	7.3	7.2	7.0	7.0	6.8	6.9	7.0	7.3	7.5	64.0
Load Displacement	14.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	14.3
Sector Enabling Activities	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Industrial Sector Total	*55.5*	*20.2*	*77.7*	*20.4*	*20.5*	*20.9*	*21.3*	*21.8*	*22.3*	*280.8*
Total Programs	**85.7**	**60.1**	**102.9**	**41.4**	**40.6**	**40.1**	**40.4**	**38.6**	**39.3**	**489.1**
Supporting Initiatives										
Public Awareness	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Indirect and Portfolio Enabling	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Supporting Initiatives Total	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
ENERGY EFFICIENCY PORTFOLIO TOTAL	**85.7**	**60.1**	**102.9**	**41.4**	**40.6**	**40.1**	**40.4**	**38.6**	**39.3**	**489.1**
Capacity Focused DSM	**7.4**	**6.7**	**9.7**	**9.7**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**33.5**
PORTFOLIO TOTAL, EE & CF DSM	**93.2**	**66.7**	**112.6**	**51.1**	**40.6**	**40.1**	**40.4**	**38.6**	**39.3**	**522.6**

Table 5. Total BC Hydro Costs ($ Million)

	Actual F2016	Forecast F2017	Forecast F2018	Forecast F2019	Forecast F2020	Forecast F2021	Forecast F2022	Forecast F2023	Forecast F2024	Total: F2016-F2024
Codes and Standards										
Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Codes and Standards	4.7	4.7	4.8	4.9	5.0	5.1	5.2	5.3	5.4	45.1
Rate Structures										
Residential Inclining Block Rate	0.5	0.5	0.3	0.7	0.8	0.3	0.3	0.5	0.7	4.6
General Service Rate	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.5
Transmission Service Rate	0.3	0.7	0.7	0.5	0.5	0.5	0.5	0.5	0.6	4.9
Total Rate Structures	**1.3**	**1.2**	**1.0**	**1.2**	**1.3**	**0.8**	**0.8**	**1.0**	**1.3**	**10.0**
DSM Programs										
Residential Sector										
Behaviour	3.2	3.9	3.2	4.0	4.0	4.0	4.1	4.6	4.2	35.2
Refrigerator Buy-back	1.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.2
Low Income	2.4	2.5	2.6	2.7	2.4	2.5	2.2	2.3	2.3	21.9
New Home	1.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.3
Retail	4.7	3.4	2.3	2.4	2.3	1.9	1.9	1.9	1.7	22.6
Home Energy Retrofit Offer	2.2	2.4	2.8	3.0	3.1	3.2	3.3	3.3	3.4	26.9
Sector Enabling Activities	1.0	0.8	0.9	0.9	0.9	0.9	0.9	0.9	1.0	8.1
Residential Sector Total	*16.0*	*13.1*	*11.8*	*13.0*	*12.8*	*12.5*	*12.4*	*13.1*	*12.5*	*117.2*
Commercial Sector										
Leaders in Energy Management - Commercial	25.2	31.3	20.3	19.4	19.6	19.9	20.1	20.3	20.7	196.8
New Construction	7.4	11.5	8.5	5.2	3.9	3.0	3.0	0.4	0.0	42.9
Sector Enabling Activities	1.1	1.0	1.0	1.0	1.1	1.1	1.1	1.1	1.1	9.7
Commercial Sector Total	*33.6*	*43.9*	*29.9*	*25.7*	*24.6*	*23.9*	*24.2*	*21.8*	*21.8*	*249.4*
Industrial Sector										
Leaders in Energy Management - Transmission	18.8	16.1	18.2	16.7	17.2	17.5	17.8	18.2	18.5	158.9
Thermo-Mechanical Pulp	19.7	0.0	55.8	0.0	0.0	0.0	0.0	0.0	0.0	75.4
Leaders in Energy Management - Distribution	10.9	9.8	9.8	9.8	9.7	9.9	10.1	10.4	10.7	91.3
Load Displacement	14.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	14.5
Sector Enabling Activities	1.0	0.8	0.8	0.8	0.8	0.9	0.9	0.9	0.9	7.8
Industrial Sector Total	*64.8*	*26.7*	*84.6*	*27.4*	*27.7*	*28.3*	*28.8*	*29.5*	*30.2*	*348.0*
Total Programs	**114.4**	**83.7**	**126.3**	**66.0**	**65.0**	**64.7**	**65.4**	**64.4**	**64.5**	**714.5**
Supporting Initiatives										
Public Awareness	8.8	6.9	6.9	7.1	7.1	7.2	7.3	7.4	7.6	66.4
Indirect and Portfolio Enabling	7.3	7.2	7.3	7.1	7.2	7.4	7.6	8.1	8.0	67.2
Supporting Initiatives Total	**16.1**	**14.0**	**14.2**	**14.2**	**14.4**	**14.6**	**14.9**	**15.6**	**15.5**	**133.6**
ENERGY EFFICIENCY PORTFOLIO TOTAL	**136.5**	**103.7**	**146.4**	**86.3**	**85.7**	**85.3**	**86.3**	**86.3**	**86.7**	**903.2**
Capacity Focused DSM	**8.6**	**10.0**	**14.2**	**14.4**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**47.3**
PORTFOLIO TOTAL, EE & CF DSM	**145.2**	**113.7**	**160.6**	**100.7**	**85.7**	**85.3**	**86.3**	**86.3**	**86.7**	**950.5**

Note:
Codes and Standards costs are provided as a total value, since they are not allocated between the three sectors

Table 6. Customer Costs ($ Million)

	Actual F2016	Forecast F2017	Forecast F2018	Forecast F2019	Forecast F2020	Forecast F2021	Forecast F2022	Forecast F2023	Forecast F2024	Total: F2016-F2024
Codes and Standards										
Residential	80.3	85.6	82.5	87.7	90.8	91.9	86.3	72.2	67.8	745.1
Commercial	17.2	19.9	24.7	30.6	40.2	40.7	35.8	35.4	29.1	273.5
Industrial	1.0	0.2	0.7	1.3	1.6	2.2	2.0	1.9	1.6	12.5
Total Codes and Standards	**98.5**	**105.7**	**107.9**	**119.6**	**132.6**	**134.8**	**124.1**	**109.5**	**98.5**	**1,031.1**
Rate Structures										
Residential Inclining Block Rate	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
General Service Rate	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Transmission Service Rate	4.2	4.2	4.2	4.3	4.4	4.5	4.5	4.6	4.7	39.8
Total Rate Structures	**4.2**	**4.2**	**4.2**	**4.3**	**4.4**	**4.5**	**4.5**	**4.6**	**4.7**	**39.8**
DSM Programs										
Residential Sector										
Behaviour	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Refrigerator Buy-back	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3
Low Income	1.5	1.3	1.3	1.3	1.1	1.1	0.9	0.9	0.9	10.5
New Home	0.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.7
Retail	-1.3	-1.6	0.2	0.4	0.3	-0.2	-0.3	-0.3	-0.3	-3.1
Home Energy Retrofit Offer	5.6	6.2	7.0	8.0	8.1	8.3	8.5	8.6	8.8	69.2
Sector Enabling Activities	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Residential Sector Total	*6.8*	*5.8*	*8.6*	*9.8*	*9.6*	*9.3*	*9.0*	*9.2*	*9.4*	*77.5*
Commercial Sector										
Leaders in Energy Management - Commercial	25.2	69.5	27.5	21.2	23.7	20.3	21.1	21.4	21.9	251.6
New Construction	14.4	20.0	14.2	4.8	7.3	4.0	7.3	0.0	0.0	71.9
Sector Enabling Activities	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Commercial Sector Total	*39.6*	*89.5*	*41.6*	*25.9*	*31.0*	*24.2*	*28.4*	*21.4*	*21.9*	*323.5*
Industrial Sector										
Leaders in Energy Management - Transmission	32.5	28.7	32.5	28.5	27.1	27.7	28.3	28.9	29.5	263.6
Thermo-Mechanical Pulp	23.7	0.0	93.7	0.0	0.0	0.0	0.0	0.0	0.0	117.4
Leaders in Energy Management - Distribution	10.1	9.4	10.1	10.4	10.2	10.4	10.6	10.8	11.1	93.0
Load Displacement	54.4	0.6	0.6	0.6	0.6	0.6	0.7	0.7	0.7	59.5
Sector Enabling Activities	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Industrial Sector Total	*120.8*	*38.6*	*136.9*	*39.5*	*37.9*	*38.7*	*39.5*	*40.4*	*41.2*	*533.6*
Total Programs	**167.2**	**133.9**	**187.1**	**75.2**	**78.6**	**72.2**	**76.9**	**71.0**	**72.5**	**934.7**
PORTFOLIO TOTAL	**269.8**	**243.8**	**299.3**	**199.1**	**215.6**	**211.6**	**205.6**	**185.1**	**175.8**	**2,005.5**

Table 7. Total Resource Costs ($ Million)

	Actual F2016	Forecast F2017	Forecast F2018	Forecast F2019	Forecast F2020	Forecast F2021	Forecast F2022	Forecast F2023	Forecast F2024	Total: F2016-F2024
Codes and Standards										
Residential	80.3	85.6	82.5	87.7	90.8	91.9	86.3	72.2	67.8	745.1
Commercial	17.2	19.9	24.7	30.6	40.2	40.7	35.8	35.4	29.1	273.5
Industrial	1.0	0.2	0.7	1.3	1.6	2.2	2.0	1.9	1.6	12.5
Total Codes and Standards	**103.2**	**110.4**	**112.7**	**124.5**	**137.6**	**139.9**	**129.3**	**114.8**	**103.9**	**1,076.2**
Rate Structures										
Residential Inclining Block Rate	0.5	0.5	0.3	0.7	0.8	0.3	0.3	0.5	0.7	4.6
General Service Rate	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.5
Transmission Service Rate	4.5	4.9	5.0	4.8	4.9	5.0	5.1	5.2	5.3	44.7
Total Rate Structures	**5.5**	**5.4**	**5.3**	**5.5**	**5.7**	**5.3**	**5.4**	**5.7**	**6.0**	**49.8**
DSM Programs										
Residential Sector										
Behaviour	2.6	3.4	2.6	3.4	3.4	3.6	3.6	4.2	3.8	30.7
Refrigerator Buy-back	0.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.9
Low Income	2.3	2.4	2.5	2.5	2.3	2.4	2.1	2.2	2.2	21.0
New Home	1.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.3
Retail	0.8	0.1	1.8	2.0	2.0	1.3	1.2	1.2	1.0	11.4
Home Energy Retrofit Offer	6.5	7.1	8.0	8.9	9.1	9.3	9.5	9.7	9.8	77.8
Sector Enabling Activities	1.0	0.8	0.9	0.9	0.9	0.9	0.9	0.9	1.0	8.1
Residential Sector Total	*15.3*	*13.8*	*15.8*	*17.8*	*17.7*	*17.4*	*17.3*	*18.2*	*17.8*	*151.2*
Commercial Sector										
Leaders in Energy Management - Commercial	33.5	76.4	34.5	28.5	31.1	27.8	28.8	29.2	29.9	319.7
New Construction	16.2	21.5	15.6	6.2	8.1	4.6	7.8	0.4	0.0	80.5
Sector Enabling Activities	1.1	1.0	1.0	1.0	1.1	1.1	1.1	1.1	1.1	9.7
Commercial Sector Total	*50.8*	*98.9*	*51.1*	*35.7*	*40.3*	*33.5*	*37.7*	*30.7*	*31.0*	*409.8*
Industrial Sector										
Leaders in Energy Management - Transmission	37.0	31.7	35.8	31.8	30.5	31.2	31.8	32.5	33.1	295.5
Thermo-Mechanical Pulp	23.7	0.0	93.7	0.0	0.0	0.0	0.0	0.0	0.0	117.5
Leaders in Energy Management - Distribution	13.7	12.0	12.8	13.2	13.1	13.4	13.7	14.0	14.3	120.3
Load Displacement	54.6	0.6	0.6	0.6	0.6	0.6	0.7	0.7	0.7	59.7
Sector Enabling Activities	1.0	0.8	0.8	0.8	0.8	0.9	0.9	0.9	0.9	7.8
Industrial Sector Total	*130.0*	*45.1*	*143.8*	*46.5*	*45.1*	*46.1*	*47.1*	*48.1*	*49.1*	*600.8*
Total Programs	**196.2**	**157.8**	**210.7**	**100.0**	**103.2**	**97.1**	**102.1**	**97.0**	**97.9**	**1,161.8**
Supporting Initiatives										
Public Awareness and Education	8.8	6.9	6.9	7.1	7.1	7.2	7.3	7.4	7.6	66.4
Indirect and Portfolio Enabling	7.3	7.2	7.3	7.1	7.2	7.4	7.6	8.1	8.0	67.2
Supporting Initiatives Total	**16.1**	**14.0**	**14.2**	**14.2**	**14.4**	**14.6**	**14.9**	**15.6**	**15.5**	**133.6**
PORTFOLIO TOTAL	**320.9**	**287.6**	**342.9**	**244.2**	**260.9**	**256.9**	**251.6**	**233.0**	**223.3**	**2,421.4**

Note:
Codes and Standards: The Total Resource Costs for each sector is based on customer costs alone. BC Hydro costs are included in the total Total Resource Costs value.

Table 8. Customer Electricity Bill Savings ($ Million)

	Actual F2016	Forecast F2017	Forecast F2018	Forecast F2019	Forecast F2020	Forecast F2021	Forecast F2022	Forecast F2023	Forecast F2024	Total: F2016-F2024
Codes and Standards										
Residential	24.5	56.6	79.1	102.2	126.8	165.1	201.4	226.5	248.8	1,231.0
Commercial	5.7	14.0	21.0	31.0	44.2	61.4	78.5	93.5	107.0	456.2
Industrial	0.5	1.2	1.6	2.2	2.8	3.8	4.8	5.5	6.3	28.7
Total Codes and Standards	**30.7**	**71.8**	**101.8**	**135.4**	**173.8**	**230.3**	**284.7**	**325.5**	**362.1**	**1,715.9**
Rate Structures										
Residential Inclining Block Rate	3.6	4.8	6.6	8.1	8.5	9.2	11.1	13.3	16.4	81.6
General Service Rate	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Transmission Service Rate	11.0	7.7	14.1	14.4	15.5	16.0	16.4	16.7	17.1	*129.0*
Total Rate Structures	**14.6**	**12.5**	**20.8**	**22.5**	**24.0**	**25.1**	**27.4**	**30.1**	**33.5**	**210.6**
DSM Programs										
Residential Sector										
Behaviour	0.9	2.5	4.2	6.1	7.8	9.4	10.9	12.2	13.5	67.6
Refrigerator Buy-back	0.2	0.3	0.3	0.4	0.4	0.4	0.4	0.1	0.0	2.5
Low Income	0.2	0.5	0.8	1.1	1.3	1.3	1.4	1.5	1.6	9.7
New Home	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.5
Retail	1.4	2.8	3.8	4.4	4.9	4.9	5.3	5.6	5.9	38.9
Home Energy Retrofit Offer	0.4	1.1	1.8	2.6	3.4	4.3	5.3	6.2	7.3	32.4
Residential Sector Total	*3.1*	*7.3*	*11.0*	*14.5*	*17.8*	*20.4*	*23.3*	*25.8*	*28.4*	151.7
Commercial Sector										
Leaders in Energy Management - Commercial	2.9	11.8	19.0	23.8	29.8	36.2	40.5	45.0	49.7	258.7
New Construction	0.5	2.6	4.5	5.6	6.5	7.3	8.2	8.9	9.0	53.0
Commercial Sector Total	*3.4*	*14.4*	*23.5*	*29.4*	*36.3*	*43.5*	*48.7*	*53.9*	*58.8*	311.7
Industrial Sector										
Leaders in Energy Management - Transmission	4.6	11.8	18.3	23.0	28.7	34.7	40.6	46.3	53.1	261.1
Thermo-Mechanical Pulp	1.5	3.7	5.0	17.6	18.0	18.5	19.0	19.5	20.0	122.7
Leaders in Energy Management - Distribution	1.4	3.3	5.1	7.4	9.9	12.5	15.2	17.9	20.3	93.1
Load Displacement	1.7	2.8	2.9	2.9	3.0	3.1	3.2	3.3	3.3	26.2
Industrial Sector Total	*9.3*	*21.6*	*31.3*	*50.9*	*59.6*	*68.8*	*78.0*	*86.9*	*96.7*	503.1
Total Programs	**15.7**	**43.3**	**65.8**	**94.8**	**113.7**	**132.7**	**150.0**	**166.5**	**183.9**	966.5
PORTFOLIO TOTAL	**61.0**	**127.6**	**188.4**	**252.7**	**311.6**	**388.1**	**462.1**	**522.1**	**579.4**	**2,892.9**

Table 9. Benefit Cost Ratios

	LRMC			Reference Price		Market Price
	Total Resource Cost Test	Utility Cost Test	Modified TRC	Total Resource Cost Test	Utility Cost Test	Utility Cost Test
Codes and Standards						
Residential	6.2	n/a	7.3	5.2	n/a	n/a
Commercial	7.5	n/a	9.4	6.4	n/a	n/a
Industrial	14.5	n/a	16.7	12.1	n/a	n/a
Total Codes & Standards	**6.4**	**149.1**	**7.6**	**5.4**	**125.8**	**77.3**
Rate Structures						
Residential Inclining Block Rate	19.9	19.9	22.9	16.4	16.4	10.2
General Service Rate	0.0	0.0	0.0	0.0	0.0	0.0
Transmission Service Rate	3.1	21.5	3.6	1.6	11.1	7.5
Total Rate Structures	**6.4**	**19.8**	**7.4**	**4.5**	**14.0**	**8.9**
DSM Programs						
Residential Sector						
Behaviour	4.0	3.7	4.6	3.3	3.0	1.9
Low Income	1.1	0.8	1.1	0.9	0.5	0.3
Retail	7.1	3.8	7.7	5.3	2.9	2.0
Home Energy Retrofit Offer	1.5	3.8	2.1	1.3	3.3	2.1
Residential Sector Total	*2.6*	*3.0*	*3.1*	*2.1*	*2.4*	*1.6*
Commercial Sector						
Leaders in Energy Management - Commercial	1.8	2.8	2.2	1.4	2.1	1.2
New Construction	1.9	2.9	2.3	1.5	2.2	1.3
Commercial Sector Total	*1.8*	*2.7*	*2.2*	*1.4*	*2.0*	*1.2*
Industrial Sector						
Leaders in Energy Management - Transmission	2.2	3.8	2.5	1.7	2.9	1.6
Thermo-Mechanical Pulp	3.0	4.4	3.5	2.2	3.2	1.9
Leaders in Energy Management - Distribution	1.9	2.5	2.2	1.5	1.9	1.1
Industrial Sector Total	*2.1*	*3.5*	*2.5*	*1.6*	*2.7*	*1.5*
Total Programs	**2.1**	**3.2**	**2.5**	**1.6**	**2.4**	**1.4**
Rate Structures and Programs	**2.3**	**3.5**	**2.7**	**1.7**	**2.7**	**1.6**
PORTFOLIO TOTAL	**4.0**	**10.3**	**4.7**	**3.3**	**8.3**	**5.1**

Note:
Benefit Cost Ratios include supporting initiative costs allocated to rate structures and programs.

Table 10. Levelized Costs ($/MWh)

	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	Modified TRC	Total Resource Cost Test	Utility Cost Test	Modified TRC	Total Resource Cost Test	Utility Cost Test	Modified TRC	Total Resource Cost Test	Utility Cost Test	Modified TRC	Total Resource Cost Test	Utility Cost Test	Modified TRC	Total Resource Cost Test	Utility Cost Test	Modified TRC
Codes and Standards																		
Residential	$21	$0	$21	$0	$0	-$20	-$1	$0	-$4	-$23	-$23	-$23	-$4	-$4	-$4	-$7	-$27	-$30
Commercial	$16	$0	$16	$0	$0	-$20	-$5	$0	-$15	-$12	-$12	-$12	-$2	-$2	-$2	-$3	-$14	-$33
Industrial	$8	$0	$8	$0	$0	-$17	$0	$0	$0	-$11	-$11	-$11	-$2	-$2	-$2	-$5	-$12	-$22
Total Codes & Standards	**$20**	**$1**	**$20**	**$0**	**$0**	**-$20**	**-$2**	**$0**	**-$7**	**-$19**	**-$19**	**-$19**	**-$3**	**-$3**	**-$3**	**-$5**	**-$22**	**-$30**
Rate Structures																		
Residential Inclining Block Rate	$6	$6	$6	$0	$0	-$19	$0	$0	$0	-$20	-$20	-$20	-$3	-$3	-$3	-$17	-$17	-$36
General Service Rate	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Transmission Service Rate	$35	$5	$35	$0	$0	-$16	$0	$0	$0	-$6	-$6	-$6	-$2	-$2	-$2	$27	-$3	$11
Total Rate Structures	**$19**	**$6**	**$19**	**$0**	**$0**	**-$18**	**$0**	**$0**	**$0**	**-$14**	**-$14**	**-$14**	**-$3**	**-$3**	**-$3**	**$2**	**-$11**	**-$16**
DSM Programs																		
Residential Sector																		
Behaviour	$31	$34	$31	$0	$0	-$19	$0	$0	$0	-$19	-$19	-$19	-$3	-$3	-$3	$9	$12	-$10
Low Income	$156	$163	$156	-$49	$0	-$49	$0	$0	$1	-$16	-$16	-$16	-$3	-$3	-$3	$88	$144	$88
Retail	$19	$35	$19	$0	$0	-$19	$3	$0	$10	-$27	-$27	-$27	-$5	-$5	-$5	-$10	$4	-$22
Home Energy Retrofit Offer	$107	$40	$107	$0	$0	-$29	-$13	$0	-$42	-$35	-$35	-$35	-$5	-$5	-$5	$54	$0	-$4
Residential Sector Total	*$53*	*$44*	*$53*	*-$2*	*$0*	*-$22*	*-$2*	*$0*	*-$7*	*-$24*	*-$24*	*-$24*	*-$4*	*-$4*	*-$4*	*$21*	*$16*	*-$4*
Commercial Sector																		
Leaders in Energy Management - Commercial	$65	$42	$65	$0	$0	-$19	-$3	$0	-$10	-$12	-$12	-$12	-$2	-$2	-$2	*$48*	*$28*	*$23*
New Construction	$80	$45	$80	-$8	$0	-$22	-$9	$0	-$31	-$13	-$13	-$13	-$2	-$2	-$2	*$47*	*$29*	*$12*
Commercial Sector Total	*$69*	*$44*	*$69*	*-$1*	*$0*	*-$19*	*-$4*	*$0*	*-$13*	*-$12*	*-$12*	*-$12*	*-$2*	*-$2*	*-$2*	*$50*	*$30*	*$22*
Industrial Sector																		
Leaders in Energy Management - Transmission	$52	$30	$52	$0	$0	-$17	$0	$0	$0	-$10	-$10	-$10	-$2	-$2	-$2	$41	$19	$24
Thermo-Mechanical Pulp	$37	$26	$37	$0	$0	-$17	$0	$0	$0	-$10	-$10	-$10	-$2	-$2	-$2	$26	$14	$9
Leaders in Energy Management - Distribution	$60	$47	$60	$0	$0	-$17	$0	$0	$0	-$11	-$11	-$11	-$2	-$2	-$2	$47	$34	$30
Industrial Sector Total	*$53*	*$32*	*$53*	*$0*	*$0*	*-$17*	*$0*	*$0*	*$0*	*-$10*	*-$10*	*-$10*	*-$2*	*-$2*	*-$2*	$41	$20	$24
Total Programs	**$57**	**$37**	**$57**	**-$1**	**$0**	**-$18**	**-$1**	**$0**	**-$5**	**-$12**	**-$12**	**-$12**	**-$2**	**-$2**	**-$2**	**$41**	**$22**	**$20**
Rate Structures and Programs	**$53**	**$33**	**$53**	**-$1**	**$0**	**-$18**	**-$1**	**$0**	**-$4**	**-$13**	**-$13**	**-$13**	**-$2**	**-$2**	**-$2**	**$36**	**$19**	**$16**
PORTFOLIO TOTAL	**$31**	**$12**	**$31**	**$0**	**$0**	**-$19**	**-$2**	**$0**	**-$6**	**-$17**	**-$17**	**-$17**	**-$3**	**-$3**	**-$3**	**$9**	**-$8**	**-$14**

Note:
Levelized Costs include supporting initiative costs allocated to rate structures and programs.

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Fiscal 2017 to Fiscal 2019
Revenue Requirements Application

Appendix X

Demand-Side Management Assumptions

[Revision 1 – August 17, 2016]

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1 Portfolio-Wide Assumptions

Table X-1summarizes the portfolio-wide assumptions used in the Demand-side Management Plan.

Table X-1 Portfolio-Wide Assumptions

Base Year	Fiscal 2016
Timeframe for DSM Plan Analysis	Fiscal 2016 to fiscal 2024: Fiscal 2016 aligns with the base year of the 2016 Load Forecast, while fiscal 2024 aligns with the end year of the 2013 10 Year Rates Plan. While activity is shown ending at this point, energy and capacity savings continue due to the persistence of savings.
Inflation	2.0 per cent.
Discount Rates	7 per cent nominal and 5 per cent real, representing BC Hydro's corporate discount rates.
Avoided Costs	*Electric energy:* LRMC: $102 per MWh (Fiscal 2016 $) *Reference Price:* Fiscal 2016 to fiscal 2021 market price Fiscal 2022 to fiscal 2033 $87 per MWh (Fiscal 2016 $) Fiscal 2034 onwards: $102 per MWh (Fiscal 2016 $) *Market price of electricity:* used as an additional filter for the Utility Cost test BC Hydro's forecast of market sell prices at the B.C.-U.S. border, has a levelized value of approximately $36/MWh (Fiscal 2016 $) over a 17-year period from fiscal 2017 to fiscal 2033. *Generation capacity:* Fiscal 2016 to fiscal 2019: $37 per kW-year (Fiscal 2016 $) Fiscal 2020 to fiscal 2028: $58 per kW-year (Fiscal 2016 $) Fiscal 2029 onwards: $118 per kW-year (Fiscal 2016 $) Representing BC Hydro's current long-run marginal cost generation capacity price. See Chapter 3. *Bulk transmission capacity:* $0 per kW-year (Fiscal 2011 $) because there are no bulk transmission capacity investments expected to be deferred by demand-side management initiatives. *Regional transmission and substation capacity:* $11 per kW-year (Fiscal 2011 $), based on BC Hydro estimates of the regional transmission and substation capacity costs avoided by demand-side management initiatives.

	Distribution capacity: \$1 per kW-year (Fiscal 2011 \$), based on BC Hydro estimates of the distribution capacity costs avoided by demand-side management initiatives. *Natural gas for the Standard Total Resource Cost Test:* BC Hydro's forecast of wholesale natural gas prices at Sumas. *Natural gas for the Modified Total Resource Cost Test:* 100 per cent of the long-run marginal cost of electricity, converted to GJ.
Generation System Reserve Margin	14 per cent
Reference Date for Allocation of Supporting Initiative Costs	March 31, 2025. Supporting initiative costs in all years are allocated to rate structures and programs based on their proportion of total cumulative electricity savings from these two demand-side management tools on this date.
Rates	The following BC Hydro rates were used to calculate customer bill savings and lost revenues: • Residential Inclining Block; • Small General Service; • Medium General Service; • Large General Service; and • Transmission Service.
Line Losses	Avoided electric energy and generation capacity costs are valued at the Lower Mainland, while avoided transmission and distribution capacity costs are valued in the regions. This requires an adjustment for line losses between customers and these points in the grid using the following values: • Distribution: 4 per cent; • Intra-regional transmission: 3 per cent; and • Inter-regional transmission: region-specific values.

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Appendix Y

Demand-Side Management Annual Report to the British Columbia Utilities Commission

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Fiscal F2017 to Fiscal 2019
Revenue Requirements Application

Appendix Y

Attachment 1

Report on Demand-Side Management Activities for the 12 months ending March 31, 2014

BC hydro
FOR GENERATIONS

Janet Fraser
Chief Regulatory Officer
Phone: 604-623-4046
Fax: 604-623-4407
bchydroregulatorygroup@bchydro.com

August 15, 2014

Ms. Erica Hamilton
Commission Secretary
British Columbia Utilities Commission
Sixth Floor – 900 Howe Street
Vancouver, BC V6Z 2N3

Dear Ms. Hamilton:

**RE: British Columbia Utilities Commission (BCUC or the Commission)
British Columbia Hydro and Power Authority (BC Hydro)
F2005/F2006 Revenue Requirements Application
BCUC Decision: October 29, 2004; Directive 69 (page 201)
(AMENDED pursuant to 2006 Integrate Electricity Plan and
2006 Long-Term Acquisition Plan
BCUC Decision: May 11, 2006; Directive 16 (page 145-146))**

BC Hydro writes to provide its Report on Demand-Side Management Activities for the 12 months ending March 31, 2014.

For further information, please contact Geoff Higgins at 604-623-4121 or by email at bchydroregulatorygroup@bchydro.com.

Yours sincerely,

Original signed

Janet Fraser
Chief Regulatory Officer

sh/rh

Enclosure

Report on Demand-Side Management Activities for Fiscal 2014

August 15, 2014

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1 Introduction

This BC Hydro annual report to the British Columbia Utilities Commission (**BCUC**) on Demand Side Management (**DSM**) activities responds to Directive 69 from the BCUC decision on BC Hydro's F2005/F2006 Revenue Requirements Application (**F05/F06 RRA**), Directive 16 from the BCUC decision on BC Hydro's 2006 Integrated Electricity Plan and Long Term Acquisition Plan (**2006 IEP/LTAP**) and Directives 36 and 38 from the BCUC decision on BC Hydro's 2008 LTAP. The report provides information on DSM expenditures, electricity savings, plan performance and mitigation measures for the 2014 fiscal year (**F2014**), or the twelve months ending March 31, 2014.

Directive 69 directed BC Hydro "to provide information to the BCUC for on-going review of Power Smart performance through:

- Executive Summaries of milestone evaluation reports and full final evaluation reports for each program
- Semi-annual reports on DSM activities which, amongst others, will include:
  - detailed breakdown of OMA expenses related to support activities carried out within the Power Smart group and in other departments that support the Power Smart organization;
  - detailed description of the functions of portfolio level costs and how these costs are allocated to programs;
  - summaries of the overall performance of Power Smart with reference to program objectives; and
  - variances of fiscal year budgeted and actual deferred capital expenditures and explanation of variances."

Directive 16 of the 2006 IEP/LTAP Decision directed BC Hydro "to continue to file reports on DSM performance as described in Directive 69 of the

F05/F06 RRA Decision included in Order No. G-96-04 and to file its Semi Annual Demand Side Management Reports in the same format as the June 2005 Report with the following enhancements:

Provide annual and cumulative totals since program inception;

(i) Express these values on a per unit basis; and

(ii) Provide the benefit to cost ratios for the three DSM tests."

Directive 36 of the 2008 LTAP Decision directed BC Hydro to switch from semi-annual to annual DSM performance reports while Directive 38 of the same Decision directed BC Hydro to include in these reports "metrics for each initiative, achievements in relation to milestones, and description of past or planned mitigation measures where warranted. These mitigation measures should include shifting program resources and alternative supply options for each program. Ongoing DSM performance reporting should demonstrate how BC Hydro is continuously pursuing DSM and that specific programs are cost-effective."

BC Hydro is filing evaluation reports as a separate package. This report addresses the balance of Directives 69 and 16, as well as Directives 36 and 38.

2 Expenditures and Electricity Savings for Fiscal 2014

F2014 was a year in transition for BC Hydro's DSM initiatives, with B.C. Government approval of the 2013 Integrated Resource Plan (**IRP**) providing revised direction for the DSM savings activities over the next few years through a reduction in planned expenditures for F2014-F2016, while still preserving the ability to achieve the long-term targets.[1] BC Hydro's DSM expenditures[2] in F2014 totalled $120.3 million with incremental DSM electricity savings totalling 686 GWh/year. This was $34 million or 22 per cent below the DSM Plan presented in BC Hydro's F2015 to

[1] Refer to Recommendation Number 1 of the approved 2013 IRP, pages 9-8 to 9-9.

[2] Comprising all DSM-related deferred operating and specific capital expenditures. DSM operating expenditures are presented in Table 6 of this report.

F2016 Revenue Requirements Rate Application (**F15-F16 RRRA**) as the F2014 DSM Forecast. Incremental electricity savings were 93 GWh/year or 12 per cent below the DSM Plan. From a cumulative perspective electricity savings are 135 GWh/year or 7 per cent below the DSM Plan.

Table 1 presents planned and actual DSM expenditures and incremental electricity savings in F2014.

Table 1 **Expenditures and Incremental Electricity Savings for F2014**

	Expenditures[1]				Incremental Electricity Savings			
	Plan[2] $ 000	Actual $ 000	Variance $ 000	%	Plan[2] GWh/yr	Actual[3] GWh/yr	Variance GWh/yr	%
Codes and Standards								
Residential	1,798	1,257	(540)	(30%)	123	112	(11)	(9%)
Commercial	772	307	(465)	(60%)	30	27	(3)	(9%)
Industrial	92	64	(28)	(31%)	6	6	(0)	(7%)
Total Codes and Standards	2,661	1,628	(1,033)	(39%)	159	145	(14)	(9%)
Rate Structures								
Residential	720	302	(418)	(58%)	-	14	14	n/a
Commercial & Industrial Distribution	696	409	(287)	(41%)	189	205	16	8%
Industrial Transmission	631	300	(331)	(52%)	39	54	15	37%
Total Rate Structures	2,047	1,011	(1,035)	(51%)	228	272	44	19%
DSM Programs								
Residential Sector								
Behaviour	5,772	4,112	(1,660)	(29%)	31	20	(11)	(36%)
Refrigerator Buy-back	2,463	2,239	(224)	(9%)	9	9	(0)	(0%)
Low Income	2,652	2,185	(467)	(18%)	3	4	0	14%
New Home	2,049	2,706	657	32%	3	4	2	57%
Retail Rebate[4]	4,692	4,063	(630)	(13%)	9	11	2	25%
Renovation Rebate	1,293	1,264	(30)	(2%)	4	1	(3)	(76%)
Load Displacement	-	-	-	-	-	-	-	n/a
Sector Enabling Activities	1,303	1,013	(290)	(22%)	n/a	n/a	n/a	n/a
Residential Sector Total	20,224	17,582	(2,642)	(13%)	59	49	(10)	(17%)
Commercial Sector								
Power Smart Partner[5]	40,191	33,784	(6,407)	(16%)	107	80	(27)	(25%)
New Construction	8,393	7,672	(721)	(9%)	16	17	1	9%
Load Displacement	-	-	-	-	-	-	-	n/a
Sector Enabling Activities	1,238	1,176	(62)	(5%)	n/a	n/a	n/a	n/a
Commercial Sector Total	49,822	42,631	(7,191)	(14%)	123	97	(25)	(21%)
Industrial Sector								
Power Smart Partner - Transmission[6]	36,354	20,437	(15,917)	(44%)	147	81	(65)	(44%)
Power Smart Partner - Distribution	12,397	10,126	(2,271)	(18%)	32	24	(9)	(27%)
Load Displacement	7,089	4,537	(2,551)	(36%)	30	17	(13)	(43%)
Capacity Focused DSM	-	28	28	n/a	-	-		
Sector Enabling Activities	1,228	1,003	(225)	(18%)	n/a	n/a	n/a	n/a
Industrial Sector Total	57,068	36,131	(20,937)	(37%)	209	122	(87)	(42%)
Total Programs	**127,114**	**96,345**	**(30,770)**	**(24%)**	**391**	**269**	**(122)**	**(31%)**
Supporting Initiatives								
Public Awareness and Education	7,336	7,018	(318)	(4%)	-	-	-	-
Community Engagement	4,402	4,137	(264)	(6%)	-	-	-	-
Advanced DSM Strategies[7]	2,712	1,940	(772)	(28%)	-	-	-	-
Information Technology[8]	-	-	-	-	-	-	-	-
Indirect and Portfolio Enabling	8,233	8,200	(33)	(0%)	-	-	-	-
Supporting Initiatives Total	**22,684**	**21,296**	**(1,388)**	**(6%)**	-	-	-	-
TOTAL DSM	**154,506**	**120,279**	**(34,226)**	**(22%)**	**778**	**686**	**(93)**	**(12%)**

Notes:

1 Including all DSM-related deferred operating and specific capital expenditures that are relevant for DSM cost-effectiveness.

[2] Plan figures are from BC Hydro's F15-F16 RRRA, Appendix G. The Plan includes additional DSM-related expenditures of $2.9 million for In-Home Feedback, $0.8 million for Information Technology (**IT**), and $0.3 million project proponent costs in the Lead by Example program. These costs are relevant for DSM cost-effectiveness because full costs are utilized for cost effectiveness calculations but only direct DSM expenditures are shown in the F15-F16 RRRA.

[3] Reported savings from codes and standards, and residential and commercial & industrial distribution rate structures, are based on planned estimates as well as evaluated results.

[4] The Retail Rebate program was created as a result of integrating Appliances, Consumer Electronics and Lighting programs into a single retail offer to align with the DSM Plan in the 2013 IRP.

[5] Power Smart Partner and Product Incentive programs have been combined in order to align with the DSM Plan in the 2013 IRP.

[6] Power Smart Partner Transmission and New Plant Design programs have been combined in order to align with the DSM Plan in the 2013 IRP.

[7] Supporting Initiative name change from Technology Innovation to Advanced DSM Strategies. Effective F2014 Advanced DSM Strategies comprises Technology Innovation and Sustainable Communities expenditures.

[8] In F2014 there were no planned or actual specific capital expenditures for general IT projects.

The following corresponds to the information provided in Table 1 and are explanations for the above variances:

Codes and Standards	
Residential Commercial Industrial	Expenditures were below plan due to higher than planned leveraging of co-funding with government and utility organizations on standard development work at the Canadian Standards Association as well as a reduction in funding needed for BC Hydro building energy code training as a result of encouraging industry stakeholders to take on the responsibility for development and delivery of training sessions. Reported codes and standards electricity savings were below plan primarily due to an increase in the efficiency assumed in the lighting savings baseline.
Rate Structures	
Residential	Expenditures were below plan due to the residential rate design application moving to a later start date. Electricity savings were above plan due to an adjustment in the savings calculation.
Commercial & Industrial Distribution	Expenditures were below plan due to lower implementation costs as a result of reduced call centre costs and need for training. Also, because there was no Medium General Service and Large General Service regulatory proceedings in F2014, the program incurred lower regulatory and rate design costs, including consulting and legal costs than anticipated. Electricity savings were on plan.
Industrial Transmission	Expenditures were below plan to allow for the release of recommendations arising from the Industrial Electricity Policy Review. Electricity savings were above plan due to greater than expected customer self-generation attributed to the rate structure.

DSM Programs	
Residential Sector	
Behaviour	Expenditures and electricity savings were below plan due to delays in a program specific IT project, reductions in call-handling and labour associated with the more efficient launch of the Energy Visualization Portlet (**EVP**) and adjustments to the savings associated with EVP.
Refrigerator Buy-Back	Expenditures and electricity savings were approximately on plan.
Low Income	Expenditures were below plan due to slightly lower participation than planned for the more advanced offer and unanticipated partner funding. Electricity savings were slightly above plan due primarily to higher savings from energy savings kits as a result of changes to customize for apartments vs. detached homes.
New Home	Expenditures and energy savings were above plan because a cost effective extension was found that would continue supporting further enhancements to the BC Building Code and not forgo the lost opportunity of electricity savings in the new construction market.
Retail Rebate	Expenditures were below plan due to integrating Appliances, Lighting and Consumer Electronics programs into a single retail offer that allowed for additional cost efficiencies. Electricity savings were above plan due primarily to stronger than anticipated sales of LED bulbs, with increased incentive payments being largely offset by reduced advertising expenditures.
Renovation Rebate	Expenditures and electricity savings were below plan due to the program being in a transition year with reduced partner funding, resulting in lower customer incentives and greatly reduced participation.
Load Displacement	No expenditures or electricity savings were planned.
Sector Enabling Activities	Expenditures were below plan primarily due to lower than expected volume in the Home Loan pilot program.
Commercial Sector	
Power Smart Partner	Expenditures and electricity savings were below plan primarily due to lower participation resulting from adjustments made to the offer to manage incentive expenditures.
New Construction	Expenditures were below plan due to some projects not completing as planned and delays in some activities. Electricity savings were above plan due to a higher mix of lower cost projects completing sooner than planned.
Load Displacement	No expenditures or electricity savings were planned.
Sector Enabling Activities	Expenditures were approximately on plan.
Industrial Sector	
Power Smart Partner – Transmission	Expenditures and electricity savings were below plan due to projects being delayed until F2015 and F2016 and one project shifting from incented to customer funded.
Power Smart Partner – Distribution	Expenditures and electricity savings were below plan due to the delay of several projects until F2015 as well as lower than planned participation in lighting, compressed air and refrigeration projects.

Load Displacement	Expenditures and electricity savings were below plan due to one project being delayed until F2015.
Sector Enabling Activities	Expenditures were below plan due to the cancellation or delay of selected enabling activities.
Total Programs	Expenditures and electricity savings were below plan largely because of lower than planned costs in the Industrial Power Smart Partner – Transmission program due to project delays and adjustments made to the offer to manage participation and incentive levels in the Commercial Power Smart Partner program.
Supporting Initiatives	
Public Awareness & Education	Expenditures were approximately on plan.
Community Engagement	Expenditures were approximately on plan.
Advanced DSM Strategies	Expenditures were below plan primarily due to implementing changes to align with the DSM Plan in the 2013 IRP.
Information Technology	No expenditures were planned.
Indirect and Portfolio Enabling Activities	Expenditures were approximately on plan.
Total DSM	Expenditures were 22 per cent and electricity savings 12 per cent below plan primarily due to project delays in the Industrial Power Smart Partner – Transmission program and adjustments made to the offer to manage participation and incentive levels in the Commercial Power Smart Partner program.

3 Expenditures to Date

BC Hydro's DSM expenditures from F2013 through F2014 totalled $270.4 million.

Table 2 presents DSM expenditures from April 1, 2012 to March 31, 2014.[3]

[3] Comprising all DSM deferred operating and specific capital expenditures that are relevant for DSM cost-effectiveness.

Table 2 Expenditures since F2013

	F2013 ($ 000)	F2014 ($ 000)	Total ($ 000)
Codes and Standards			
Residential	1,323	1,257	2,581
Commercial	245	307	551
Industrial	47	64	110
Total Codes and Standards	**1,615**	**1,628**	**3,242**
Rate Structures			
Residential	330	302	632
Commercial & Industrial Distribution	557	409	966
Industrial Transmission	407	300	707
Total Rate Structures	**1,294**	**1,011**	**2,305**
DSM Programs			
Residential Sector			
Behaviour	4,419	4,112	8,532
Refrigerator Buy-back	3,754	2,239	5,994
Low Income	3,040	2,185	5,225
New Home	2,321	2,706	5,027
Retail Rebate[1]	9,141	4,063	13,204
Renovation Rebate	3,636	1,264	4,900
Load Displacement	-	-	-
Sector Enabling Activities	1,220	1,013	2,233
Residential Sector Total	27,532	17,582	45,115
Commercial Sector			
Power Smart Partner[2]	42,472	33,784	76,256
New Construction	8,680	7,672	16,352
Load Displacement	-	-	-
Sector Enabling Activities	1,100	1,176	2,276
Commercial Sector Total	52,252	42,631	94,883
Industrial Sector			
Power Smart Partner - Transmission[3]	18,146	20,437	38,584
Power Smart Partner - Distribution	12,397	10,126	22,523
Load Displacement	10,009	4,537	14,546
Capacity Focused DSM	-	28	28
Sector Enabling Activities	1,015	1,003	2,018
Industrial Sector Total	41,567	36,131	77,699
Total Programs	**121,352**	**96,345**	**217,696**
Supporting Initiatives			
Public Awareness and Education	7,235	7,018	14,254
Community Engagement	7,232	4,137	11,369
Advanced DSM Strategies[4]	1,863	1,940	3,803
Information Technology	145	-	145
Indirect and Portfolio Enabling	9,386	8,200	17,586
Supporting Initiatives Total	**25,861**	**21,296**	**47,157**
Total DSM	**150,121**	**120,279**	**270,400**

Notes:

1 The Retail Rebate program was created as a result of integrating Appliances, Consumer Electronics and Lighting programs into a single retail offer to align with the DSM Plan in the 2013 IRP.

2 Power Smart Partner and Product Incentive programs have been combined in order to align with the DSM Plan in the 2013 IRP.

3 Power Smart Partner Transmission and New Plant Design programs have been combined in order to align with the DSM Plan in the 2013 IRP.

4 Supporting Initiative name change from Technology Innovation to Advanced DSM Strategies. Effective F2014 Advanced DSM Strategies comprises Technology Innovation and Sustainable Communities expenditures.

4 Plan Performance

The 2013 IRP provided the revised baseline for DSM savings activities beginning in F2013. BC Hydro's DSM electricity savings since F2013 totalled 1,898 GWh/year at March 31, 2014, which equates to 93 per cent of the planned savings of 2,033 GWh/yr in the F15-F16 RRRA. Table 3 presents actual cumulative savings as a percentage of plan in F2013 to F2014.

Table 3 Cumulative Electricity Savings since April 1, 2012

Actual as a Percentage of Plan[1]	
	F2014
Codes and Standards	
Residential	93%
Commercial	76%
Industrial	84%
Total Codes and Standards	**89%**
Rate Structures	
Residential	111%
Commercial & Industrial Distribution	103%
Industrial Transmission	112%
Total Rate Structures	**105%**
DSM Programs	
Residential Sector	
Behaviour	70%
Refrigerator Buy-back	101%
Low Income	106%
New Home	122%
Retail Rebate[2]	104%
Renovation Rebate	76%
Load Displacement	n/a
Residential Sector Total	91%
Commercial Sector	
Power Smart Partner[3]	107%
New Construction	103%
Load Displacement	n/a
Commercial Sector Total	107%
Industrial Sector	
Power Smart Partner - Transmission[4]	68%
Power Smart Partner - Distribution	92%
Load Displacement	61%
Industrial Sector Total	70%
Total Programs	**85%**
Total DSM	**93%**

Notes:

[1] Reported savings for codes and standards and rates structures are based on planned estimates as well as evaluated results.

[2] The Retail Rebate program was created as a result of integrating Appliances, Consumer Electronics and Lighting programs into a single retail offer to align with the DSM Plan in the 2013 IRP.

[3] Power Smart Partner and Product Incentive programs have been combined in order to align with the DSM Plan in the 2013 IRP.

[4] Power Smart Partner Transmission and New Plant Design programs have been combined in order to align with the DSM Plan in the 2013 IRP.

The DSM electricity savings presented in Table 3 have been achieved at an average net levelized utility cost of -$2 per MWh. Table 4 presents the net levelized utility cost of actual DSM electricity savings achieved from April 1, 2013 through March 31, 2014. See footnote 1 to Table 4 for a definition of "net levelized utility cost".

Table 4 Utility Cost of Electricity Savings: F2013 to F2014

	Net Levelized Utility Cost ($/MWh)[1]
Codes and Standards	
Residential	-20
Commercial	-18
Industrial	-8
Total Codes and Standards	**-19**
Rate Structures	
Residential	-14
Commercial & Industrial Distribution	-8
Industrial Transmission	-5
Total Rate Structures	**-9**
Programs	
Residential Sector	
Behaviour	22
Refrigerator Buy-back	37
Low Income	66
New Home	30
Retail Rebate[2]	16
Renovation Rebate	12
Load Displacement	n/a
Sector Enabling Activities	n/a
Residential Sector Total	26
Commercial Sector	
Power Smart Partner[3]	27
New Construction	36
Load Displacement	n/a
Sector Enabling Activities	n/a
Commercial Sector Total	29
Industrial Sector	
Power Smart Partner - Transmission[4]	27
Power Smart Partner - Distribution	28
Load Displacement	12
Capacity Focused DSM	n/a
Sector Enabling Activities	n/a
Industrial Sector Total	23
Total Programs	**26**
Rate Structures and Programs	**4**
Total DSM	**-2**

Notes:

[1] Net levelized utility cost is calculated by subtracting capacity benefits from gross utility costs and then dividing the resulting net utility costs by electricity savings. A negative net levelized utility cost means that the subtracted capacity benefits exceed gross utility costs.

[2] The Retail Rebate program was created as a result of integrating Appliances, Consumer Electronics and Lighting programs into a single retail offer to align with the DSM Plan in the 2013 IRP.

[3] Power Smart Partner and Product Incentive programs have been combined in order to align with the DSM Plan in the 2013 IRP.

[4] Power Smart Partner Transmission and New Plant Design programs have been combined in order to align with the DSM Plan in the 2013 IRP.

Table 5 presents Total Resource Cost Test benefit cost-ratios of actual DSM electricity savings achieved from April 1, 2013 through March 31, 2014. Table 5 shows the Total Resource Cost Test benefit-cost ratios for the Total Resource Cost test and the Total Resource Cost test as modified by the Demand Side Management Regulation, B.C. Reg. 326/2008 as amended by B.C Reg. 228/2011.

Table 5 Benefit Cost Ratios of Electricity Savings: F2013 to F2014

	Benefit Cost Ratios			
	Utility Test	Total Resource Cost Test	Total Resource Cost Test as modified by DSM Regulation[1]	Ratepayer Impact Measure Test[2]
Codes and Standards				
Residential	273.0	7.7	9.4	1.5
Commercial	258.5	4.6	5.3	1.7
Industrial	210.8	63.1	75.1	2.2
Total Codes and Standards	**268.5**	**7.1**	**8.7**	**1.6**
Rate Structures				
Residential	52.7	52.7	61.6	1.3
Commercial & Industrial Distribution	56.5	56.5	66.9	1.2
Industrial Transmission	27.5	2.9	4.7	0.9
Total Rate Structures	**55.4**	**45.3**	**53.8**	**1.2**
Programs				
Residential Sector				
Behaviour	2.9	3.8	4.7	0.9
Refrigerator Buy-back	2.5	3.3	3.8	0.8
Low Income[3]	1.4	1.6	1.6	0.7
New Home	2.5	1.6	1.8	1.0
Retail Rebate[4]	3.6	3.2	3.7	1.1
Renovation Rebate	4.2	1.5	1.6	1.1
Load Displacement	n/a	n/a	n/a	n/a
Sector Enabling Activities	n/a	n/a	n/a	n/a
Residential Sector Total	2.9	2.4	2.7	0.9
Commercial Sector				
Power Smart Partner[5]	3.4	2.7	3.2	1.1
New Construction	2.5	1.5	1.7	0.9
Load Displacement	n/a	n/a	n/a	n/a
Sector Enabling Activities	n/a	n/a	n/a	n/a
Commercial Sector Total	3.2	2.4	2.8	1.0
Industrial Sector				
Power Smart Partner - Transmission[6]	3.2	2.1	2.5	1.1
Power Smart Partner - Distribution	3.2	1.8	2.2	1.0
Load Displacement	6.4	4.8	5.7	1.8
Capacity Focused DSM	n/a	n/a	n/a	n/a
Sector Enabling Activities	n/a	n/a	n/a	n/a
Industrial Sector Total	3.7	2.4	2.9	1.2
Total Programs	**3.3**	**2.4**	**2.9**	**1.1**
Rate Structures and Programs	**8.5**	**6.1**	**7.3**	**1.2**
Total DSM	**11.5**	**6.4**	**7.6**	**1.2**

Notes:

1 In keeping with the DSM Regulation, the avoided cost of natural gas is valued at 50 per cent of BC Hydro's long run marginal cost of acquiring electricity generated from clean or renewable resources in B.C. and non-energy benefits are valued at 15 per cent of electricity and natural gas benefits.

2 While subsection 4(6) of the DSM Regulation precludes the use of the Ratepayer Impact Measure Test in determining cost-effectiveness of a demand-side measure, this benefit cost ratio is included in the table consistent with Directive 42 from the BCUC decision on BC Hydro's 2008 LTAP.

3 The Total Resource Cost Test benefit-cost ratio for the Low Income program includes a 30 per cent adder to program benefits, rather than a 15 per cent value for non-energy benefits, in keeping with the DSM Regulation.

4 The Retail Rebate program was created as a result of integrating Appliances, Consumer Electronics and Lighting programs into a single retail offer to align with the DSM Plan in the 2013 IRP.

5 Power Smart Partner and Product Incentive programs have been combined in order to align with the DSM Plan in the 2013 IRP.

6 Power Smart Partner Transmission and New Plant Design programs have been combined to align with the DSM Plan in the 2013 IRP.

5 Mitigation Measures

Table 3 indicates that most DSM initiatives are on or above plan in terms of cumulative electricity savings in F2014 while Table 5 indicates that the portfolio has delivered electricity savings at a substantially lower cost than new electricity supply. Based on the experience gathered over the past few years through initiative tracking, the following are mitigation measures that have been undertaken or are planned for the future.

Codes and Standards	
Residential	Cumulative electricity savings in F2014 were below plan. BC Hydro will manage risk by tracking Codes & Standards progress against a number of milestones or indicators to anticipate savings shortfalls or identify trends that may trigger the need for saving adjustments to the DSM Plan.
Commercial	
Industrial	
Rate Structures	
Residential	Cumulative electricity savings in F2014 were approximately on plan.
Commercial & Industrial Distribution	
Industrial Transmission	
DSM Programs	
Residential Sector	
Behaviour	Cumulative electricity savings in F2014 were below plan. Once the program-specific IT project is completed in F2015, program promotion will be re-instituted to drive higher program participation.
Refrigerator Buy-Back	Cumulative electricity savings in F2014 were approximately on plan.
Low Income	Cumulative electricity savings in F2014 were approximately on plan.

New Home	Cumulative electricity savings in F2014 were above plan. No mitigation measures are warranted.
Retail Rebate	Cumulative electricity savings in F2014 were approximately on plan.
Renovation Rebate	Cumulative electricity savings in F2014 were below plan. Following program re-launch in F2015 BC Hydro and Fortis BC will increase promotional efforts and work closely with BC's home renovation industry to increase program participation.
Load Displacement	No electricity savings were planned in F2014.
Commercial Sector	
Power Smart Partner	Cumulative electricity savings in F2014 were approximately on plan. Electricity savings have increased slightly relative to plan in response to program improvements and strong trade ally support.
New Construction	Cumulative electricity savings in F2014 were approximately on plan.
Load Displacement	No electricity savings were planned in F2014.
Industrial Sector	
Power Smart Partner – Transmission	Cumulative energy savings were below plan in F2014 due to project delays. No short-term mitigation measures are being contemplated as the program is expected to recover the energy savings over the mid-term period.
Power Smart Partner – Distribution	Cumulative electricity savings were approximately on plan in F2014. No mitigation measures are warranted as planned cumulative electricity savings are expected to be achieved.
Load Displacement	Cumulative energy savings were below plan in F2014 due to the delay of one project. No mitigation measures are warranted as planned cumulative electricity savings are expected to be achieved. Delays in load displacement projects are possible due to the long lead times for equipment delivery, installation and commissioning.

6 Operating Expenditures for Fiscal 2014

BC Hydro's DSM operating expenditures in F2014 totalled $531,970.[4] Table 6 presents DSM operating expenditures in F2014.

Table 6 Operating Expenditures for Fiscal 2014

	($000)
Labour	403
Consultants/Contractors/Temp Labour	14
ABS Services	23
Other	92
Total	**532**

4 DSM operating expenditures are not included in earlier tables.

7 Allocation of Supporting Initiative Costs to Programs[5]

This section describes how supporting initiative costs are allocated to programs for the purpose of cost test calculations.

In keeping with Directive 61 from the BCUC decision on the F05/F06 RRA, when calculating levelized costs and benefit-cost ratios for this report, supporting initiative costs are allocated to DSM programs and rate structures based on their share of DSM electricity savings in F2018. For example, rate structures and programs are forecast to save roughly 4,508 GWh/year in F2018, so a program that is forecast to save 45 GWh/year in F2018 represents one per cent of the total. In turn, one per cent of supporting initiative costs would be allocated to that program in each year when calculating the program's levelized cost or benefit-cost ratio.

[5] A description of supporting initiatives is available in the F12-F14 RRA (Appendix II, Attachment 4).

Fiscal F2017 to Fiscal 2019
Revenue Requirements Application

Appendix Y

Attachment 2

Report on Demand-Side Management Activities for the 12 months ending March 31, 2015

Tom A. Loski
Chief Regulatory Officer
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Fax: 604-623-4407
bchydroregulatorygroup@bchydro.com

July 15, 2015

Ms. Erica Hamilton
Commission Secretary
British Columbia Utilities Commission
Sixth Floor – 900 Howe Street
Vancouver, BC V6Z 2N3

Dear Ms. Hamilton:

RE: British Columbia Utilities Commission (BCUC or Commission)
British Columbia Hydro and Power Authority (BC Hydro)
F2005/F2006 Revenue Requirements Application
Commission Decision: October 29, 2004; Directive 69 (page 201)
(AMENDED pursuant to 2006 Integrate Electricity Plan and
2006 Long-Term Acquisition Plan
Commission Decision: May 11, 2006; Directive 16 (pages

BC Hydro writes to provide its Report on Demand-Side Management Activities for the 12 months ending March 31, 2015.

For further information, please contact Geoff Higgins at 604-623-4121 or by email at bchydroregulatorygroup@bchydro.com.

Yours sincerely,

Original signed

Tom Loski
Chief Regulatory Officer

sh/ma

Enclosure (1)

Report on Demand-Side Management Activities for Fiscal 2015

July 15, 2015

BC hydro powersmart

Table of Contents

List of Tables

1 Introduction

This BC Hydro annual report to the British Columbia Utilities Commission (**BCUC or Commission**) on Demand Side Management (**DSM**) activities responds to Directive 69 from the Commission decision on BC Hydro's F2005/F2006 Revenue Requirements Application (**F05/F06 RRA**), Directive 16 from the Commission decision on BC Hydro's 2006 Integrated Electricity Plan and Long Term Acquisition Plan (**2006 IEP/LTAP**) and Directives 36 and 38 from the Commission decision on BC Hydro's 2008 LTAP. The report provides information on DSM expenditures, electricity savings, plan performance and mitigation measures for the 2015 fiscal year (**F2015**), for the 12 months ending March 31, 2015.

Directive 69 of the F05/F06 RRA Decision directed BC Hydro "to provide information to the Commission for on-going review of Power Smart performance through:

- Executive Summaries of milestone evaluation reports and full final evaluation reports for each program;
- Semi-annual reports on DSM activities which, amongst others, will include:
  - detailed breakdown of OMA expenses related to support activities carried out within the Power Smart group and in other departments that support the Power Smart organization;
  - detailed description of the functions of portfolio level costs and how these costs are allocated to programs;
  - summaries of the overall performance of Power Smart with reference to program objectives; and
  - variances of fiscal year budgeted and actual deferred capital expenditures and explanation of variances."

Directive 16 of the 2006 IEP/LTAP Decision directed BC Hydro “to continue to file reports on DSM performance as described in Directive 69 of the F05/F06 RRA Decision and to file its Semi Annual Demand Side Management Reports in the same format as the June 2005 Report with the following enhancements:

Provide annual and cumulative totals since program inception;

(i) Express these values on a per unit basis; and

(ii) Provide the benefit to cost ratios for the three DSM tests.”

Directive 36 of the 2006 IEP/LTAP Decision directed BC Hydro to switch from semi-annual to annual DSM performance reports while Directive 38 directed BC Hydro to include in these reports “metrics for each initiative, achievements in relation to milestones, and description of past or planned mitigation measures where warranted. These mitigation measures should include shifting program resources and alternative supply options for each program. Ongoing DSM performance reporting should demonstrate how BC Hydro is continuously pursuing DSM and that specific programs are cost-effective.”

BC Hydro files its evaluation reports pursuant to Directive 69 of the F05/F06 RRA Decision separately. This report addresses the balance of Directives 69 and 16, as well as Directives 36 and 38 of the 2006 IEP/LTAP Decision.

2 Expenditures and Electricity Savings for F2015

BC Hydro's DSM expenditures[1] in F2015 totalled $124.8 million while incremental DSM electricity savings totalled 444 GWh/year. This was $26 million or 17 per cent below the DSM Plan presented in BC Hydro's F2015 to F2016 Revenue Requirements Rate Application (**F15-F16 RRRA**) as the F2015 DSM Forecast. Overall, incremental electricity savings as shown in Table 1, were 133 GWh/year or 23 per cent below the DSM Plan and cumulative electricity savings were 783 GWh/year or 30 per cent below the DSM Plan. The primary cause of these electricity savings variances is less than planned electricity savings from rate structures. Incremental electricity savings from DSM Programs were 3 GWh/year or 1 per cent above the DSM Plan and cumulative electricity savings were 109 GWh/year or 9 per cent below the DSM Plan.

Table 1 presents planned and actual DSM expenditures and incremental electricity savings in F2015.

[1] Comprising all DSM-related deferred operating and specific capital expenditures. DSM operating expenditures are presented in Table 6 of this report.

BC hydro powersmart

Table 1 Expenditures and Incremental Electricity Savings for F2015

	Expenditures[1]				Incremental Electricity Savings			
	Plan[2]	Actual	Variance		Plan[2]	Actual[3]	Variance	
	$ 000	$ 000	$ 000	%	GWh/yr	GWh/yr	GWh/yr	%
Codes and Standards								
Residential	2,809	2,296	(513)	(18%)	115	108	(7)	(6%)
Commercial	1,047	660	(387)	(37%)	30	31	1	2%
Industrial	142	115	(27)	(19%)	6	5	(0)	(2%)
Total Codes and Standards	3,998	3,071	(927)	(23%)	151	144	(6)	(4%)
Rate Structures								
Residential	641	314	(327)	(51%)	109	67	(42)	(38%)
Commercial & Industrial Distribution	692	521	(171)	(25%)	(19) [4]	(77)	(59)	318%
Industrial Transmission	644	400	(244)	(38%)	28	(1)	(29)	(102%)
Total Rate Structures	1,977	1,236	(741)	(37%)	119	(11)	(130)	(109%)
DSM Programs								
Residential Sector								
Behaviour	3,613	2,770	(843)	(23%)	36	21	(15)	(41%)
Refrigerator Buy-back	1,239	934	(305)	(25%)	9	3	(6)	(70%)
Low Income	2,478	1,925	(553)	(22%)	3	3	0	15%
New Home	2,200	2,716	516	23%	3	4	2	56%
Retail Rebate	4,023	4,011	(12)	(0%)	8	13	5	63%
Renovation Rebate	2,940	972	(1,968)	(67%)	5	3	(3)	(52%)
Load Displacement	-	-	-	n/a	-	-	-	n/a
Sector Enabling Activities	1,240	874	(366)	(30%)	n/a	n/a	n/a	n/a
Residential Sector Total	17,734	14,202	(3,532)	(20%)	64	47	(17)	(27%)
Commercial Sector								
Power Smart Partner	29,576	26,394	(3,182)	(11%)	72	61	(11)	(15%)
New Construction	8,764	9,011	247	3%	18	21	3	18%
Load Displacement	-	-	-	-	-	-	-	n/a
Sector Enabling Activities	1,127	1,245	118	11%	n/a	n/a	n/a	n/a
Commercial Sector Total	39,467	36,650	(2,817)	(7%)	91	83	(8)	(9%)
Industrial Sector								
Power Smart Partner - Transmission	29,577	28,296	(1,282)	(4%)	58	126	68	118%
Thermo-Mechanical Pulp	-	134	134	-	-	-	-	-
Power Smart Partner - Distribution	12,152	13,505	1,353	11%	28	35	7	24%
Load Displacement	21,321	2,919	(18,402)	(86%)	68	20	(47)	(70%)
Sector Enabling Activities	1,233	853	(380)	(31%)	n/a	n/a	n/a	n/a
Industrial Sector Total	64,283	45,708	(18,575)	(29%)	153	181	28	18%
Capacity Focused DSM	2,430	4,742	2,311	95%	-	-	-	-
Total Programs	**123,914**	**101,302**	**(22,612)**	**(18%)**	**308**	**311**	**3**	**1%**
Supporting Initiatives								
Public Awareness and Education	6,050	5,974	(77)	(1%)	-	-	-	-
Community Engagement	3,958	3,715	(243)	(6%)	-	-	-	-
Advanced DSM Strategies	1,871	984	(886)	(47%)	-	-	-	-
Information Technology	225	-	(225)	(100%)	-	-	-	-
Indirect and Portfolio Enabling	8,731	8,470	(261)	(3%)	-	-	-	-
Supporting Initiatives Total	**20,834**	**19,142**	**(1,692)**	**(8%)**	-	-	-	-
TOTAL DSM	**150,723**	**124,750**	**(25,973)**	**(17%)**	**578**	**444**	**(133)**	**(23%)**

Notes:

1 Including all DSM-related deferred operating and specific capital expenditures that are relevant for DSM cost-effectiveness.

2 Plan figures are from BC Hydro's F15-F16 RRRA, Appendix G. The Plan includes additional DSM-related expenditures of $0.2 million for Information Technology (**IT**). These costs are relevant for DSM cost-effectiveness because full costs are utilized for cost-effectiveness calculations but only direct DSM expenditures are shown in the F15-F16 RRRA.

3 Reported savings from codes and standards and residential, commercial & industrial distribution rate structures are based on planned estimates as well as evaluated results.

4 The approach to applying rate increases for F2015 onto the two-part rate structure of the MGS and LGS rates results in a lessening of the conservation price signal. As a result, the incremental plan savings are negative.

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The following corresponds to the information provided in Table 1 and are explanations for the above variances:

Codes and Standards	
Residential Commercial Industrial	Expenditures were below plan because BC Hydro was able to leverage the involvement of other industry stakeholders/organizations to take on the responsibility of training for the recent BC building code energy efficiency updates as well as the deferral of market/technical studies to support development of Amendment 6 to the BC Energy Efficiency Standards Regulation. Energy savings were below plan due to a shift in timing of the anticipated effective date of the proposed product regulations in Amendment 13 to Canada's Energy Efficiency Regulations by NRCan.
Rate Structures	
Residential	Expenditures were below plan due to reduced use of consultants for work related to the residential rate design for the 2015 Rate Design Application. Electricity savings were below plan due to an adjustment in the savings calculation due to the incorporation of the 2013 RIB Evaluation outcomes into the forecast model.
Commercial & Industrial Distribution	Expenditures were below plan due to reduced use of consultants for work related to the commercial and industrial distribution rate design for the 2015 Rate Design Application. Electricty savings were below plan due to the incorporation of the F2014 LGS/MGS evaluation results. As a result, no further conservation is forecast from the commercial and industrial distribution conservation rates.
Industrial Transmission	Expenditures were below plan due to delays in IT work, as well as less than expected engagement costs for the Transmission Rate part of the Rate Design Application. Electricity savings were lower than forecast due to a drop in non-contracted customer self-generation.
DSM Programs	
Residential Sector	
Behaviour	Expenditures were below plan due to reduced advertising expenditures,as well as lower incentive costs resulting from fewer successful challenge completions. Electricity savings were below plan in accordance with a new more conservative definition for engaged users through the Energy Visualization Portlet while the estimated savings per engaged user remained the same.
Refrigerator Buy-Back	Expenditures and electricity savings were below plan due to lower than planned participation as a result of a change in the program offer to be seasonal rather than year-round in order to reduce expenditures. Operational efficiencies were also gained from a new online registration process and bill credit option for customer rebates.

Low Income	Expenditures were below plan due to lower than forecast participation in the Energy Conservation Assistance Program (**ECAP**) portion of the program as a result of lower contractor lead generation occurring during the rebidding for contractors. Electricity savings were above plan due to higher than planned volumes of energy savings kits due to an increase in identified participants as a result of our partnerships with FortisBC and the Ministry of Social Development.
New Home	Expenditures and electricity savings were higher than plan due to higher than forecast program participation, particularly amongst detached homes.
Retail Rebate	Expenditures were on plan. Electricity savings were above plan due to higher than planned participation in the lower cost LED portion of the program particularly in the number of multi-pack bulb sales that was as a result of successful spring and fall campaigns.
Renovation Rebate	Expenditures and electricity savings were below plan due to a delayed launch following the transition from the provincial LiveSmart program to the new utility led model.
Sector Enabling Activities	Expenditures were below plan due to the suspension of the Home Loan pilot in order to pursue a different option that involved a third party as the financier instead of BC Hydro.
Commercial Sector	
Power Smart Partner	Expenditures and electricity savings were below plan due to projects not completing as planned and being deferred to the next fiscal.
New Construction	Expenditures were approximately on plan. Energy savings were above plan due to higher participation for lower cost projects.
Sector Enabling Activities	Expenditures were slightly above plan due to advancing industry engagement and communication activities related to Power Smart Alliance and a targeted information package to small and medium business customers.
Industrial Sector	
Power Smart Partner – Transmission	Expenditures were approximately on plan. Electricity savings were above plan due to more customer-funded DSM projects completing than expected.
Thermo-Mechanical Pulp	No expenditures and electricity savings were planned. The Thermo-Mechanical Pulp initiative was introduced after the DSM plan was completed. Projects are expected to complete in the future.
Power Smart Partner – Distribution	Expenditure and electricity savings are above plan due to an increase in participation in the self-serve incentive component of the program.
Load Displacement	Expenditure and electricity savings are below plan due to a large customer project being delayed until F2016.
Sector Enabling Activities	Expenditures are below plan due to less contract services required than planned.

Capacity Focused DSM	Expenditures are above plan due to a project that was accelerated in F2015 as a proof of concept project to inform future activities.
Total Programs	Expenditures were below plan largely because of lower than planned costs in the Industrial Load Displacement program due to a large customer project being delayed until F2016. Electricity savings were approximately on plan.
Supporting Initiatives	
Public Awareness & Education	Expenditures were approximately on plan.
Community Engagement	Expenditures were approximately on plan.
Advanced DSM Strategies	Expenditures were below plan due to the merging and integration of Communities activities with Technology Innovation and Policies activities. In addition, take-up of policy implementation funding by local governments was lower than planned.
Information Technology	Expenditures were below plan due to a delay in an IT project.
Indirect and Portfolio Enabling Activities	Expenditures were approximately on plan.
Total DSM	Expenditures were 17 per cent below plan primarily due to an Industrial Load Displacement large customer project being delayed until F2016. Electricity savings were 23 per cent below plan due to the incorporation of evaluation results for Residential and Commercial and Industrial Distribution Rate Structures.

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3 Expenditures to Date

BC Hydro's DSM expenditures from F2013 through F2015 totalled $395.2 million. Table 2 presents DSM expenditures from April 1, 2013 to March 31, 2015.[2]

Table 2 Expenditures since F2013

	F2013 ($ 000)	F2014 ($ 000)	F2015 ($ 000)	Total ($ 000)
Codes and Standards				
Residential	1,323	1,257	2,296	4,877
Commercial	245	307	660	1,211
Industrial	47	64	115	225
Total Codes and Standards	**1,615**	**1,628**	**3,071**	**6,313**
Rate Structures				
Residential	330	302	314	946
Commercial & Industrial Distribution	557	409	521	1,487
Industrial Transmission	407	300	400	1,107
Total Rate Structures	**1,294**	**1,011**	**1,236**	**3,540**
DSM Programs				
Residential Sector				
Behaviour	4,419	4,112	2,770	11,302
Refrigerator Buy-back	3,754	2,239	934	6,928
Low Income	3,040	2,185	1,925	7,150
New Home	2,321	2,706	2,716	7,743
Retail Rebate	9,141	4,063	4,011	17,215
Renovation Rebate	3,636	1,264	972	5,872
Load Displacement	-	-	-	-
Sector Enabling Activities	1,220	1,013	874	3,108
Residential Sector Total	27,532	17,582	14,202	59,317
Commercial Sector				
Power Smart Partner	42,472	33,784	26,394	102,649
New Construction	8,680	7,672	9,011	25,363
Load Displacement	-	-	-	-
Sector Enabling Activities	1,100	1,176	1,245	3,521
Commercial Sector Total	52,252	42,631	36,650	131,533
Industrial Sector				
Power Smart Partner - Transmission	18,146	20,437	28,296	66,879
Thermo-Mechanical Pulp	-	-	134	134
Power Smart Partner - Distribution	12,397	10,126	13,505	36,028
Load Displacement	10,009	4,537	2,919	17,465
Sector Enabling Activities	1,015	1,003	853	2,871
Industrial Sector Total	41,567	36,103	45,708	123,378
Capacity Focused DSM	-	28	4,742	4,770
Total Programs	**121,352**	**96,345**	**101,302**	**318,998**
Supporting Initiatives				
Public Awareness and Education	7,235	7,018	5,974	20,227
Community Engagement	7,232	4,137	3,715	15,084
Advanced DSM Strategies	1,863	1,940	984	4,788
Information Technology	145	-	-	145
Indirect and Portfolio Enabling	9,386	8,200	8,470	26,056
Supporting Initiatives Total	**25,861**	**21,296**	**19,142**	**47,157**
Total DSM	**150,121**	**120,279**	**124,750**	**395,151**

2 Comprising all DSM deferred operating and specific capital expenditures that are relevant for DSM cost-effectiveness.

BC Hydro's DSM electricity savings since F2013 totalled 1,828 GWh/year at March 31, 2015, which equates to 70 per cent of the planned savings of 2,611 GWh/year in the F15-F16 RRRA. Table 3 presents actual cumulative savings as a percentage of plan in F2013 to F2015.

Table 3 Cumulative Electricity Savings since April 1, 2013

Actual as a Percentage of Plan[1]	
	F2015
Codes and Standards	
Residential	94%
Commercial	83%
Industrial	88%
Total Codes and Standards	**91%**
Rate Structures	
Residential	73%
Commercial & Industrial Distribution	0%
Industrial Transmission	91%
Total Rate Structures	**30%**
DSM Programs	
Residential Sector	
Behaviour	64%
Refrigerator Buy-back	79%
Low Income	109%
New Home	133%
Retail Rebate	114%
Renovation Rebate	68%
Load Displacement	n/a
Residential Sector Total	84%
Commercial Sector	
Power Smart Partner	91%
New Construction	117%
Load Displacement	n/a
Commercial Sector Total	94%
Industrial Sector	
Power Smart Partner - Transmission	112%
Thermo-Mechanical Pulp	n/a
Power Smart Partner - Distribution	104%
Load Displacement	51%
Industrial Sector Total	90%
Capacity Focused DSM	n/a
Total Programs	**91%**
Total DSM	**70%**

Notes:
1 Reported savings for codes and standards and rates structures are based on planned estimates as well as evaluated results.

The cumulative DSM electricity savings since F2013 have been achieved at an average net levelized utility cost of $5 per MWh. Table 4 presents the net levelized utility cost of actual DSM electricity savings achieved from April 1, 2013 through March 31, 2015. Refer to footnote 1 to Table 4 for a definition of “net levelized utility cost”.

Table 4 Utility Cost of Electricity Savings: F2013 to F2015

	Net Levelized Utility Cost ($/MWh)[1]
Codes and Standards	
Residential	-19
Commercial	-9
Industrial	-8
Total Codes and Standards	**-17**
Rate Structures	
Residential	-12
Commercial & Industrial Distribution	-2
Industrial Transmission	-4
Total Rate Structures	**-10**
Programs	
Residential Sector	
Behaviour	15
Refrigerator Buy-back	44
Low Income	65
New Home	32
Retail Rebate	14
Renovation Rebate	14
Load Displacement	n/a
Sector Enabling Activities	n/a
Residential Sector Total	23
Commercial Sector	
Power Smart Partner	37
New Construction	33
Load Displacement	n/a
Sector Enabling Activities	n/a
Commercial Sector Total	37
Industrial Sector	
Power Smart Partner - Transmission	22
Thermo-Mechanical Pulp	n/a
Power Smart Partner - Distribution	31
Load Displacement	19
Sector Enabling Activities	n/a
Industrial Sector Total	24
Capacity Focused DSM	n/a
Total Programs	**28**
Total DSM	**5**

Notes:
1 Net levelized utility cost is calculated by subtracting capacity benefits from gross utility costs and then dividing the resulting net utility costs by electricity savings. A negative net levelized utility cost means that the subtracted capacity benefits exceed gross utility costs.

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Table 5 presents Total Resource Cost Test benefit-cost ratios of actual DSM electricity savings achieved from April 1, 2013 through March 31, 2015. Table 5 shows the Total Resource Cost Test benefit-cost ratios for the Total Resource Cost test and the Total Resource Cost test as modified by the Demand Side Measures Regulation.

Table 5 Benefit Cost Ratios of Electricity Savings: F2013 to F2015

	Benefit Cost Ratios			
	Utility Test	Total Resource Cost Test	Total Resource Cost Test as modified by DSM Regulation[1]	Ratepayer Impact Measure Test[2]
Codes and Standards				
Residential	189.4	6.5	8.1	1.5
Commercial	152.4	4.4	5.0	1.5
Industrial	139.6	51.5	61.7	2.1
Total Codes and Standards	**180.6**	**6.2**	**7.6**	**1.5**
Rate Structures				
Residential	28.8	28.8	34.5	1.1
Commercial & Industrial Distribution	16.9	16.9	19.4	1.3
Industrial Transmission	22.8	2.3	4.4	0.7
Total Rate Structures	**26.7**	**14.3**	**18.0**	**1.0**
Programs				
Residential Sector				
Behaviour	3.5	4.1	5.1	0.9
Refrigerator Buy-back	2.1	2.8	3.0	0.7
Low Income[3]	1.3	1.7	1.8	0.7
New Home	2.3	1.5	1.5	0.9
Retail Rebate	3.5	3.4	3.9	1.0
Renovation Rebate	3.9	1.5	1.7	1.1
Load Displacement	n/a	n/a	n/a	n/a
Sector Enabling Activities	n/a	n/a	n/a	n/a
Residential Sector Total	2.9	2.5	2.9	0.9
Commercial Sector				
Power Smart Partner	2.4	1.9	2.4	0.9
New Construction	2.4	1.7	2.7	0.8
Load Displacement	n/a	n/a	n/a	n/a
Sector Enabling Activities	n/a	n/a	n/a	n/a
Commercial Sector Total	2.4	1.8	2.5	0.9
Industrial Sector				
Power Smart Partner - Transmission	3.3	2.0	2.5	1.0
Thermo-Mechanical Pulp	n/a	n/a	n/a	n/a
Power Smart Partner - Distribution	2.7	2.3	2.8	0.9
Load Displacement	4.5	2.6	3.0	1.5
Sector Enabling Activities	n/a	n/a	n/a	n/a
Industrial Sector Total	3.3	2.2	2.7	1.0
Capacity Focused DSM	n/a	n/a	n/a	n/a
Total Programs	**2.8**	**2.1**	**2.6**	**1.0**
Total DSM	**6.2**	**3.4**	**4.3**	**1.1**

Notes:

1 In accordance with the DSM Regulation (Ministerial Order M233/2014), the avoided cost of natural gas is valued at BC Hydro's long run marginal cost of acquiring electricity generated from clean or renewable resources in B.C converted to $/GJ in all time periods. Non-energy benefits are valued at 15 per cent of the energy and capacity benefits of electricity and natural gas.

2 While subsection 4(6) of the DSM Regulation precludes the use of the Ratepayer Impact Measure Test in determining cost-effectiveness of a demand-side measure, this benefit cost ratio is included in the table to comply with Directive 42 from the Commission decision on BC Hydro's 2008 LTAP.

3 The Total Resource Cost Test benefit-cost ratio for the Low Income program includes a 40 per cent adder to program benefits, rather than a 15 per cent value for non-energy benefits, in accordance with the DSM Regulation.

4 Mitigation Measures

Table 3 indicates that most DSM initiatives are approximately on or above plan in terms of cumulative electricity savings in F2015 while Table 5 indicates that the portfolio has delivered electricity savings at a substantially lower cost than new electricity supply. Based on the experience gathered over the past few years through initiative tracking, the following are mitigation measures that have been undertaken or are planned for the future.

Codes and Standards	
Residential Commercial Industrial	Cumulative electricity savings in F2015 were below plan. BC Hydro will manage risk by tracking Codes & Standards progress against a number of milestones or indicators to anticipate savings shortfalls or identify trends that may trigger the need for saving adjustments to the DSM Plan as well as continuing to work closely with both the federal and provincial governments to anticipate and adjust code and regulation approval timelines as appropriate. No additional mitigation measures are required.
Rate Structures	
Residential Commercial & Industrial Distribution	Cumulative electricity savings in F2015 were below plan. Adjustments have been made to the conservation forecasts to reflect the outcomes from their respective evaluation reports. Any rate structure changes will come as a result of BC Hydro's 2015 RDA process.
Industrial Transmission	Cumulative electricity savings were approximately on plan in F2015.
DSM Programs	
Residential Sector	
Behaviour	Cumulative electricity savings in F2015 were below plan. With program infrastructure enhancements complete in mid-F2015, program performance is expected to meet F2016 targets.
Refrigerator Buy-Back	Cumulative electricity savings in F2015 were below plan. With one year experience in the new seasonal model of the program offering and with IT enhancements made to the customer online registration process, program participation is expected to increase.
Low Income	Cumulative electricity savings in F2015 were above plan.
New Home	Cumulative electricity savings in F2015 were above plan.
Retail Rebate	Cumulative electricity savings in F2015 were above plan.
Renovation Rebate	Cumulative electricity savings in F2015 were below plan. Following program re-launch in F2015, program monthly participation is now on track and expected to meet F2016 targets.

Commercial Sector	
Power Smart Partner	Cumulative electricity savings in F2015 were below plan. Targeted sector program promotion will be launched in F2016 to drive higher program participation.
New Construction	Cumulative electricity savings in F2015 were above plan.
Industrial Sector	
Power Smart Partner – Transmission	Cumulative electricity savings in F2015 were above plan.
Thermo-Mechanical Pulp	No electricity savings were planned in F2015.
Power Smart Partner – Distribution	Cumulative electricity savings in F2015 were above plan.
Load Displacement	Cumulative energy savings were below plan in F2015 due to the delay of one project. No mitigation measures are warranted as planned cumulative electricity savings are expected to be achieved. Delays in load displacement projects are possible due to the long lead times for equipment delivery, installation and commissioning.
Capacity Focused DSM	No capacity savings were planned in F2015.

5 Operating Expenditures for F2015

BC Hydro's DSM operating expenditures in F2015 totalled $392,257.[3] Table 6 presents DSM operating expenditures in F2015.

Table 6 Operating Expenditures for F2015

	($000)
Labour	307
Consultants/Contractors/Temp Labour	28
Other	57
Total	**392**

3 DSM operating expenditures are not included in earlier tables.

6 Allocation of Supporting Initiative Costs to Programs

This section describes how supporting initiative costs are allocated to programs for the purpose of cost test calculations.

In keeping with Directive 61 from the Commission decision on the F05/F06 RRA, when calculating levelized costs and benefit-cost ratios for this report, supporting initiative costs are allocated to DSM programs and rate structures based on their share of DSM electricity savings in F2018. For example, rate structures and programs are forecast to save roughly 4,508 GWh/year in F2018, so a program that is forecast to save 45 GWh/year in F2018 represents 1 per cent of the total. In turn, 1 per cent of supporting initiative costs would be allocated to that program in each year when calculating the program's levelized cost or benefit-cost ratio.

Fiscal F2017 to Fiscal 2019
Revenue Requirements Application

Appendix Y

Attachment 3

Report on Demand-Side Management Activities for the 12 months ending March 31, 2016

BC Hydro
Power smart

Tom A. Loski
Chief Regulatory Officer
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bchydroregulatorygroup@bchydro.com

August 5, 2016

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)
F2005/F2006 Revenue Requirements Application
Commission Decision: October 29, 2004; Directive 69 (page 201)
(AMENDED pursuant to 2006 Integrate Electricity Plan and
2006 Long-Term Acquisition Plan
Commission Decision: May 11, 2006; Directive 16 (pages 145 to 146)
2008 Long-Term Acquisition Plan
Commission Decision: July 27, 2009; Directive 36 (page 184))
F2016 Demand-Side Management Activities Annual Report

BC Hydro writes to provide its Report on Demand-Side Management Activities for the 12 months ending March 31, 2016.

For further information, please contact Geoff Higgins at 604-623-4121 or by email at bchydroregulatorygroup@bchydro.com.

Yours sincerely,

Tom Loski
Chief Regulatory Officer

st/ma

Enclosure (1)

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Report on Demand-Side Management Activities for Fiscal 2016

July 25, 2016

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1 Introduction

This BC Hydro annual report to the British Columbia Utilities Commission (**BCUC or Commission**) on Demand-Side Management (**DSM**) activities provides information on DSM expenditures, electricity savings, plan performance and mitigation measures for the 2016 fiscal year (**F2016**), which is the twelve months ending March 31, 2016. This annual report is filed in compliance with the following Commission Directives:

- Directive 69 from the Commission Decision on BC Hydro's F2005/F2006 Revenue Requirements Application (**F05/F06 RRA**),
- Directive 16 from the Commission Decision on BC Hydro's 2006 Integrated Electricity Plan and Long Term Acquisition Plan (**2006 IEP/LTAP**) and
- Directives 36 and 38 from the Commission decision on BC Hydro's 2008 LTAP.

Directive 69 of the F05/F06 RRA Decision directed BC Hydro "to provide information to the Commission for on-going review of Power Smart performance through:

- Executive Summaries of milestone evaluation reports and full final evaluation reports for each program;
- Semi-annual reports on DSM activities which, amongst others, will include:
  - detailed breakdown of OMA expenses related to support activities carried out within the Power Smart group and in other departments that support the Power Smart organization;
  - detailed description of the functions of portfolio level costs and how these costs are allocated to programs;
  - summaries of the overall performance of Power Smart with reference to program objectives; and
  - variances of fiscal year budgeted and actual deferred capital expenditures and explanation of variances."

Directive 16 of the 2006 IEP/LTAP Decision directed BC Hydro "to continue to file reports on DSM performance as described in Directive 69 of the F05/F06 RRA Decision included in Order No. G-96-04 and to file its Semi Annual Demand-Side Management Reports in the same format as the June 2005 Report with the following enhancements:

Provide annual and cumulative totals since program inception;

(i) Express these values on a per unit basis; and

(ii) Provide the benefit to cost ratios for the three DSM tests."

Directive 36 of the 2006 IEP/LTAP Decision directed BC Hydro to switch from semi-annual to annual DSM performance reports. Directive 38 from the same Decision directed BC Hydro to include in these reports:

> "metrics for each initiative, achievements in relation to milestones, and description of past or planned mitigation measures where warranted. These mitigation measures should include shifting program resources and alternative supply options for each program. Ongoing DSM performance reporting should demonstrate how BC Hydro is continuously pursuing DSM and that specific programs are cost-effective."

BC Hydro files its evaluation reports pursuant to Directive 69 of the F05/F06 RRA Decision separately. This annual report addresses the balance of Directives 69 and 16, as well as Directives 36 and 38 of the 2006 IEP/LTAP Decision.

2 Expenditures and Electricity Savings for F2016

BC Hydro's DSM expenditures[1] in F2016 totalled $145.2 million while incremental DSM electricity savings totalled 872 GWh/year. This was $5 million or 4 per cent below the F2016 DSM Plan presented in BC Hydro's Fiscal 2015 to Fiscal 2016 Revenue Requirements Rate Application (**F15-F16 RRRA**) after the addition of DSM-related expenditures for the Thermo-Mechanical Pulp program, cost recovery of which is

[1] Comprising all DSM-related deferred operating and specific capital expenditures. DSM operating expenditures are presented in Table 6 of this report.

prescribed by the Direction to the British Columbia Utilities Commission Respecting the Authority's TMP Program (B.C. Reg. 139/2015). Overall, net incremental electricity savings as shown in Table 1 were 122 GWh/year or 12 per cent below the DSM Plan. The primary cause of these electricity savings variances is less than planned electricity savings from rate structures. Net incremental electricity savings from DSM Programs were 18 GWh/year or 6 per cent above the DSM Plan.

Table 1 presents planned and actual DSM expenditures and incremental electricity savings in F2016.

Table 1 Expenditures and Incremental Electricity Savings for F2016

	Expenditures[1]				Net Incremental Electricity Savings			
	Plan[2] $ 000	Actual $ 000	Variance $ 000	%	Plan[2] GWh/yr	Actual[3] GWh/yr	Variance GWh/yr	%
Codes and Standards								
Residential	2,970	2,370	(600)	(20%)	422	420	(2)	(0%)
Commercial	1,108	667	(441)	(40%)	137	118	(18)	(13%)
Industrial	143	103	(40)	(28%)	21	18	(3)	(14%)
Total Codes and Standards	4,221	3,140	(1,081)	(26%)	580	557	(23)	(4%)
Rate Structures								
Residential	517	506	(11)	(2%)	108	29	(79)	(73%)
Commercial & Industrial Distribution	421	487	65	16%	(14) [4]	-	14	(100%)
Industrial Transmission	740	309	(431)	(58%)	7	(44)	(51)	(712%)
Total Rate Structures	1,678	1,302	(376)	(22%)	102	(15)	(117)	(115%)
DSM Programs								
Residential Sector								
Behaviour	4,616	3,236	(1,380)	(30%)	26	13	(13)	(50%)
Refrigerator Buy-back	1,308	1,188	(120)	(9%)	9	3	(6)	(68%)
Low Income	2,517	2,425	(92)	(4%)	2	3	1	68%
New Home	2,114	1,255	(859)	(41%)	-	1	1	-
Retail Rebate	3,867	4,712	845	22%	7	18	11	156%
Renovation Rebate	3,214	2,241	(973)	(30%)	6	6	(1)	(8%)
Sector Enabling Activities	1,241	973	(268)	(22%)	n/a	n/a	n/a	n/a
Residential Sector Total	18,876	16,030	(2,847)	(15%)	50	43	(7)	(13%)
Commercial Sector								
Power Smart Partner	31,400	25,159	(6,240)	(20%)	63	57	(7)	(11%)
New Construction	7,416	7,360	(56)	(1%)	13	17	4	33%
Sector Enabling Activities	1,174	1,089	(84)	(7%)	n/a	n/a	n/a	n/a
Commercial Sector Total	39,990	33,609	(6,381)	(16%)	76	73	(3)	(3%)
Industrial Sector								
Power Smart Partner - Transmission	23,462	18,771	(4,691)	(20%)	92	72	(20)	(21%)
Thermo-Mechanical Pulp	19,566	19,657	90	0%	66	66	0	0%
Power Smart Partner - Distribution	11,850	10,897	(953)	(8%)	28	26	(2)	(7%)
Load Displacement	6,344	14,481	8,136	128%	-	49	49	-
Sector Enabling Activities	1,236	968	(267)	(22%)	n/a	n/a	n/a	n/a
Industrial Sector Total	62,459	64,774	2,315	4%	186	214	28	15%
Capacity Focused DSM	3,102	8,644	5,542	179%	-	-	-	-
Total Programs	**124,427**	**123,057**	**(1,370)**	**(1%)**	**312**	**330**	**18**	**6%**
Supporting Initiatives								
Public Awareness and Education	6,044	6,227	183	3%	-	-	-	-
Community Engagement	3,942	2,611	(1,331)	(34%)	-	-	-	-
Advanced DSM Strategies	1,874	1,547	(326)	(17%)	-	-	-	-
Indirect and Portfolio Enabling	8,443	7,278	(1,166)	(14%)	-	-	-	-
Supporting Initiatives Total	**20,303**	**17,663**	**(2,640)**	**(13%)**	-	-	-	-
TOTAL DSM	**150,629**	**145,162**	**(5,467)**	**(4%)**	**993**	**872**	**(122)**	**(12%)**

Notes:

1 Including all DSM-related deferred operating and specific capital expenditures that are relevant for DSM cost-effectiveness.

2 Plan figures are from BC Hydro's F15-F16 RRRA, Appendix G. The Plan also includes DSM-related expenditures of $19.6 million and electricity savings of 66.3 GWh/year for the Thermo-Mechanical Pulp program, covered by the Direction to the British Columbia Utilities Commission Respecting the Authority's TMP Program (B.C. Reg. 139/2015).

3 Reported savings from codes and standards and residential, commercial & industrial distribution rate structures are based on planned estimates as well as evaluated results.

4 The approach to applying rate increases for F2016 onto the two-part rate structure of the MGS and LGS rates results in a shift of savings from DSM to the rate level savings claimed in the Load Forecast. As a result, the incremental plans savings are negative.

The following corresponds to the information provided in Table 1 and are explanations for the above variances:

Codes and Standards	
Residential Commercial Industrial	Expenditures were below plan primarily due to BC Hydro's ability to reduce expenditures by leveraging local governments to explore additional opportunities for increased compliance and more savings from codes and standards. Energy savings were below plan due to the delay in adoption of Amendment 13 to the Federal Energy Efficiency Regulation.
Rate Structures	
Residential	Expenditures were approximately on plan. Electricity savings were below plan due to an adjustment in the savings calculation due to the incorporation of lower savings from the 2013 RIB Evaluation outcomes into the forecast model.
Commercial & Industrial Distribution	Expenditures were above plan due to stakeholder engagement on possible rate structure changes, in advance of the Rate Design Application. No further conservation is forecast from the commercial and industrial distribution conservation rates as BC Hydro has revised its conservation forecast to zero due to the outcomes of the F2014 LGS/MGS Evaluation report.
Industrial Transmission	Expenditures were below plan due to the timing of the Transmission Service Rate evaluation and the ability to move forward with a lower cost solution for a data centralization project. Energy savings were below plan due to a reduction in incremental customer self-generation.
DSM Programs	
Residential Sector	
Behaviour	Expenditures and electricity savings were below plan due to a change in campaign strategy to field one promotional campaign instead of the two that were originally planned. Electricity savings were also below plan due to the transition to a more conservative definition for engaged users of the Energy Visualization Portlet.
Refrigerator Buy-Back	The program had a change in strategy to shift from a year-round program offer to a seasonal program offer with reduced budgets and energy targets. The seasonal program offer was reflected in the planned expenditures while the initial year-round program offer was still reflected in the planned electricity savings. As a result, expenditures were approximately on the revised plan and energy savings below the initial plan.
Low Income	Expenditures were approximately on plan. Electricity savings were above plan due to higher than planned participation in the Energy Saving Kit portion of the program offer, resulting largely from leads generated through the BC Hydro call centre.
New Home	The program had a change in strategy that extended the program end date from F2015 to F2016. A F2016 end date is reflected in the planned expenditures while a F2015 end date is reflected in the planned electricity savings. As a result, no electricity savings appear in the plan. Expenditures were below plan due to lower participation following the decision to remove the incentive offer from the market in mid F2016.
Retail Rebate	Expenditures and electricity savings were above plan due to higher than planned participation in the lighting portion of the program, with strong sales of LED lighting, particularly multi-packs which provided more savings than planned.
Renovation Rebate	Expenditures and electricity savings were below plan due to the mix of project measures installed by customers varying from the planned measure mix.
Sector Enabling Activities	Expenditures were below plan due to a change in timing related to work to develop a residential contractor network.

Commercial Sector	
Power Smart Partner	Expenditures and electricity savings were below plan due to customer projects not completing as planned and being deferred to the next fiscal. Expenditures were also below plan due to a higher mix of lower cost projects completing than planned.
New Construction	Expenditures were approximately on plan. Energy savings were above plan due to higher participation of lower cost projects.
Sector Enabling Activities	Expenditures were approximately on plan.
Industrial Sector	
Power Smart Partner – Transmission	Expenditures and electricity savings were below plan due to a number of projects being deferred by customers to F2017.
Thermo-Mechanical Pulping	Expenditures and electricity savings were approximately on plan.
Power Smart Partner – Distribution	Expenditures and electricity savings were below plan due to a number of projects being cancelled or deferred by customers.
Load Displacement	Expenditures and electricity savings were above plan due to the delay of a large project from F2015 to F2016. This was partially offset by the dissolution of a project completed in F2014.
Sector Enabling Activities	Expenditures are below plan due to planned studies being cancelled or deferred.
Capacity Focused DSM	Expenditures are above plan due to the implementation of a load curtailment pilot program in F2016. This pilot was advanced in order to test the viability of using industrial customers to deliver capacity savings.
Total Programs	Expenditures were approximately on plan. Electricity savings were above plan primarily due to the delay of an Industrial Load Displacement project from F2015 to F2016.
Supporting Initiatives	
Public Awareness & Education	Expenditures were approximately on plan.
Community Engagement	Expenditures were below plan due to the development of a new operating model and a condensed in-market season.
Advanced DSM Strategies	Expenditures were below plan due to BC Hydro leveraging local government and community energy manager work plans to support BC Hydro's codes and standards goals and activities, particularly with respect to building code compliance.
Indirect and Portfolio Enabling Activities	Expenditures were below plan due to lower than expected costs and timing for the Conservation Potential Review and IT projects.
Total DSM	Expenditures were approximately on plan. Electricity savings were 12 per cent below plan due primarily to the incorporation of evaluation results for Residential Rate Structures and a reduction in incremental customer self-generation.

3 Expenditures to Date

BC Hydro's DSM expenditures from F2013 through F2016 totalled $540.3 million. Table 2 presents DSM expenditures from April 1, 2013 to March 31, 2016.[2]

Table 2 Expenditures since F2013

	F2013 ($ 000)	F2014 ($ 000)	F2015 ($ 000)	F2016 ($ 000)	Total ($ 000)
Codes and Standards					
Residential	1,323	1,257	2,296	2,370	7,247
Commercial	245	307	660	667	1,878
Industrial	47	64	115	103	329
Total Codes and Standards	**1,615**	**1,628**	**3,071**	**3,140**	**9,453**
Rate Structures					
Residential	330	302	314	506	1,453
Commercial & Industrial Distribution	557	409	521	487	1,974
Industrial Transmission	407	300	400	309	1,416
Total Rate Structures	**1,294**	**1,011**	**1,236**	**1,302**	**4,842**
DSM Programs					
Residential Sector					
Behaviour	4,419	4,112	2,770	3,236	14,538
Refrigerator Buy-back	3,754	2,239	934	1,188	8,116
Low Income	3,040	2,185	1,925	2,425	9,575
New Home	2,321	2,706	2,716	1,255	8,998
Retail Rebate	9,141	4,063	4,011	4,712	21,926
Renovation Rebate	3,636	1,264	972	2,241	8,113
Sector Enabling Activities	1,220	1,013	874	973	4,081
Residential Sector Total	27,532	17,582	14,202	16,030	75,347
Commercial Sector					
Power Smart Partner	42,472	33,784	26,394	25,159	127,809
New Construction	8,680	7,672	9,011	7,360	32,723
Sector Enabling Activities	1,100	1,176	1,245	1,089	4,610
Commercial Sector Total	52,252	42,631	36,650	33,609	165,142
Industrial Sector					
Power Smart Partner - Transmission	18,146	20,437	28,296	18,771	85,650
Thermo-Mechanical Pulp	-	-	134	19,657	19,791
Power Smart Partner - Distribution	12,397	10,126	13,505	10,897	46,925
Load Displacement	10,009	4,537	2,919	14,481	31,946
Sector Enabling Activities	1,015	1,003	853	968	3,839
Industrial Sector Total	41,567	36,103	45,708	64,774	188,152
Capacity Focused DSM	-	28	4,742	8,644	13,414
Total Programs	**121,352**	**96,345**	**101,302**	**123,057**	**442,055**
Supporting Initiatives					
Public Awareness and Education	7,235	7,018	5,974	6,227	26,454
Community Engagement	7,232	4,137	3,715	2,611	17,695
Advanced DSM Strategies	1,863	1,940	984	1,547	6,335
Information Technology	145	-	-	-	145
Indirect and Portfolio Enabling	9,386	8,200	8,470	7,278	33,333
Supporting Initiatives Total	**25,861**	**21,296**	**19,142**	**17,663**	**83,962**
Total DSM	**150,121**	**120,279**	**124,750**	**145,162**	**540,312**

2 Comprising all DSM deferred operating and specific capital expenditures that are relevant for DSM cost-effectiveness.

BC Hydro's DSM electricity savings since F2013 totalled 2,710 GWh/year at March 31, 2016, which equates to 75 per cent of the planned savings of 3,537 GWh/year in the F15-F16 RRRA and electricity savings of 66 GWh/year for the Thermo-Mechanical Pulp program, cost recovery of which is prescribed by the Direction to the British Columbia Utilities Commission Respecting the Authority's TMP Program (B.C. Reg. 139/2015). DSM programs delivered 92 per cent of planned savings. Table 3 presents actual cumulative savings as a percentage of plan in F2013 to F2016.

Table 3 Cumulative Electricity Savings since April 1, 2012

Actual as a Percentage of Plan[1]	
	F2016
Codes and Standards	
Residential	95%
Commercial	85%
Industrial	87%
Total Codes and Standards	**93%**
Rate Structures	
Residential	54%
Commercial & Industrial Distribution	0%
Industrial Transmission	95%
Total Rate Structures	**31%**
DSM Programs	
Residential Sector	
Behaviour	55%
Refrigerator Buy-back	69%
Low Income	119%
New Home	138%
Retail Rebate	133%
Renovation Rebate	73%
Residential Sector Total	82%
Commercial Sector	
Power Smart Partner	94%
New Construction	110%
Commercial Sector Total	96%
Industrial Sector	
Power Smart Partner - Transmission	101%
Thermo-Mechanical Pulp	100%
Power Smart Partner - Distribution	101%
Load Displacement	65%
Industrial Sector Total	92%
Capacity Focused DSM	n/a
Total Programs	**92%**
Total DSM	**75%**

Notes:

1 Reported savings for codes and standards and rates structures are based on planned estimates as well as evaluated results.

The cumulative portfolio DSM electricity savings since F2013 have been achieved at an average net levelized utility cost of -$1 per MWh. Table 4 presents the net levelized utility cost of actual DSM electricity savings achieved from April 1, 2012 through March 31, 2016. Net levelized utility cost is calculated by subtracting capacity benefits from gross utility costs and then dividing the resulting net utility costs by electricity savings. A negative net levelized utility cost means that the subtracted capacity benefits exceed gross utility costs.

Table 4 Utility Cost of Electricity Savings: F2013 to F2016

	Net Levelized Utility Cost ($/MWh)[1]
Codes and Standards	
Residential	-25
Commercial	-11
Industrial	-9
Total Codes and Standards	**-21**
Rate Structures	
Residential	-13
Commercial & Industrial Distribution	4
Industrial Transmission	-4
Total Rate Structures	**-11**
Programs	
Residential Sector	
Behaviour	18
Refrigerator Buy-back	37
Low Income	63
New Home	35
Retail Rebate	9
Renovation Rebate	9
Sector Enabling Activities	n/a
Residential Sector Total	21
Commercial Sector	
Power Smart Partner	36
New Construction	37
Sector Enabling Activities	n/a
Commercial Sector Total	37
Industrial Sector	
Power Smart Partner - Transmission	19
Thermo-Mechanical Pulp	19
Power Smart Partner - Distribution	31
Load Displacement	22
Sector Enabling Activities	n/a
Industrial Sector Total	22
Capacity Focused DSM	n/a
Total Programs	**27**
Total DSM	**-1**

Table 5 presents Total Resource Cost Test benefit cost-ratios of actual DSM electricity savings achieved from April 1, 2012 through March 31, 2016. Table 5 shows the Total Resource Cost Test benefit-cost ratios for the Total Resource Cost test and the Total Resource Cost test as modified by the Demand-Side Measures Regulation.

Table 5 Benefit Cost Ratios of Electricity Savings: F2013 to F2016

	Benefit Cost Ratios			
	Utility Test	Total Resource Cost Test	Total Resource Cost Test as modified by DSM Regulation[1]	Ratepayer Impact Measure Test[2]
Codes and Standards				
Residential	229.5	7.4	8.6	1.3
Commercial	202.5	6.5	7.6	1.3
Industrial	174.9	35.7	41.0	2.0
Total Codes and Standards	**222.3**	**7.4**	**8.6**	**1.4**
Rate Structures				
Residential	21.3	21.3	24.5	1.0
Commercial & Industrial Distribution	9.4	9.4	10.7	0.9
Industrial Transmission	45.1	3.4	3.9	1.1
Total Rate Structures	**21.9**	**10.9**	**12.5**	**1.0**
Programs				
Residential Sector				
Behaviour	3.3	3.6	4.2	0.9
Refrigerator Buy-back	2.3	3.4	3.1	0.7
Low Income[3]	1.4	1.9	1.8	0.7
New Home	2.1	1.4	1.4	0.9
Retail Rebate	3.6	5.5	5.9	1.0
Renovation Rebate	3.5	1.4	1.5	0.9
Sector Enabling Activities	n/a	n/a	n/a	n/a
Residential Sector Total	2.9	2.6	2.8	0.9
Commercial Sector				
Power Smart Partner	2.4	1.8	2.2	0.8
New Construction	2.3	1.7	2.8	0.8
Sector Enabling Activities	n/a	n/a	n/a	n/a
Commercial Sector Total	2.3	1.8	2.3	0.8
Industrial Sector				
Power Smart Partner - Transmission	3.8	2.2	2.6	1.0
Thermo-Mechanical Pulp	3.6	3.1	3.6	1.3
Power Smart Partner - Distribution	2.6	2.2	2.5	0.9
Load Displacement	3.4	1.5	1.7	1.2
Sector Enabling Activities	n/a	n/a	n/a	n/a
Industrial Sector Total	3.4	2.0	2.4	1.0
Capacity Focused DSM	n/a	n/a	n/a	n/a
Total Programs	**2.9**	**2.0**	**2.4**	**0.9**
Total DSM	**7.2**	**3.7**	**4.4**	**1.1**

Notes:

1 In accordance with the DSM Regulation (Ministerial Order M233/2014), the avoided cost of natural gas is valued at BC Hydro's long run marginal cost of acquiring electricity generated from clean or renewable resources in B.C converted to $/GJ in all time periods. Non-energy benefits are valued at 15 per cent of the energy and capacity benefits of electricity and natural gas.

2 While subsection 4(6) of the DSM Regulation precludes the use of the Ratepayer Impact Measure Test in determining cost-effectiveness of a demand-side measure, this benefit cost ratio is included in the table to comply with Directive 42 from the Commission decision on BC Hydro’s 2008 LTAP.

3 The Total Resource Cost Test benefit-cost ratio for the Low Income program includes a 40 per cent adder to program benefits, rather than a 15 per cent value for non-energy benefits, in accordance with the DSM Regulation.

4 Mitigation Measures

Based on the experience gathered over the past few years through initiative tracking, the following are mitigation measures that have been undertaken or are planned for the future.

Codes and Standards	
Residential	Cumulative electricity savings in F2016 were below plan. BC Hydro will manage risk by tracking Codes & Standards progress against a number of milestones or indicators to anticipate savings shortfalls or identify trends that may trigger the need for adjustments to the DSM Plan as well as continuing to work closely with both the federal and provincial governments to anticipate and adjust code and regulation approval timelines as appropriate.
Commercial	
Industrial	
Rate Structures	
Residential	Cumulative electricity savings in F2016 were below plan. Adjustments have been made to the conservation forecasts to reflect the outcomes from their respective evaluation reports.
Commercial & Industrial Distribution	
Industrial Transmission	Cumulative electricity savings were approximately on plan in F2016.
DSM Programs	
Residential Sector	
Behaviour	Cumulative electricity savings in F2016 were below plan. New cumulative electricity savings targets were set based on past performance and are reflected in the new DSM Plan in the F2017-F2019 RRA. The program is expected to reach F2017 targets.
Refrigerator Buy-Back	Cumulative electricity savings in F2016 were below plan. The program has ended per the new DSM Plan in the F2017-F2019 RRA.
Low Income	Cumulative electricity savings in F2016 were above plan.
New Home	Cumulative electricity savings in F2016 were above plan. The program has ended per the new DSM Plan in the F2017-F2019 RRA.
Retail Rebate	Cumulative electricity savings in F2016 were above plan.
Renovation Rebate	Cumulative electricity savings in F2016 were below plan. New cumulative electricity savings targets were set based on past performance and are reflected in the new DSM Plan in the F2017-F2019 RRA. The program is expected to reach F2017 targets.
Commercial Sector	
Power Smart Partner	Cumulative electricity savings in F2016 were below plan. New cumulative electricity savings targets were set based on past performance and are reflected in the new DSM Plan in the F2017-F2019 RRA. The program is expected to reach F2017 targets.
New Construction	Cumulative electricity savings in F2016 were above plan.
Industrial Sector	
Power Smart Partner – Transmission	Cumulative electricity savings in F2016 were above plan.
Thermo-Mechanical Pulping	Cumulative electricity savings in F2016 were on plan.
Power Smart Partner – Distribution	Cumulative electricity savings in F2016 were above plan.
Load Displacement	Cumulative electricity savings in F2016 were below plan. The program has ended per the new DSM Plan in the F2017-F2019 RRA.
Capacity Focused DSM	No capacity savings were planned in F2016 as these are pilot initiatives.

5 Operating Expenditures for F2016

BC Hydro's DSM operating expenditures in F2016 totalled $569,517.[3] Table 6 presents DSM operating expenditures in F2016.

Table 6 Operating Expenditures for F2016

	($000)
Labour	433
Consultants/Contractors/Temp Labour	29
Other	107
Total	**570**

6 Allocation of Supporting Initiative Costs to Programs

This section describes how supporting initiative costs are allocated to programs for the purpose of cost test calculations.

In accordance with Directive 61 from the Commission decision on the F05/F06 RRA, when calculating levelized costs and benefit cost ratios for this report, supporting initiative costs are allocated to DSM programs and rate structures based on their share of DSM electricity savings. F2025 has been used as the year for energy savings allocation. As an example, rate structures and programs are forecast to save roughly 2,107 GWh/year in F2025, so a program that is forecast to save 21 GWh/year in F2025 represents 1 per cent of the total. In turn, 1 per cent of supporting initiative costs would be allocated to that program in each year when calculating the program's levelized cost or benefit cost ratio.

[3] DSM operating expenditures are not included in earlier tables.

Fiscal 2017 to Fiscal 2019
Revenue Requirements Application

Appendix Z

Demand-Side Management Evaluation, Measurement and Verification

Table of Contents

1 Introduction

Measurement and verification, and evaluation are the final steps in BC Hydro's process to refine our estimates of energy savings from demand-side management initiatives. Evaluation also identifies opportunities to improve demand-side management program effectiveness or efficiency.

This appendix provides an overview of BC Hydro's evaluation and measurement and verification activities, including their purpose and objectives, the principles that guide them, the types of activities undertaken and planned work in the three-year period of fiscal 2017 to fiscal 2019. It also provides an overview of the organizational structure of BC Hydro's evaluation, measurement and verification functions.

2 Evaluation

Purpose and Objectives

The purpose of the evaluation function is to refine the demand-side management savings estimates and identify program improvements in a rigorous and neutral manner in support of demand-side management and integrated resource planning decisions, risk management and stakeholder confidence.

The objectives of the evaluation function are as follows:

- Support demand-side management investment and integrated resource planning decisions by evaluating impacts of demand-side management initiatives;
- Support demand-side management program management decisions by identifying opportunities to improve programs; and
- Fulfill Commission directives and guidelines regarding demand-side management evaluation.

Principles

Evaluation activities are guided by the following six principles:

1. Neutrality
   The evaluation function is intended to be neutral and unbiased. A systematic, data-driven approach is used that relies on primary research and analysis in order to provide accurate and unbiased results.
2. Professional Standards
   Evaluation work is consistent with industry standards and protocols, such as the U.S. Department of Energy Uniform Methods Project Protocols and the California Evaluation Framework and Protocols.
3. Qualified Practitioners
   BC Hydro employs qualified and professional staff members and consultants to conduct demand-side management evaluations.
4. Appropriate Coverage
   BC Hydro strives to achieve the following levels of coverage for evaluation.
   - Within each sector – residential, commercial and industrial – conduct impact evaluations of 75 per cent of cumulative program savings within three years and 100 per cent within six years, subject to a decision on the value of an evaluation of the final years of a terminated program;
   - Conduct impact evaluations of conservation rates every three years;
   - Conduct impact evaluations of 50 per cent of cumulative codes and standards savings within three years; and
   - Conduct at least one process evaluation every two years.
5. Business Integration
   Evaluation is integrated into BC Hydro's business process for demand-side

management planning, implementation, verification and reporting. This integration supports continuous improvement of programs and initiatives and ensures they can be evaluated.

6. Coordination
Evaluation efforts are coordinated with FortisBC Energy Inc. and other demand-side management partners where feasible.

Activities

Two main types of evaluations are conducted: impact and process.

The purpose of an impact evaluation is to estimate the impacts attributable to a specific demand-side management program or initiative within a specific timeframe. Impact evaluations are scoped to analyze the major impacts associated with a program, which can include:

- Gross and/or net electric energy savings
- Gross and/or net electric demand savings
- Free ridership
- Participant and non-participant spillover
- Market impacts

Evaluated gross savings provide an estimate of actual savings realized among participating customers, without exploring or adjusting for the attribution of the savings to specific interventions. Common methods for evaluating gross savings are:

- Measurement of a key parameter in the energy savings calculation formula is conducted on a sample of projects. Parameters that are not measured are specified based on historical data, manufacturers' specification, BC Hydro standard values or engineering judgement. Statistical analysis is used to extrapolate results from the measured sample to the population of all projects.

- Measurement of the baseline and post implementation energy use is conducted on a sample of projects. Statistical analysis is used to extrapolate results from the sample that underwent measurement and verification to the population of all projects.
- Billing analysis is completed on all or a sample of customers. This method is used for the evaluation of programs targeting multiple measures or behaviours that may interact with each other, and where savings are large enough to detect at the account or sub-meter level. For impact evaluation purposes, savings are commonly represented as group averages across all or a sample of participants. If sampling is used, then statistical analysis is used to extrapolate results from the sample to the population.
- Energy use simulation using engineering models is completed for a sample of program participants. The simulation is calibrated with data such as: site audit findings, hourly or monthly utility billing data, and energy end use metering. Statistical analysis is used to extrapolate results from the sample to the population of all projects.

Evaluated net savings provide an estimate of the savings attributable to a specific intervention, such as a demand-side management program or conservation rate. Net savings can be estimated in several ways:

- Design-based evaluation methods includes experimental and quasi-experimental approaches, which rely on the use of a counterfactual (i.e., a control group or a comparison group consisting of non-participants from a similar population).

- Free ridership and spillover adjustments can be applied to evaluated gross savings estimates to produce evaluated net savings estimates. Generally accepted methods to produce stand-alone estimates of program free ridership and spillover include: analysis of the results of participant, non-participant, and market actor surveys; analysis of sales or other market data; case study or historical tracing; and discrete choice modeling.
- Econometric and other regression based modelling techniques can be used to model the effects of a program or initiative on a segment of the economy or population. These methods model the variable of interest (e.g., electricity use, product saturations) as a function of drivers such as prices, income, program activity, etc.

Market impacts can include changes to sales, prices or other market factors. Evaluation of market impacts draws on the same evaluation methods as used in the evaluation of net savings.

The purpose of a process evaluation is to identify program improvements that will increase program effectiveness or efficiency while maintaining high levels of participant satisfaction. These evaluations are infrequent and not meant to duplicate ongoing process and productivity improvement efforts, but rather are more formalized and comprehensive reviews that review end-to-end program effectiveness.

Common methods for process evaluations include qualitative analysis of information collected through structured interviews or focus groups and quantitative analysis of customer and market actor survey results.

Various types of studies and data collection activities are conducted to inform evaluations. These include comprehensive surveys of residential and commercial customers to determine how electricity is used in these sectors as well as periodic surveys of energy efficiency industry stakeholders such as retailers, energy managers and providers of energy efficiency products and services.

In addition, surveys of program participants and non-participants are completed to inform the evaluation of program impacts and regular studies of retail store stocking practices support the evaluation of market trends related to demand-side management programs and initiatives.

The evaluation work plan is guided by Principle 4, and is shown in the table below.

Evaluation Work Plan

Impact Evaluations	F2017	F2018	F2019
Residential Programs			
Retail	X		
Low Income		X	
Home Energy Rebate Offer			X
Commercial Programs			
Continuous Optimization Offer	X		
New Construction	X		
Leaders in Energy Management - Commercial			X
Industrial Programs			
Leaders in Energy Management - Transmission	X		
Leaders in Energy Management - Distribution		X	
Load Displacement		X	
Rate Structures			
Transmission Service		X	
Residential Inclining Block			X
Codes and Standards			
General Service Lamps		X	
Commercial Building Code			X
Process Evaluations			
TBD		X	

Data Collection Activities			
Retail Program Survey	X	X	X
Commercial/Industrial Program Survey	X	X	X
Retail Shelf Space Study	X	X	X
TV Sales Data	X	X	X
Residential In Home Audits	X		
Commercial New Construction Trade Ally Interviews	X		
Residential Behaviour Program Survey		X	
Residential End Use Survey		X	
Residential Inclining Block Rate Survey		X	
Home Energy Rebate Offer Surveys			X
Commercial End Use Survey			X

3 Measurement and Verification

Purpose and Objectives

The primary objective of BC Hydro’s measurement and verification activities is to support demand-side management investment decisions, rate structure implementation decisions, demand-side management program evaluations and customer satisfaction by verifying electrical energy savings at the project level.

Principles

BC Hydro’s measurement and verification activities are guided by the following six principles:

1. Neutrality
   BC Hydro’s measurement and verification efforts are intended to be neutral and unbiased when verifying electrical energy savings resulting from demand-side management projects.
2. Professional Standards
   BC Hydro’s measurement and verification efforts are consistent with the

industry standard protocol, the International Performance Measurement and Verification Protocol. This protocol is a guidance document describing common practice in measuring, computing and reporting savings achieved by energy efficiency projects at end user facilities.

3. Qualified Practitioners

BC Hydro employs qualified and professional staff members and contractors who are familiar with the International Performance Measurement and Verification Protocol to perform measurement and verification.

4. Specified Selection Criteria

Energy savings projects are selected to undergo measurement and verification in accordance with specified criteria that are designed to provide a sufficient level of coverage. BC Hydro's measurement and verification efforts are concentrated primarily in the commercial and industrial sectors. BC Hydro's practice of undertaking limited measurement and verification activities in the residential sector is consistent with common industry practice.

5. Business Integration

BC Hydro integrates measurement and verification into the business process of demand-side management planning, implementation, verification and reporting. This enables continuous improvement of demand-side management programs and initiatives.

6. Coordination

BC Hydro strives to coordinate measurement and verification efforts with FortisBC Energy Inc. and other demand-side management partners where feasible.

Activities

BC Hydro's measurement and verification efforts involve three major activities: data collection, data analysis and the review of Transmission Service Rate customer submissions under the Tariff Supplement No. 74 Customer Baseline Load Guidelines.

Data collection can involve the collection of data from a variety of sources, including:

1. Electricity billing data for a whole facility from BC Hydro;
2. Electricity consumption data at an end use or equipment level from the customer and/or from temporary metering installed by BC Hydro;
3. Hours of use data at an end use or equipment level from the customer and/or from temporary metering installed by BC Hydro;
4. Production or operational data at a facility or operating area level from the customer; and
5. Weather data from weather data providers.

The collected data is analyzed to estimate the energy savings resulting from the demand-side management project. BC Hydro reports energy savings based on conditions during the reporting or post-retrofit period. Energy savings are quantified relative to the energy use that would have occurred during the reporting period in the absence of the project. In this situation, energy savings are calculated as follows:

Energy savings = Adjusted Baseline Energy Consumption – Reporting Period Energy Consumption

The analysis imposes the reporting period operating conditions (e.g., production levels, weather) on the pre-retrofit or baseline configuration to estimate the energy consumption that would have occurred during the reporting period in the absence of the energy saving measures. This is adjusted baseline energy consumption. The difference between adjusted baseline energy consumption and actual energy consumption during the reporting period constitutes the energy savings during the reporting period.

Depending on the energy saving measures implemented, a variety of data analysis techniques can be used, including:

1. Regression analysis of measured energy consumption against measured drivers of electricity consumption;
2. Multiplication of measured lighting hours of use and changes in lighting fixture wattages; or
3. Calibrated computer simulation modelling of a facility or end-use equipment.

Measurement and verification is performed on both small and large commercial and industrial projects. Small project measurement and verification provides input data for program evaluations and enables BC Hydro to check the accuracy of earlier steps in the demand-side management energy savings refinement process. Large project measurement and verification does the same and also informs final incentive payments and demand-side management energy savings reporting.

BC Hydro’s measurement and verification function also supports implementation of the Transmission Service Rate for large industrial customers. The Transmission Service Rate uses a customer-specific Customer Baseline Load to calculate the customer’s energy bill. The Customer Baseline Load is determined in accordance with Tariff Supplement No. 74, and is an estimate of the customer’s historical annual energy consumption prior to the customer commencing service under the Transmission Service Rate. To take advantage of the rate’s pricing structure, customers that have implemented energy saving measures or increased the capacity of their plants must submit a Customer Baseline Load adjustment claim to

BC Hydro. BC Hydro reviews these submissions to substantiate the Customer Baseline Load adjustment claim.

4 Organizational Structure

Evaluation, measurement and verification is an integral part of demand-side management program and conservation rate implementation. The Evaluation, Measurement and Verification departments are located within Conservation and Energy Management, BC Hydro's demand-side management business unit. This supports quality and valuable evaluation, measurement and verification services by facilitating information exchange between Evaluation, Measurement and Verification staff and internal clients. Evaluation, Measurement and Verification staff understand BC Hydro's demand-side management programs and initiatives and are well-positioned to satisfy internal client needs for evaluation, measurement and verification services. Similarly, internal clients are better able to understand evaluation, measurement and verification objectives, principles and activities because of their proximity to the evaluation, measurement and verification functions.

Independence

The independence of the evaluation, measurement and verification function from other functions in Conservation and Energy Management is important and established through the organizational structure. The Evaluation, Measurement, and Verification departments are separate from, and have different managers than, the departments responsible for the development and management of demand-side management programs and initiatives. Independence of the evaluation, measurement and verification functions is further maintained through the oversight processes described below.

Oversight

In the interest of quality and independence, both evaluation, and measurement and verification have oversight processes to ensure that their products are neutral and align with industry practice.

For evaluation, the oversight process includes the following steps:

1. Evaluation plans and methodologies are reviewed by Evaluation, Measurement and Verification management as well as an internal evaluation peer. Evaluation plans involving new methodologies may also be reviewed by external evaluation advisors;
2. Draft evaluation reports are reviewed by two external evaluation advisors who ensure that BC Hydro evaluations utilize appropriate methodologies and align with industry practice. Draft reports are also reviewed by Evaluation, Measurement and Verification management and internal peers; and
3. Final evaluation reports are reviewed and subject to approval by an Evaluation Oversight Committee made up of BC Hydro staff representing business units with an interest in demand-side management and chaired by a staff person from outside the Conservation and Energy Management business unit. The external evaluation advisors are present as a resource to the Evaluation Oversight Committee and able to provide their opinions on issues related to the reports. The Evaluation Oversight Committee ensures that BC Hydro's demand-side management evaluations are objective, unbiased and of sufficient quality.

For measurement and verification, the oversight process includes the following steps:

1. Measurement and verification results for complex projects are reviewed by internal measurement and verification peers; and

2. A sample of measurement and verification reports are reviewed by an external measurement and verification advisor to ensure that they utilize appropriate methodologies and align with industry practice.

5 Annual Evaluation Reports to the Commission

In compliance with Directive 66 (page 197) of the Commission Decision dated October 29, 2004, BC Hydro submits an annual Demand-Side Management Milestone Evaluation Summary Report to the Commission. Appendix Z includes the past three annual reports, covering fiscal 2013, fiscal 2014 and fiscal 2015.

BC Hydro
Power smart

Fiscal 2017 to Fiscal 2019
Revenue Requirements Application

Appendix Z

Attachment 1

Fiscal 2013 Demand-Side Management Milestone Evaluation Summary Report

Janet Fraser
Chief Regulatory Officer
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February 28, 2014

Ms. Erica Hamilton
Commission Secretary
British Columbia Utilities Commission
Sixth Floor – 900 Howe Street
Vancouver, BC V6Z 2N3

Dear Ms. Hamilton:

RE: British Columbia Utilities Commission (BCUC)
British Columbia Hydro and Power Authority (BC Hydro)
2004/05 and 2005/06 Revenue Requirements Application
BCUC Decision: Order No. G-96-04 October 29, 2004, Directive 66 (page 197)

BC Hydro writes to submit its F2013 Demand Side Management Milestone Evaluation Summary Report (**the Report**), dated February 28, 2014 in compliance with Directive 66 (page 197) of the BCUC Decision dated October 29, 2004. Directive 66 directs BC Hydro to file the executive summaries of its milestone evaluation reports and full final evaluation reports for all its Power Smart programs. The Report summarizes the milestone evaluations completed during F2013 for the following:

1. Consumer Electronics Program: F2010
2. Residential Lighting Program: F2012
3. Refrigerator Buy-Back Program: F2011 – F2012
4. Residential Behaviour Program: F2011 – F2012
5. Renovation Rebate Program: F2009 – F2011
6. Power Smart Partners – Transmission Program: F2010 – F2011

BC Hydro notes that the Report has been prepared for the purpose of this compliance filing.

BChydro

For further information, please contact Geoff Higgins at 604-623-4121 or by email at bchydroregulatorygroup@bchydro.com.

Yours sincerely,

Janet Fraser
Chief Regulatory Officer

sh/ma

Enclosure (1)

Demand Side Management Milestone Evaluation

Summary Report F2013

February 2014

ABSTRACT

This report provides a summary of Milestone Demand Side Management (**DSM**) Evaluations completed by Power Smart Evaluation during F2013.

ACKNOWLEDGEMENTS

The Power Smart Evaluation team wishes to thank the members of the Evaluation Oversight Committee and the external DSM evaluation advisors for their assistance and support.

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1.0 Introduction

BC Hydro evaluates its DSM initiatives to document their activities and impacts, to validate energy and peak savings and to improve the design and operation of initiatives. The objective of BC Hydro's DSM evaluation function is to provide timely, credible, actionable, and cost-effective evaluation studies. BC Hydro uses the California Evaluation Framework[1] as a guide to undertaking DSM evaluations and related activities.

1.1 Background

BC Hydro undertakes a comprehensive approach to confirm the electricity savings that result from its DSM initiatives. A key aspect of this approach is the evaluation of DSM initiatives. Evaluation activities center on three main categories, which are described below: process evaluations, market evaluations and impact evaluations. The basic objectives of evaluations are to document activities, assess impacts, and identify opportunities for improvement.

The British Columbia Utilities Commission (***BCUC***) Resource Planning Guidelines note: "*Because of measurement difficulties and uncertainty about consumer behaviour, DSM programs should be evaluated before and after implementation to determine their full impacts*." Further, in Directive 69 of its decision on BC Hydro's F05/06 Revenue Requirements Application, the BCUC directed BC Hydro to file "*executive summaries of its milestone evaluation reports and full final evaluation reports for each program*".

BC Hydro determines the impact of its DSM initiatives in the following manner. First, a complete evaluation plan is prepared covering the scope, issues, timing and expected costs of the evaluation study(s). Second, evaluations are conducted at major initiative milestones and can include elements of process, market, and impact evaluations. Third, evaluations are reviewed and approved by a BC Hydro cross-functional DSM Evaluation Oversight Committee (**EOC**), chaired by a manager from outside the Power Smart business group. The structure of the EOC follows recommendations from the BCUC in 2004 to diversify the membership to ensure third party DSM evaluation oversight. BC Hydro also has two external senior advisors who provide assistance and support to the Power Smart Evaluation department to ensure that BC Hydro's DSM evaluations align with industry best practice.

[1] The California Evaluation Framework provides a consistent, systemized, cyclic approach for planning and conducting evaluations of energy efficiency programs. The framework is widely used in the DSM evaluation industry.

1.2 DSM Evaluation Principles and Approach

BC Hydro's approach to DSM evaluation emphasizes four main principles:

1. Undertaking baseline studies and periodic data collection to understand the nature and size of the pre-program market and changes in the market over time.
2. Leveraging existing program, market, and customer data to minimize evaluation costs.
3. Using multiple lines of evidence to increase the credibility, validity, and reliability of evaluation findings
4. Reviewing and approving completed evaluation studies by the Evaluation Oversight Committee, which represents key stakeholders.

DSM evaluations are often divided into three main categories: process evaluations, market evaluations, and impact evaluations. These three types of studies can be summarized as follows:

Process Evaluations. In process evaluations, the researcher identifies and describes the program model or program logic, start-up procedures, implementation procedures and anticipated outcomes. Key issues for process evaluations may include the following:

- Are program goals clear, well defined, measurable, and achievable?
- Are the goals clearly communicated through the organization?
- Is responsibility clearly defined?
- How efficient and effective are program processes?
- How can program processes be improved?
- What is the extent of stakeholder awareness of and participation in the program?
- How satisfied are the stakeholders with the program and its components?

Market Evaluations. In market evaluations, the researcher attempts to understand the impact of the program on the demand-side and the supply-side of the market. Key issues for market evaluations include the following:

- What is the size of the market?
- How much of the market has been captured?
- What is the remaining market potential?
- What are the barriers to market transformation?
- How successfully are the market barriers being addressed?
- What are the sales of more efficient and less efficient products?
- What are the prices of more efficient and less efficient products?

Impact Evaluations. In impact evaluations, the researcher evaluates the goals and objectives of the DSM initiative with respect to the outcomes, whether intended or unintended. Key issues for impact evaluations include the following:

- What are the short-term impacts on clients or stakeholders?
- What are the long-term impacts on stakeholders?
- What are the gross impacts of the initiative on energy consumption and peak demand?
- What are the net impacts of the initiative on energy consumption and peak demand?

1.3 Evaluation Studies

Evaluations summarized in this report include the following:

- Consumer Electronics Program: F2010
- Residential Lighting Program: F2012
- Refrigerator Buy-Back Program: F2011 – F2012
- Residential Behaviour Program: F2011 – F2012
- Renovation Rebate Program: F2009 – F2011
- Power Smart Partners – Transmission Program: F2010 – F2011

2.0 Residential Programs

2.1 Consumer Electronics Program: F2010

2.1.1 Introduction

The Consumer Electronics program is a multi-year energy acquisition and market transformation initiative that encourages its customers to purchase energy efficient televisions and recycle unneeded televisions. The program goals are to:

1. Generate energy savings and increase the market penetration of more efficient televisions by partnering with retailers to influence the consumer television buying decision;
2. Generate energy savings by reducing the number of obsolete televisions in the home; and
3. Increase consumer awareness of energy efficiency by calling attention to the electricity use of televisions, both in older televisions in the home and new televisions being purchased.

The purpose of this study is to conduct an evaluation of the Consumer Electronics program for BC Hydro's fiscal year 2010 (**F2010**). The study includes an impact evaluation and elements of a market evaluation.

The target market includes both residential customers and supply chain actors, including manufacturers, retailers, and recyclers. The initial ENERGY STAR® 3.0 (Energy Star) specification for televisions came into force in November 2008, with subsequent standards developed by the Consortium for Energy Efficiency (**CEE**). The Power Smart Consumer Electronics program was launched on April 1, 2009, with an initial mid-stream or retailer incentive of $20.00 per CEE Tier 2 television, with the CEE Tier 2 specification being 15 per cent better than Energy Star 3.0. Given the rapid evolution of the market, there have been frequent revisions of the Consumer Electronics mid-stream retailer offer.

2.1.2 Objectives and Methods

For this study, there were six main objectives:

1. Conduct a program review
2. Undertake a supply-side assessment
3. Undertake a demand-side assessment
4. Produce and analyze television hours of use and load information
5. Estimate energy and peak demand savings
6. Conduct a comparison with comparable programs of other leading utilities

The study approach used multiple lines of evidence, since no single line of evidence provided information on all of the evaluation issues for this study of the television market.

1. **Program Review.** To conduct the program review and develop the program logic model, we reviewed program documents, interviewed BC Hydro program staff, and conducted a literature review focussing on recent studies and reports on televisions. Information from the CEE was particularly useful.

2. **Supply Side Assessment.** To undertake the supply side assessment, we tabulated and examined relevant results of an annual retail store tracking study that covers representative samples of stores. We also conducted a Consumer Electronics trade ally survey.
3. **Demand Side Assessment.** To undertake the demand side assessment, we tabulated and examined relevant results of the Energy Star Awareness Quarterly Tracking Survey and the Television Baseline Survey.
4. **Hours of Use.** To produce and analyze information on hours of use profiles by season, we conducted a one-year Residential Monitoring Study that measured television hours of use.
5. **Energy and Peak Demand Savings.** To estimate peak demand and energy savings, engineering algorithms were populated with the results of items 2 through 4 described above.
6. **Program Comparison.** To compare BC Hydro Power Smart's Consumer Electronics program with those of other leading utilities, a literature review was conducted.

2.1.3 Results

Program Review. At the time of program launch in 2009, market analysis indicated that there were several barriers to increased sales of energy efficient televisions in British Columbia including low awareness of Energy Star and CEE qualified televisions among consumers, relatively low availability of televisions with high energy efficiency levels in retail stores, and relatively high prices for energy efficient televisions.

BC Hydro has employed a phased strategy to transform the television market and acquire energy and peak demand savings. The program has successfully addressed these barriers through four main components: specifications development, information and promotions, financial incentives, and retailer training. The program rationale was examined using a program logic model, which was developed from interviews with program staff, a documents review and a literature review. This review and analysis confirmed that the basic program logic was valid. There were strong linkages among inputs, outputs, purposes and goal statements. Indicators for key components of the logic model were clear, well defined and measurable.

Supply Side Assessment. There was a shift in the distribution of televisions for sale in retail stores in British Columbia towards higher energy efficiency levels between 2009 and 2010. Average price decreased by about 5 per cent, from $1,134 in 2009 to $1,084 in 2010. There is generally an increase in price as the energy efficiency level increases. The average price of a Tier 4 television, the highest efficiency level, was found to be $1,390 compared to the average price of $640 for base television sets that do not meet minimum Energy Star requirements.

Demand Side Assessment. Highlights of the demand side assessment are as follows:

- Number Owned. 97 per cent of the 641 Television Baseline Survey respondents stated that they had at least one television, while the remaining 3 per cent stated that they had none. About two-thirds of respondents owned more than one television.
- Hours of Use. For their four most important televisions ranked by hours of use, respondents to the Television Baseline Survey were asked how many hours per day they used each television. First televisions were reportedly used an average of 4.5 hours per day on weekdays and 5.4 hours per day on weekends.
- Purchase decision factors. Those respondents who had purchased a television in the previous two years were asked to state the most important factor in their decision to choose that

particular television instead of choosing another television. Thirty-five per cent said that factor was the price, 16 per cent said it was picture quality, 13 per cent said it was features, 12 per cent said it was overall quality, 11 per cent said it was size, 6 per cent said it was brand name and 3 per cent said it was energy efficiency.

- Customer Awareness. Respondents to the Energy Star Awareness Quarterly Tracking Survey had high levels of awareness of Energy Star televisions and of television recycling.

Hours of Use. A 12-month Residential Monitoring Study of hours of use was conducted in 48 households. Run time meters were used to collect fifteen minute interval data for the production of load shapes, hourly use by season and annually, and peak coincident television usage. Average measured daily hours of use were 5.6 hours, and the measured share of televisions on during BC Hydro's peak demand period was 49.7 per cent.

Energy and Peak Demand Savings. Net energy savings for new televisions are estimated as the product of participating units, unit kW savings, measured hours of use, electricity cross effects adjustment and net to gross ratio. Net energy savings for recycled televisions are estimated as the product of incremental units, unit kWh savings, electricity cross effects adjustment and a net to gross ratio. Peak demand savings refer to program impact on the load during the peak demand period, which is 4:00 p.m. to 9:00 p.m. during the winter.

To estimate peak demand (kW) and energy (kWh) savings for new televisions, we used the algorithms (1) and (2) shown below.

(1) ΔkWh = Incented units * unit power savings * measured hours of use * electricity cross effects adjustment * net to gross ratio.

(2) ΔkW = Incented units * unit power savings * peak coincidence factor * electricity cross effects adjustment * net to gross ratio.

To estimate peak demand (kW) and energy (kWh) savings for recycled televisions, we used the algorithms (3) and (4) shown below. Evaluated peak demand savings were derived by applying the residential rate class load shape (capacity) factor to the net evaluated energy savings. The factor was developed through internal BC Hydro calculations.

(3) ΔkWh = Recycled units * unit energy savings * electricity cross effects adjustment * net to gross ratio.

(4) ΔkW = Recycled units * unit energy savings * capacity factor * electricity cross effects adjustment * net to gross ratio.

Table 2.1 New Energy Efficient Televisions Energy Savings, F2010

CEE Energy Specification	Incented Units (000)	Unit Power Savings (W)	Annual Hours of Use	Cross Effects Adjustment (1 – electricity cross effects)	Net to Gross Ratio (1 – free riders)	Net Energy Savings (GWh/year)
Tier 2	58	22	2,044	0.92	0.74	1.8
Tier 3	37	45	2,044	0.92	0.74	2.3
Tier 4	15	94	2,044	0.92	0.74	2.0
Total	110					6.1

Table 2.2 New Energy Efficient Televisions Peak Demand Savings, F2010

CEE Energy Specification	Incented Units (000)	Unit Power Savings (W)	Peak Coincidence Factor	Cross Effects Adjustment (1 - electricity cross effects)	Net to Gross Ratio (1 - free riders)	Net Peak Demand Savings (MW)
Tier 2	58	22	0.497	0.92	0.74	0.4
Tier 3	37	45	0.497	0.92	0.74	0.6
Tier 4	15	94	0.497	0.92	0.74	0.5
Total	110					1.5

Table 2.3 Recycled Televisions Energy and Peak Demand Savings, F2010

	Units (000)	Share Plugged In	Unit Energy Use (kWh/year)	Cross Effects Adjustment (1 - electricity cross effects)	Net to Gross ratio	Net Energy Savings (GWh/year)	Peak Coincidence Factor	Net Peak Demand Savings (MW)
Total	153	0.80	79	0.92	0.42	3.7	0.25	0.9

Summary savings estimates are shown in the following table.

Table 2.4 Energy and Peak Demand Savings, F2010

Year	Energy Savings (GWh/year)		Peak Demand Savings (MW)	
	Reported	Evaluated	Reported	Evaluated
F2010	8.6	9.8	2.0	2.4

Program Comparison. It is useful to compare Power Smart's program offering with those of other utilities. Incentives offered by 24 organizations for five consumer electronics technologies were included in comparison, based on CEE data. The key observation is that BC Hydro's offer is comparable to those of other leading utilities in the market for consumer electronics.

2.2 Residential Lighting Program: F2012

2.2.1 Introduction

This report provides an impact evaluation and elements of a market evaluation of the Residential Lighting program, a multi-year energy acquisition and market transformation initiative that encourages its customers to use energy-efficient lighting, with a focus on compact fluorescent lamps (**CFLs**), light emitting diodes (**LEDs**), energy efficient fixtures and LED fixtures. The objectives of the program include:

1. Sustain and increase a greater market share of energy efficient lighting products in advance of regulations for more efficient lighting
2. Promote efficient lighting products not covered by regulations and newer products such as LEDs
3. Promote and increase awareness province wide and drive customers to retailers to purchase efficient products
4. Provide residents province-wide with an accessible and simple lighting program

2.2.2 Objectives and Methods

For this study, there were six main objectives: (1) conduct a program review; (2) undertake a supply side assessment; (3) undertake a demand side assessment; (4) measure hours of use and peak demand; (5) estimate energy and peak demand savings; and (6) conduct a program comparison.

1. **Program Review.** To conduct the program review and develop the program logic model, we conducted staff interviews and reviewed program documents.
2. **Supply Side Assessment.** To undertake the supply side assessment, we conducted trend analysis using data from an annual retail store tracking study that covers representative samples of stores (about 40 establishments per year) and a trade ally survey.
3. **Demand Side Assessment.** To undertake the demand side assessment, we conducted customer surveys in British Columbia (n = 601) and the comparison group of North and South Dakota (n = 601) and undertook z-tests for differences.
4. **Hours of Use and Peak Coincidence.** To measure hours of use and peak coincidence, we used load monitoring data (n =377 measurement points) with each lamp monitored for at least 12 months.
5. **Energy and Peak Demand Savings.** To estimate energy and demand savings, we used engineering algorithms based on the information just cited as well as sales data.
6. **Program Comparison.** To conduct the program comparison, we undertook a detailed literature review.

2.2.3 Results

Program Review. From a program logic perspective, there were three main program activities: retailer education, product rebates and consumer education.

1. Power Smart has provided retailer education for the residential lighting market since the inception of the program. Retailer education is a key component of the current Residential Lighting program, with retailer education conducted both in-store and on-line.

2. Product rebates are aimed at creating customer interest in energy efficient lighting and reducing first costs. The Lighting Campaign in Spring 2011 included in-store instant discounts on selected lighting products from March 1 to April 30, 2011, while the Lighting Campaign in Fall 2011 included in-store instant discounts on selected lighting products from October 1 to November 30, 2011.
3. Consumer education is aimed at creating customer awareness, knowledge and purchase intent for energy efficient lighting products, and the lighting campaigns included radio, print, television and point of purchase materials.

The program rationale was examined using a program logic model, which was developed from interviews with program staff, a documents review and a literature review. This review and analysis confirmed that the basic program logic was valid. There were strong linkages among inputs, outputs, purposes and goal statements. Indicators for key components of the logic model were clear, well defined and measurable.

Supply Side Assessment. The purpose of the supply side analysis was to examine product shelf space share, product prices, and product wattages.

1. For the three years for which we have data, the shelf stock shares by lamp type are constant, with the combined share of CFL and LED lamps at 28 per cent
2. From F2010 to F2012, incandescent lamps have fallen in price, and most types of CFLs have increased in price. Reasons for the increases in CFL prices are not known
3. Average wattage for incandescent lamps declined significantly from F2011 to F2012, which is what one might expect given the Provincial lamp regulation, which effectively eliminated standard A-line shape 75 watt and 100 watt lamps. Average wattage for CFLs and LEDs did not change significantly from F2011 to F2012.
4. The trade ally survey focussed on marketing executives and managers responsible for consumer lighting with major retail chains and examined retailer views on several program dimensions. Surveys were completed with nine retailers. Almost all of the trade allies surveyed responded that: the lighting program marketing materials were very or somewhat effective in promoting sales of Energy Star lighting; the program incentives were very effective in encouraging them to purchase and stock Energy Star lighting products; and, current program activities were effective in encouraging the retailer to sell more Energy Star lighting products. All of the respondents responded that they were very or somewhat satisfied with Power Smart's current Residential Lighting Program.

Demand Side Assessment. The purpose of the demand side analysis was to examine customer product awareness, lamp purchase behaviour and program attribution of energy savings for six product categories - four lamp categories and two fixture categories - using information from North and South Dakota for comparisons.

1. British Columbia (**B.C.**) survey respondents show a higher level of product awareness than Dakota survey respondents for all four lamp categories, and these differences are statistically significant for three lamp product categories, but not for incandescent lamps
2. BC survey respondents show a higher level of purchase than Dakota survey respondents for incandescent lamps, LED lamps, halogen lamps and fixtures, but a lower rate of purchase for basic CFLs and specialty CFLs
3. Customer satisfaction for specialty CFL and LED lamps was very similar in the two jurisdictions

4. Survey respondents were asked how influential program activity was in their decision to purchase energy efficient lighting products, and free rider rates were calculated by weighting the responses and finding a weighted average, with a free rider rate of 19 per cent for specialty CFLs and 27 per cent for Energy Star fixtures
5. Sales data was used to develop a free rider rate of 11 per cent for LED lamps and 16 per cent for LED fixtures
6. Spillover was estimated by comparing the purchase rates between B.C. and North and South Dakota, and found to be zero for CFLs and 293 per cent for LEDs

Hours of Use and Peak Coincidence. Estimates for daily hours of use and peak coincidence were based on an in home monitoring study. Daily hours of use is an annual average based on twelve months of monitoring, and peak coincidence is the share of lamps which were on during the typical winter peak period. Information on location of lamps and fixtures by room was used to weight the monitored hours of use by room to calculate daily hours of use and peak coincidence for lamps and for fixtures, with the results shown.

Table 2.5 Hours of Use and Peak Demand

	Daily Hours of Use	Peak Coincidence (Share of products on during peak)
Lamps	2.56	31.1%
Fixtures	3.18	39.4%

Energy and Peak Demand Savings. Key variables in the calculation of energy and peak demand savings algorithms are unit energy savings, unit peak demand savings, the installation rate net of replacements, the free rider rate, the spillover rate, the electricity cross effects (**CE**) adjustment, and the number of rebated units in millions. The delta watts estimates were provided from program information based on BC Hydro internal analysis, and the annual hours and peak coincidence estimates came from the Residential Load Monitoring Study. Installation rates were derived from participant surveys. Free rider rates are explained above, while the estimate of one minus cross effects comes from a recent internal BC Hydro study. For energy savings, the basic algorithm is:

$$\Delta GWh = \Delta W * Hours * Install * (1 - FR + SO) * (1 - CE) * Units.$$

For peak savings, the basic algorithm is:

$$\Delta MW = \Delta W * \text{Coincidence} * \text{Install} * (1 - FR + SO) * (1 - CE) * \text{Units}.$$

Table 2.6 Net Unit Savings

Product	Unit energy savings (kWh/year)	Unit peak demand savings (W)	Install rate	1 - free rider rate	1 - electricity cross effects	Net unit energy savings (kWh/year)	Net unit peak demand savings (W)
CFL	49.5	16.4	0.94	0.81	0.95	35.8	11.9
LED	41.1	13.6	0.82	0.89	0.94	28.2	9.3
LED fixtures	61.5	20.7	1.00	0.84	0.94	48.6	16.3
CFL fixtures	127.7	42.9	1.00	0.73	0.98	91.4	30.7

Table 2.7 Net Energy and Demand Savings

Product	Net unit Energy Savings (kWh/year)	Net unit peak demand Savings (W)	Program Incented Units	Energy Savings without Spillover (GWh/year)	Peak Demand Savings without Spillover (MW)	Energy Savings with Spillover (GWh/year)	Peak Demand savings with Spillover (MW)
CFL	35.8	11.9	236,532	8.5	2.8	8.5	2.8
LED	28.2	9.3	140,402	4.0	1.3	15.6	5.1
LED fixtures	48.6	16.3	12,322	0.6	0.2	0.6	0.2
ES fixtures	91.4	30.7	40,567	3.7	1.2	3.7	1.2
			Total	**16.7**	**5.6**	**28.4**	**9.3**

Evaluated energy savings were 28.4 GWh compared to reported energy savings of 15.5 GWh, while evaluated peak savings were 9.3 MW compared to reported peak savings of 5.5 MW.

Table 2.8 Energy and Peak Demand Savings

Year	Energy Savings (GWh/y)		Peak Demand Savings(MW)	
	Reported	Evaluated	Reported	Evaluated
F2012	15.5	28.4	5.5	9.3

Program Comparison. The purpose of the program comparison was to compare Power Smart's residential lighting offering with those of other leading utilities, including the budget, forecast savings, and the scope of the offer. BC Hydro's offer is comparable to those of other leading utilities in the market for energy efficient lighting.

2.3 Refrigerator Buy-Back Program: F2011 and F2012

2.3.1 Introduction

This report provides an impact evaluation and elements of a market evaluation of the Refrigerator Buy-Back program for BC Hydro's fiscal years 2011 and 2012 (F2011-F2012). The Refrigerator Buy-Back program is a multi-year energy acquisition and market transformation initiative that encourages its customers to turn in unused or little used refrigerators for recycling in an environmentally friendly manner. The program offer has three main features:

1. Free refrigerator pick-up from customers' homes
2. Free disposal of the refrigerator in an environmentally friendly manner
3. $30 incentive for each refrigerator collected with a maximum of two refrigerators per household. The program also offered limited freezer pick up

The Refrigerator Buy-Back program objectives are to:

1. Generate energy savings for BC Hydro by reducing the number of inefficient spare refrigerators in the market and by removing inefficient refrigerators from the resale market
2. Provide a specific opportunity for customers to reduce their electricity bills
3. Increase consumer awareness of energy efficiency and home energy management by educating customers about the high electricity consumption associated with spare refrigerators

2.3.2 Objectives and Methods

For this study, there were six main objectives: (1) conduct a program review; (2) undertake a supply side assessment; (3) undertake a demand side assessment; (4) produce and analyze hours of use and load information data; (5) estimate energy and peak demand savings; and (5) examine the extent of market transformation.

1. **Program Review.** To conduct the program review and develop the program logic model, we reviewed program documents, interviewed BC Hydro program staff, and conducted a literature review focussing on recent studies and reports on appliance recycling programs.
2. **Supply Side Assessment.** To conduct the supply side assessment we tabulated and examined relevant results of an annual retail store tracking study that covers representative samples of stores (about 40 appliance retailers per year).
3. **Demand Side Assessment.** To conduct the demand side assessment we tabulated and examined relevant results of the participant and non-participant surveys. Each of these surveys included 401 respondents and provides accuracy of plus or minus 5 per cent, 19 times out of 20.
4. **Metering Study.** To analyze refrigerator power consumption, we conducted energy consumption testing at BC Hydro's Powertech Labs facility.
5. **Energy and Peak Demand Savings.** To estimate peak demand (kW) and energy (kWh) savings for recycled refrigerators and freezers, we used engineering algorithms.
6. **Market Transformation.** To estimate the extent of market transformation, we estimated times-series models of the saturation rate for second refrigerators.

2.3.3 Results

Program Review. The program had three main activities: marketing, refrigerator pick-up and recycling. The rationale for the Refrigerator Buy-Back program was examined using this program logic model, which was developed from interviews with staff, a documents review and a literature review. This review and analysis confirmed that the basic program logic was valid. There were strong linkages among inputs, outputs, purposes and goal statements. Indicators for key components of the logic model were clear, well defined and measurable.

Supply Side Assessment. The assessment of the supply side of the market for refrigerators was based on the four most recent annual retail store tracking studies, conducted in about 40 appliance retail stores each year. Key supply trends were as follows:

- **Capacity.** For all refrigerator types, average capacity was 20.3 cubic feet in each of 2009, 2010 and 2011 and increased slightly to 20.9 cubic feet in 2012.
- **Energy Consumption of New Refrigerators.** Average energy consumption has not changed significantly over the period 2009-2012, and for all refrigerator types, average energy consumption was 488 kWh per year in 2009, 471 kWh per year in 2010, 469 kWh per year in 2011 and 470 kWh per year in 2012.
- **Price.** The average price of a refrigerator was $1,613 in 2012, an increase of $85 from 2011. The lowest priced refrigerator was $290 and the highest priced refrigerator was $14,350.

Demand Side Assessment. The assessment of the demand side of the market was based on a quasi-experimental design using a survey of 401 program participants and 401 non-participants. Highlights of the demand side assessment are as follows:

- **Refrigeration Saturation.** Non-participants owned an average of 2.37 refrigerators compared to 1.48 refrigerators for participants, and the difference was statistically significant.
- **Operational Rate.** Participants were more likely to have disposed of a refrigerator that was operational at the time of disposal (91 per cent) than were non-participants (74 per cent), and the difference was statistically significant.
- **Capacity of Refrigerator.** There is no significant difference in refrigerator capacity between refrigerators recycled by program participants and non-participants.
- **Age of Refrigerator.** Participants recycled refrigerators which were significantly older than those recycled by non-participants, with an average age of 18.0 years for participants compared to 13.5 years for non-participants.
- **Program Influence.** Participants were more likely to be influenced by the program in their decision to recycle the refrigerator than non-participants, and the difference was statistically significant.
- **Participant Satisfaction.** Participants had high levels of satisfaction with the initial call to arrange a refrigerator pick-up, arranging a pick-uptime, and overall satisfaction with the program.
- **Program Awareness.** Seventy one per cent of non-participant respondents had heard of the program before the survey was administered.

Metering Study. BC Hydro pick-up contractors delivered 400 refrigerators to the BC Hydro Powertech Labs testing facility. Of the 400 units, only 337 refrigerators were operative and tested. The 63 units not included in the final database did not operate for various reasons or developed problems soon after they were plugged in at the testing facility. Units are moved multiple times before reaching the Powertech Labs, resulting in damage to some units rendering them inoperable. The refrigerators operating between 1°C and 5°C consumed an average of 69.3 kWh per month, while the average for all the refrigerators that provided acceptable test data was 75.4 kWh per month or 905 kWh per year.

Energy and Peak Demand Savings. Gross unit refrigerator energy consumption was calculated based on the results of the metering study, while gross unit freezer energy consumption was calculated based on an industry standard refrigerator to freezer energy consumption ratio.

Free ridership was calculated using the destination approach with participant survey data as inputs. The destination approach is a standard framework for the evaluation of appliance recycling programs and is used to assess the probability that a fridge would stay connected to the BC Hydro grid in the absence of the program recycling it. Non-participant spillover was calculated based on the outcome of the non-participant survey and market data. Free ridership and non-participant spillover were combined to generate a net to gross ratio.

An adjustment for electricity cross effects was applied to account for the space heating penalty and cooling system benefit associated with increased energy efficiency. A deduction was also applied to account for the operational rate, the proportion of refrigerators that were not operational.

The program is not assumed to induce the purchase of new refrigerators and therefore no deduction is made for the energy consumption of new refrigerators. This assumption is supported by the program design and evaluation industry standard practice for appliance recycling programs, as well as evidence from the Supply Side Assessment, Demand Side Assessment, and Metering Study.

To estimate net peak demand (kW) and energy (kWh) savings for recycled refrigerators and freezers, we used engineering algorithms.

(1) ΔkWh = Program incented units * unit energy savings * operational rate * electricity cross effects adjustment * net to gross ratio.

(2) ΔkW = Program incented units * unit demand savings * operational rate * electricity cross effects adjustment * net to gross ratio.

The following table provides the net unit energy and peak demand savings for refrigerators and freezers.

Table 2.9 Net Unit Energy and Peak Demand Savings

	Gross Unit Energy Savings (kWh/y)	Gross Unit Demand Savings (W)	Net to Gross Ratio	Electricity Cross Effects Adjustment	Operational Rate	Net Unit Energy Savings (kWh/y)	Net Unit Demand Savings (W)
Refrigerator	905	109	0.74	0.94	0.85	535	63
Freezer	812	97	0.74	0.98	0.85	501	60

Net total energy savings are the product of net unit energy savings and the number of units picked up by the program. Net total peak demand savings are the product of net unit peak demand savings and the number of units picked up by the program.

Table 2.10 Net Total Energy and Demand Savings

Year	Appliance	Net Unit Energy Savings (kWh/year)	Net Unit Demand Savings (W)	Units	Net Energy Savings (GWh/year)	Net Demand Savings (MW)
F2011	Refrigerator	535	63	33,573	18.0	2.1
	Freezer[2]	501	60	625	0.3	0.0
				Total	**18.3**	**2.2**
F2012	Refrigerator	535	63	31,493	16.8	2.0
	Freezer[2]	501	60	633	0.3	0.0
				Total	**17.2**	**2.0**

Reported and evaluated energy and peak demand savings for the Refrigerator Buy-Back Program in F2011 and F2012 are compared in the following table.

Table 2.11 Reported and Evaluated Energy and Peak Demand Savings

Year	Energy Savings (GWh/year)		Peak Demand Savings (MW)	
	Reported	Evaluated	Reported	Evaluated
F2011	21.2	18.3	2.4	2.2
F2012	17.9	17.2	2.0	2.0

Market Transformation. The key findings are that:

- Presence of the program reduces the overall saturation rate of second refrigerators by about 1.4 per cent per year
- Presence of the program reduces the single family dwelling saturation rate of second refrigerators by about 2.2 per cent per year
- Presence of the program reduces the duplex and row house saturation rate of second refrigerators by about 1.2 per cent per year

2 Freezers were included in the program for a brief period on a trial, promotional basis.

2.4 Residential Behaviour Program F2011 – F2012

2.4.1 Introduction

BC Hydro launched the Residential Behaviour Program in October 2008 under the Team Power Smart advertising campaign as a multi-year behavioural change and energy acquisition program. It resides alongside the Residential Inclining Block (**RIB**) rate and Smart Metering Infrastructure (**SMI**) as one of three complementary Demand Side Management initiatives that aim to capture cost-effective behavioural energy savings by encouraging customers to improve energy efficiency and to adopt more energy conscious behaviours in their homes.

Energy reduction challenges form the core of the Behaviour Program. Participating households have the opportunity to engage in a 1-year challenge to reduce their home electricity consumption by 10 per cent during that time and, for those that are successful, they can earn a $75 reward in addition to the bill savings that will have incurred. The Behaviour Program had 61,905 participant households in F2011 (fiscal year ending March 31, 2011) and 78,955 households in F2012 (fiscal year ending March 31, 2012).

This report provides an impact evaluation and elements of a process evaluation of the Residential Behaviour Program for F2011 and F2012.

2.4.2 Objectives and Methods

The objectives of this study are to:

1. Profile the population of Behaviour Program participants in terms of their status in the program, their demographic and housing composition, as well as their motivations and attitudes towards energy conservation
2. Estimate the electricity savings attributable to the Program for F2011 and F2012
3. Identify the groups of participants and their associated conservation behaviours that produced the majority of the electricity savings
4. Profile participants in terms of their behaviours, attitudes and experience as related to program achievement

Overview

The program's electricity savings in F2011 and F2012 were estimated using a quasi-experimental design that compared electricity consumption before and after each fiscal year among participant households and a group of pair-matched comparison households. This difference-of-differences method drew on four parameters:

1. Pre-program consumption values among comparison households
2. In-program consumption values among comparison households
3. Pre-program consumption values among participant households
4. In-program consumption values among participant households

The final measure of interest then became the difference of (1) and (2) minus the difference of (3) and (4).

Participant profiling and program insights have been based on survey samples among participants and non-participants. Note that the non-participant survey sample was drawn from BC Hydro's billing system independently of the exercise that pair-matches comparison households.

Approach for Matching

From the total population of program participants, 46,119 participant households in F2011 and 57,703 participant households in F2012 were successfully pair-matched with comparison households based on nearest neighbour matching of annual consumption during their respective pre-program periods (the year before). To address and control for observable parameters, the pool of comparison households eligible to be matched to a given participant was first restricted to those that shared the same region, dwelling type, main space heating fuel and rate group as recorded in BC Hydro's customer billing system. This matching methodology strengthened the internal validity of the quasi-experimental design because the participant and comparison households were pair-matched on critical characteristics. Although matching was based on annual consumption in each pre-program year, post-hoc analysis proved that the two groups were also virtually identical in their monthly consumption values within the pre-program year.

Participant households that went unmatched – 15,786 in F2011 and 21,252 in F2012 – were excluded from average annual household savings calculations, but were later credited when the savings estimates were extrapolated to the entire population of participants.

Approach for Program Impacts

For each fiscal year evaluated, annual savings estimates were computed for nine separate sub-groups of program participants (six 'In-Challenge' groups, one 'Past Challengers' group, and two 'Never Challenged' groups) based on the aggregation of their monthly savings estimates.

Average annual savings per household in a participant sub-group was an equally weighted sum of the 12 average monthly savings estimates in the in-program year. These average annual savings estimates for the participant sub-group were then extrapolated to the entire population of households in that sub-group, including those households that were deemed ineligible for the pair matching.

Total program impacts for the fiscal year of interest were computed by summing the annual savings estimates from all nine participant sub-groups. Evaluated peak demand savings were derived by applying the residential rate class load shape factor to the net evaluated energy savings. The factor was developed through internal BC Hydro calculations.

2.4.3 Results

Population Profiling

The table on the following page summarizes the status of participating households in each of F2011 and F2012 and their estimated electricity savings. One key finding is that the number of participant households engaged in a 1-year energy reduction challenge nearly doubled from 9,646 in F2011 to 19,905 in F2012. This is an important observation because the majority of program savings were expected to come from households engaged in a challenge – be it their first 1-year challenge, their second 1-year challenge, etc. – rather than from households that were idle.

Table 2.12 Net Program Electricity Savings by Participant Sub-Group

Participant Sub-Group	F2011					F2012				
	Total Count		Average Savings per Household (kWh/year)		Total Annual Savings (GWh/year)	Total Count		Average Savings per Household (kWh/year)		Total Annual Savings (GWh/year)
	⇓		⇓		⇓	⇓		⇓		⇓
In Challenge 1 (1st 1-year challenge)	6,145	x	453.0	=	2.8	12,065	x	491.8	=	5.9
In Challenge 2 (2nd 1-year challenge)	2,394	x	189.5	=	0.5	4,481	x	313.3	=	1.4
In Challenge 3 (3rd 1-year challenge)	894	x	50.0	=	<0.1	2,303	x	244.4	=	0.6
In Challenge 4 (4th 1-year challenge)	212	x	50.0	=	<0.1	911	x	46.5	=	<0.1
In Challenge 5 (5th 1-year challenge)	1	x	50.0	=	<0.1	143	x	46.5	=	<0.1
In Challenge 6 (6th 1-year challenge)	0	x	-	=	0.0	2	x	46.5	=	<0.1
Total In Challenge	9,646		341.4	=	3.3	19,905		399.4	=	7.9
Past Challenger: in hiatus	19,389	x	(24.9)	=	(0.5)	17,935	x	(36.1)	=	(0.6)
Never Challenged: sufficient baseline	25,353	x	18.6	=	0.5	30,212	x	31.9	=	1.0
Never Challenged: insufficient baseline	7,517	x	18.6	=	0.1	10,903	x	31.9	=	0.3
Total	**61,905**		**55.3** [1]		**3.4**	**78,955**		**109.1** [1]		**8.6**
Total Peak Savings (MW)					**0.65** [2]					**1.63** [2]

1 Total average annual electricity savings are weighted by participant sub-group.
2 Based on BC Hydro's peak coincidence factor 0.19 for residential behaviour capacity savings.

Electricity Savings by Participant Sub-Group

Another key insight gleaned from the table is the finding that annual savings per household measured highest among Challenge 1 households, stepped down through the challenge numbers, and measured lowest among Never Challenged households. Although the savings estimates for these Never Challenged households were fairly nominal, the finding supports the hypothesis that these households could incur some energy savings due to having been exposed to program messaging and collateral such as brochures or other marketing materials.

Past Challengers were the only participant sub-group to incur greater consumption of electricity relative to their comparison group over the course of F2011 and F2012. This finding may point to both the rationalization and effectiveness of an energy reduction challenge in that by not being in one, Past Challengers may be comparably less engaged than others in their conservation efforts as they go without a formalized, structured goal and without milestone dates to work towards. Their increased consumption may simply reflect some slight fatigue – a relaxation in effort – after completing a yearlong challenge.

All of these findings support program theory that households enrolled in a behavioural program with enabling tools, communications and feedback mechanisms will be more apt to reduce their home electricity consumption. Further along these lines, households engaged in a structured energy reduction challenge are most successful in their efforts.

Free Ridership and Spillover

The estimation of free ridership and spillover was not pursued due to the complexity of a behavioural change program coupled with a quasi-experimental approach to its evaluation. There was no consistent or persuasive evidence to suggest that there was a significant level of free ridership unaccounted for in the gross savings estimates, yet there was reason to believe that there was some unestimated spillover. The energy savings estimates that have been presented are unadjusted for free ridership and spillover, but are considered to be net of these.

Total F2011 and F2012 Net Program Savings

As detailed in Table 2.13 below, total net energy savings attributable to the Power Smart Residential Behaviour Program measured 3.4 GWh/year for F2011 and 8.6 GWh/year for F2012, with associated peak demand savings of 0.6 MW and 1.6 MW, respectively.

Table 2.13 Reported and Evaluated Energy and Peak Demand Savings

Year	Energy Savings (GWh/year)		Peak Demand Savings (MW)	
	Reported	Evaluated	Reported	Evaluated
F2011	3.8	3.4	-	0.6
F2012	5.2	8.6	-	1.6

The substantial increase in energy savings from F2011 to F2012 can be attributed to both a higher number of households engaged in a challenge, particularly a first one when the savings opportunities are the greatest, and higher average annual savings for most of the participant sub-groups in F2012.

Participant and Program Insights

Findings strongly suggest that participants likely incurred savings due to enhanced efforts on four main fronts – space heating, space cooling, laundry and dishwashing behaviours. To a lesser extent, in-home behaviours relating to lighting, smaller plug-load items and water use also measured more favourably among participants than among non-participants.

Participants rated the program's analysis tools, information and feedback mechanisms favourably in terms of supporting their conservation efforts. Multiple lines of evidence uncovered in this study strongly suggest that the program's value is assisting households operationalize and transform their intention and effort around conservation to a successful outcome in the form of better habits and behaviours.

A total of 62 per cent of participants rated their experience to date with the Behaviour Program favourably, rating it as having been either 'excellent' (11 per cent) or 'good' (51 per cent). All of these findings support program theory that households enrolled in a behavioural program with enabling tools, communications and feedback mechanisms will be more apt to reduce their home electricity consumption.

2.5 Renovation Rebate F2009 – F2011

2.5.1 Introduction

The *LiveSmart BC Efficiency Incentive Program* (**LiveSmart**) is a partnership between the British Columbia Ministry of Energy, Mines and Natural Gas (**MEMNG**) and the major provincial utilities: Fortis BC Gas (formerly Terasen Gas), Fortis BC Electric, and BC Hydro. LiveSmart consists of education and financial incentives for homeowners to make their homes more energy efficient. Following a comprehensive home energy assessment by a certified energy advisor, homeowners were provided with a report that includes a list of recommended energy-efficient upgrades to their home. Based on the advisor's recommendations, homeowners choose to complete one or more retrofits to improve their home's energy efficiency. LiveSmart participants received an average of approximately $1,250 in incentives through the program.

The overall goals of the LiveSmart program are to:

- Reduce GHG emissions
- Provide a specific opportunity for residential customers to reduce their energy and water bills
- Generate energy savings for utility program partners by improving the level of energy efficiency of B.C.'s housing stock
- Increase customer awareness of energy efficiency and home energy management by educating customers about the high consumption associated with inefficient homes
- Build industry delivery capacity to advance the whole home energy retrofit market in B.C. and enable future implementation of mandatory building labeling

The Renovation Rebate Program is BC Hydro's internal name for its role within LiveSmart to support whole home energy efficiency retrofits that lead to electricity savings. All Renovation Rebate program incentives are distributed through LiveSmart.

This report provides an impact evaluation and elements of a process evaluation of the Renovation Rebate program for F2009 through F2011.

2.5.2 Objectives and Methods

There were two main objectives considered for this study:

1. Estimate gross and net energy and GHG savings attributed to the Renovation Rebate program between April 2008 and March 2011 (fiscal years F2009 - F2011)
2. Investigate customer satisfaction with the program and the influence of other factors determining program participation, including demographics, household characteristics and behaviors surrounding in-home energy use

Customer surveys were used to collect information on participant experience and satisfaction, and participant and non-participant decision-making to inform free rider and spillover estimates. Monthly billing data from April 2005 through December 2011 was collected for a sample of program participants and non-participants.

The majority of the retrofit activities expected to result in electricity savings for BC Hydro fell into three main categories:

1. Air-source heat pump installations for electrically heated homes
2. Building envelope measures (insulation, windows, doors, draftproofing) for electrically heated homes
3. Variable speed motors (**VSM**) in furnace and heat pump installations

Evaluated Gross Savings Method: The primary methodology for the gross savings analysis was a regression analysis using a quasi-experimental design comparing annual household consumption of participants and non-participant groups, using pre and post-retrofit weather-adjusted consumption data. Participants were defined as all customers in the analysis sample with electrically-heated homes receiving a BC Hydro-funded rebate, and non-participants were electrically-heated homes without rebates. This was used to calculate the average annual electricity savings per participant. This figure was multiplied by the total number of program participants with the same characteristics.

Estimating savings in homes without electric heat was more challenging. BC Hydro incentives in these homes were primarily for variable speed furnace motors, which included households installing a VSM on the blower in conjunction with furnaces and air-source heat pumps (**ASHP**). Estimating energy savings for households installing a VSM with a natural gas furnace used a comparison of pre and post retrofit consumption of participants for households where only a new furnace with VSM was installed.

To estimate electricity savings due to BC Hydro funding for a VSM in households in homes (formerly) without electric heat with a heat pump, a method was required to factor out changes in electricity consumption due to ASHPs, since BC Hydro did not contribute toward ASHP incentives. It was difficult to use regressions to estimate savings for homes installing heat pumps due to any savings effect from the VSM being overwhelmed by the additional electricity consumption requirements of the ASHP. For the purpose of this evaluation, the average electricity savings from a VSM installed with a natural gas furnace obtained above was used for the unit energy savings for a VSM installed with a furnace or a heat pump, and multiplied by the total number of participants installing either.

Net Savings Method: To arrive at net savings estimates, a net-to-gross ratio was developed based on results of the participant and non-participant surveys where respondents were asked a series of questions about their prior plans to complete home upgrades and what they would have done in the absence of the program. Evaluated peak demand savings were derived by applying the residential rate class load shape factor to the net evaluated energy savings. The factor was developed through internal BC Hydro calculations.

2.5.3 Results

Customer Awareness of and Satisfaction with LiveSmart: Fifty-eight per cent of all program eligible households in British Columbia knew of LiveSmart and/or the federal *ecoENERGY Retrofit Homes* program by name, including an understanding that the programs provide financial assistance in the form of rebates to encourage homeowners to make energy efficiency upgrades. Based on LiveSmart program eligibility criteria, the total potential home energy efficiency upgrade market in British Columbia was comprised of approximately 1.2 million households. It is estimated that over 600,000 households completed some type of energy efficiency upgrades between F2009 and F2011.

When asked about the primary reason why they participated in LiveSmart, participants most frequently selected: *to save on home energy costs* (48 per cent); and *to take advantage of the incentives/rebates* (34 per cent).

Non-participants selected three main reasons for why they chose not to participate in the program. Nearly one-half (48 per cent) of these households felt it was *too expensive to hire a Certified Energy Advisor to conduct the initial energy assessment* while 32 per cent felt that the *incentive amounts were too small to make the effort worthwhile* and 27 per cent felt the *steps necessary to participate in the program were too complicated*.

Participants were asked a variety of questions about their experience with various aspects of the program, including their perceptions of the information provided, interaction with the Certified Energy Advisor and their contractor, rebate amount and satisfaction with the program overall. Ninety one per cent of participants reported being satisfied with the program overall including 55 per cent being 'very satisfied'. Most participants agree that the *LiveSmart upgrades have led to a more comfortable home* (89 per cent) while somewhat fewer agree that the *upgrades have led to lower household energy bills* (77 per cent), and that the *upgrades have led to a higher resale value of their home* (67 per cent). Participants also *feel more proud of their home since participating in the LiveSmart program* (72 per cent) and believe the *value of the program far outweighs the cost of the energy assessments and upgrades* (70 per cent). LiveSmart received its strongest endorsement in the finding that nearly all participants would recommend the program to other households thinking about beginning home renovation activities (92 per cent).

Energy and Peak Demand Savings:

Overall, BC Hydro contributions to LiveSmart resulted in estimated gross electricity savings of 4.1 GWh/year in F2009, 8.3 GWh/year in F2010 and 9.2 GWh/year in F2011, across BC Hydro's service territory.

Table 2.14 Gross Electricity Savings for Renovation Rebate: F2009-F2011

Fiscal Year	Pre-Retrofit Heating Fuel	Average Annual Electricity Savings per Participant (kWh/year)	Total Participants[3]	Subtotal (GWh/year)	Gross Electricity Savings (GWh/year)
F2009	Electricity	2,853	770	2.2	4.1
	Natural Gas & Other	414	4,511	1.9	
F2010	Electricity	2,853	1,797	5.1	8.3
	Natural Gas & Other	414	7,635	3.2	
F2011	Electricity	2,853	1,926	5.5	9.2
	Natural Gas & Other	414	9,036	3.7	

Gross electricity savings in each year were estimated using a three-year estimate of average savings per participant. To the extent that the mix of products or measures differed year to year, actual savings in each year will vary from these estimates.

Electrically heated homes that received BC Hydro incentives saved an average of 2,853 kWh per year in electricity during the 3 year time period assessed. This represents a savings of 17.3 per cent[4] of total average annual consumption.

3 Total number of participants based on data provided by BC Hydro based on total number of invoices from the MEMNG.
4 Average electricity consumption across LiveSmart eligible households with electric heat in 2010 was 16,483 kWh.

The average electricity savings per household as a result of BC Hydro's incentives in natural gas heated homes was assumed to be equivalent to the standalone estimate of electricity savings for furnace installations – which is primarily attributed to the installation of the variable speed motor on the furnace blower. As outlined in the methodology section, it was not practical or possible to directly estimate the electricity savings for this group due to the proportion of households installing air-source heat pumps.

Determination of net savings attempted to separate out the program impacts that were a result of other influences, such as consumer self-motivation. The evaluated average free-ridership and participant spillover was 44 and 12 per cent respectively. The evaluation also estimated the program influenced a significant amount of non-participant spillover - equivalent to 84 per cent of the total program gross savings.[5] Together, these adjustments amount to an overall net-to-gross ratio of 1.5 for the entire LiveSmart program. The same net-to-gross ratio was applied to the Renovation Rebate program gross savings to arrive at net savings estimates.

The following table summarizes the estimates of evaluated gross and net savings. LiveSmart's electric efficiency measures funded by contributions by BC Hydro saved saved 6.2 GWh/year in F2009, 12.5 GWh/year in F2010, and 13.9 GWh/year in F2011 on a net basis.

Table 2.15 Gross and Net Energy and Peak Demand Savings

Year	Gross Electricity Savings (GWh/year)	Gross Peak Demand Savings (MW)	Free Ridership Rate	Participant Spillover Rate	Non-Participant Spillover Rate	Net to Gross Ratio	Net Electricity Savings (GWh/year)	Net Peak Demand Savings (MW)
F2009	4.1	1.1	0.44	0.12	0.84	1.51	6.2	1.7
F2010	8.3	2.3					12.5	3.5
F2011	9.2	2.6					13.9	3.9

Note: Totals may not add due to rounding.

Reported and evaluated energy and peak demand savings for the Renovation Rebate Program are compared in the following table.

Table 2.16 Reported and Evaluated Energy and Peak Demand Savings

Year	Energy Savings (GWh/year)		Peak Demand Savings (MW)	
	Reported	Evaluated	Reported	Evaluated
F2009	3.0	6.2	-	1.7
F2010	7.6	12.5	-	3.5
F2011	7.2	13.9	-	3.9

5 For a small proportion of non-participants, their early experience with the program appeared to have some influence on their decisions to install retrofits. Many of these respondents reportedly looked into or even began the process of participating in the program – some as far as having hired a Certified Energy Advisor to conduct an initial energy assessment. A large proportion of the total non-participant spillover savings can be attributed to these particular households, as their mean spillover scores were much higher than other non-participants.

3.0 Industrial Programs

3.1 Power Smart Partners – Transmission Program: F2010-F2011

3.1.1 Introduction

BC Hydro's Power Smart Partners – Transmission (**PSP-T**) program is a multi-year energy acquisition and market transformation initiative. This program encourages BC Hydro's large industrial transmission service customers to undertake energy-efficient investments while supporting their response to the conservation price signals of the Transmission Service Rate.

This report presents an impact evaluation and elements of a process evaluation of the program for BC Hydro's fiscal years 2010 and 2011 (F2010 and F2011). This evaluation covers the gross and net program savings achieved through two approaches: program enabled and incentive. Program enabled savings are electricity savings that resulted from technical and business enablers funded by the program. Program enabled savings projects did not receive direct project funding from BC Hydro. Instead they benefited from the transmission service conservation rate structure. Incentive savings are electricity savings funded by the program with a direct incentive. Outside the scope of this evaluation are industrial self-generation projects and the impact of the Transmission Service Rate.

3.1.2 Objectives and Methods

This evaluation had one objective: to estimate energy and peak demand savings. The following methods were employed:

Evaluated Gross Savings: Evaluated gross savings provide an estimate of actual energy savings produced by the projects that participated in the program. Evaluated gross savings were derived by segmenting the projects into four categories:

1. For projects with completed measurement and verification (**M&V**) results, evaluated gross savings are determined on the basis of M&V results. M&V involves electrical and hours of use metering. Project specific, and end use average, realization rates were calculated as the ratio of M&V'd savings to reported savings. Projects with M&V accounted for approximately half of the program's reported savings over the two-year period.
2. For large projects without M&V, evaluated gross savings are based on reported savings adjusted for evaluation review. Evaluation review includes file review, visual inspection of the project, and customer interviews. Project specific, and end use average, realization rates were calculated as the ratio of evaluation review savings to reported savings. Projects without M&V that underwent evaluation review accounted for approximately 25 per cent of the program's reported savings.
3. For projects without M&V or evaluation review, and where a closely matched realization rate was available, evaluated gross savings are based on reported savings adjusted with a matched realization rate. The realization rate was derived by considering the results of steps 1 and 2 above as well as the industrial sectors and energy end uses of the projects. Projects without M&V or evaluation review that were adjusted with a closely matched realization rate accounted for approximately 15 per cent of the program's reported savings.
4. For projects without M&V, evaluation review, or a closely matched realization rate, average realization rates by energy end use were applied to reported savings to calculate gross savings.

The average realization rates were calculated using the results of steps 1 and 2. These projects were generally small and unique. These projects made up approximately 10 per cent of the program's reported savings.

Evaluated gross savings (kWh/year) = Savings from projects with M&V results + Savings from projects from evaluation review + Savings from remaining projects

Net to Gross Ratio: The net to gross ratio provides an estimate of the proportion of evaluated gross savings that are attributable to the PSP-T Program. The net to gross ratio adjusts for free riders and spillover. Free riders are program participants who would have implemented the energy saving project reported by the program even in the absence of program activities. Spillover refers to program participants and non-participants whose energy savings projects occur through actions that were not reported by the program but which were influenced by the program.

The net to gross ratio was derived through an online survey of PSP-T participants and non-participants. The surveys included a number of detailed questions to provide an understanding of customers' decision making criteria and also presented specific information on projects reported by the program in cases where the survey respondent was a program participant. Survey results were checked for consistency and for sample representativeness and then input to a decision tree in order to calculate the net to gross ratio.

Evaluated Net Energy Savings: Evaluated net energy saving were calculated as the product of evaluated gross energy saving and the net to gross ratio.

Evaluated net energy savings (kWh/year) = Evaluated gross energy savings * Net to gross ratio

Evaluated Peak Demand Savings: Evaluated peak demand savings were derived by applying the transmission rate class load shape factor to the net evaluated energy savings. The factor was developed through internal BC Hydro calculations.

Evaluated net peak demand savings (kW) = Evaluated net energy savings * Load factor.

3.1.3 Results

Evaluated Gross Savings: Evaluated gross savings and the overall realization rate are presented below by funding approach and fiscal year. Evaluated gross savings were 83 per cent and 97 per cent of reported savings in F2010 and F2011, respectively. Reported savings in this instance refer to savings expected by the program, less the impact of any M&V already completed on individual projects and less the impact of any program level adjustments such as a deemed net to gross ratio.

Table 3.1 F2010 Evaluated Gross Savings and Realization Rate by Funding Approach

Funding Approach	Reported Energy Savings (GWh/year)	Realization Rate	Evaluated Gross Energy Savings (GWh/year)
Program Enabled	37.1	82%	30.5
Incentive	4.2	93%	3.9
Totals	**41.3**	**83%**	**34.4**

Table 3.2 F2011 Evaluated Gross Savings and Realization Rate by Funding Approach

	Reported Energy Savings (GWh/year)	Realization Rate	Evaluated Gross Energy Savings (GWh/year)
Program Enabled	52.6	96%	50.3
Incentive	11.8	104%	12.3
Totals	**64.4**	**97%**	**62.6**

Incentive savings achieved higher realization rates than did program enabled savings. This trend is partly explained by the prevalence of operational and procedural projects in the program enabled savings category, which have lower savings certainty than the equipment upgrades more common in the incentive category. It is further explained by the higher proportion of incentive savings that undergo M&V relative to program enabled savings. The increase in the realization rate between F2010 and F2011 is due to an increase in M&V activity across both funding approaches.

Net to Gross Ratio: Presented below are the results of the net to gross ratio analysis. The net to gross ratio was estimated to be 81 per cent, comprising 45 per cent free ridership offset by 26 per cent spillover. Free ridership of 45 per cent was in turn the average of 65 per cent free ridership among program enabled savings and 7 per cent free ridership among incented savings.

Table 3.3 Free Ridership, Spillover and Net to Gross Ratio Results

Adjustment	Incentive	Program Enabled	Overall Mean
Free Ridership	7%	65%	45%
Participant Spillover	N/A	N/A	22%
Non-Participant Spillover	N/A	N/A	4%
Net to Gross Ratio			**81%**

The survey asked free ridership questions on each project reported by the program. This allowed free ridership to be assessed separately for incented and program enabled savings. Spillover was also calculated using the survey method. Spillover could not be assessed by funding approach, because by definition spillover projects are those projects that were influenced by the program but did not make use of either funding approach offered by the program. Due to the relatively small number of eligible program participants, a distinct net to gross ratio cannot be calculated for each fiscal year.

Reported and Evaluated Savings: The tables below show evaluated net savings by fiscal year.

Table 3.4 F2010 Reported and Evaluated Net Savings

Funding Approach	Energy Savings (GWh/year)		Peak Demand Savings (MW)	
	Reported	Evaluated	Reported	Evaluated
Program Enabled	37.1	24.7	4.3	2.9
Incentive	4.2	3.2	0.5	0.4
Totals	**41.3**	**27.9**	**4.8**	**3.2**

Table 3.5 F2011 Reported and Evaluated Net Savings

Funding Approach	Energy Savings (GWh/year)		Peak Demand Savings (MW)	
	Reported	Evaluated	Reported	Evaluated
Program Enabled	52.6	40.7	6.1	4.7
Financial Incentive	11.8	10.0	1.4	1.2
Totals	**64.4**	**50.7**	**7.5**	**5.9**

Glossary

***Baseline* -** Energy consumption based on the existing or pre-implementation stage of the process. This level of consumption can be established by the measurements and or engineering calculations and is based on a specific level of production or operation.

***Certified Energy Advisor (CEA)* –** Independent experts in application of energy-related systems, assemblies and components for improved residential energy efficiency. CEAs are affiliated with Natural Resources Canada to deliver the EnerGuide rating service. Before being certified, each EnerGuide rating service energy advisor must complete training in a number of fields related to residential energy efficiency and also conduct several home evaluations under the guidance of an instructor.

***Challenge n households* –** Households in engaged in their n^{th} energy reduction challenge as of the cut-date in the fiscal year of interest.

***Comparison Group* –** Households included in the matching analysis and the difference-of-differences impact equation that have not joined the Behaviour Program.

***Cross Effects (CE)* -** Change in energy consumption of one process due to change of energy consumption of another process (usually in heating ventilation and air conditioning, HVAC, systems due to change in lighting).

***Demand* -** Demand refers to the amount of electricity that is consumed at any instant in time, measured in multiples of watts. Peak demand savings are the reduction in amount of electricity that is consumed at system peak demand, which for BC Hydro occurs on a winter weekday between approximately 5 p.m. and 7 p.m.

Difference-of-Differences Method (Double Difference) – Compares a treatment and a comparison group before and after an intervention. This method can be applied in both experimental and quasi-experimental designs and requires baseline and follow-up data from the same treatment and control group.

***End Use* -** The final level of electrical energy use considered for an industrial application.

***Energy* -** Energy refers to the amount of electricity consumed (or produced) over a certain time period, measured in watt-hours. Energy savings are the reduction in the amount of electricity consumed over a certain time period.

***Reported Savings* -** Estimate of savings based on customer initially reported savings, engineering review and site inspection. These estimates represent the unverified savings.

***Experiment* -** In an experimental design, participants are randomly assigned to a treatment group or to a control group.

***Free Riders* -** Free-riders are those participants who would have made similar energy efficiency improvements in the absence of the program.

***Free ridership (FR)* -** Energy use of a program participant who would have implemented the program measure or practice in the absence of the program. *In the Power Smart Partner - Transmission report, the free ridership is expressed as a fraction of the reduction of energy savings due to the free ridership to the gross energy savings of the program participant.*

Gross Savings - The change in energy consumption and/or demand that results directly from program-related action taken by the participants in the demand side management program irrespective of why they participated.

Ministry of Energy, Mines and Natural Gas (MEMNG) – Provincial Government of BC Ministry of Energy, Mines and Natural Gas and Responsible for Housing.

Net savings - The change in energy consumption and/or demand that is attributable to the utility demand side management program. The change in consumption or demand may include the effects of free riders and spillover.

Net to Gross Ratio - The combination of free rider and spillover estimates which are then applied to the gross savings to provide an estimate of attributable net savings for the program. Reflects program influence, does not reflect project performance in terms of energy savings estimated or measured.

Never Challenged Households: Sufficient Baseline Consumption – participant households that have never commenced an energy reduction challenge, though they are able to do so.

Never Challenged Households: Insufficient Baseline Consumption – participant households that have never commenced an energy reduction challenge because they do not have the required 12 months of baseline consumption at their current residence.

Past Challenge(r) Households – participant households that have completed at least one energy reduction challenge, but are currently not engaged in one.

Quasi-experiment - In a quasi-experimental design, there is no random assignment to a treatment or control group. Treatment and comparison group members are matched post-hoc on relevant characteristic(s).

Realization Rate - The ratio of initial estimates of savings to savings adjusted for data errors and measurement and verification results. Does not reflect program attribution or influence on the savings achieved.

Spillover (SO) - Spillover occurs when individuals are influenced or impacted by the program (either directly as program participants or indirectly as non-participants) to make additional energy efficiency improvements without any assistance from the program.

Variable Speed Motor (VSM) – In the context of the LiveSmart report, VSMs are installed on the blower in furnaces and heat pump air-handling units to distribute air throughout the home's duct system. VSMs operate at lower speeds most of the time, and higher only when necessary.

Acronyms and Abbreviations

CFL – Compact Fluorescent Lamp

DSM – Demand Side Management

EOC – Evaluation Oversight Committee

LED – Light Emitting Diode

M&V – Measurement and Verification

PSP – Power Smart Partners

Fiscal 2017 to Fiscal 2019
Revenue Requirements Application

Appendix Z

Attachment 2

Fiscal 2014 Demand-Side Management
Milestone Evaluation Summary Report

BC hydro
FOR GENERATIONS

Janet Fraser
Chief Regulatory Officer
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January 14, 2015

Ms. Erica Hamilton
Commission Secretary
British Columbia Utilities Commission
Sixth Floor – 900 Howe Street
Vancouver, BC V6Z 2N3

Dear Ms. Hamilton:

RE: British Columbia Utilities Commission (BCUC or Commission)
British Columbia Hydro and Power Authority (BC Hydro)
2004/05 and 2005/06 Revenue Requirements Application
BCUC Decision: Order No. G-96-04, October 29, 2004, Directive 66 (page 197)

BC Hydro writes to submit its F2014 Demand Side Management Milestone Evaluation Summary Report (**the Report**), dated January 15, 2015 in compliance with Directive 66 (page 197) of the Commission Decision dated October 29, 2004. Directive 66 directs BC Hydro to file the executive summaries of its milestone evaluation reports and full final evaluation reports for all its Power Smart programs. The Report summarizes the impact evaluations completed during F2014 for the following:

1. Residential Inclining Block (**RIB**) Conservation Rate: F2009 - F2012
2. Large General Service (**LGS**) and Medium General Service (**MGS**) Conservation: Calendar Years 2011 – 2012
3. Product Incentive Program (**PIP**): F2011 – F2013
4. Workplace Conservation Awareness (**WCA**) Initiative: F2011 - F2012

BC Hydro notes that the Report has been prepared for the purpose of this compliance filing.

For further information, please contact Geoff Higgins at 604-623-4121 or by email at bchydroregulatorygroup@bchydro.com.

Yours sincerely,

Original signed by Fred James

(for) Janet Fraser
Chief Regulatory Officer

sh/ma

Demand Side Management Milestone Evaluation

Summary Report F2014

January 2015

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List of Tables

1.0 Introduction

This report summarizes the milestone evaluations of demand-side management (**DSM**) initiatives completed by BC Hydro in fiscal year 2014 (F2014). It is filed in compliance with Directive 66 of the British Columbia Utilities Commission (**BCUC**) decision on BC Hydro's F05/F06 Revenue Requirements Application (dated October 29, 2004), which "*directs BC Hydro to file the executive summaries of its milestone evaluation reports and full final evaluation reports of all its Power Smart programs*" (page 197).

BC Hydro evaluates its DSM initiatives to improve its estimates of realized DSM electricity savings and to improve their effectiveness and efficiency.

DSM evaluation activities are guided by the following six principles:

- Objectivity and Neutrality: Evaluations are to be objective and neutral.
- Professional Standards: Evaluation work is guided by industry standards and protocols.
- Qualified Practitioners: BC Hydro employs qualified staff and consultants to conduct evaluations.
- Appropriate Coverage: BC Hydro strives to achieve defined coverage levels for its evaluation of DSM initiatives.
- Business Integration: The evaluation function is integrated into BC Hydro's DSM business process of planning, implementation, reporting and evaluation.
- Coordination: BC Hydro evaluation work is coordinated with FortisBC and other DSM partners where feasible.

BC Hydro DSM evaluations are subject to an independent oversight process to ensure that they are neutral and unbiased, of sufficient quality for their intended purposes, and consistent with industry standards and protocols.

1.1 Completed Evaluations

Impact evaluations summarized in this report include the following:

- Residential Inclining Block (**RIB**) Conservation Rate: F2009 - F2012
- Large General Service (**LGS**) and Medium General Service (**MGS**) Conservation: Calendar Years 2011 – 2012
- Product Incentive Program (**PIP**): F2011 – F2013
- Workplace Conservation Awareness (**WCA**) Initiative: F2011 - F2012

2.0 Conservation Rates

2.1 RIB Rate:[1] F2009 - F2012

2.1.1 Introduction

The RIB rate is a two-step rate structure, where BC Hydro's residential customers pay a lower per-unit rate for electricity consumption below a 1350 kWh bi-monthly threshold, and a higher per-unit rate for electricity consumption above the kWh threshold.

In August 2008 the BCUC determined that it was in the public interest for BC Hydro to implement the new RIB rate and required the new RIB rate structure go into effect October 1, 2008. The Step 1 to Step 2 threshold was set at 1,350 kWh per billing period, which was approximately 90 per cent of the median consumption of BC Hydro's residential customers. The Step 2 rate was established at BC Hydro's estimate of the cost of new energy supply, grossed up for losses and the Step 1 rate was calculated to achieve revenue neutrality for the residential class.

This study is an evaluation of the impacts and customer response to the RIB rate, net of Power Smart and natural conservation over the first four years. The evaluation period covers F2009 through F2012.

2.1.2 Approach

The overall objective of this study is to evaluate the customer response to the RIB rate and to estimate energy and associated peak demand savings resulting from the rate. The table below summarizes BC Hydro's evaluation objectives and research questions to be addressed.

1 This summary differs from the report included as Appendix C to the 2013 RIB Rate Re-pricing Application (Exhibit B-1; copy available at http://www.bcuc.com/ApplicationView.aspx?ApplicationId=419). It has been updated to reflect the information presented in the BC Hydro responses to Information Requests (IRs) in that proceeding (refer to the response to BCU IRs 1.21.1 and 1.21.2 and BCPSO IR 1.26.1) and for consistency in presentation with the other summaries in this report.

Table 2.1.1 Evaluation Objectives and Research Questions

Evaluation Objective	Research Questions
1. Estimate price elasticity.	What is the price elasticity of Step 1 and Step 2 consumption? What is the price elasticity of the class average in response to general rate increases?
2. Estimate the conservation impacts of the RIB.	What were the energy savings due to BC Hydro's RIB rate from F2009 to F2012? What were the associated peak demand savings due to BC Hydro's RIB rate from F2009 to F2012?
3. Analyze differences in price elasticity by customer characteristics.	Are there differences in price elasticity by region? Are there differences in price elasticity by dwelling type? Are there differences in price elasticity by space heating type? Are there differences in price elasticity by consumption level?
4. Evaluate the customer response and understanding of the RIB Rate.	Are there differences in the characteristics or demographics of customers who are never billed in Step 2 compared to those who are sometimes or always billed in Step 2? What is the level of customer awareness and understanding of the RIB rate? To what degree do electricity prices provide an incentive to manage electricity consumption? To what extent does the total electricity bill amount provide an incentive to manage electricity consumption? What is customers' understanding of their prevailing electricity price under the RIB rate? To what extent does the RIB rate provide an incentive to manage electricity consumption? Did the RIB rate encourage customers to modify their energy-use behaviours? Did the RIB rate encourage customers to make investments in energy efficient equipment? Did the RIB rate encourage customers to increase participation in Power Smart programs?

The individual evaluation objectives and a summary of the methodology for each are listed below.

Objective 1: Estimate Price Elasticity.

Price elasticity was estimated with econometric models that explain how electricity consumption per account might have changed in response to the RIB rate, after controlling for the effects of factors such as weather, region, electric heating, and income. These models were based on linear regression specifications commonly used in the residential electricity demand literature.

Objective 2: Estimate the Conservation Impacts of the RIB Rate.

Energy and associated peak demand savings due to the RIB rate were estimated using the following steps:

1. Estimate total conservation, measured by the change in total Step 1 and Step 2 consumption using estimates of the RIB price elasticity, the change in Step 1 and Step 2 prices and the previous year's Step 1 and Step 2 consumption levels.
2. Estimate natural conservation (the baseline scenario) using a class average price elasticity for general rate increases, the change in the equivalent flat rate price (Rate Schedule 1151), and the total consumption for the entire RIB rate class.
3. Estimate structural conservation of the RIB rate as the difference between total and natural conservation.
4. Multiply total energy savings by a load shape factor to estimate associated peak demand savings.

Objective 3: Analyze Differences in Price Elasticity by Customer Characteristics.

The data used to estimate Step 1 and Step 2 elasticity was partitioned by region, space heating type and dwelling type to enable estimates of the price elasticity of the different groups. To analyze elasticity by consumption level, customers were divided into five size categories based on their average bi-monthly consumption levels. Consumption level elasticity estimates were then found by estimating a separate per-account consumption regression for each size category.

Objective 4: Evaluate the Customer Response and Understanding of the RIB Rate.

Examination of the customer response and understanding of the RIB relied on the customer survey data and billing data. Customer surveys were used to collect information on customer awareness, understanding and decision making related to the RIB rate, opinions on electricity pricing, and behaviours around energy use, along with additional demographic and housing parameters to inform the evaluation.

The table below summarizes the data sources and methods employed in this study for each evaluation objective.

Table 2.1.2 Summary of Evaluation Objectives, Data Sources and Methodology

Evaluation Objective	Main Data Sources	Methods
1. Estimate price elasticity	Aggregate BC Hydro bi-monthly billing data from April 2004 to March 2012, including consumption, heating type, region and dwelling type by account BC Hydro Residential Rate Tariffs (historical prices) BC Hydro records of expenditures on DSM from April 2004 to March 2012 Statistics Canada Consumer Price Index data from April 2004 to March 2012 BC Stats records of personal real disposable income from April 2004 to March 2012 BC Hydro records of heating and cooling degree days by region from April 2004 to March 2012	Econometric models - linear regression using Ordinary Least Squares.
2. Estimate the conservation impacts of the RIB Rate	Data and results from Objective 1 BC Hydro rate class load shape	Arithmetic
3. Analyze differences in price elasticity by customer characteristics	Same as Objective 1	Same as Objective 1
4. Evaluate the customer response and understanding of the RIB Rate	Customer Surveys (n = 2,831) BC Hydro monthly billing data from April 2011 to March 2012	Cross Tabulations of Survey Responses Linking of survey responses to respondent billing history Difference of Means Tests using Analysis of Variance

2.1.3 Results

Objective 1: Price Elasticity

An estimate of Step 1 elasticity could not be precisely estimated due to the limited variation in the flat rate price prior to the RIB rate implementation and the Step 1 price after the RIB rate was introduced after adjusting for inflation over the time period analyzed.

Three different econometric models, all plausible and selected based on theoretical and statistical merit, estimated a range of Step 2 price elasticity between -0.08 to -0.13. Step 2 price elasticity estimates were very sensitive to the inclusion of weather and economic variable specifications; hence it was prudent that the evaluation adopted a range estimate of price elasticity rather than a single definitive value.

Absent conclusive results to reject the original assumption of -0.05 for class average price elasticity, the evaluation used the same assumption for estimating the baseline rate impacts (natural conservation) in the scenario of general price increases under a flat rate.

Objective 2: Conservation Impacts

Since the modeling to estimate Step 2 price elasticity resulted in a range of plausible elasticities, the RIB rate structure impacts derived from them are also presented as a range estimate. The following table compares reported and evaluated incremental annual savings from the RIB rate structure. The low estimate and high estimates assume a Step 2 elasticity of -0.08 and -0.13 respectively.

Table 2.1.3 Reported versus Evaluated Incremental Annual Electricity Savings Impacts

Fiscal Year	Energy Savings (GWh)			Associated Peak Demand Savings (MW)		
	Reported	Evaluated Low	Evaluated High	Reported	Evaluated Low	Evaluated High
F09	92	57	94	20	12	20
F10	230	94	202	49	20	43
F11	26	11	41	6	2	9
F12	101	33	86	22	7	18

The evaluated incremental annual conservation impacts as a result of the RIB rate ranged from a low of 11 GWh in F2011 to a high of 202 GWh in F2010. The average total impacts per BC Hydro customer account ranged between 7 kWh and 124 kWh for the four year period. The range of the RIB rate's structural conservation impacts represent approximately 0.1 per cent - 1.2 per cent of the total annual residential class consumption during the time period evaluated.

The annual associated peak demand savings were estimated at between 2 MW and 43 MW assuming an average residential sector peak-to-energy ratio (capacity factor) of 0.214 MW/GWh across the four years based on the residential rate class load shape.

Objective 3: Price Elasticity by Customer Characteristics.

Based on the results from the three different models, the low and high estimates for Step 2 price elasticity associated with different types of customer segments are summarized in the following table. While these estimates show that Step 2 price elasticity varies by region, dwelling type, space heating type and total consumption, the estimated ranges suggest that customer Step 2 price responsiveness is reasonably close to the initial assumption of an average Step 2 price elasticity of -0.10, except for customers on Vancouver Island and the North, those living in row/townhouses or apartments, or those with consumption above 2400 kWh.

Table 2.1.4 Step 2 Price Elasticity by Customer Characteristics

Customer Segment	Step 2 Elasticity – Low Estimate	Step 2 Elasticity – High Estimate
Region		
Lower Mainland	-0.11	-0.13
North	-0.12	-0.15
Southern Interior	-0.08	-0.12
Vancouver Island	-0.15	-0.15
Dwelling Type		
Single Family Dwelling	-0.08	-0.14
Row/Townhouse	- 0.06	-0.07
Apartment	-0.03	-0.04
Mobile Home	-0.10	-0.10
Other	-0.05	0.09
Space Heating		
Electric	-0.10	-0.14
Non-Electric	-0.08	-0.09
Consumption		
1350 kWh –2400 kWh	-0.13	-0.13
2400 kWh and above	-0.16	-0.18

Objective 4: Customer Understanding and Response

In total, 35 per cent of all customer households in the survey sample ‘never’ (0 months) incurred Step 2 consumption in F2012, 40 per cent ‘sometimes’ (1-11 months) incurred Step 2 consumption, and 25 per cent ‘always’ (12 months) incurred Step 2 consumption. This distribution – based on actual consumption – very closely reflected the actual distribution of all RIB qualified accounts in the billing system.

Regionally, households on Vancouver Island were the most likely to have incurred Step 2 consumption in F2012. Considering space heating, the incidence of any Step 2 consumption measured 72 per cent among households with electric space heating and compared to 61 per cent among those with non-electric heat. Considering water heating, the incidence of any Step 2 consumption measured 85 per cent among households with electric hot water heaters, 66 per cent among those with non-electric hot water heaters, and just 28 per cent among those who rely on hot water from a central system.

The total amount of their bills emerged to be assessed by customers as being a greater incentive to manage electricity than electricity prices. Over nine in ten customers reported that the total dollar amount of their electricity bills serves as either a ‘major incentive’ (48 per cent) or a ‘minor incentive’ (42 per cent) to manage their household’s consumption rather than ‘no incentive at all’. This compares to just over eight in ten customers who indicated that they believe BC Hydro’s electricity prices serve as either a ‘major incentive’ (41 per cent) or a ‘minor incentive’ (43 per cent). Customer households that 'always' or 'sometimes' incurred Step 2 consumption in F2012 were more likely than those that 'never' did so to view both price and the total bill amount as having a 'major incentive' on their management of electricity.

A total of 50 per cent of customers demonstrated that they were previously aware they were charged for electricity on an inclining block rate. A total of 31 per cent of customers believed their household's use of electricity was charged on a flat rate (as it was for many years prior to October 2008) while 2 per cent of customers believed that their consumption was charged on a declining block rate (a rate structure not used since the early 1990s). A total of 17 per cent reported not knowing how they were charged for their consumption of electricity. Statistical analysis showed that awareness of the inclining block rate does not directly lead households to having lower consumption as strictly compared to households unaware of the rate.

For customers who identified that their household's consumption of electricity was charged on an inclining block rate, when asked what they perceive to be their price of electricity under the RIB rate, 43 per cent considered each of the Step 1 and Step 2 prices as being their household's price of electricity, depending on the point in time in the billing period and/or their consumption in the billing period.

Customers who correctly identified that their household's consumption of electricity was charged on an inclining block rate were no more likely to have participated in BC Hydro's Power Smart programs, and were less likely to have purchased and installed energy-efficient lamps – such as CFLs and LEDs. Customers previously aware of the inclining block rate did outperform all other customers on energy conservation behaviours related to space heating, laundry, dishwashing, lighting and other plug-load behaviours.

2.1.4 Findings and Recommendations

Findings

Objective 1: Estimate Price Elasticity

1. The estimated range of Step 2 price elasticity (-0.08 to -0.13) encompasses the Step 2 elasticity assumption for in the BC Hydro 2008 RIB application of -0.10 for forecasting the RIB impacts.
2. Price elasticity for BC Hydro's small residential customers with only Step 1 consumption was not able to be measured due to the limited variation in real prices over time.
3. The class average elasticity due to general price increases under a flat rate was not able to be estimated using empirical data. The evaluation used the assumption of -0.05 as the class average price elasticity to determine the natural conservation baseline.
4. Price elasticity is very sensitive to various factors affecting electricity consumption that were included in the econometric models, including weather, disposable income, dwelling type, space heating fuel and total account consumption.

Evaluation Objective 2: Estimate Conservation of the RIB

1. The evaluated incremental annual energy savings of the RIB rate from F2009 to F2012 ranged between 11 GWh and 202 GWh during the four years evaluated.
2. The evaluated incremental annual associated peak demand savings ranged between 2 MW and 43 MW during the four years evaluated.

Evaluation Objective 3: Differences in Price Elasticity by Customer Characteristics

1. Price elasticity was generally higher for customer segments with higher consumption.
    - Price elasticity was higher on Vancouver Island and the Northern region than the overall average.
    - Price elasticity was higher for single family dwellings compared to other dwelling types.
    - Price elasticity was higher for households with electric heat versus non-electric heat.
2. Large residential users consuming more than 2,400 kWh bi-monthly show a substantially higher than average response to higher prices.

Evaluation Objective 4: Customer Response, Awareness, and Understanding

1. The approximate proportions of residential customers that ‘never’, ‘sometimes’ or ‘always’ saw the Step 2 price in F2012 were 35 per cent, 40 per cent and 25 per cent, respectively.
2. A total of 50 per cent of residential customers appear to be aware of the RIB rate as of February 2012.
3. The total amount of the household electricity bill serves as the greatest incentive to manage electricity consumption among residential customers, followed by electricity prices.
4. A total of 79 per cent of residential customers aware of the RIB rate believed it serves as an incentive to manage electricity consumption.
5. There are small but statistically significant differences in the prevalence of energy conservation behaviors among customers who are aware of the RIB rate compared to those who are not.
6. Awareness of the RIB rate does not appear to have significant influence on customer investments in energy-efficient equipment or participation in Power Smart programs.
7. Higher consumption is correlated with both higher awareness of the RIB rate and higher price elasticity, however no firm conclusions can be drawn about how RIB rate awareness is related to the customer price response.

Recommendations

1. **Continue to attempt to estimate Step 1 and the class average price elasticity.** Future evaluations will likely be improved by accumulation of empirical data and price variation over time and the exploration of alternative methods to estimate the class average elasticity.
2. **Future RIB rate evaluation may benefit from the complementary econometric analysis of a select sample of customers.** This would require additional data collection on changes (stock

turnover) in major household energy end-uses (e.g., appliance replacements, heating system upgrades), changes in economic and demographic circumstances (e.g., occupancy) and participation in other DSM programs to attempt to further isolate the effects of electricity prices on consumption.

3. **Consider ways to increase awareness of the RIB rate, particularly targeted at customer segments that have shown the largest response to price.** The evaluation results indicate there are correlations between RIB rate awareness and energy conservation behaviours. While causation is unclear, this could mean that increasing RIB rate awareness will lead to increases in energy conservation behaviours and corresponding energy savings.

2.1.5 Conclusions

The RIB rate appears to be achieving its overall objective of encouraging conservation through the customer response to higher marginal prices – particularly amongst the customer with the highest consumption.

2.2 LGS and MGS Conservation Rates:[2] Calendar Years 2011 - 2012

2.2.1 Introduction

The purpose of this study is to provide a comprehensive evaluation of the impacts and customer response to BC Hydro's LGS and MGS conservation rate structures for the period January 1, 2011 through December 31, 2012. The scope of this study includes electric energy conservation effects as well as customer understanding and experience with the LGS and MGS rates.

BC Hydro's LGS and MGS rate classes are made up of all BC Hydro accounts that purchase electricity at distribution voltage and have a monthly peak demand above 35 kW. MGS refers to general service accounts with a monthly peak demand that is equal to or greater than 35 kW but less than 150 kW, or whose energy consumption in any 12 consecutive periods is less than or equal to 550,000 kWh. LGS refers to general service accounts with a monthly peak demand equal to or greater than 150 kW, or whose energy consumption in any 12 month-period is greater than 550,000 kWh.

This diverse group of customers includes a wide range of facility types, such as hospitals, manufacturing facilities, office buildings, retail, and the common areas of multi-unit residential buildings. The total electricity purchases of these rates classes was approximately 13,000 GWh in calendar year 2010, covering approximately 23,000 accounts.

Prior to the implementation of the conservation rate structures, LGS and MGS customers were all served under a declining block energy charge. Starting in January 2011, conservation rate structures were introduced that were designed to encourage customers to conserve electricity. Under the LGS and MGS conservation rate structure, this encouragement is provided through a bill credit when consumption is lower than historical average consumption, and an additional charge when consumption is higher.

To support the implementation of the LGS and MGS rates, BC Hydro undertook consultations with relevant customers and conducted a variety of information and advertising activities. These activities included the development of a dedicated website, letters to customers, bill inserts, and online tools.

[2] This summary differs from the report included as Appendix A to the January 1, 2014 LGS and MGS Three-Year Report (Compliance with BCUC Order No. G-110-10 Directive 3). It has been updated for formatting consistency in presentation with the other summaries in this report.

To evaluate the impact of the conservation rates, and with the approval of the BCUC, BC Hydro assigned 400 accounts to control groups before the implementation of the conservation rate structures. Two hundred accounts were drawn from the MGS population, and 200 from the LGS population. The control group accounts were maintained on the pre-existing rates but increased each year by general rate increases. The remaining population of accounts (called the treatment groups in this report) started transition to the conservation rate structures on January 1, 2011.

LGS customers transitioned as one group to the conservation rate structure on January 1, 2011. MGS customers were divided into three groups for the purpose of transitioning to the conservation rate structure. The MGS1 treatment group started on an interim rate shaping stage on January 1, 2011 and transitioned to the conservation rate structure April 1, 2012. The MGS2 and MGS3 treatment groups started on an interim rate shaping stage in January 1, 2011, and transitioned to the conservation rate structure April 1, 2013.

2.2.2 Approach

Table 2.2.1 summarizes the evaluation objectives and research questions for this study.

Table 2.2.1 Evaluation Objectives and Research Questions

Evaluation Objective	Research Questions
1. Assess the effectiveness of the LGS and MGS control groups for the evaluation of energy savings.	Were the treatment and control groups equivalent in the year prior to the introduction of the conservation rate structures (calendar year 2010)? Are the control groups representative of the treatment groups? What is the relative precision of the control groups?
2. Estimate the energy and associated peak demand savings attributable to the LGS and MGS conservation rate structures.	What are the energy and associated peak demand savings due to the LGS conservation rate in 2011 and 2012? What are the energy and associated peak demand savings due to the MGS rate shaping in 2011 and 2012? What are the energy and associated peak demand savings due to the MGS conservation rate structure in 2012?
3. Assess customer awareness, understanding and acceptance of the LGS and MGS rate structures.	What is unaided awareness of the energy and demand charges? Has there been a change in unaided awareness? What is aided awareness of the energy and demand charges? How easy or difficult is it to understand how the rate works? How did customers first become aware of the conservation rate? Which communication method did customers find most useful in understanding the rate? What best reflects customers' understanding of the basis for the conservation rate? How much support do customers have for the energy charge?
4. Assess customer response to the LGS and MGS conservation rate structures.	How much of an incentive to conserve do the energy and demand charges provide? How easy or difficult is it for customers to manage their energy consumption? How much of an effort do organizations put into minimizing energy charges? What are the key enablers and barriers to energy conservation? Is awareness of the conservation rate structure required for a conservation response?

Table 2.2.2 summarizes, for each of the evaluation objectives, the evaluation data and methods used.

Table 2.2.2 Evaluation Objectives, Data and Methods

Evaluation Objective	Main Data Sources	Methods
1. Assess the effectiveness of the LGS and MGS control groups for the evaluation of energy savings.	BC Hydro billing data from January 2010 to December 2012 Power Smart program tracking data BC Hydro account data by region	Statistical tests Stratified sampling design analysis
2. Estimate the energy and associated peak demand savings attributable to the LGS and MGS conservation rate structures.	BC Hydro billing data from January 2010 to December 2012	Experimental design with randomized controlled trial Difference-in-differences Rate class average peak to energy ratio
3. Assess customer awareness, understanding and acceptance of the LGS and MGS rate structures.	2010 customer survey (n = 504) 2012 customer survey (n = 421)	Cross tabulations Z-tests
4. Assess customer response to the LGS and MGS conservation rate structures.	2010 customer survey (n = 504) 2012 customer survey (n = 421) BC Hydro billing data from January 2010 to December 2012	Cross tabulations Z-tests Analysis of variance Regression

Because of the availability of a valid control group, and the complexity of the LGS and MGS pricing scheme, experimental design was used to estimate quantitative impacts. Experimental design with a randomized control trial is considered the strongest research method across many fields because it controls for all factors aside from the treatment of interest.

The individual evaluation objectives and a summary of the methodology for each are listed below.

Objective 1: Assess the Effectiveness of the Control Groups.

The key to conducting a valid cause and effect analysis through experimental design is to construct a control group that is equivalent to the treatment group on all factors that impact the variable of interest in the base year period. For this study the variable of interest is energy consumption, and the base year is calendar year 2010, which is the year prior to the introduction of the conservation rate structures.

The following steps were used to assess the effectiveness of the control group:

1. Identify remaining valid control group accounts. Valid control accounts were defined as those accounts that remained on the pre-existing rate schedule and for which consecutive three-year consumption data during 2010 to 2012 was available.

2. Test the remaining valid control group accounts for equivalency to the treatment groups on the following basis:

    a. Average base year consumption by rate class and demand classification.

    b. Average base year consumption by account sector.

    c. Average base year consumption by BC Hydro service territory region.

    d. Base year consumption distribution by percentile (from 10 per cent to 90 per cent).

   e. Two year Power Smart program participation rates.

3. Post-stratify the remaining valid control group accounts and estimate their relative precision. Post-stratification is a statistical method for assessing the variance of a sample,[3] after the completion of an experiment, which can then be used to estimate relative precision. Relative precision provides an estimate of how closely the sample can predict the population.

4. Identify control accounts that have corporate parent and/or sister accounts in the treatment groups (e.g., chain stores, government buildings). Test for control group contamination[4] at these sites by comparing their change in consumption to control accounts that are not associated with treatment accounts.

The primary data for the analysis was energy consumption and data on account characteristics obtained from the BC Hydro billing system and Power Smart program tracking systems, for the time period January 2010 through December 2012. The analysis was conducted on only those accounts with continuous electricity consumption records between January 2010 and December 2012.

Objective 2: Estimate Energy and Associated Peak Demand Savings.

Energy and associated peak demand impacts were estimated through the difference-in-differences method which relies on comparing the consumption between treatment and control accounts before and after the introduction of the conservation rate, according to Equation 3.2.1.

Equation 3.2.1

$$DDE = (Treatment_{Post} - Treatment_{Pre}) - (Control_{Post} - Control_{Pre})$$

Where,

The difference-in-differences estimator (**DDE**) is the estimation of the difference between the two groups

$Treatment_{Post}$ is the average electricity consumption for the treatment group in the time period after the introduction of the conservation rates.

$Treatment_{Pre}$ is the average electricity consumption for the treatment group in 2010 before the introduction of the conservation rates.

$Control_{Post}$ is the average electricity consumption for the control group in the time period after the introduction of the conservation rates.

$Control_{Pre}$ is the average electricity consumption for the control group in 2010 before the introduction of the conservation rates.

[3] Variance is assessed by partitioning the population into distinct groups such that the variance of each group is minimized. For this study groups were selected on the basis of 2010 electricity consumption, across the entire rate class. Groups with larger variance will need a larger number of control accounts in order to reach a given precision level. Once the variance of each group was known, relative precision can be calculated based on the actual number of control accounts.

[4] Control group contamination occurs if the control group is influenced by the treatment, which could occur if head office directs energy management activities for a number of different sites, in a manner that is consistent with the assumption that all are under the conservation rate structures.

The method described above provides an estimate of evaluated net savings, on a cumulative run rate basis.[5]

Associated peak demand savings were calculated by applying a peak-to-energy ratio of 0.139 MW/GWh. This ratio is calculated from a rate class load shape.

Objectives 3 and 4: Assess Customer Awareness, Understanding, Acceptance and Response.

Customer surveys were used to collect information on customer awareness, understanding and decision making related to the LGS and MGS conservation rates, opinions on electricity pricing, and behaviours around energy use, along with additional business-specific parameters to inform the evaluation. Detailed customer surveys of LGS and MGS customers were conducted prior to the implementation of the conservation rate in July 2010. In July 2012, 18 months after the implementation of the LGS rate, a second round of surveys was conducted. The survey was customized for the various rate groups.

With the permission of survey respondents, survey responses were linked to billing history in order to conduct analysis of variance and regression, to determine the relationship between responses and consumption.

A quasi-experimental design was used to assess the impacts on customer conservation actions. The LGS and MGS1 customers who were exposed to the conservation rates at the time of the customer survey in July 2012 are the treatment groups. The MGS2/3 customers who were not yet exposed to the conservation rate at the time of the survey in July 2012 are the comparison group.

2.2.3 Results

Objective 1: Effectiveness of Control Groups

Of the 400 control accounts assigned in 2010, 320 were found to still be valid at the time of this study. The other 80 accounts were lost from the control group either because of account closure, or migration to a different rate class as a result of significant changes in account consumption.

Effective control groups will be equivalent to their treatment groups on all factors that are expected to impact electricity consumption, with the exception of their electricity rate. Analysis of the factors listed below was completed in order to test the effectiveness of the control groups.

- Average electricity consumption in the year prior to conservation rate implementation.
- Distribution of consumption by percentile.
- Representation by major account sector (industrial, commercial, and multi-unit residential).
- Representation by region.
- Power Smart program participation.
- Relative precision.
- Potential for control group contamination resulting from accounts with parent corporations outside the control group.

The results indicate that the control groups are equivalent to their treatment groups on the basis of electricity consumption in the year prior to conservation rate implementation, and are representative of the treatment groups by account sector and region, at a 90 per cent confidence level. Further, the

[5] Run rate savings refers to the rate at which energy is saved at a given point in time, expressed in units of GWh/year or kWh/year. Cumulative run rate savings provides the annualized rate of all savings achieved since the start of the initiative.

distribution of annual electricity consumption, and the level of Power Smart program participation, were found to be similar between the control and treatment groups. The relative precision was found to be good for MGS control group and fair for the LGS control group. Finally, control account consumption was not influenced as a result of having a corporate parent or sister accounts in the treatment groups.

Objective 2: Energy and Associated Peak Demand Savings

Shown below are the combined energy and associated peak demand savings for the LGS and MGS conservation rate structures and MGS rate shaping, in calendar years 2011 and 2012. Evaluated net savings are statistically significant at the 90 per cent confidence level.

Table 2.2.3 Comparison of Cumulative Reported and Evaluated Net Impacts

Calendar Year	Energy Savings (GWh/year)		Associated Peak Demand Savings (MW)	
	Reported	Evaluated	Reported	Evaluated
2011	286	144	40	20
2012	616	200	86	28

All evaluated net savings resulted from the LGS conservation rate structure with no statistically significant savings from the MGS1 conservation rate or from rate shaping. Note these results are based on an analysis timeframe encompassing only 9 months with the LGS Part 2 price at the long-run marginal cost (LRMC),[6] only nine months of MGS1 customers being exposed to the conservation rate, and the initial customer baselines[7] were set higher than they would be under normal operation of the rate. An increasing response is observed for LGS customers over time, with relative savings increasing from 1.33 per cent in 2011 to 1.82 per cent of annual consumption in 2012.

Objective 3: Customer Awareness, Understanding and Acceptance of their Rate Structures

Customers were asked about several dimensions of rate awareness. Unaided awareness was measured by asking survey respondents to identify their rate structure from a list of possibilities. About 33 per cent of LGS customers, 20 per cent of MGS1 customers, and 7 per cent of MGS2/3 correctly identified the structure of their energy charge. Aided awareness was much higher. Aided awareness was measured by describing their rate structure to survey respondents and then asking them whether they were previously familiar with it. Aided awareness was 81 per cent of LGS customers, 69 per cent of MGS1 customers and 30 per cent of MGS2/3 customers.

To examine ease of understanding of their rate, customers were provided with a detailed description of the conservation rate structures and then asked how easy or difficult they found it to understand. About 66 per cent of LGS customers said that it was very easy or somewhat easy to understand as did 70 per cent of MGS1 customers and 67 per cent of MGS2/3 customers.

Customers were asked if they support the rate. About 57 per cent of LGS customers indicated that they strongly or somewhat support the rate as did 45 per cent of MGS1 customers and 28 per cent of MGS2/3 customers.

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6 Part 2 refers to the credit / charge mechanism of the conservation rate structure. LRMC used in the context of the Part 2 rate refers to the levelized weighted average plant-gate price for firm energy from BC Hydro's F2006 Call for Tenders (grossed up to account for line losses and inflation) as a proxy. The conservation rate design intent is for the Part 2 rate to be valued at the LRMC. A transitional value was temporarily applied to Part 2 starting January 2011 before moving it to LRMC in April 2012.

7 The conservation rate structure includes the setting of unique customer baselines. The baseline level is a determining factor in the calculation of the Part 2 Credit or Charge.

Objective 4: Customer Response to the Conservation Rate Structures

Most customers felt that the rate had an impact on their energy conservation efforts. About 84 per cent of LGS customers said their rate had a major or a minor incentive effect, as did 70 per cent of MGS1 and 52 per cent of MGS2/3 customers.

To examine customers' ease of managing their accounts, customers were asked "assuming your organization wanted to do so, how easy or difficult is it to currently manage this account to minimize total energy charge on the bill?" Responses were similar across the three customer groups. About two-thirds of respondents indicated it would be very or somewhat difficult to respond, with the balance indicating it would be very or somewhat easy to respond.

Customers were asked about the major drivers of energy conservation. For all customer groups, the top three drivers of energy conservation were: "want energy costs to be as low as possible"; "right thing to do"; and "overall level of electricity prices". Responding to the conservation rate structure was cited as a driver of conservation for 35 per cent of LGS customer respondents.

Analysis of variance revealed that customers who are aware of the LGS or MGS conservation rates on an unaided basis have a higher mean annual consumption than customers who are not aware. Regression analysis indicated that awareness of the rate structure is not required for a conservation response.

2.2.4 Findings and Recommendations

Findings

The study has six key findings, which are summarized as follows.

1. The control groups closely matched the treatment groups in a number of important ways, and they are therefore valid and effective control groups for the purpose of evaluating the LGS and MGS rate structures. Significant control group attrition has already occurred. Twenty per cent of control accounts were lost over three years. The relative precision of the control groups, while fair overall, could be improved by increasing the number of large LGS control accounts.

2. Unaided awareness and understanding of the LGS and MGS rate structures were relatively low. Awareness and understanding increased significantly following an explanation of the conservation rate structures.

3. The top three drivers of energy conservation were: "want energy costs to be as low as possible"; "right thing to do"; and "overall level of electricity prices". Awareness of the conservation rate structure is not required for a conservation response.

4. The LGS rate structure resulted in energy savings of 144 GWh/year by December 31, 2011, increasing to 200 GWh/year by December 31, 2012. This is considerably less than forecast energy savings. Note the timeframe evaluated incorporated only 9 months of data with the Part 2 price at the LRMC-based rate and the initial customer baselines were set higher than they would be under normal operation of the rate.

5. There were no measurable savings for MGS rate shaping in 2011 and 2012.

6. There were no measurable savings for those MGS customers (MGS1) that transitioned to the conservation rate structure April 1, 2012. Note the timeframe evaluated included only nine months of data with MGS1 customers exposed to the two-part conservation rate.

Recommendations

Listed below are recommendations related to the management of the LGS and MGS conservation rate structures (1 to 3) and the evaluation of the rate structures (4 to 7).

1. To promote a conservation response, focus communication and advertising on energy costs, “doing the right thing”, and energy prices.
2. If customer awareness and understanding of the rate is of value, consider simplifying the rate structure or expanding advertising and communication efforts.
3. Revisit the savings forecast method in light of the variance between evaluated and forecast savings.
4. Consider using focus groups or structured interviews to better understand the mechanism by which customers respond to the rates, given the finding that awareness of the rate is not required for a conservation response.
5. Request approval of the BCUC to maintain existing control accounts and to assign a proportion of new accounts to control group status to preserve an effective control group for future evaluation of the LGS and MGS conservation rate structures.
6. Request approval of the BCUC to assign an increased proportion of new, large accounts to control group status, specifically LGS customers expected to have consumption above 6.5 GWh/year.
7. Consider re-evaluating the conservation rate structures after all conservation rate design elements are fully implemented and customers have had time to respond to them.

2.2.5 Conclusions

The study conclusions are as follows.

1. The LGS rate structure is achieving its objective of encouraging conservation in the LGS rate class. However, evaluated savings achieved are significantly lower than forecast.
2. In 2012, the MGS rate structure had not achieved its objective of encouraging conservation in the MGS rate class.

3.0 Commercial Programs

3.1 PIP: F2011 - F2013

3.1.1 Introduction

BC Hydro's PIP is a multi-year energy acquisition initiative that encourages small and medium-sized commercial and institutional customers to undertake energy-efficient investments in existing facilities. This evaluation covers two program offers: the Rebate and Direct Install offers. The Rebate offer provides rebates for a range of qualifying energy efficient products, focusing primarily but not exclusively on lighting. The target market for the Rebate offer has evolved over time and during the evaluation time period encompassed small and medium commercial customers, as well as the common areas of multi-unit residential buildings. The Direct Install offer funds the full cost of the installation of energy efficient lighting projects for qualifying customers. The target market for the Direct Install offer is the very small, hard-to-reach commercial customers.

The objectives of PIP were to: (1) generate energy savings for BC Hydro via replacing inefficient technologies with newer energy efficient products; and (2) increase energy efficiency awareness by actively communicating product options and educating customers on the benefits, thereby contributing to market transformation. This report includes an impact evaluation and elements of process and market evaluation for F2011, F2012 and F2013.

3.1.2 Approach

For this study, the objectives were to evaluate: (1) customer and trade ally feedback; (2) determinants of investment decisions; (3) market analysis; (4) free ridership and spillover; and (5) energy and associated peak demand savings. For each of the evaluation objectives, there were several specific research questions, as summarized in the following table.

Table 3.1.1 Evaluation Objectives and Questions

Evaluation Objective	Research Questions
1. Customer and trade ally feedback	How important are, and how satisfied are customers and trade allies with, the various program components? How aware are customers of the program? What are customer and trade ally ratings of the various program components? How knowledgeable are customers of the program? How knowledgeable are customers with respect to various energy-efficient technologies? What are the main sources of awareness for the program?
2. Determinants of investment decisions	What is the most typical circumstance for equipment replacement? What are the key drivers and barriers of energy use management? What are the drivers and barriers of retrofit installation?
3. Market analysis	What are trade ally views of recent trends in prices of energy efficient products? What are trade ally forecasts of sales of energy efficient products? What is the market share among program participants of incandescent and halogen lamps prior to program participation?
4. Free ridership and spillover	What is the free rider rate for the Rebate and Direct Install offers? What is the spillover rate for the Rebate and Direct Install offers?
5. Energy and peak associated demand savings	What are the net evaluated energy and peak associated demand savings of the Rebate and Direct Install offers?

The objectives, data sources and methods used for this evaluation are summarized in the following table.

Table 3.1.2 Evaluation Objectives, Data Sources and Methods

Evaluation Objective	Main Data sources	Method
1. Customer and trade ally feedback	Rebate offer participant surveys (n = 908) Rebate offer non-participant survey (n = 169) Direct Install offer participant survey (n = 150) Direct Install offer non-participant survey (n = 150) Trade ally survey (n = 35)	Cross tabulations, z-tests
2. Determinants of investment decisions	Same as Objective 1	Same as Objective 1
3. Market analysis	Program tracking data Trade ally survey (n = 35)	Same as Objective 1
4. Free ridership and spillover	Rebate offer participant survey (n = 908) Rebate offer non-participant survey (n = 169) Direct install offer participant survey (n = 150)	Net to gross algorithms
5. Energy and associated peak demand savings	Program tracking data Metering studies Peak to energy ratio	Engineering algorithms

Objectives 1 and 2: Customer and Trade Ally Feedback & Determinants of Investment Decisions

Detailed customer surveys of program participants and non-participants as well as a survey of trade allies provided the main sources of data for objectives one and two. The surveys for the Direct Install offer were conducted by telephone in September and October 2011. The surveys for the Rebate offer were conducted via an online survey in March to April 2013. The survey of trade allies was conducted by telephone in August to September 2013.

Objective 3: Market Analysis

Program tracking data on the levels of product installation by product type was the main data source for the market analysis. The trade ally survey results were also used for the market analysis.

Objective 4: Free Ridership and Spillover

Free ridership and spillover were estimated separately for the Rebate and Direct Install offers and calculated on the basis of survey responses to a series of questions designed specifically to measure free rider and spillover effects.

Objective 5: Energy and Associated Peak Demand Savings

Gross energy savings were estimated using Equation 2.2.1, where W_{pre} and W_{post} are the wattages of the original and replacement products, hours of use refers to hours of lighting or equipment use for the relevant space type, and area refers to the area of the relevant space type. The summation is over areas. Hours of use were obtained through metering studies, whereas wattages and space type shares were obtained from program tracking data.

Equation 2.2.1

Gross Evaluated $kWh_{savings} = \sum (W_{pre} - W_{post}) * \text{hours of use}_{area} / 1000.$

Net savings were estimated using Equation 2.2.2. The inputs to the algorithm were obtained through the steps previously described, with the exception of the Cross Effects factor which was obtained from the relevant Power Smart Standard.

Equation 2.2.2

Net Evaluated $kWh_{savings}$ *= Gross Evaluated Savings*(1 – free rider rate + spillover rate)*(1 –cross effects).*

Net associated peak demand savings were estimated by using the ratio of average kWh to peak kWh from internal calculations, based on a rate class load shape. For the purpose of this evaluation, the ratio was 0.130 MW/GWh for the Rebate offer and 0.125 MW/GWh for the Direct Install offer.

3.1.3 Results

Objective 1: Customer and Trade Ally Feedback

Satisfaction among program participants and trade allies with a number of important program components was high. The highest rated program components for Rebate offer participants were: the service provided by the [trade allies]; the length of time for the project to be completed; and the overall application procedure. The highest rated program components for the Direct Install offer were: the application procedure; service provided by their [trade ally]; and the products installed. The highest rated program components for trade allies were: the content of program communication; the range of products offered; and the overall program.

Some program components received relatively low ratings (< 51 per cent) by program participants. Rebate offer participants gave their lowest ratings on: the usability of the online application; the variety of products funded; and direct mail information. Trade ally respondents provided their lowest ratings on BC Hydro training about the program.

Objective 2: Determinants of Investment Decisions

Rebate offer participants and non-participants were asked how influential various considerations were as a driver of energy-efficient investment. For both participants and non-participants, the top factors emerged to include operating costs, electricity prices and the environment. For participants, participation in PIP was also a top factor.

Direct Install participants and non-participants were asked whether or not various considerations were a “major factor”, a “minor factor” or “not a factor at all” as a driver of energy-efficient investment. For participants and non-participants, the top three major factors were operating costs, the environment, and the overall level of electricity prices.

Objective 3: Market Analysis

Over the five years ending in F2013, a total of 2,394,700 products were incented through PIP. Most (2,051,000) were incented through the Rebate offer. Lighting products made up 96 per cent of all products installed.

To gauge the state of market transformation, trade allies who indicated that they were very knowledgeable or somewhat knowledgeable about the broader energy efficiency market place were asked additional questions about recent price trends and forecast sales for six main types of products.

The most commonly cited price increase trends were for standard T8 lamps and energy saving T8 lamps. The most commonly cited price stability trends were for occupancy sensors and high bay luminaires. The most commonly cited price decrease trends were for LED screw in lamps and high wattage LED luminaires.

The most commonly cited sales increase forecasts were for LED screw in lamps and high wattage LED luminaires. Few respondents indicated a sales decrease forecast. The most commonly cited stable sales forecast were for standard T8 lamps and energy saving T8 lamps.

Rebate offer participants who installed LEDs through the program were asked about the baseline lighting technologies in place prior to their energy efficient retrofit. Eighty-five per cent reported that the baseline lighting technology was incandescent or halogen, while 15 per cent reported that it was compact or linear fluorescent.

Objective 4: Free Ridership and Spillover

Free ridership and spillover estimates were based on multiple-question, self-report survey information. The free ridership rate was 17 per cent and 18 per cent for the Rebate and Direct Install offers, respectively. The participant spillover rate for the Direct Install offer was 11 per cent; non-participant spillover was not estimated. For the Rebate offer the combined spillover rate was 19 per cent, made up of 15 per cent participant spillover and 4 per cent non-participant spillover.

Objective 5: Energy and Associated Peak Demand Savings

Energy and associated peak demand estimates are shown below. Energy savings are incremental annual net run rate savings achieved for each fiscal year. Results are presented by offer and for the whole program overall in the tables that follow. The primary driver for the differences between reported and evaluated savings is the inclusion of the cross effects adjustment factor.

Table 3.1.3 Rebate Offer Comparison of Incremental Reported and Evaluated Net Impacts

Fiscal Year	Energy Savings (GWh/year)		Associated Peak Demand Savings (MW)	
	Reported	Evaluated	Reported	Evaluated
F2011	59.1	55.1	7.7	7.2
F2012	89.7	82.5	11.7	10.7
F2013	33.8	30.6	4.4	4.0

Table 3.1.4 Direct Install Comparison of Incremental Reported and Evaluated Net Impacts

Fiscal Year	Energy Savings (GWh/year)		Associated Peak Demand Savings (MW)	
	Reported	Evaluated	Reported	Evaluated
F2011	14.1	10.3	1.8	1.3
F2012	12.0	10.7	1.5	1.3
F2013	2.8	2.3	0.4	0.3

Table 3.1.5 Total Program Comparison of Incremental Reported and Evaluated Net Impacts

Fiscal Year	Energy Savings (GWh/year)		Associated Peak Demand Savings (MW)	
	Reported	Evaluated	Reported	Evaluated
F2011	73.2	65.4	9.4	8.5
F2012	101.7	93.2	13.2	12.0
F2013	36.6	32.9	4.8	4.3

3.1.4 Findings and Recommendations

Findings

1. Satisfaction among program participants and trade allies with a number of important program components is high. Over 60 per cent of participants across both offers gave favorable ratings to service provided by the trade allies, and the overall application procedures to receive funding. Among trade allies at least three-quarters rated the content of program communications, the range of products offered, the frequency of program communications, and the overall program as excellent or good.

2. Some program components received relatively low ratings (< 51 per cent) from survey respondents. Rebate offer participants provided the lowest ratings on the usability of the online application, variety of products funded, and direct mail information. Trade ally respondents provided their lowest ratings on BC Hydro training on the program.

3. The Rebate offer had high levels of non-participant awareness, with 63 per cent of non-participants aware of the offer. Only 15 per cent of non-participants reported being aware of the Direct Install offer.

4. Power Smart Alliance members play an important role in promoting the program. Twenty-five per cent of Rebate offer participants reported being contacted by an Alliance member.

5. Eighty-five per cent of participants who installed LED lighting technologies through the program reported baseline conditions that matched program assumptions regarding energy efficiency.

6. Metered hours of use were very close to the deemed hours of use for both offers. Consequently, the realization rates for gross energy and peak savings rates were very close to one.

7. For the Direct Install offer, free ridership was estimated to be 18 per cent for all program years evaluated. This was partially offset by an estimated spillover rate of 11 per cent, resulting in a net-to-gross ratio of 0.93.

8. For the Rebate offer, free ridership was estimated at 17 per cent for all program years evaluated but this was completely offset by an estimated participant spillover of 4 per cent and non-participant spillover of 15 per cent, resulting in a net-to-gross ratio of 1.02.

Total program savings for both offers were 65.4 GWh/year in F2011, 93.2 GWh/year in F2012, and 32.9 GWh/year in F2013.

Recommendations

Listed below are recommendations resulting from this study, starting with recommendations for program management (1, 2 and 3) followed by recommendations that could serve both program evaluation and program management purposes (4 and 5), and recommendations for future evaluation (6 and 7).

1. Consider expanding the variety of products offered by the program, given feedback from participants.

2. Investigate ways to improve the online application process.

3. Further explore the reasons for low satisfaction ratings from trade allies on training from BC Hydro, to determine if investment in additional training is warranted.

4. Consider increasing the frequency of surveying of participants and non-participants. This could inform updates to program baseline assumptions, and facilitate the estimate of free ridership and spillover for individual program years in a multi-year evaluation period.

5. Survey customers and trade allies on their awareness, understanding, and satisfaction at the overall program level and at the individual program component (i.e., offer) level. Understanding customer perceptions at both levels will facilitate continuous improvement to the program design and components.

6. Use stratified sampling techniques for the selection of sites that undergo measurement of hours of use. This approach to sample design would allow for the estimation of precision, which would help clarify the strength (or limitation) of the evaluation results.

7. Investigate whether hours of use are changing over time as a result of technology changes such as widespread adoption of building energy management systems. This investigation could be completed by adding relevant questions to periodic surveys of trade allies.

3.1.5 Conclusions

PIP has achieved its objective of generating energy savings. Participant and trade ally satisfaction with the program is generally high.

3.2 WCA Initiative: F2011 - F2012

3.2.1 Introduction

BC Hydro offers the WCA initiative to its large commercial customers (in both public and private sectors) as part of its Power Smart Partner (**PSP**) program. WCA encourages workplace activities that promote sustained energy reduction through behavior changes related to energy use.

After beginning in 2007 as a pilot offer with ten customers, in 2010 the initiative expanded to 30 large commercial customers. These customers represent approximately 300 sites in six sectors: advanced education, K-12 schools, healthcare, municipalities, property management (office buildings), and retail/hospitality.

In June 2011, BC Hydro commissioned a consultant (The Cadmus Group, Inc.) to conduct an impact and process evaluation of the WCA initiative to assess its energy savings and to understand its influence on energy-efficiency behaviors in the workplace.

The evaluation period covers F2011 through F2012.

3.2.2 Approach

The study objectives were to estimate the gross electricity impacts and net electricity savings of the WCA initiative, and to evaluate the effectiveness of the WCA initiative delivery, as summarized below.

Table 3.2.1 Summary of Evaluation Objectives and Research Questions

Evaluation Objective	Research Questions
1. Estimate gross electricity impacts for WCA initiative participants	What factors influence electricity consumption at WCA initiative participant sites? What is the year-over-year change in electricity consumption at WCA initiative participant sites, after controlling for known variables?
2. Estimate net electricity savings of the WCA initiative	Can valid comparison sites be identified for WCA initiative participants? What are the net energy savings from the WCA initiative? Is the hypothesis that net savings equaled 5 per cent of total site consumption valid? How can the reliability and accuracy of behavioral energy savings estimates for the commercial sector initiatives be improved?
3. Evaluate the effectiveness of the WCA initiative delivery	What were the perspectives of BC Hydro staff and consultants regarding WCA participation? What were BC Hydro staff and WCA consultants' perceptions of customer needs and marketplace trends? How effective were the initiative's social marketing strategies? What were the barriers to participation that can be addressed by initiative design and implementation? What were the key opportunities and obstacles in the WCA initiative compared with similar behavior programs at other utilities?

The following table summarizes the data sources and methods employed in this study for each evaluation objective.

Table 3.2.2 Summary of Evaluation Objectives, Data Sources and Methodology

Evaluation Objective	Main Data Sources	Methods
1. Estimate gross electricity impacts	WCA initiative data for participants, including WCA enrollment status and activity start date BC Hydro monthly billing data for WCA initiative participants, from April 2006 to March 2012, including site consumption, demand, region, business sector BC Hydro records of expected savings and savings effective dates from non-WCA initiatives BC Hydro records of heating and cooling degree days by region from April 2006 to March 2012 BC Hydro tariff change dates	Econometric models - linear regression using Ordinary Least Squares.
2. Estimate net electricity savings	BC Stats demographic and economic data BC Hydro monthly billing data from April 2006 to March 2012 for comparison group sites, including site consumption, demand, region, business sector BC Hydro records for comparison group sites, of expected savings and savings effective dates from non-WCA initiatives. BC Hydro records of heating and cooling degree days by region from April 2006 to March 2012 BC Hydro tariff change dates Results from Objective 1	Econometric models – linear regression using Ordinary Least Squares Quasi-experimental design using Difference-in-Differences
3. Evaluate the effectiveness of the WCA initiative delivery	WCA participant quarterly reports, pre-post surveys and recorded event data BC Hydro staff interviews (n = 12) WCA consultant interviews (n = 8) Energy Champion interviews (n = 30)	File review Qualitative analysis

Objective 1: Estimate Gross Electricity Impacts

Regression analysis was used to estimate gross electricity impacts for each participating sector. The regression model included terms for certain non-initiative factors that typically affect energy usage patterns. These non-initiative factors included heating degree days, cooling degree days, engineering estimates of energy savings due to other BC Hydro energy-efficiency programs, and BC Hydro's implementation of conservation rate structures.

While this method controls for a number of factors, it does not produce an estimate of electricity savings attributable to the WCA initiative. The method does not account for other factors that were potentially correlated with WCA activity, such as naturally occurring energy efficiency trends, trends in occupancy, or patterns of business activity. These other factors are accounted for in the estimation of net electricity savings in Objective 2.

Objective 2: Estimate Net Electricity Savings

Quasi-experimental design using difference-in-differences was used to estimate net electricity savings. Difference-in-differences adjusts the gross energy impacts by the difference in energy consumption observed at comparable non-participants over the same time period. This method controls for factors that were potentially correlated with WCA activity, such as naturally occurring energy efficiency, trends in occupancy, or patterns of business activity. If both participants and non-participants groups are reasonably similar, then any remaining differences in consumption between groups are attributed to be a result of the initiative.

Successful application of the D-in-D model with the benefit of a well matched comparison group should produce results that are net of natural conservation, participant spillover and electricity cross effects (natural gas cross effects were not evaluated). If the comparison group can be matched to participants on a wide range of factors such as corporate culture and demographics then results may also be net of free ridership.

Net associated demand savings were estimated using an energy-to-peak coincidence factor calculated from a class average load shape.

Objective 3: Initiative Delivery

Interviews were used to evaluate the effectiveness of the WCA initiative's delivery. Information from the WCA participant's quarterly reports, pre- and post-participation surveys, and recorded event data was also collected and analyzed. These sources were useful for assessing the building occupants' awareness and attitudes and identifying key activities contributing to the outcomes of the WCA initiative.

1. Interviews were conducted with 12 WCA program staff and BC Hydro key account managers (**KAMs**) and with eight WCA consultants. In addition, interviews were conducted with 30 energy champions – individuals who played key roles leading "Green Teams" and coordinating and reporting on WCA activities at participating sites – within 22 of the 30 organizations that participated. During these stakeholder and energy champion interviews, the evaluators gathered perspectives about the initiative's planning, implementation, and reporting. In addition, respondent insights were gathered about initiative effects, satisfaction, motivations and barriers, and opportunities to improve initiative design, marketing, and implementation.

3.2.3 Results

Objective 1: Gross Electricity Impacts

The Retail/Hospitality sector was divided into three groups according to the nature of the business (e.g., restaurant, hotel, etc).

Statistically significant estimates[8] of gross electricity impacts could not be found for the following sectors/subsectors: Municipalities (other buildings), Government, Advanced Education or Healthcare.

8 20 per cent or lower probability that the true impacts are zero

Statistically significant gross energy impact results were found for the remaining six sectors, although in some cases not for each year of program participation. These results are summarized below.

Table 3.2.3 Gross Electricity Impacts

Participant Group	Gross Electricity Impacts (% Change in Consumption)	
	First Year of Participation (%)	Second Year of Participation (%)
K-12 Schools	-5.7	-4.7
Property Management	-3.1	N/A
Municipalities (Libraries/Administration)	N/A	-5.5
Retail/Hospitality Group 1	N/A	-4.2
Retail/Hospitality Group 2	+3.4	N/A
Retail/Hospitality Group 3	+6.2	+17.4

Note: Negative values represent electricity savings, positive values represent relative increases in consumption. N/A indicates no measurement possible or not statistically significant.

As shown in Table 2.1.3, gross electricity impacts were found to be negative for some sectors (indicating that a reduction in consumption occurred, after controlling for the factors described in the Approach section), and positive for others (indicating a consumption increase). Consumption increases are likely due, at least in part, to factors not included in the model, such as patterns of business activity.

Objective 2: Net Electricity Savings

Valid comparison groups could only be identified for the following three sectors: K-12 schools, Property Management, and Municipalities. Comparison groups could not be identified for the remaining sectors, because of a lack of similar non-participant sites.

Statistically significant net energy savings were found only for the K-12 School sector and only for the second year of WCA initiative participation. Net savings as a per cent of consumption for this sector in the second year of participation year were 3 per cent. This equates to evaluated net savings for the K-12 school sector of 0.4 GWh/year in F2012, compared to reported savings of 0.8 GWh for K-12 schools in F2012.

Statistically significant net energy savings were not found for Property Management or Municipalities, in either year of participation, or for K-12 schools in the first year of participation. Because of the wide error bounds on the estimates, an overall estimate of evaluated net savings could not be produced.

Table 3.2.4 Comparison of Incremental Reported and Evaluated Net Impacts

Fiscal Year	Energy Savings (GWh/year)		Associated Demand Savings (MW)	
	Reported	Evaluated	Reported	Evaluated
F2011	18.5	N/A	2.2	N/A
F2012	12.7	N/A	1.5	N/A

Note: N/A indicates no statistically significant estimate available.

Objective 3: Effectiveness of the Initiative Delivery.

Interviews with the various WCA stakeholders (BC Hydro staff, KAMs, and outside consultants) and energy champions explored experiences, successes and challenges with the initiative. These are summarized below.

- Energy Champions were excited about reducing energy and promoting energy conservation through behavior change in the workplace. They reported that the behavior change initiative enhances many environmental initiatives at their organizations. They also said that they believe WCA produces energy savings beyond energy-efficiency retrofits installed through BC Hydro's Power Smart Partner Program.
- Energy champions emphasized that visible senior management support for WCA was necessary to ensure sustained WCA involvement from their green team members (those who help deploy specific initiative activities) and building occupants. They said senior management support could be demonstrated through sustainability policies or direct engagement in the WCA initiative launch or activities.
- Energy champions who had real-time data collection methods, and who were able to report energy savings from the initiative's activities to building occupants and senior management, reported that such feedback generated excitement, additional support, and initiative visibility throughout the year.

The following challenges were identified:

- WCA energy champions reported they had limited funding, time, and staff resources to keep up with the demands of launching, implementing, and reporting the initiative activities. Many champions said the WCA incentive was important, but that funding was not enough to cover the costs of additional materials needed to enhance the marketing toolkit provided by BC Hydro.
- While most energy champions were positive about the consulting assistance they received, some champions said they expected more communication and support from the WCA consultants.
- Some KAMs and WCA consultants said they would like to have greater feedback from participating organizations regarding initiative successes and lessons learned.
- Energy champions and stakeholders said that the lack of marketing materials or outreach support reduced the ability of their green teams to maintain visibility of the initiative. KAMs and consultants specifically suggested that BC Hydro develop a targeted brochure for WCA that would more effectively enlist senior management support.
- Energy champions reported they had limited ability to track energy savings resulting from initiative activities. Many stated that they would like to track the targeted behaviors and events, but lacked a consistent method, sub-metering resources, or sufficient staff support.

Despite developing success indicators (e.g., involving senior management) and rating participating organizations according to those indicators, the evaluation was not able to find consistent correspondence between the ratings and the savings estimates. This is likely due to imprecision in the savings estimates and incomplete data about participant activities

3.2.4 Findings and Recommendations

Findings

Objectives 1 and 2: Estimate Gross Impacts and Net Electricity Savings

1. A number of factors made it difficult to use statistical and econometric methods to detect WCA savings. Savings for most sectors were not able to be precisely estimated for a number of reasons, including:

    - ***WCA savings represented a small percentage of total site consumption***. When savings are a small share of consumption, the signal-to-noise ratio is typically large, and it can be hard to detect the savings even after controlling for energy-use drivers, such as weather.
    - ***Building occupancy and business activity data was not available for most buildings.***[9] Information about major contributors to energy use, such as building occupancy and business or economic activity, was unavailable for most sites and years. The lack of these data increased the amount of unexplained variation in the consumption data and decreased the ability to detect savings from WCA-supported activities.
    - ***The initiative study enrolled a relatively small number of sites in each sector***. The small number of sites increased the savings uncertainty due to variability in sampling.
    - ***Initiative activity leading to savings was only roughly tracked***. Each initiative site had a WCA activity start date, but little variability in these dates appeared between sites, and it was unclear if the dates corresponded to the start of WCA activity in particular buildings or the start of activity in the sectors.

2. It was difficult to establish a causal relationship between the WCA initiative and estimated reductions in consumption because of the non-experimental research design for the evaluation. To estimate net savings, the evaluation employed a quasi-experimental research design that involved developing a comparison group through attempts to match consumption and other characteristics of participants to nonparticipants. However, a comparison group could not be identified for all of the sectors, limiting this more robust type of analysis.

Objective 3: Assess the Effectiveness of the Initiative Delivery

The following were identified by BC Hydro staff, consultants and energy champions as barriers that interfered with achieving WCA initiative goals: Budget constraints, difficulty obtaining senior manager support, lack of staff support in participating organizations, inability to provide timely feedback to employees about the effects of energy savings activities, and keeping employees engaged over time.

Recommendations

A list of recommendations is identified below, organized into areas of consideration for program implementation and future evaluations of similar programs.

[9] WCA initiative consultants attempted to collect occupancy and business activity data for a sample of approximately 60 participant buildings (ten in each of the six sectors) during the initiative period. While this data would likely help explain more variation in consumption, the consultants and participants indicated that the data collection is time-consuming and tedious. Many experienced difficulties understanding what data to collect and how to collect it accurately.

Program Implementation

1. Consider increasing the WCA initiative incentives, and require that participants propose how they will use the funding source to meet the requirements of the initiative. Additional incentives may enable participants to assign more staff resources, develop more customized promotional materials and activities, and ensure that the program continues to engage employees and maintain visibility throughout the year.
2. Provide additional communication and guidance that clarifies what participants should receive from consultants throughout the duration of the WCA campaign. Communicate with consultants more regularly about their initiative roles and responsibilities.
3. Consider additional communication strategies to share lessons learned among the initiative participating organizations and stakeholders. Some examples are monthly or quarterly newsletters and regularly scheduled participant events that will foster networking and allow BC Hydro to compile and circulate tips, successes, and dos and don'ts for succeeding with WCA.
4. Consider developing a WCA initiative brochure that provides information at a glance to upper-level management decision makers.
5. Investigate a more targeted and quantifiable approach to collecting WCA insights and savings results through consistent yearly surveys of employees and a modified reporting template. Provide additional guidance on approaches to collect results data, such as a checklist to record the numbers of lights turned off or monitors shut down in a month.
6. Consider investigating different feedback mechanisms. BC Hydro's program management staff suggested that there may be opportunities to help participating organizations track and report WCA event savings by leveraging Smart Meter data, dashboards, sub-metering, or online portals currently under development, or by providing them with customized energy-savings reports.

Future Evaluations

7. Collect additional site and WCA activity data to determine reasons for the variations in site energy use. This should include passenger traffic, occupancy rates and business activity data for participant and nonparticipant sites for at least the 12 months before and all months during WCA participation. Detailed information about WCA activity might include dates when significant activity occurred. BC Hydro should collect this information uniformly and systematically across sites.
8. Collect higher frequency (hourly, daily, or weekly) site energy-use data to increase the chances of detecting WCA savings. The variance of the savings estimates will decrease as the number of energy-use observations increases. Also, with higher frequency data, observable variables such as weather may be able to explain more of the variation in energy use, increasing the precision of the savings estimates.
9. Consider sub-metering particular end uses. With more detailed information about the timing of specific energy-saving activities, it may be possible to estimate savings at the end-use level. These actions will also help BC Hydro provide timely feedback to participants about their success in reducing energy use.
10. Incorporate more experimental research design elements in future evaluations, when feasible. This would increase confidence in the attribution of savings to the initiative. For example, for sectors with large numbers of relatively homogeneous sites, BC Hydro should consider randomly

assigning some sites to the initiative and others to a control group, recognizing that there is potential for contamination of control sites in organizations that also have treatment sites.

11. Prior to program participation, perform a statistical power analysis to estimate the probability of detecting the WCA savings. This analysis will allow BC Hydro to determine whether it can expect to estimate savings and whether additional sites, data collection (such as end-use metering), or a longer intervention period is needed. BC Hydro could use data on baseline energy use and the results of this evaluation to develop assumptions for the analysis.

3.2.5 Conclusions

Overall, energy champions were excited about reducing energy and promoting energy conservation through behavior change in the workplace. They reported that the behavior change initiative enhances many environmental initiatives at their organizations. They also said that they believe WCA produces energy savings beyond energy-efficiency retrofits installed through BC Hydro’s Power Smart Partner Program.

The impact evaluation suggests that the WCA initiative saved energy in F2011 and F2012, as noted below. The estimated savings were positive in most years and for most sectors. However, wide error bounds also meant it was often not possible to reject the hypothesis of zero savings. Despite best efforts, savings could not be estimated precisely because: (1) the savings were small relative to consumption; (2) information about site occupancy and business conditions was not available for all participants; and (3) the initiative enrolled a relatively small number of sites in each sector. Because of this uncertainty, the savings estimates should be interpreted with caution.

Precise estimation of net energy savings cannot be achieved without either increasing site level data collection well beyond current practice, or significantly changing the participant recruitment approach such that new participants are matched to control sites.

Glossary

Baseline **-** Energy consumption based on the existing or pre-implementation stage of the process. This level of consumption can be established by the measurements and or engineering calculations and is based on a specific level of production or operation.

Cross Effects (CE) **-** Change in energy consumption of one process due to change of energy consumption of another process (usually in heating ventilation and air conditioning, HVAC, systems due to change in lighting).

Difference-of-Differences Method (Double Difference) – Compares a treatment and a comparison group before and after an intervention. This method can be applied in both experimental and quasi-experimental designs and requires baseline and follow-up data from the same treatment and control group.

End Use **-** The final level of electrical energy use considered for an industrial application.

Energy **-** Energy refers to the amount of electricity consumed (or produced) over a certain time period, measured in watt-hours. Energy savings are the reduction in the amount of electricity consumed over a certain time period.

Experiment **-** In an experimental design, participants are randomly assigned to a treatment group or to a control group.

Free Ridership **-** Free-riders are those participants who would have made similar energy efficiency improvements in the absence of the program.

Gross Savings **-** The change in energy consumption and/or associated demand that results directly from program-related action taken by the participants in the DSM program irrespective of why they participated.

Net savings **-** The change in energy consumption and/or associated demand that is attributable to the utility DSM program. The change in consumption or associated demand may include the effects of free riders and spillover.

Net to Gross Ratio **-** The combination of free rider and spillover estimates which are then applied to the gross savings to provide an estimate of net savings attributable to the program. Reflects program influence, does not reflect project performance in terms of energy savings estimated or measured.

Peak Demand **-** Demand refers to the amount of electricity that is consumed at any instant in time, measured in multiples of watts. Peak demand savings are the reduction in amount of electricity that is consumed at system peak demand, which for BC Hydro occurs on a winter weekday between approximately 5 p.m. and 7 p.m.

Price Elasticity **-** The most commonly used measure in the electricity industry when analyzing consumption changes due to rate adjustments. It provides a straightforward and easy-to-compare means to measure the price impacts on electricity consumption and the magnitude of customers' price sensitivity. It is defined as the percentage change in quantity demanded divided by the percentage change in price. For example, a price elasticity assumption of -0.10 means that for each one per cent increase in real price, electricity usage declines by 0.10 per cent.

***Realization Rate* -** The ratio of initial estimates of gross savings to gross savings adjusted for evaluation, measurement and verification results. The realization rate does not reflect program attribution or influence on the (net) savings achieved.

***Reported Savings* –** Initial estimate of net savings based on engineering calculations, review and site inspection, adjusted by program assumptions for free-ridership, spillover and market effects. These estimates represent the unevaluated savings.

***Spillover* -** Spillover occurs when individuals are influenced or impacted by the program (either directly as program participants or indirectly as non-participants) to make additional energy efficiency improvements without additional assistance from the program.

Fiscal 2017 to Fiscal 2019
Revenue Requirements Application

Appendix Z

Attachment 3

Fiscal 2015 Demand-Side Management
Milestone Evaluation Summary Report

BC Hydro
Power smart

Tom A. Loski
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December 14, 2015

Ms. Erica Hamilton
Commission Secretary
British Columbia Utilities Commission
Sixth Floor – 900 Howe Street
Vancouver, BC V6Z 2N3

Dear Ms. Hamilton:

RE: British Columbia Utilities Commission (BCUC or Commission)
British Columbia Hydro and Power Authority (BC Hydro)
2004/05 and 2005/06 Revenue Requirements Application
Commission Decision: Order No. G-96-04, October 29, 2004, Directive 66 (page 197)

BC Hydro writes to submit its F2015 Demand Side Management Milestone Evaluation Summary Report (**the Report**), dated November 2015 in compliance with Directive 66 (page 197) of the Commission Decision dated October 29, 2004. Directive 66 directs BC Hydro to file the executive summaries of its milestone evaluation reports and full final evaluation reports for all its Power Smart programs. The Report summarizes the impact evaluations completed during F2015 for the following:

1. Large and Medium General Service Conservation Rates: F2014 (F2014 LGS and MGS Evaluation Report). BC Hydro notes that a copy of the F2014 LGS and MGS Evaluation Report has been submitted as part of the 2015 Rate Design Application (Exhibit B-1, Appendix C-4A, pages 399 to 560 of 813).
2. Power Smart Partners Commercial Program: F2011 – F2012.

For further information, please contact Geoff Higgins at 604-623-4121 or by email at bchydroregulatorygroup@bchydro.com.

Yours sincerely,

Original signed by Fred James

(for) Tom Loski
Chief Regulatory Officer

sh/ma

Enclosure (1)

BC hydro powersmart

Demand Side Management Milestone Evaluation

Summary Report F2015

November 2015

Table of Contents

1.0 Introduction

This report summarizes the milestone evaluations of demand-side management (**DSM**) initiatives completed by BC Hydro in fiscal year 2015 (**F2015**). It is filed in compliance with Directive 66 of the British Columbia Utilities Commission (**BCUC**) decision on BC Hydro's F05/F06 Revenue Requirements Application (dated October 29, 2004), which "*directs BC Hydro to file the executive summaries of its milestone evaluation reports and full final evaluation reports of all its Power Smart programs*" (page 197).

BC Hydro evaluates its DSM initiatives to improve its estimates of realized DSM electricity savings and to improve their effectiveness and efficiency.

DSM evaluation activities are guided by the following six principles:

- Objectivity and Neutrality: Evaluations are to be objective and neutral;
- Professional Standards: Evaluation work is guided by industry standards and protocols;
- Qualified Practitioners: BC Hydro employs qualified staff and consultants to conduct evaluations;
- Appropriate Coverage: BC Hydro strives to achieve defined coverage levels for its evaluation of DSM initiatives;
- Business Integration: The evaluation function is integrated into BC Hydro's DSM business process of planning, implementation, reporting and evaluation; and
- Coordination: BC Hydro evaluation work is coordinated with FortisBC and other DSM partners where feasible.

BC Hydro DSM evaluations are subject to an independent oversight process to ensure that they are neutral and unbiased, of sufficient quality for their intended purposes, and consistent with industry standards and protocols.

1.1 Completed Evaluations

Impact evaluations summarized in this report include the following:

- Large and Medium General Service Conservation Rates: F2014; and
- Power Smart Partners Commercial Program: F2011 – F2012.

2.0 Large and Medium General Service Conservation Rates: F2014

2.1 Introduction

The purpose of this report is to provide a comprehensive evaluation of the impacts and customer response to BC Hydro's Large General Service (**LGS**) and Medium General Service (**MGS**) conservation rates for BC Hydro's fiscal year 2014 (**F2014**), which covers the period April 1, 2013 through March 31, 2014. The scope of this evaluation includes electric energy conservation effects as well as customer understanding and experience with the LGS and MGS rates. BC Hydro previously completed an evaluation of the LGS and MGS conservation rates for calendar years 2011 and 2012. The current evaluation extends that analysis.

BC Hydro's LGS and MGS rate classes are made up of all BC Hydro general service accounts that purchase electricity at distribution voltage and have a monthly peak demand above 35 kilowatts (**kW**). MGS refers to general service accounts with a monthly peak demand that is equal to or greater than 35 kW but less than 150 kW, or whose energy consumption in any 12 consecutive periods is less than or equal to 550,000 kilowatt-hours (**kWh**). LGS refers to general service accounts with a monthly peak demand equal to or greater than 150 kW, or whose energy consumption in any 12-month period is greater than 550,000 kWh.

This diverse group of customers includes a wide range of facility types, such as hospitals, manufacturing facilities, office buildings, retail, and the common areas of multi-unit residential buildings. The total electricity purchases of these rate classes was approximately 13,600 gigawatt hours (**GWh**) in F2014, covering approximately 23,000 accounts.

Prior to the implementation of the conservation rates, LGS and MGS customers were served under a declining block energy charge. Starting in January 2011, conservation rates were introduced that were designed to encourage customers to conserve electric energy. Under the LGS and MGS conservation rate, this encouragement is provided through a credit when consumption is lower than historical average consumption, and an additional charge when consumption is higher. The credit and charge (referred to as Part 2 of the conservation rate) are priced at a higher level than the base rate (referred to as Part 1). In effect, the conservation rates deliver a marginal price signal to customers that approximates BC Hydro's long run marginal cost (**LRMC**) of new energy supply.

To evaluate the impact of the conservation rates, and with the approval of the BCUC, in 2010 BC Hydro assigned 400 accounts to control groups before the implementation of the conservation rates. Experimental design methods were used to select control accounts. Two hundred accounts were drawn from the MGS population and 200 from the LGS population. The control group accounts were maintained on the pre-existing rate, with prices increasing each year in concert with general rate increases. The remaining population of accounts (called the **treatment groups** in this report) started a transition to the conservation rate on January 1, 2011.

LGS customers transitioned as one group to the conservation rate structure on January 1, 2011. MGS customers were divided into two groups (MGS1, and MGS2/3) for the purpose of transitioning to the conservation rate structure. MGS1 was made up of 4,000 accounts, and MGS2/3 was made up of 12,500 accounts. All MGS customers completed transition to the conservation rate by April 1, 2013.

2.2 Approach

Table 2.1 summarizes the evaluation objectives and research questions for this evaluation.

Table 2.1 Evaluation Objectives and Research Questions

Evaluation Objective	Research Questions
1. Assess customer awareness, understanding and acceptance of the LGS and MGS rates.	• What is the current level of unaided awareness of the energy charges? • How easy or difficult is it to understand how the rate works? • What is the customers' level of understanding on using the rate as a tool in managing their energy bill? • How much support do customers have for the conservation rate? Do customers believe the rate is fair? How does this compare between customers experiencing growth vs. those who are conserving? • What changes were observed in awareness, understanding and acceptance since the previous evaluation?
2. Understand customer response to the conservation rates.	• How much of an incentive to conserve does the energy charge (Part 1 and Part 2) provide? • How easy or difficult is it for customers to manage their energy consumption? • How much effort are customers putting into minimizing their energy charge? • What are the major factors behind customer efforts to manage electricity use? • What is the price signal to which customers are responding? • What changes were observed in customer response since the past evaluation?
3. Assess the effectiveness of the LGS and MGS control groups for the evaluation of energy savings.	• Are the control groups still equivalent to the treatment groups? • What is the relative precision of the control groups?
4. Estimate the energy and peak demand savings attributable to the LGS and MGS conservation rates.	• What are the energy and peak demand savings due to the LGS and MGS conservation rates in F2014, relative to calendar year 2010? • What changes are observed in energy savings since the past evaluation? • What are possible explanations for any variance between reported and evaluated electricity savings?
5. Large customer impact analysis	• Can a response to the introduction of the LGS conservation rate be detected at the site level for a selection of key account customers[1] with energy management initiatives?

[1] Key account customers are BC Hydro's largest Industrial, Commercial, Institutional and Government accounts.

Table 2.2 summarizes, for each of the evaluation objectives, the evaluation data and methods used.

Table 2.2 Evaluation Objectives, Data and Methods

Evaluation Objective	Data	Methods
1. Assess customer awareness, understanding and acceptance of the LGS and MGS conservation rates.	• Customer surveys • Customer focus groups • Key Account Manager[2] interviews	• Qualitative analysis • Cross tabulations
2. Understand customer response to the conservation rates.	• Customer surveys • Customer focus groups • Key Account Manager interviews	• Qualitative analysis • Cross tabulations
3. Assess the effectiveness of the LGS and MGS control groups for the evaluation of energy savings.	• BC Hydro billing data on electricity purchases from January 2010 to March 2014 • BC Hydro account data on customers characteristics (e.g., region, account sector) • Power Smart program tracking data	• Statistical tests • Stratified sampling design analysis
4. Estimate the energy and peak demand savings attributable to the LGS and MGS conservation rates.	• BC Hydro billing data from January 2010 to March 2014	• Experimental design with randomized controlled trial • Statistical outlier identification (Grubbs' test) • Difference-in-differences • Statistical bootstrapping • Rate class average peak to energy ratio
5. Large customer impact analysis	• BC Hydro billing data • Customer-level data (e.g., production)	• Customer-level regression models

2.3 Results

Results for Objective 1: Customer Awareness, Understanding and Acceptance of the Conservation Rates

Unaided awareness of the conservation rate in 2014 was 35 per cent for LGS customers, 26 per cent for MGS1 customers and 22 per cent for MGS2/3 customers. Of these three groups, LGS customers have been on the conservation rate the longest (since January 2011). For these customers, unaided awareness has remained fairly steady since 2012, when it was at 33 per cent. These levels of unaided awareness are lower than found for other BC Hydro conservation rates. Unaided awareness of their conservation rate was measured at 50 per cent for residential customers[3] and 83 per cent for large industrial customers[4].

[2] Key Account Managers manage BC Hydro's relationship with its largest Industrial, Commercial, Institutional and Government accounts.

[3] BC Hydro, 2014, Evaluation of the Residential Inclining Block Conservation Rate F2009-F2012, page 33.

[4] BC Hydro, 2013, F2012 Demand Side Management Milestone Evaluation Summary Report, page 43

Fewer than one quarter of LGS and MGS customers reported that, following a written description and illustration of the rate, it is very easy to understand how the rate works. Reported levels of ease of understanding how the rate works, again following a written description and illustration of their conservation rate, stayed fairly constant between 2012 and 2014, with the exception of LGS customers reporting that the rate is very easy to understand, where an increase from 16 per cent to 23 per cent was observed. These levels of understanding are lower than found for the residential conservation rate structure, where the same approach to testing understanding resulted in 44 per cent of residential customers reporting that their rate was very easy to understand.[5,6]

Focus group participants, who were decision makers regarding energy at LGS and MGS sites, demonstrated key gaps in understanding how to use the rate as a tool to manage their energy bill through changes in consumption, even after video and moderator explanations.

After being informed that the intent of the rate was to promote conservation, between 9 per cent and 21 per cent of customers strongly supported the rate, depending on their rate class, while 5 per cent to 7 per cent strongly opposed it. The share of LGS customers who strongly supported the rate increased from 14 per cent in 2012 to 21 per cent in 2014. Most focus group participants and key account customers complained about the mechanics of the rate. The energy charge was viewed as a penalty by customers with growing electricity consumption. The complexity of the rate structure created an administrative burden for customers with a single BC Hydro account and multiple tenants.

Results for Objective 2: Customer Response to the Conservation Rates

Of the 35 per cent of LGS, 26 per cent MGS1, and 22 per cent of MGS2/3 customers who could correctly identify the energy charge component of their rate unaided, 41 per cent indicated that it served as a major incentive to conserve electricity while 35 per cent indicated that it served as no incentive at all. These results indicate that the overall incentive effect of the energy charge was modest.

Focus group participants reported that the conservation rate was too complicated to act on because there are various inputs to the rate that were perceived as too difficult for customers to measure and manage themselves.

Most customers did not find it easy to minimize their energy charges. In 2014, 64 per cent of LGS customers, 55 per cent of MGS1 customers and 59 per cent of MGS2/3 customers said that it was very difficult or somewhat difficult to manage their account to minimize energy charges. Nonetheless, 63 per cent of LGS customers, 57 per cent of MGS1 customers, and 47 per cent of MGS2/3 customers reported putting a great or fair deal of effort into minimizing energy charges. The share of customers reporting a great deal of effort to minimize energy charges increased from 2012 to 2014 across all customer groups. Particularly large increases are seen for the MGS1 group (from 6 per cent to 17 per cent) and for the LGS group (from 17 per cent to 25 per cent)

Customers were asked about the various factors that were major drivers of managing their electricity consumption. The most commonly cited major driver was wanting operating costs to be as low as possible (76 per cent of respondents), followed by the overall level of electricity prices (59 per cent of respondents). The incentive to save electricity built into the rate was assessed as a major driver of managing electricity consumption by 21 per cent of respondents.

The economic price signal to which customers responded is varied. Focus group participants reported that they mainly look at the total bill amount only. Few customers took the time to dissect their energy

5 BC Hydro, 2012, Residential Rate Survey

6 Comparable results are not available for the Transmission Service Rate

bill because they had limited understanding of the rate structure. However, some key account customers did understand the rate structure and managed their electricity to minimize Part 2 charges.

Results for Objective 3: Assess the Effectiveness of the Control Group

Of the 400 control accounts assigned in 2010, 295 were found to still be valid at the time of this evaluation (i.e., they remained in the control group). The other 105 accounts were lost from the control groups either because of account closure, or migration to a different rate class as a result of significant changes in account consumption. A similar proportion of LGS and MGS treatment accounts also experienced account closure or migration to a different rate class, and these accounts were not included in the analysis[7].

Effective control groups are equivalent to their treatment groups on all observable factors that are expected to impact electricity consumption, with the exception of their electricity rate. Analysis of the factors listed below was completed to test the effectiveness of the control groups:

- Equivalent average electricity consumption in the base year prior to conservation rate implementation (calendar year 2010);
- Distribution of consumption by percentile;
- Equivalent average base year consumption by major account sector (industrial, commercial, and multi-unit residential);
- Equivalent average base year consumption by region;
- Equivalent average participation rates in Power Smart programs;
- Relative precision, indicating how closely a sample can predict a variable of interest for a population; and
- Control group contamination resulting from control accounts with parent corporations in the treatment group.

The control groups were found to be effective for the purpose of evaluating energy savings due to the LGS and MGS conservation rates. The control groups were equivalent to their treatment groups on the basis of electricity consumption in the year prior to conservation rate implementation, account sector and region. Further, the percentile distribution of annual electricity consumption and the level of Power Smart program participation were found to be similar between the control and treatment groups. The relative precision was found to be good for the MGS control group (overall 2 per cent relative to a target of 20 per cent or lower) and fair for the LGS control group (overall 12 per cent relative to a target of 20 per cent or lower). Finally, the control groups were found to be uncontaminated by having a parent corporation in the treatment group.

Results for Objective 4: Energy and Peak Demand Savings

The past evaluation estimated the annual rate of savings at 144 GWh/year by the end of 2011 and 200 GWh/year by the end of 2012, both relative to calendar year 2010. These results were statistically significant at the 90 per cent confidence level. The current evaluation estimated the annual rate of savings at 77 GWh/year by the end of F2014, relative to calendar year 2010. The F2014 results are statistically significant at the 85 per cent confidence level, but not at the 90 per cent confidence level that was achieved in the past evaluation. This means that the F2014 savings have a lower level of certainty than did the 2011 and 2012 savings, and that the F2014 savings are statistically equivalent to zero at the 90 per cent confidence level.

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[7] 16,500 valid treatment accounts were identified for the purpose of this analysis, relative to a population of 23,000 in 2010.

The minimum acceptable level of certainty varies by industry and needs to be determined by each user of the information. BC Hydro aims for a confidence level of 80 per cent or better for net evaluated energy savings derived from sampling based methods such as the one employed in this evaluation. Results that meet or exceed this level are reported as statistically significant, along with their associated confidence level.

Shown below are the reported and evaluated energy and peak demand savings for the LGS and MGS conservation rates during the evaluation time period. Energy savings are shown as an annual rate of savings in F2014, relative to calendar year 2010. This annual rate of savings includes any savings that commenced in 2011 or 2012 and continued to persist in F2014. This means that the F2014 energy savings are cumulative since the implementation of the conservation rates, and cannot be added to savings from 2012 and 2011.

Evaluated net energy savings for F2014 are 77 GWh per year, which is substantially less than the forecasted (reported) savings of 919 GWh per year. All evaluated net savings resulted from the LGS conservation rate with no savings from the MGS conservation rate.

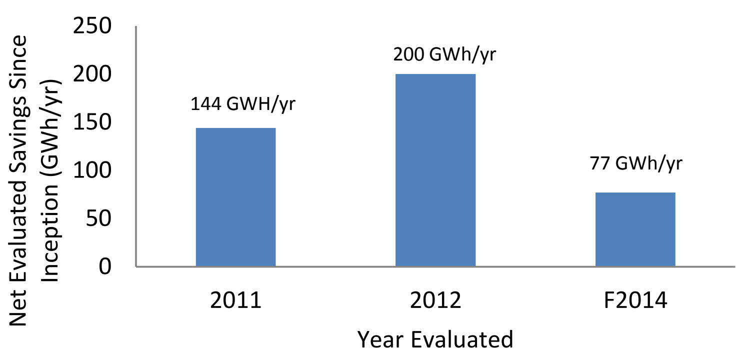
Table 2.1 Summary of Energy and Peak Demand Savings, F2014

Year	Cumulative Energy Savings (GWh/year)		Peak Demand Savings (MW)	
	Reported	Evaluated Net	Reported	Evaluated Net
F2014	919	77*	128	11

* Statistically significant at the 85 per cent confidence level. p-value = 0.14.

Net evaluated savings for each year, at a confidence level of at least 85 per cent, are shown below.

Figure 2.1 Net Evaluated Savings for Each Year Evaluated



Research[8] indicates that more informed customers are more responsive to price changes than are less informed customers. Evidence from this evaluation indicates that unaided awareness and demonstrated understanding of the conservation rate was low, and that customers found the rate structure to be too complex to inform their decision making on investment in energy efficiency. This suggests that one reason for the variance between evaluated and reported savings was low levels of customer awareness and understanding of the conservation rates, due at least in part to their complexity.

[8] Carter, D. W. and J. W. Milon 2005. Price Knowledge in Household Demand for Utility Services. Land Economics 81(2): 265 to 283.

Results for Objective 5: Large Customer Impact Analysis

Regression modelling of 12 industrial key account LGS customers with dedicated energy managers on staff did not detect a statistically significant response to the introduction of the LGS conservation rate. These customers would be expected to be responsive to the conservation rate, because they consume considerable amounts of electricity and have staff dedicated to energy management.

2.4 Findings and Recommendations

Findings

1. Only a small portion of LGS and MGS customers were able to correctly identify their rate structure without assistance. Unaided awareness of the rate structure was 35 per cent, 26 per cent, and 22 per cent among LGS, MGS1, and MGS2/3 customers respectively;

2. Survey results indicated that most customers (between 68 per cent and 77 per cent across the rate groups) believed that how the rate works was very or somewhat easy to understand after reading a description and illustration of their conservation rate. However, only a minority of these believed that it was very easy to understand and further exploration of this issue in the focus groups revealed that the rate may be much harder to understand than these survey results would suggest. Even though focus group participants were decision makers around the management of energy accounts and had previously completed the survey which aided their understanding of the rate structure, few demonstrated a good understanding of the rate structure. Key gaps in their understanding persisted even after video and moderator explanations of the rate;

3. After being informed that the intent of the rate was to conserve electricity, between 9 per cent and 21 per cent of customers strongly supported the conservation rate structures, depending on their rate class, while 5 per cent to 7 per cent strongly opposed it. Qualitative research indicated that customers experiencing consistent moderate growth did not support the rate, and saw the Part 2 energy charge as a penalty for growth. Some customers complained that the complexity of the rate structure created an administrative burden;

4. The incentive effect of the Part 2 energy charge and credit appeared to be modest. A total of 41 per cent of customers with unaided awareness of the energy charge reported that it served as a major incentive to conserve electricity. However, another 35 per cent of these customers reported that it served as no incentive at all. Qualitative research indicated that customers found the Part 2 energy charge and credit mechanism to be too complex to serve as a motivator for conservation;

5. The control groups closely matched the treatment groups in a number of important ways, and they were therefore valid and effective control groups for the purpose of evaluating the LGS and MGS rates;

6. The MGS conservation rate structure did not produce statistically significant energy savings. This result is consistent with the past evaluation;

7. Evaluated net energy savings for the LGS conservation rate structure were 77 GWh per year in F2014, relative to calendar year 2010 while evaluated net energy savings for the MGS conservation rate were zero. This is 8 per cent of reported savings (919 GWh/year for both MGS and LGS combined as of March 2014);

8. The variance between evaluated and reported savings is substantial. Evidence from this evaluation suggests that one reason for the variance is low levels of customer awareness and understanding of their conservation rates due at least in part to their complexity; and

9. Regression modeling of 12 large LGS sites failed to detect an effect on energy consumption due to the introduction of the LGS conservation rate in 2011.

Recommendations

10. Maintain the LGS and MGS control groups, so long as the MGS and LGS conservation rates are continued in their current form. Maintenance of the control group is required for future evaluation of the LGS and MGS conservation rates;

11. Consider revising the LGS and MGS conservation rates. Unaided awareness of the rate structure has remained low at approximately one third of LGS customers, demonstrated understanding of the conservation rate structures is low, customers indicated that the rate is too complex to inform their decision-making on energy efficiency and energy savings remain well below forecast; and

12. Consider revising the LGS and MGS savings forecast model, given the variance between evaluated and reported energy savings.

2.5 Conclusions

Multiple lines of evidence indicate that the customer response to the LGS and MGS conservation rates was considerably less than forecast. Awareness and demonstrated understanding of the conservation rates was low. Evaluated net energy savings in F2014 were 77 GWh per year, or 8 per cent of reported savings. Analysis of 12 key account customers, who would be expected to be responsive to the LGS rate, did not detect a statistically significant response to the introduction of the LGS rate.

3.0 Power Smart Partners Commercial Program: F2011-F2012

3.1 Introduction

BC Hydro's Power Smart Partners Commercial Program (**PSP-Commercial**) is a multi-year market transformation and energy acquisition initiative that encourages BC Hydro's largest commercial, government, institutional and First Nations customers to undertake energy-efficient investments in existing facilities. It also aims to transform the market to higher levels of energy efficiency by encouraging and assisting customers in integrating energy efficiency into their ongoing business practices and corporate culture.

This study provides an impact evaluation of net electricity savings achieved by the PSP-Commercial program for BC Hydro fiscal years 2011 and 2012 (**F2011 and F2012**), as well as elements of a process and market evaluation. The scope of the impact evaluation includes PSP-Commercial's two incentive offers: the custom incentive offer and the Express offer (PSP-X), as well as savings claimed for custom projects through the program enabled process. The custom incentive and PSP-X offers both provided capital incentives for retrofits, with a large focus on lighting projects. The custom incentive offer accepted a wider range of configurations than did PSP-X, while PSP-X offered a faster customer application process. Program enabled savings came from custom projects that received technical and/or strategic support from the program, but did not receive direct capital incentives. Energy savings from the Workplace Conservation Awareness initiative were claimed by the program in F2011 and F2012, but are excluded from the scope of the impact analysis as this initiative was previously evaluated under separate cover.[9]

3.2 Approach

Table 3.1 summarizes the evaluation objectives and research questions for this evaluation.

[9] The Workplace Conservation Awareness initiative targeted energy saving through employee behavioural changes. Refer to BC Hydro, *Workplace Conservation Awareness Initiative Evaluation.* April 30, 2013

Table 3.1 Evaluation Objectives and Research Questions

Objectives	Research Questions
1. Assess customer and Power Smart Alliance[10] participation, satisfaction, and attitudes towards conservation	What are the motivators of energy management? What is the level of awareness for the various program components? How satisfied are program participants and trade allies with the various program components? What is trade ally level of knowledge and participation in the program? How many trade allies use the program as a sales tool and how influential do they believe it is in encouraging their customers to implement energy saving projects?
2. Assess the results of the Energy Manager offer and trends related to market transformation	How many Energy Manager positions were funded? What percentage of program energy savings results from participants with Energy Managers? How many Strategic Energy Management Plans (**SEMPs**) were completed and signed off by an executive? How have organizations changed their approach to energy management over time? How engaged are participants' senior management with the Energy Manager?
3. Assess other trends related to market transformation	Are there changes in customer implementation of behavioral and operational energy conservation measures? What are the trends in participant experience with energy efficiency measures?
4. Estimate gross and net electricity and peak demand savings	What are the gross realization rates? How much free ridership and participant spillover occurred? What are the net electric energy and peak demand savings?

Table 3.2 summarizes, for each of the evaluation objectives, the evaluation data and methods used.

Table 3.2 Evaluation Objectives, Data Sources and Methods

Objectives	Data sources	Method
1. Assess customer and Power Smart Alliance participation, satisfaction, and attitudes towards energy conservation.	• Participant survey (n = 248) Power Smart Alliance survey (n = 35)	• Cross tabulations
2. Assess the results of the Energy Manager offer and trends related to market transformation	• Energy Manager survey (n = 60) • Program tracking data	• Cross tabulations
3. Assess other trends related to market transformation	• Power Smart Alliance survey (n = 35) • Participant survey (n = 248)	• Cross tabulations
4. Estimate gross and net electricity and peak demand savings	• Participant survey (n = 248) • Program tracking data • On-site inspections (21 sites) • Measurement and verification of a selection of projects(n = 70) • Power Smart Standard Procedure for Cross Effects • Rate class average peak to energy factor	• Evaluated gross savings based on ratio estimation using measurement and verification • Free ridership and spillover based on survey data and algorithms • Peak demand savings based on rate class average peak to energy factor

10 The Power Smart Alliance are a network of consultants, equipment vendors and other trade allies involved in the study, sale and installation of energy efficient technologies and solutions.

3.3 Results

Results for Objective 1: Customer and Trade Ally Experience with the Program

Participants in the custom offer (custom incentive and program enabled) most commonly cited reducing operating costs (89 per cent) and participation in the PSP-Commercial program (88 per cent) as their top two drivers of conservation. PSP-X participants most commonly cited reducing operating costs (89 per cent), and to benefit the environment (78 per cent).

Key Account Managers[11] were the highest rated individual program component for both custom and PSP-X participants (94 per cent and 78 per cent respectively rated them as either excellent or good). The highest rated program experience among custom offer participants was the service provided by BC Hydro personnel (94 per cent excellent or good). Among PSP-X participants the highest rated program experience was the service provided by their contractor (80 per cent excellent or good).

Trade ally knowledge of PSP-X was moderate, with 45 per cent reporting that they were somewhat or very knowledgeable about the offer. Among those who reported that they were somewhat or very knowledgeable, 20 per cent reported that they were very active with the program and 40 per cent that they were somewhat active. Eighty per cent of those who reported that they were somewhat or very knowledgeable of PSP-X reported it was either somewhat or very influential at encouraging their customers to purchase and install energy-efficient products.

Results for Objective 2: The Energy Manager Offer

In F2011 there were 79 Energy Managers in place, and participants with Energy Managers accounted for 62 per cent of overall program savings across all program offers. By F2014, 92 per cent of organizations with Energy Managers had completed a Strategic Energy Management Plan. However, only 43 per cent had a dedicated budget for its implementation.

Participants with Energy Managers improved their energy management practices over time, as measured by Energy Manager Assessment scores. Average scores increased from 0.89 to 1.59 over three years, moving the scores from the tactical approach category (0.00 – 1.00) to the strategic approach category (1.01 – 2.00).

Results for Objective 3: Trends Related to Market Transformation

Custom incentive and program enabled participants reported that, relative to 2009, they 'more often discussed energy use and conservation measures', 'more often turned-off lights when not in use' and 'more often checked the settings for the energy management system'. PSP-X participants reported that, relative to 2009, they 'more often turned-off lights when not in use', 'more often discussed energy use and conservation measures' and 'more often turned-off computers when they have not been used'.

Through the program, 42-49 per cent of custom or PSP-X participants implemented projects involving measures or technologies with which they had little or no prior experience, indicating that the program has broadened participant awareness of energy efficiency opportunities and technologies.

Results for Objective 4: Electricity and Peak Demand Savings

Results for electric energy and peak demand savings are summarized below.

[11] Key Account Managers manage BC Hydro's relationship with its largest Industrial, Commercial, Institutional and Government accounts.

Table 3.3 Summary of Electric Energy and Peak Demand Savings

Fiscal Year	Offer	Energy Savings (GWh/year) Reported	Evaluated	Peak Demand Savings (MW) Reported	Evaluated[12]
F2011	PSP-X	27.0	25.3	3.4	3.1
	Custom Incentive	28.2	31.5	3.3	3.8
	Program Enabled	6.5	7.1	0.8	0.9
	F2011 Sub-Total	**61.7**	**63.9**	**7.5**	**7.7**
F2012	PSP-X	48.1	43.1	5.8	5.2
	Custom Incentive	35.4	38.4	4.3	4.6
	Program Enabled	4.5	5	0.5	0.6
	F2012 Sub-Total	**88.1**	**86.5**	**10.7**	**10.5**
Sum of F2011 and F2012		**149.8**	**150.3**	**18.1**	**18.2**

Evaluated net savings are 150.3 GWh/year over F2011 and F2012, which is approximately 100 per cent of reported savings.

3.4 Findings and Recommendations

Findings

1. Overall satisfaction among custom incentive and program enabled participants was very high with 97 per cent of participants reporting that they were either 'very satisfied' (69 per cent) or 'somewhat satisfied' (28 per cent) with the program. Overall satisfaction with the PSP-X offer among participants was slightly lower at 89 per cent and was more evenly distributed between those who reported being 'very satisfied' (43 per cent) and those who reported being 'somewhat satisfied' (46 per cent);

2. Eighty per cent or more of program participants rated the service provided by BC Hydro personnel, their suppliers and distributors, and their contractors as excellent or good. In contrast, the lowest ratings for both offer participants (40 per cent PSP-X, 52 per cent custom rated as excellent or good) were for direct mail about the program. In addition PSP-X participants provided relatively lower ratings on the usability of the online application (52 per cent excellent or good), and the overall application procedure to receive funding (54 per cent excellent or good);

3. The most common program improvement suggestions from PSP-X participants were to provide more information and training about the program, and to increase the incentive amounts and range of eligible products. The most common program improvement suggestions from custom incentive and program enabled participants were to simplify the application process and provide more information and training about the program;

[12] Peak demand savings were calculated by applying a peak-to-energy ratio of 0.121 MW/GWh. This ratio is calculated using the ratio of average kWh to peak kWh from BC Hydro internal calculations, based on the commercial rate class load shape. The rate class load shapes are developed based on hourly load data collected for a sample of sites. The shapes were generated based on data collected for F2004 and F2005.

4. Key Account Managers appear to be playing an important role in promoting this program and helping customers access it. The Key Account Managers' role in relation to their support of the program emerged as the highest rated component among participants in both offers (94 per cent 'excellent' or 'good' for custom participants, and 78 per cent for PSP-X participants). Key Account Managers also emerged as the program component with the highest awareness among custom participants (89 per cent awareness);
5. Alliance members reported modest levels of knowledge about the PSP-X program, and few PSP-X participants recalled having been contacted by an Alliance member about the offer. Alliance members who did report being very or somewhat knowledgeable about the PSP-X offer found it to be a useful sales tool that influenced customers decisions to implement energy efficient products. Alliance members rated the promotional materials provided by the program and the e.catalogue lowest among all elements rated;
6. The Energy Manager offer appears to have been successful in achieving energy savings and organizational changes over time. Between 2009 and 2014, organizations that undertook repeated Energy Manager Assessments increased their average scores from 0.89 to 1.59, moving them from a tactical to a strategic approach to energy management. By F2014, program participants with energy managers were achieving average savings over twice that of participants without energy managers;
7. Free ridership was 16 per cent for custom incentive and program enabled savings and 25 per cent for PSP-X. Participant spillover was 22 per cent for custom incentive and program enabled savings and 9 per cent for PSP-X; and
8. Evaluated net savings for the custom incentive, program enabled and PSP-X offers were 63.9 GWh/year in F2011 and 86.5 GWh/y in F2012. This is 104 per cent of reported savings in F2011 and 98 per cent of reported savings in F2012.

Recommendations

Recommendations for program management:

1. Explore ways to improve trade ally awareness and satisfaction with the PSP-X offer, for example through marketing and training;
2. Consider improving the usability of the online application for PSP-X participants, streamlining the overall application process for custom incentive participants, and increasing communication and training activities for both offers; and
3. Continue support for the Energy Manager initiative, which appears to be achieving its intended medium term outcomes of achieving energy and bill savings and improving energy management practices at participating organizations.

Recommendations for future evaluations:

4. Consider revising the M&V criteria to improve M&V coverage across all offers and size ranges for future evaluations;
5. Investigate options to increase the number of non-participant survey responses, in order to estimate non-participant spillover, explore barriers to participation, inform baselines for savings estimation, and better understand market trends and program market effects; and

6. Investigate ways to improve data collection of market trends for future evaluations. Options may include leveraging the existing trade ally survey and creating data collection tools for contractors, suppliers and consultants outside the Power Smart Alliance.

3.5 Conclusions

The PSP-Commercial program's PSP-X, custom incentive and program enabled offers achieved 150.3 GWh/year of net energy savings in F2011 and F2012, which is equivalent to 100 per cent of reported savings. Customer satisfaction with the program is generally high, while trade ally satisfaction with the PSP-X offer is more mixed.

Glossary

Baseline - Energy consumption based on the existing or pre-implementation stage of the process. This level of consumption can be established by the measurements and or engineering calculations and is based on a specific level of production or operation.

Cross Effects (CE) - Change in energy consumption of one process due to change of energy consumption of another process (usually in heating ventilation and air conditioning, HVAC, systems due to change in lighting).

Difference-of-Differences Method (Double Difference) – Compares a treatment and a comparison group before and after an intervention. This method can be applied in both experimental and quasi-experimental designs and requires baseline and follow-up data from the same treatment and control group.

End Use - The final level of electrical energy use considered for an industrial application.

Energy - Energy refers to the amount of electricity consumed (or produced) over a certain time period, measured in watt-hours. Energy savings are the reduction in the amount of electricity consumed over a certain time period.

Experiment - In an experimental design, participants are randomly assigned to a treatment group or to a control group.

Free Ridership - Free-riders are those participants who would have made similar energy efficiency improvements in the absence of the program.

Gross Savings - The change in energy consumption and/or associated demand that results directly from program-related action taken by the participants in the demand side management program irrespective of why they participated.

Net savings - The change in energy consumption and/or associated demand that is attributable to the utility DSM program. The change in consumption or associated demand may include the effects of free riders and spillover.

Net to Gross Ratio - The combination of free rider and spillover estimates which are then applied to the gross savings to provide an estimate of net savings attributable to the program. Reflects program influence, does not reflect project performance in terms of energy savings estimated or measured.

Peak Demand - Demand refers to the amount of electricity that is consumed at any instant in time, measured in multiples of watts. Peak demand savings are the reduction in amount of electricity that is consumed at system peak demand, which for BC Hydro occurs on a winter weekday between approximately 5 p.m. and 7 p.m.

Price Elasticity - The most commonly used measure in the electricity industry when analyzing consumption changes due to rate adjustments. It provides a straightforward and easy-to-compare means to measure the price impacts on electricity consumption and the magnitude of customers' price sensitivity. It is defined as the percentage change in quantity demanded divided by the percentage change in price. For example, a price elasticity assumption of -0.10 means that for each one per cent increase in real price, electricity usage declines by 0.10 per cent.

***Realization Rate* -** The ratio of initial estimates of gross savings to gross savings adjusted for evaluation, measurement and verification results. The realization rate does not reflect program attribution or influence on the (net) savings achieved.

***Reported Savings* –** Initial estimate of net savings based on engineering calculations, review and site inspection, adjusted by program assumptions for free-ridership, spillover and market effects. These estimates represent the unevaluated savings.

***Spillover* -** Spillover occurs when individuals are influenced or impacted by the program (either directly as program participants or indirectly as non-participants) to make additional energy efficiency improvements without additional assistance from the program.

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Appendix AA

Generator Baseline Load Guidelines

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CONTRACTED GENERATOR BASELINE GUIDELINES
November 2015

1.0 Purpose and Principles of Contracted GBLs

These Contracted Generator Baseline (**Contracted GBL**) Guidelines describe the criteria and procedures that BC Hydro uses in setting a Contracted GBL for a transmission service or general service customer that has existing Self-Generation Facilities and is considering entering into a prospective Electricity Purchase Agreement (**EPA**) or Load Displacement Agreement (**LDA**) with BC Hydro.

The Contracted GBL is used, in a LDA or EPA between BC Hydro and a customer with existing Self-Generation Facilities, to identify the Incremental or New Electricity that BC Hydro will incentivize pursuant to the LDA or procure pursuant to the EPA. A Contracted GBL demarks the amount of electricity that the customer generates for self-supply in current normal operating conditions, and electricity in excess of the Contracted GBL is recognized as Incremental or New Electricity. The purpose of the Contracted GBL is to mitigate the risk to other ratepayers when BC Hydro incentivizes or procures customer Incremental or New Electricity pursuant to an LDA or EPA at the same time BC Hydro is selling electricity to the customer at regulated rates pursuant to an electricity supply or service agreement.

These Guidelines do not apply to:

- design of a BC Hydro electricity procurement process, or to the design of EPA or LDA terms and conditions;
- determination of a Non-Contracted GBL which BC Hydro may use for the purposes of applying Tariff Supplement No. 74 to a transmission service customer that has Self-Generation Facilities but does not have an EPA or LDA;
- determination of a contract demand for the purposes of an electricity supply or service agreement and do not define BC Hydro's level of service to the customer;
- determination of a baseline, if any, that might be used in a LDA or EPA by BC Hydro and a new customer installing Self-Generation Facilities, or a current customer that does not have existing Self-Generation Facilities; and
- determination of a baseline, if any, that might be used by BC Hydro and a customer in the context of the customer selling self-generation output to a party other than BC Hydro.

2.0 Definitions

The following terms used in these guidelines have the following meanings respectively:

(a) **Contracted Generating Unit** means a Self-Generation Facility that might or will be used to make self-generation output in accordance with a prospective EPA or LDA.

(b) **Electricity Purchase Agreement (EPA)** means an agreement between BC Hydro and a customer establishing the terms and conditions under which BC Hydro purchases self-generation output produced at the customer's Contracted Generating Unit.

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(c) **Force Majeure** includes but is not limited to strikes, legal lockouts, other labour disturbances (including exercises of non-affiliation rights but excluding illegal lockouts), fire, flood, accidents, tempest or acts of God, sabotage or acts of the Queen's enemies, acts or failure to act by lawful authority or any other cause whatsoever beyond the reasonable control of the customer, provided that in no event shall lack of finances, loss of markets or inability to perform due to the financial condition of the customer constitute Force Majeure.

(d) **Load Displacement Agreement (LDA)** means an agreement between BC Hydro and a customer establishing the terms and conditions under which BC Hydro provides the customer with a financial incentive to make self-generation output for self-supply from a Contracted Generating Unit that is deemed to be energy savings attributable to the load displacement project, and that reduces an equivalent portion of the customer's energy purchases.

(e) **Incremental or New Electricity** means additional electricity generated at (i) existing idle or underutilized Self-Generation Facilities, (ii) upgrades to existing Self-Generation Facilities, and (iii) a new generator installed at a site with existing Self-Generation Facilities.

(f) **Point of Delivery** is as defined in the customer's electricity supply or service agreement with BC Hydro (either the Electricity Supply Agreement or Electric Service Agreement, as the case may be).

(g) **Self-Generation Facilities** means electrical power generation facilities that are installed at the same site as the customer's plant, on the customer's side of the Point of Delivery, and are used to supply a portion of the customer's plant load.

3.0 Contracted GBL Setting

3.1 If BC Hydro and a customer with existing Self-Generation Facilities are considering entering into a prospective EPA or LDA, during the negotiation process for the agreement a Contracted GBL will be determined to demark the amount of self-generation that the customer normally generates for self-supply under current normal operating conditions and, thereby, to identify the New or Incremental Electricity in excess of the Contracted GBL that is eligible for payment in the context of an EPA or for a financial incentive in the context of an LDA.

3.2 The Contracted GBL will represent the customer's self-generation output under current normal operating conditions and over a 365-day period (in MWh or GWh) that the customer normally generates for self-supply.

3.3 BC Hydro will consider a number of economic, technical, and operational factors in setting the Contracted GBL. The foundational information is the customer's historical self-generation output, plant load and electricity purchases from BC Hydro. BC Hydro and the customer will typically review the customer's data from the most recent three years in setting a Contracted GBL.

3.4 The Contracted GBL will be set on the basis of the customer's self-generation output during the most recent 365 days, or other period that BC Hydro and the customer agree better represents current normal operating conditions for the customer. The data and information typically must be normalized by taking into

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account the specific circumstances of the customer including its operational requirements and constraints, the specific industry, economic conditions, and any abnormalities during the time period of the data that may impact the customer's normal operating conditions, as set out in section 3.5 below.

3.5 Adjustments will be made to the Contracted GBL to reflect the following:

3.5.1 *Force Majeure Event(s).* If the customer's self-generation output was affected by Force Majeure event(s) during the period used as the basis for the Contracted GBL, the historical data will be adjusted to remove the effect of the event(s) over 365 days of normal operations.

3.5.2 *Non-recurring Downtime.* If the customer had unusual self-generation downtime events during the period used as the basis for the Contracted GBL and which are not expected to recur in the future (e.g., planned or unplanned maintenance) the historical data will be adjusted to remove the effect of these events over 365 days of normal operations.

3.5.3 *Self-Generation Capacity Increase Projects.* If the customer has implemented a project which has resulted in a permanent increase in self-generation output and the project came into service during the period used as the basis for the Contracted GBL, the historical data will be adjusted to reflect the impact of the self-generation capacity increase project over 365 days of normal operations.

3.5.4 *Plant Changes.* If the customer has implemented operational or capital changes at their plant which have resulted in a permanent change in self-generation output and the changes came into service during the period used as the basis for the Contracted GBL, the historical data will be adjusted to reflect the impact of the changes on self-generation output over 365 days of normal operations.

3.5.5 *Non-recurring Generation.* If the customer sold self-generated energy during the period used as the basis for the Contracted GBL and is not expected to self-generate that energy for self-supply or sale in the future (e.g., the sales contract(s) terminated during the period), the historical data will be adjusted to remove that amount of energy over 365 days of normal operations.

3.5.6 The amount of the adjustments described above may be determined using data from the days, weeks or months prior to the event, as well as data from the same period during the prior two years. As part of this process, the customer may be required to provide professional or certified technical data and opinions regarding the amounts of these adjustments.

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4.0 Use of Contracted GBLs

4.1 The Contracted GBL is to be incorporated into a prospective EPA and/or LDA and will be defined in the applicable agreement. The agreement might include adjustments for planned and unplanned generation maintenance shutdowns, and it might also refine the annual Contracted GBL into time period components (e.g., seasonal or hourly). If the customer and BC Hydro decide not to enter into an EPA or LDA, any Contracted GBL determined will have no ongoing effect or meaning. A Contracted GBL is a defined commercial term of an EPA or LDA and has no ongoing effect or meaning after the contract terminates or expires.

4.2 If the customer and BC Hydro consider in the future renewing or entering into a new EPA or LDA, the Contracted GBL in the expired or expiring EPA or LDA would not be used in the renewed or new contract. A new Contracted GBL would be set based on normal operating conditions prevailing at the time of contract renewal or replacement, and in accordance with section 3.0 above.

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Fiscal 2017 to Fiscal 2019
Revenue Requirements Application

Appendix BB

Minister's Letter of Support
on Demand-Side Management Plan

BRITISH
COLUMBIA

DEC 16 2015

Ref.: 92462

Ms. Jessica McDonald
President and Chief Executive Officer
BC Hydro
18th Floor, 333 Dunsmuir
Vancouver, BC V6B 5R3

Dear Ms. McDonald:

I am writing in regard to BC Hydro's proposed demand side management (DSM) expenditures for the Fiscal 2017 to Fiscal 2019 period, which BC Hydro is planning to file with the British Columbia Utilities Commission as part of its Revenue Requirements Application in February 2016.

As part of its 2013 Integrated Resource Plan (2013 IRP), BC Hydro consulted on its DSM Plan and established a target for electricity savings based on resource needs and government policy objectives. Government approved this plan as part of the overall 2013 IRP in November 2013.

Government expects BC Hydro to continually evaluate its expenditures, including its DSM expenditures, to identify opportunities to achieve cost savings, keep rates low and respond to customer and system needs. Accordingly, I understand that BC Hydro undertook a process to review its DSM programs and is making adjustments to its DSM Plan for the Fiscal 2017 to Fiscal 2019 period.

I understand that this process was informed by BC Hydro's updated 2015 load and supply forecast which reflects events that have occurred subsequent to the approval of the 2013 IRP, including the closure of Paper Excellence's Howe Sound Thermo-Mechanical Pulp Facility as well as the impact of declining commodity prices on BC Hydro's resource sector customers, which have reduced the need for new energy supply resources and demand side measures.

I also understand that BC Hydro continues to measure performance with respect to the 66 percent energy objective in the *Clean Energy Act* based on its mid-load forecasts without load related to LNG facilities, consistent with the approach taken in the 2013 IRP and that based on this approach and the adjustments made to its DSM Plan, BC Hydro expects to exceed the objective. I further understand that, as a result of these changes, BC Hydro anticipates a lower level of electricity savings than was established in the 2013 IRP.

. . ./2

Ministry of Energy and Mines and Minister Responsible for Core Review

Office of the Minister

Mailing Address:
PO Box 9060, Stn Prov Govt
Victoria, BC V8W 9E2

Telephone: 250 387-5896
Facsimile: 250 356-2965

BC Hydro is proposing DSM expenditures averaging $125 million per year for the 2017, 2018 and 2019 Fiscal periods. The proposed DSM expenditures reflect the outcome of BC Hydro's review process and achieve the following objectives:

- Exceed the *Clean Energy Act* energy objective to meet at least 66 percent of incremental demand from 2008 to 2020 through conservation.
- Provide access to conservation opportunities and information for all customer groups.
- Reflect a prudent approach including discontinuing or reducing programs that are not as cost-effective and have served their purpose, reducing marketing dollars and adjusting certain offers.
- Support areas best suited to meet evolving customer and resource needs such as building codes and standards, capacity-focused DSM and customer energy management solutions.
- Leverage investments in smart meters and a smart grid by providing customers with the information they need to make smart energy choices.

The purpose of this letter is to inform you that, for the reasons outlined above, government supports the proposed DSM expenditures for the Fiscal 2017 to Fiscal 2019 period as a prudent and responsible evolution of the DSM Plan approved by government as part of the 2013 IRP.

I also expect BC Hydro to consult on a new long-term conservation target, beyond 2020, through the 2018 IRP process.

Sincerely,

Bill Bennett
Minister

pc: Ms. Elaine McKnight
Deputy Minister
Ministry of Energy and Mines

Fiscal 2017 to Fiscal 2019

Revenue Requirements Application

Appendix CC

Thermo-Mechanical Pulping Direction

PROVINCE OF BRITISH COLUMBIA

ORDER OF THE LIEUTENANT GOVERNOR IN COUNCIL

Order in Council No. 404 *, Approved and Ordered* July 14, 2015

Lieutenant Governor

Executive Council Chambers, Victoria

On the recommendation of the undersigned, the Lieutenant Governor, by and with the advice and consent of the Executive Council, orders that the attached Direction to the British Columbia Utilities Commission Respecting the Authority's TMP Program is made.

DEPOSITED

July 15, 2015

B.C. REG. **139/2015**

Minister of Energy and Mines and Minister Responsible for Core Review

Presiding Member of the Executive Council

(This part is for administrative purposes only and is not part of the Order.)

Authority under which Order is made:

Act and section: *Utilities Commission Act*, R.S.B.C. 1996, c. 473, s. 3

Other:

May 19, 2015 R/182/2015/27

DIRECTION TO THE BRITISH COLUMBIA UTILITIES COMMISSION RESPECTING THE AUTHORITY'S TMP PROGRAM

Definitions

1 In this direction,

"**Act**" means the *Utilities Commission Act*;

"**DSM regulatory account**" means the regulatory account of the authority established under commission order G-55-95;

"**TMP program**" means the authority's program to provide funding to increase the electrical energy efficiency of mills that use thermo-mechanical pulping processes.

Application

2 This direction is issued to the commission under section 3 of the Act.

TMP program

3 (1) Subject to subsection (2), in setting rates for the authority, the commission must not disallow for any reason the recovery in rates of the costs incurred by the authority in carrying out the TMP program.

(2) The costs recovered by rates referred to in subsection (1) must not exceed $100 million.

(3) The commission must, in regard to the DSM regulatory account, allow the authority to defer to that account the authority's costs incurred as a result of carrying out the TMP program.

Fiscal 2017 to Fiscal 2019
Revenue Requirements Application

Appendix DD

Summary of Organizational Changes

Table of Contents

List of Tables

A summary of the organizational changes that occurred since the Fiscal 2015 – Fiscal 2016 Revenue Requirements Application are shown below.

Table DD-1 Summary of Organizational Changes since F2015 to F2016 Revenue Requirements Application

Work Function	Key Business Unit in F2015-F2016 RRA	Business Group in F2015-F2016 RRA	Key Business Unit in F2017-F2019 RRA	Business Group in F2017-F2019 RRA
Aboriginal Relations	Aboriginal Relations and Negotiations	Transmission and Distribution	Aboriginal Relations	Capital Infrastructure Project Delivery
Communications	Communications	Corporate Groups	Corporate Affairs	Operations Support
Customer Services	Customer Care and Power Smart	Corporate Groups	Customer Service and Distribution Design	Transmission, Distribution and Customer Service
Dam Safety	Dam Safety	Generation	Dam Safety	Capital Infrastructure Project Delivery
Energy Planning	Energy Planning	Generation	Corporate Affairs	Operations Support
Enterprise Risk	Finance and Supply Chain	Corporate Groups	Corporate Affairs	Operations Support
Environmental Risk Management	Environmental Risk Management	Generation	Environmental Risk Management	Capital Infrastructure Project Delivery
Finance	Finance and Supply Chain/Generation Finance/ Transmission and Distribution Finance	Corporate Groups/ Generation/ Transmission and Distribution	Finance and Supply Chain	Operations Support
Human Resources	Human Resources and Safety	Corporate Groups	Corporate Affairs	Operations Support
Technology	Technology	Generation	Technology	Transmission, Distribution and Customer Service
Power Smart (Conservation and Energy Management)	Customer Care and Power Smart	Corporate Groups	Corporate Affairs	Operations Support

Work Function	Key Business Unit in F2015-F2016 RRA	Business Group in F2015-F2016 RRA	Key Business Unit in F2017-F2019 RRA	Business Group in F2017-F2019 RRA
Project Delivery	Transmission and Distribution Project and Program Delivery/Generation Project Delivery	Transmission and Distribution/ Generation	Project Delivery	Capital Infrastructure Project Delivery
Properties	Corporate Service and General Counsel	Corporate Groups	Properties	Capital Infrastructure Project Delivery
Regulatory	Finance and Supply Chain	Corporate Groups	Corporate Affairs	Operations Support
Safety	Human Resources and Safety/ Generation Operational Safety	Corporate Groups/ Generation	Safety, Security, and Emergency Management	Operations Support
Training and Development	Human Resources and Safety	Corporate Groups	Training and Development	Training, Development and Generation

In general, operating costs in Appendix A (Schedules 5.0 Operating Costs and Provisions and Schedule 16.0 FTE) for fiscal 2015 to fiscal 2019 are comparable given re statements of fiscal 2015 and fiscal 2016 to reflect these organization changes and cost classification

Fiscal 2017 to Fiscal 2019
Revenue Requirements Application

Appendix EE

Hydro Quebec Rate Report

COMPARISON OF ELECTRICITY PRICES IN MAJOR NORTH AMERICAN CITIES

Rates in effect April 1, 2015

Hydro Québec

TABLE OF CONTENTS

INTRODUCTION

Every year, Hydro-Québec compares the monthly electricity bills of Québec customers in the residential, commercial, institutional and industrial sectors with those of customers of the various utilities serving 21 major North American cities.

This report details the principal conclusions of this comparative analysis of prices in effect on April 1, 2015. There are three sections. The first describes the method used to estimate electricity bills. The second examines the highlights of the seven consumption levels analyzed, with the help of charts. Finally, the third section presents the results of the 21 consumption levels for which data were collected and compiled in the form of summary and detailed tables.

The most recent rate adjustments, time-of-use rates, adjustment clauses and applicable taxes, as well as a profile of the utilities in the study, appear in separate appendices.

MAJOR NORTH AMERICAN CITIES

AVERAGE PRICES FOR RESIDENTIAL CUSTOMERS[1] (IN ¢/KWH)[2]

1) For a monthly consumption of 1,000 kWh; rates in effect April 1, 2015.
2) In Canadian dollars.

MAJOR NORTH AMERICAN CITIES

AVERAGE PRICES FOR LARGE-POWER CUSTOMERS[1] (IN ¢/KWH)[2]

1) For a monthly consumption of 3,060,000 kWh and a power demand of 5,000 kW; rates in effect April 1, 2015.
2) In Canadian dollars.

METHOD

In addition to Hydro-Québec, this comparative analysis of electricity prices across North America includes 22 utilities: 12 serving the principal cities in the nine other Canadian provinces, and 10 utilities in American states. The results are based, in part, on a survey to which 12 utilities responded, and in part on estimates of bills calculated by Hydro-Québec and confirmed in most cases by the utilities concerned.

The results presented here show the total bill for various consumption levels. If the bill is calculated according to an unbundled rate, it includes all components, including supply, transmission and distribution.

PERIOD COVERED

Monthly bills have been calculated based on rates in effect on April 1, 2015. The most recent rate adjustments applied by the utilities in the study between April 1, 2014, and April 1, 2015, are shown in Appendix A.

CONSUMPTION LEVELS

Seven consumption levels were selected for analysis. However, data were collected for 21 consumption levels and those results are presented in the Detailed Tables.

TAXES

With the exception of the bills presented in Section 2, taxes are not included in any of the calculations. Appendix C lists taxes applicable on April 1, 2015, by customer category; those which may be partially or fully refundable are also indicated.

OPTIONAL PROGRAMS

The bills have been calculated according to base rates. Optional rates or programs offered by some utilities to their residential, commercial, institutional or industrial customers have not been taken into account since the terms and conditions vary considerably from one utility to the next.

GEOGRAPHIC LOCATION

Electricity distributors sometimes offer different rates in the various cities they serve. As well, taxes may vary from one region to another. This, however, is not the case in Québec, where, with the exception of territories north of the 53rd parallel, taxes and rates are applied uniformly. For the purposes of this study, the bill calculations estimate as closely as possible the actual electricity bills of consumers in each target city, based on rates in effect on April 1, 2015.

TIME-OF-USE RATES

The rates offered by some utilities vary depending on the season and/or time of day when energy is consumed. In the United States, for example, a number of utilities set a higher price in summer, when demand for air-conditioning is stronger. In Québec, on the other hand, demand increases in winter because of heating requirements. Thus, for some utilities, April 1 may fall within a period in the year when the price is high, whereas for others it falls in a period when the price is low. An annual average price has therefore been calculated in the case of utilities with time-of-use rates which are listed in Appendix B.

ADJUSTMENT CLAUSES

The rates of some distributors include adjustment clauses that allow them to adjust their customers' electricity bills according to changes in different variables. Since these adjustments may be applied monthly, or over a longer period, the electricity bills issued by a given distributor may have varied between April 1, 2014, and April 1, 2015, even though base rates remained the same. Appendix B lists the adjustment clauses taken into account when calculating bills.

EXCHANGE RATE

The exchange rate used to convert bills in U.S. dollars into Canadian dollars is $0.7929 (CA$1 = US$0.7929), the rate in effect at noon on April 1, 2015. The Canadian dollar had thus depreciated by 12.6% relative to the U.S. dollar since April 1, 2014.

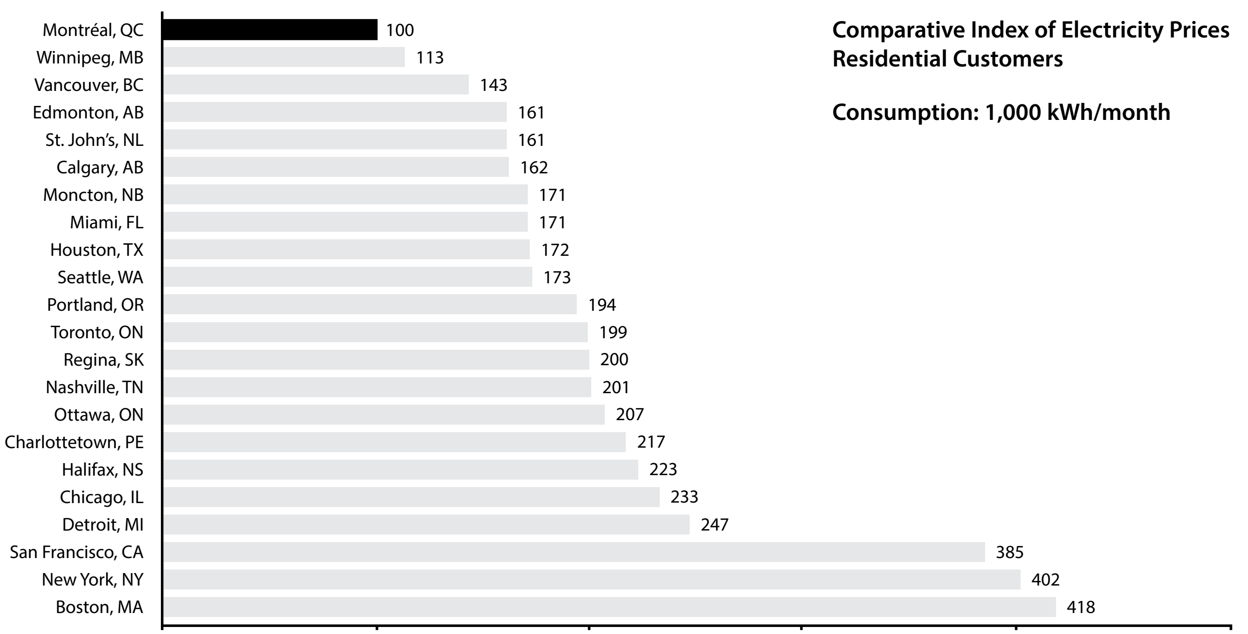
HIGHLIGHTS

The *Electricity Rates effective April 1, 2015* sets out Hydro-Québec's rates, as approved by the Régie de l'énergie (the Québec energy board) in accordance with Decision D-2015-033. Three types of rates are in effect: domestic rates, for residential customers, the industrial rate, for large-power industrial customers and general rates, for other customers. General rates are applied according to minimum billing demand: small power, medium power and large power. For comparison purposes, the electricity bills of the utilities in the study have been analyzed according to these customer categories. The industrial rate has been used to calculate the bills of large-power customers.

RESIDENTIAL CUSTOMERS

The rate applicable to Hydro-Québec's residential customers is among the most advantageous in North America. For customers whose monthly consumption is 1,000 kWh, Montréal is once again in *first* place. Figure 1 illustrates the results of this comparison.

FIGURE 1



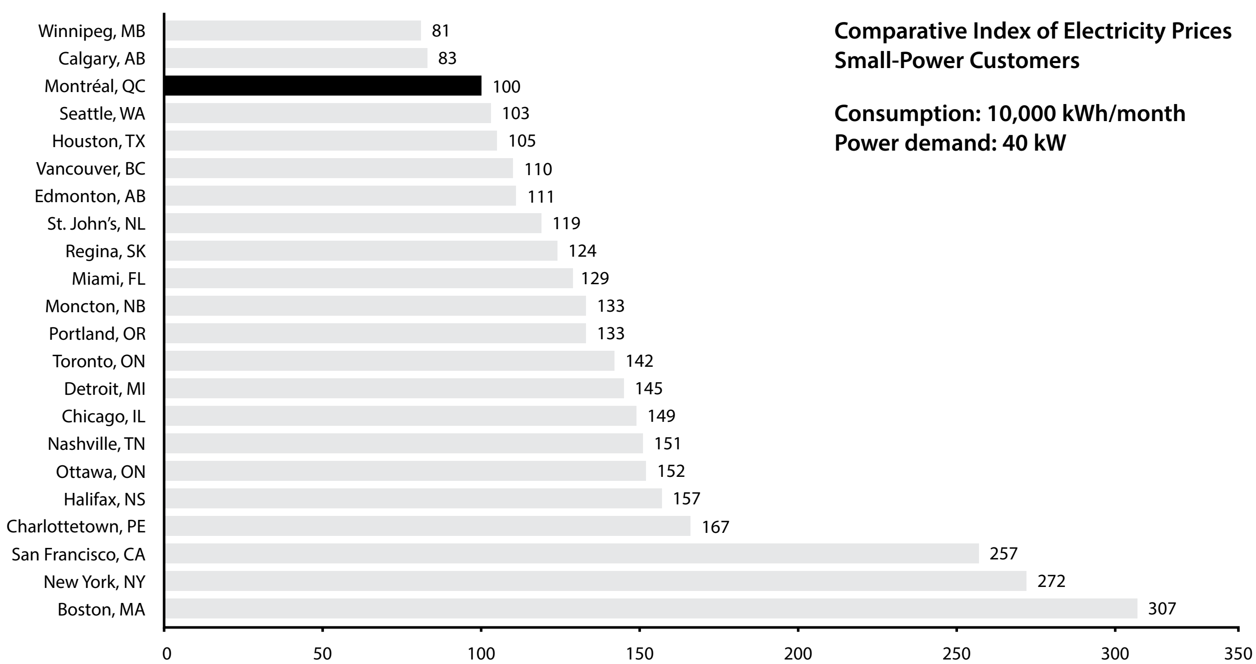
Hydro-Québec = 100

Monthly bill (excluding tax)
Rates in effect April 1, 2015

SMALL-POWER CUSTOMERS (LESS THAN 100 KW)

The comparison of bills for small-power customers is based on a monthly consumption of 10,000 kWh and a power demand of 40 kW. Montréal is in *third place*, as was the case last year. Figure 2 shows the comparative index of electricity prices.

FIGURE 2



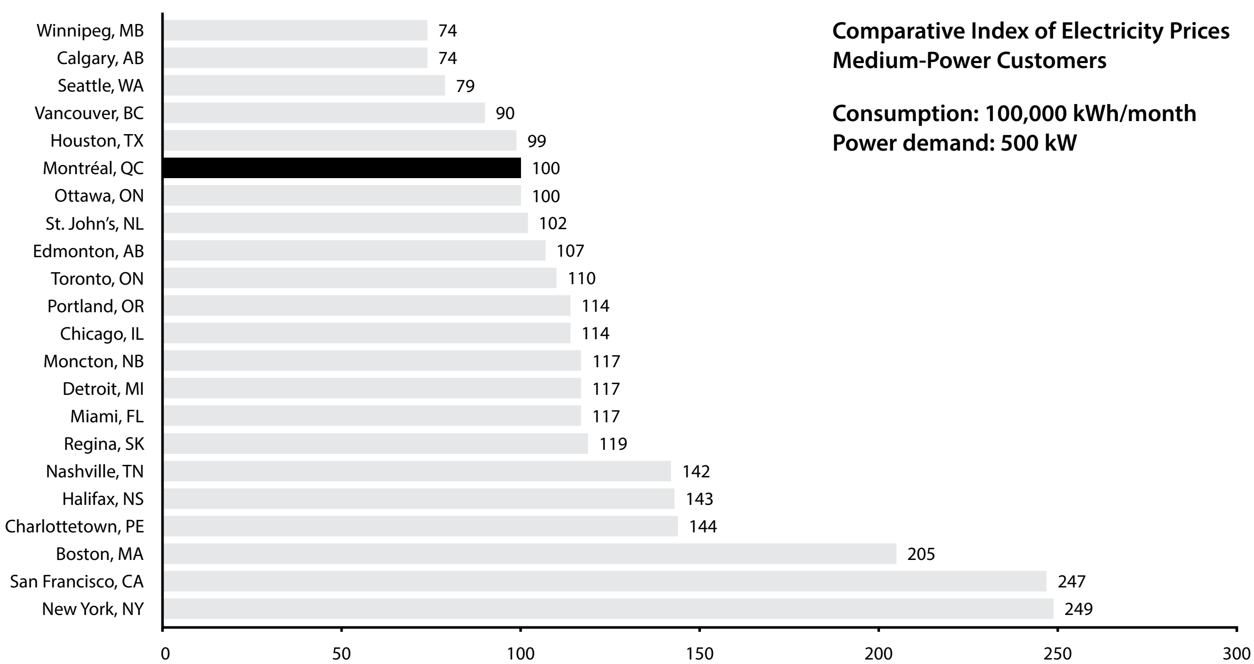
Hydro-Québec = 100
Monthly bill (excluding tax)
Rates in effect April 1, 2015

MEDIUM-POWER CUSTOMERS (100 TO 5,000 KW)

Three consumption levels were analyzed for medium-power customers. In all three cases, the bills of Hydro-Québec's customers have remained below the average of the other major North American cities. Figures 3, 4 and 5 show the comparative index of electricity prices for these consumption profiles.

For medium-power customers with a monthly consumption of 100,000 kWh and a power demand of 500 kW, Montréal holds *sixth* place, as was the case last year.

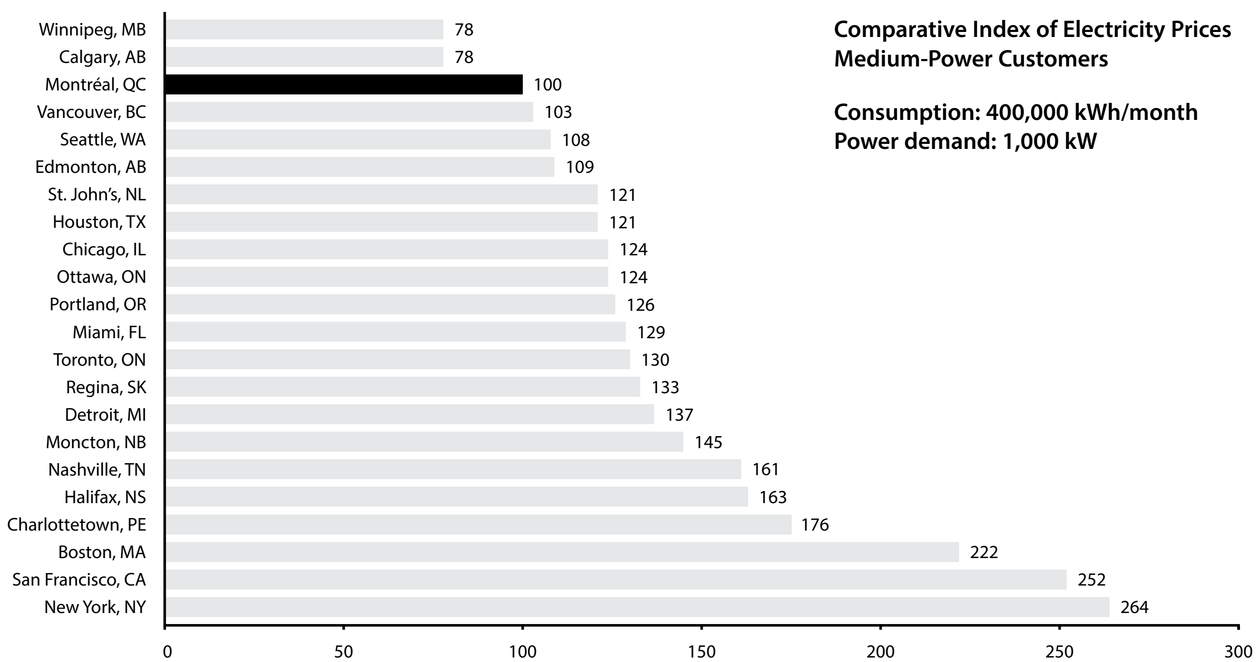
FIGURE 3



Hydro-Québec = 100
Monthly bill (excluding tax)
Rates in effect April 1, 2015

For customers with a monthly consumption of 400,000 kWh and a power demand of 1,000 kW, Montréal is in *third* place.

FIGURE 4

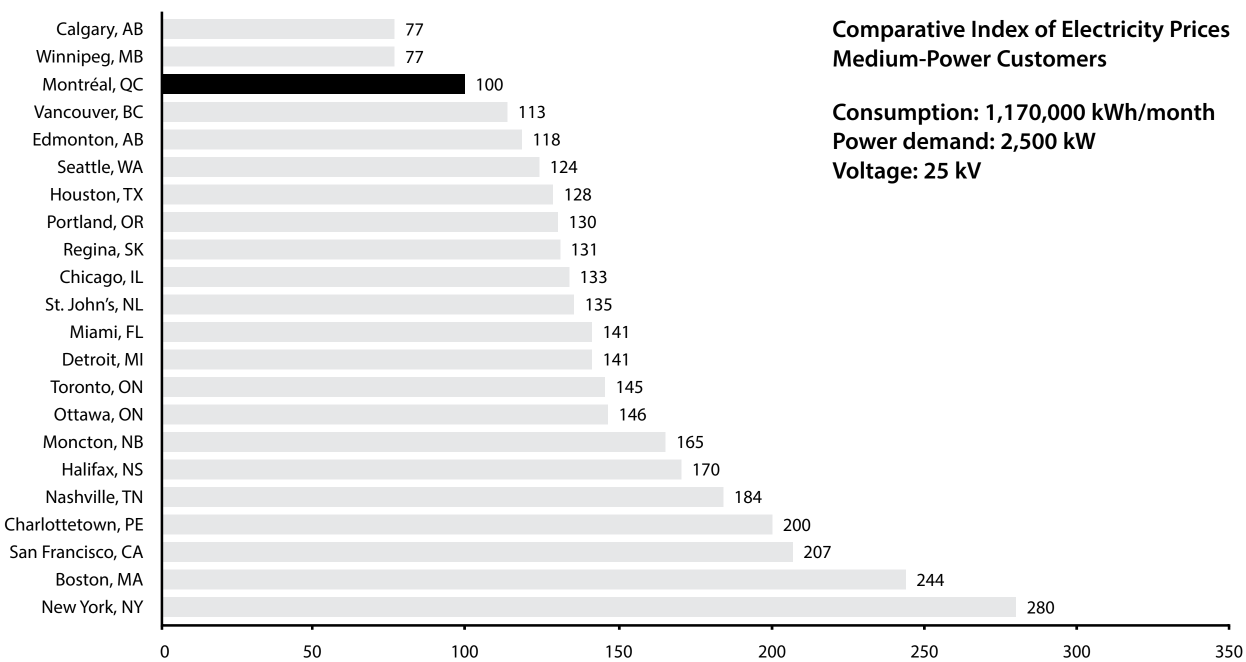


Hydro-Québec = 100

Monthly bill (excluding tax)
Rates in effect April 1, 2015

In the case of customers with a monthly consumption of 1,170,000 kWh and a power demand of 2,500 kW, Montréal ranks *third*.

FIGURE 5

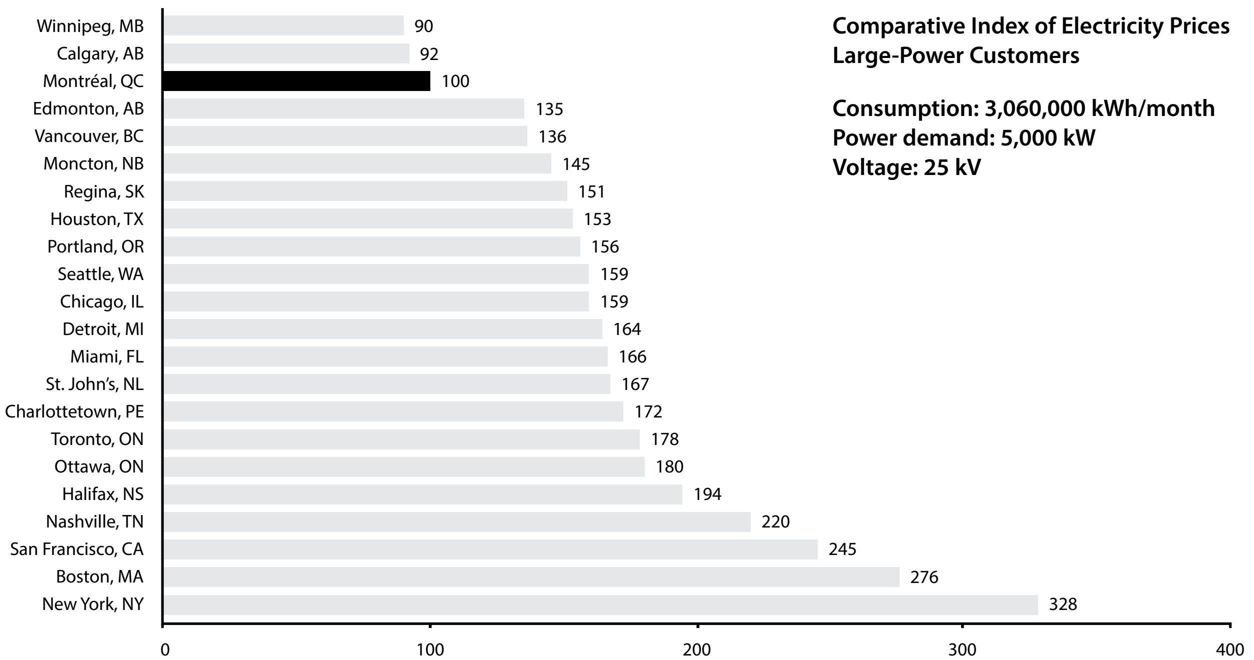


Hydro-Québec = 100
Monthly bill (excluding tax)
Rates in effect April 1, 2015

LARGE-POWER CUSTOMERS (5,000 KW OR MORE)

Figure 6 illustrates the comparative index of electricity prices for large-power customers with a monthly consumption of 3,060,000 kWh and a power demand of 5,000 kW. Montréal is in *third* place.

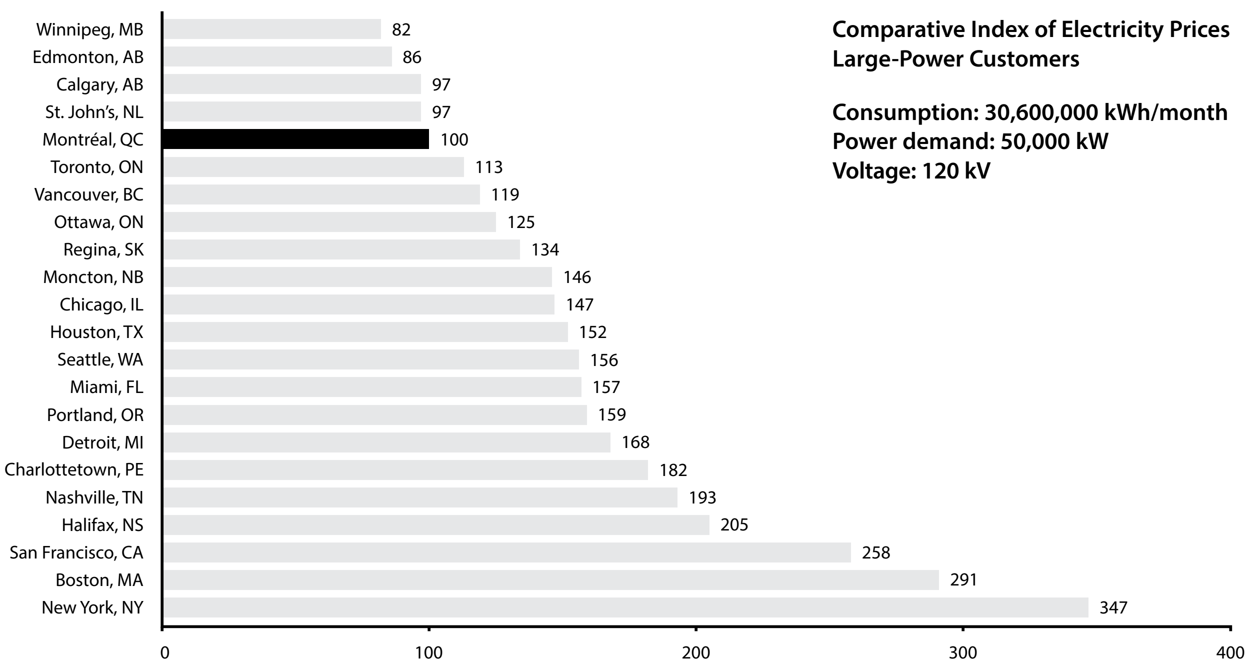
FIGURE 6



Hydro-Québec = 100
Monthly bill (excluding tax)
Rates in effect April 1, 2015

For industrial customers with a power demand of 50,000 kW and a load factor of 85%, Montréal now ranks *fifth*.

FIGURE 7



Hydro-Québec = 100

Monthly bill (excluding tax)
Rates in effect April 1, 2015

01

DETAILED RESULTS

SUMMARY TABLES (EXCLUDING TAXES)

Monthly Bills

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MONTHLY BILLS ON APRIL 1, 2015

(in CA$)

Summary Table (excluding taxes)

	Residential	Small Power	Medium Power			Large Power	
Power demand		**40 kW**	**500 kW**	**1,000 kW**	**2,500 kW**[1]	**5,000 kW**[1]	**50,000 kW**[2]
Consumption	**1,000 kWh**	**10,000 kWh**	**100,000 kWh**	**400,000 kWh**	**1,170,000 kWh**	**3,060,000 kWh**	**30,600,000 kWh**
Load factor		**35%**	**28%**	**56%**	**65%**	**85%**	**85%**
Canadian Cities							
Montréal, QC	71.91	977.33	11,940.00	31,494.00	78,105.75	158,317.50	1,498,275.00
Calgary, AB	116.55	811.41	8,807.51	24,683.73	60,030.83	145,597.96	1,449,958.28
Charlottetown, PE[3]	156.17	1,630.17	17,248.97	55,433.97	156,351.97	272,318.00	2,723,180.00
Edmonton, AB[4]	115.47	1,088.70	12,754.38	34,473.41	92,496.24	213,387.57	1,292,715.36
Halifax, NS	160.30	1,538.40	17,089.50	51,303.00	132,544.65	306,644.49	3,066,468.84
Moncton, NB	122.98	1,295.78	13,928.78	45,653.78	129,258.78	228,909.00	2,183,700.00
Ottawa, ON	148.62	1,481.62	11,991.67	39,060.42	113,689.69	284,692.47	1,875,065.61
Regina, SK	143.72	1,208.64	14,182.75	41,806.75	101,998.34	238,846.66	2,004,690.98
St. John's, NL[5]	115.53	1,162.20	12,125.59	38,181.29	105,786.32	264,808.12	1,458,856.00
Toronto, ON[3]	143.07	1,384.82	13,076.50	41,068.16	113,641.17	282,174.81	1,698,710.91
Vancouver, BC	102.90	1,074.53	10,794.32	32,492.57	88,569.85	215,469.72	1,788,147.60
Winnipeg, MB	81.09	794.93	8,798.37	24,499.32	60,512.00	142,804.00	1,230,230.00
American Cities							
Boston, MA	300.33	3,000.09	24,491.24	69,945.32	190,887.08	436,496.36	4,362,272.70
Chicago, IL[3]	167.90	1,457.10	13,574.02	38,983.76	103,740.27	251,160.35	2,208,605.46
Detroit, MI[3]	177.67	1,413.55	13,994.78	43,167.63	110,172.33	260,115.27	2,519,944.10
Houston, TX[3]	123.57	1,028.01	11,818.90	38,252.35	99,790.70	242,269.18	2,283,257.77
Miami, FL[3]	123.12	1,258.90	14,018.88	40,703.35	109,937.28	263,504.27	2,347,681.06
Nashville, TN[3]	144.51	1,471.29	17,005.42	50,555.02	143,340.11	348,055.91	2,886,134.28
New York, NY[3]	289.04	2,655.11	29,675.84	83,228.16	218,987.60	519,416.56	5,192,982.37
Portland, OR[3]	139.36	1,301.50	13,561.53	39,758.90	101,562.75	246,385.51	2,387,787.51
San Francisco, CA[3]	276.94	2,516.33	29,526.54	79,334.24	161,567.52	388,224.00	3,859,864.67
Seattle, WA	124.37	1,007.70	9,408.55	34,097.47	97,218.93	251,047.08	2,344,490.95
AVERAGE	**152.05**	**1,434.46**	**14,991.55**	**44,462.57**	**116,826.83**	**270,938.40**	**2,393,773.61**

1) Supply voltage of 25 kV, customer-owned transformer.
2) Supply voltage of 120 kV, customer-owned transformer.
3) These bills have been estimated by Hydro-Québec and may differ from actual bills.
4) Bills corresponding to consumption levels of 500 kW or more have been estimated by Hydro-Québec based on the applicable general rate.
5) Newfoundland and Labrador Hydro rates for customers with a power demand of 30,000 kW or more; Newfoundland Power rates for all other customer categories.

AVERAGE PRICES ON APRIL 1, 2015
(in ¢/kWh)[1]

Summary Table (excluding taxes)

	Residential	Small Power	Medium Power			Large Power	
Power demand		**40 kW**	**500 kW**	**1,000 kW**	**2,500 kW[2]**	**5,000 kW[2]**	**50,000 kW[3]**
Consumption	**1,000 kWh**	**10,000 kWh**	**100,000 kWh**	**400,000 kWh**	**1,170,000 kWh**	**3,060,000 kWh**	**30,600,000 kWh**
Load factor		**35%**	**28%**	**56%**	**65%**	**85%**	**85%**
Canadian Cities							
Montréal, QC	7.19	9.77	11.94	7.87	6.68	5.17	4.90
Calgary, AB	11.66	8.11	8.81	6.17	5.13	4.76	4.74
Charlottetown, PE[4]	15.62	16.30	17.25	13.86	13.36	8.90	8.90
Edmonton, AB[5]	11.55	10.89	12.75	8.62	7.91	6.97	4.22
Halifax, NS	16.03	15.38	17.09	12.83	11.33	10.02	10.02
Moncton, NB	12.30	12.96	13.93	11.41	11.05	7.48	7.14
Ottawa, ON	14.86	14.82	11.99	9.77	9.72	9.30	6.13
Regina, SK	14.37	12.09	14.18	10.45	8.72	7.81	6.55
St. John's, NL[6]	11.55	11.62	12.13	9.55	9.04	8.65	4.77
Toronto, ON[4]	14.31	13.85	13.08	10.27	9.71	9.22	5.55
Vancouver, BC	10.29	10.75	10.79	8.12	7.57	7.04	5.84
Winnipeg, MB	8.11	7.95	8.80	6.12	5.17	4.67	4.02
American Cities							
Boston, MA	30.03	30.00	24.49	17.49	16.32	14.26	14.26
Chicago, IL[4]	16.79	14.57	13.57	9.75	8.87	8.21	7.22
Detroit, MI[4]	17.77	14.14	13.99	10.79	9.42	8.50	8.24
Houston, TX[4]	12.36	10.28	11.82	9.56	8.53	7.92	7.46
Miami, FL[4]	12.31	12.59	14.02	10.18	9.40	8.61	7.67
Nashville, TN[4]	14.45	14.71	17.01	12.64	12.25	11.37	9.43
New York, NY[4]	28.90	26.55	29.68	20.81	18.72	16.97	16.97
Portland, OR[4]	13.94	13.01	13.56	9.94	8.68	8.05	7.80
San Francisco, CA[4]	27.69	25.16	29.53	19.83	13.81	12.69	12.61
Seattle, WA	12.44	10.08	9.41	8.52	8.31	8.20	7.66
AVERAGE	**15.21**	**14.34**	**14.99**	**11.12**	**9.99**	**8.85**	**7.82**

1) In Canadian dollars.
2) Supply voltage of 25 kV, customer-owned transformer.
3) Supply voltage of 120 kV, customer-owned transformer.
4) These bills have been estimated by Hydro-Québec and may differ from actual bills.
5) Bills corresponding to consumption levels of 500 kW or more have been estimated by Hydro-Québec based on the applicable general rate.
6) Newfoundland and Labrador Hydro rates for customers with a power demand of 30,000 kW or more; Newfoundland Power rates for all other customer categories.

COMPARATIVE INDEX ON APRIL 1, 2015

(Hydro-Québec = 100)

Summary Table (excluding taxes)

	Residential	Small Power	Medium Power			Large Power	
Power demand **Consumption** **Load factor**	**1,000 kWh**	**40 kW** **10,000 kWh** **35%**	**500 kW** **100,000 kWh** **28%**	**1,000 kW** **400,000 kWh** **56%**	**2,500 kW[1]** **1,170,000 kWh** **65%**	**5,000 kW[1]** **3,060,000 kWh** **85%**	**50,000 kW[2]** **30,600,000 kWh** **85%**
Canadian Cities							
Montréal, QC	100	100	100	100	100	100	100
Calgary, AB	162	83	74	78	77	92	97
Charlottetown, PE[3]	217	167	144	176	200	172	182
Edmonton, AB[4]	161	111	107	109	118	135	86
Halifax, NS	223	157	143	163	170	194	205
Moncton, NB	171	133	117	145	165	145	146
Ottawa, ON	207	152	100	124	146	180	125
Regina, SK	200	124	119	133	131	151	134
St. John's, NL[5]	161	119	102	121	135	167	97
Toronto, ON[3]	199	142	110	130	145	178	113
Vancouver, BC	143	110	90	103	113	136	119
Winnipeg, MB	113	81	74	78	77	90	82
American Cities							
Boston, MA	418	307	205	222	244	276	291
Chicago, IL[3]	233	149	114	124	133	159	147
Detroit, MI[3]	247	145	117	137	141	164	168
Houston, TX[3]	172	105	99	121	128	153	152
Miami, FL[3]	171	129	117	129	141	166	157
Nashville, TN[3]	201	151	142	161	184	220	193
New York, NY[3]	402	272	249	264	280	328	347
Portland, OR[3]	194	133	114	126	130	156	159
San Francisco, CA[3]	385	257	247	252	207	245	258
Seattle, WA	173	103	79	108	124	159	156
AVERAGE	**211**	**147**	**126**	**141**	**150**	**171**	**160**

1) Supply voltage of 25 kV, customer-owned transformer.
2) Supply voltage of 120 kV, customer-owned transformer.
3) These bills have been estimated by Hydro-Québec and may differ from actual bills.
4) Bills corresponding to consumption levels of 500 kW or more have been estimated by Hydro-Québec based on the applicable general rate.
5) Newfoundland and Labrador Hydro rates for customers with a power demand of 30,000 kW or more; Newfoundland Power rates for all other customer categories.

02

DETAILED RESULTS

SUMMARY TABLES (INCLUDING TAXES)

Monthly Bills

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Comparative Index

MONTHLY BILLS ON APRIL 1, 2015
(in CA$)

Summary Table (including taxes)

	Residential	Small Power	Medium Power			Large Power	
Power demand		**40 kW**	**500 kW**	**1,000 kW**	**2,500 kW[1]**	**5,000 kW[1]**	**50,000 kW[2]**
Consumption	**1,000 kWh**	**10,000 kWh**	**100,000 kWh**	**400,000 kWh**	**1,170,000 kWh**	**3,060,000 kWh**	**30,600,000 kWh**
Load factor		**35%**	**28%**	**56%**	**65%**	**85%**	**85%**
Canadian Cities							
Montréal, QC	82.68	1,123.69	13,728.02	36,210.23	89,802.09	182,025.55	1,722,641.68
Calgary, AB	122.38	851.98	9,247.88	25,917.92	63,032.38	152,877.86	1,522,456.19
Charlottetown, PE[3]	178.03	1,858.39	19,663.83	63,194.73	178,241.25	310,442.52	3,104,425.20
Edmonton, AB[4]	121.24	1,143.14	13,392.10	36,197.08	97,121.05	224,056.95	1,357,351.13
Halifax, NS	168.32	1,769.16	19,652.93	58,998.45	152,426.35	352,641.16	3,526,439.17
Moncton, NB	138.97	1,464.23	15,739.52	51,588.77	146,062.42	258,667.17	2,467,581.00
Ottawa, ON	167.95	1,674.23	13,550.58	44,138.27	128,469.35	321,702.49	2,118,824.14
Regina, SK	165.28	1,456.41	17,090.21	50,377.13	122,907.99	287,810.22	2,415,652.63
St. John's, NL[5]	131.86	1,313.29	13,701.92	43,144.86	119,538.54	299,233.18	1,648,507.28
Toronto, ON[3]	164.04	1,587.78	14,776.44	46,407.02	128,414.52	318,857.54	1,919,543.33
Vancouver, BC	110.04	1,203.48	12,089.64	36,391.68	99,198.23	241,326.08	2,002,725.31
Winnipeg, MB	93.77	940.00	10,404.07	28,970.45	67,683.00	159,726.00	1,376,012.00
American Cities							
Boston, MA	300.33	3,147.39	25,619.94	72,708.87	198,114.04	451,475.95	4,511,900.45
Chicago, IL[3]	186.67	1,603.70	14,886.47	43,939.82	117,700.04	286,075.97	2,518,430.14
Detroit, MI[3]	197.21	1,569.04	15,534.21	47,916.07	122,291.28	288,727.95	2,797,137.95
Houston, TX[3]	124.80	1,112.07	12,701.43	41,007.76	108,016.85	262,459.09	2,473,375.30
Miami, FL[3]	140.02	1,534.65	17,129.28	49,354.73	133,036.27	317,993.57	2,806,788.25
Nashville, TN[3]	144.51	1,574.28	18,195.79	54,093.87	153,373.92	372,419.82	3,088,163.68
New York, NY[3]	314.35	2,963.05	33,117.78	92,877.49	244,324.92	579,503.96	5,793,718.31
Portland, OR[3]	141.50	1,321.58	13,771.63	40,371.17	103,151.96	250,250.02	2,425,305.04
San Francisco, CA[3]	277.31	2,708.71	31,777.61	85,430.61	174,113.01	418,459.99	4,160,546.41
Seattle, WA	124.37	1,007.70	9,408.55	34,097.47	97,218.93	251,047.08	2,344,490.95
AVERAGE	**163.44**	**1,587.63**	**16,599.08**	**49,242.48**	**129,283.56**	**299,444.55**	**2,641,000.71**

1) Supply voltage of 25 kV, customer-owned transformer.
2) Supply voltage of 120 kV, customer-owned transformer.
3) These bills have been estimated by Hydro-Québec and may differ from actual bills.
4) Bills corresponding to consumption levels of 500 kW or more have been estimated by Hydro-Québec based on the applicable general rate.
5) Newfoundland and Labrador Hydro rates for customers with a power demand of 30,000 kW or more; Newfoundland Power rates for all other customer categories.

AVERAGE PRICES ON APRIL 1, 2015

(in ¢/kWh)[1]

Summary Table (including taxes)

	Residential	Small Power	Medium Power			Large Power	
Power demand		**40 kW**	**500 kW**	**1,000 kW**	**2,500 kW[2]**	**5,000 kW[2]**	**50,000 kW[3]**
Consumption	**1,000 kWh**	**10,000 kWh**	**100,000 kWh**	**400,000 kWh**	**1,170,000 kWh**	**3,060,000 kWh**	**30,600,000 kWh**
Load factor		**35%**	**28%**	**56%**	**65%**	**85%**	**85%**
Canadian Cities							
Montréal, QC	8.27	11.24	13.73	9.05	7.68	5.95	5.63
Calgary, AB	12.24	8.52	9.25	6.48	5.39	5.00	4.98
Charlottetown, PE[4]	17.80	18.58	19.66	15.80	15.23	10.15	10.15
Edmonton, AB[5]	12.12	11.43	13.39	9.05	8.30	7.32	4.44
Halifax, NS	16.83	17.69	19.65	14.75	13.03	11.52	11.52
Moncton, NB	13.90	14.64	15.74	12.90	12.48	8.45	8.06
Ottawa, ON	16.79	16.74	13.55	11.03	10.98	10.51	6.92
Regina, SK	16.53	14.56	17.09	12.59	10.50	9.41	7.89
St. John's, NL[6]	13.19	13.13	13.70	10.79	10.22	9.78	5.39
Toronto, ON[4]	16.40	15.88	14.78	11.60	10.98	10.42	6.27
Vancouver, BC	11.00	12.03	12.09	9.10	8.48	7.89	6.54
Winnipeg, MB	9.38	9.40	10.40	7.24	5.78	5.22	4.50
American Cities							
Boston, MA	30.03	31.47	25.62	18.18	16.93	14.75	14.74
Chicago, IL[4]	18.67	16.04	14.89	10.98	10.06	9.35	8.23
Detroit, MI[4]	19.72	15.69	15.53	11.98	10.45	9.44	9.14
Houston, TX[4]	12.48	11.12	12.70	10.25	9.23	8.58	8.08
Miami, FL[4]	14.00	15.35	17.13	12.34	11.37	10.39	9.17
Nashville, TN[4]	14.45	15.74	18.20	13.52	13.11	12.17	10.09
New York, NY[4]	31.44	29.63	33.12	23.22	20.88	18.94	18.93
Portland, OR[4]	14.15	13.22	13.77	10.09	8.82	8.18	7.93
San Francisco, CA[4]	27.73	27.09	31.78	21.36	14.88	13.68	13.60
Seattle, WA	12.44	10.08	9.41	8.52	8.31	8.20	7.66
AVERAGE	**16.34**	**15.88**	**16.60**	**12.31**	**11.05**	**9.79**	**8.63**

1) In Canadian dollars.
2) Supply voltage of 25 kV, customer-owned transformer.
3) Supply voltage of 120 kV, customer-owned transformer.
4) These bills have been estimated by Hydro-Québec and may differ from actual bills.
5) Bills corresponding to consumption levels of 500 kW or more have been estimated by Hydro-Québec based on the applicable general rate.
6) Newfoundland and Labrador Hydro rates for customers with a power demand of 30,000 kW or more; Newfoundland Power rates for all other customer categories.

COMPARATIVE INDEX ON APRIL 1, 2015

(Hydro-Québec = 100)

Summary Table (including taxes)

	Residential	Small Power	Medium Power			Large Power	
Power demand Consumption Load factor	 1,000 kWh 	40 kW 10,000 kWh 35%	500 kW 100,000 kWh 28%	1,000 kW 400,000 kWh 56%	2,500 kW[1] 1,170,000 kWh 65%	5,000 kW[1] 3,060,000 kWh 85%	50,000 kW[2] 30,600,000 kWh 85%
Canadian Cities							
Montréal, QC	100	100	100	100	100	100	100
Calgary, AB	148	76	67	72	70	84	88
Charlottetown, PE[3]	215	165	143	175	198	171	180
Edmonton, AB[4]	147	102	98	100	108	123	79
Halifax, NS	204	157	143	163	170	194	205
Moncton, NB	168	130	115	142	163	142	143
Ottawa, ON	203	149	99	122	143	177	123
Regina, SK	200	130	124	139	137	158	140
St. John's, NL[5]	159	117	100	119	133	164	96
Toronto, ON[3]	198	141	108	128	143	175	111
Vancouver, BC	133	107	88	101	110	133	116
Winnipeg, MB	113	84	76	80	75	88	80
American Cities							
Boston, MA	363	280	187	201	221	248	262
Chicago, IL[3]	226	143	108	121	131	157	146
Detroit, MI[3]	239	140	113	132	136	159	162
Houston, TX[3]	151	99	93	113	120	144	144
Miami, FL[3]	169	137	125	136	148	175	163
Nashville, TN[3]	175	140	133	149	171	205	179
New York, NY[3]	380	264	241	256	272	318	336
Portland, OR[3]	171	118	100	111	115	137	141
San Francisco, CA[3]	335	241	231	236	194	230	242
Seattle, WA	150	90	69	94	108	138	136
AVERAGE	**198**	**141**	**121**	**136**	**144**	**165**	**153**

1) Supply voltage of 25 kV, customer-owned transformer.
2) Supply voltage of 120 kV, customer-owned transformer.
3) These bills have been estimated by Hydro-Québec and may differ from actual bills.
4) Bills corresponding to consumption levels of 500 kW or more have been estimated by Hydro-Québec based on the applicable general rate.
5) Newfoundland and Labrador Hydro rates for customers with a power demand of 30,000 kW or more; Newfoundland Power rates for all other customer categories.

03

DETAILED RESULTS

RESIDENTIAL

Monthly Bills
Average Prices
Comparative Index

RESIDENTIAL

Monthly Bills on April 1, 2015
(in CA$)

Consumption	625 kWh	750 kWh	1,000 kWh	2,000 kWh	3,000 kWh
Canadian Cities					
Montréal, QC	47.69	54.79	71.91	157.91	243.91
Calgary, AB	80.88	92.77	116.55	211.68	306.81
Charlottetown, PE[1]	106.82	123.27	156.17	287.77	391.57
Edmonton, AB	80.67	92.27	115.47	208.27	301.07
Halifax, NS	104.25	122.93	160.30	309.77	459.24
Moncton, NB	84.54	97.36	122.98	225.48	327.98
Ottawa, ON	96.51	113.88	148.62	287.61	426.60
Regina, SK	97.41	112.85	143.72	267.22	390.72
St. John's, NL[2]	77.55	90.22	115.53	216.80	318.07
Toronto, ON[1]	94.13	110.36	143.07	279.83	416.59
Vancouver, BC	57.94	71.53	102.90	228.38	353.85
Winnipeg, MB	53.41	62.64	81.09	154.90	228.71
American Cities					
Boston, MA	190.74	227.29	300.33	592.55	884.77
Chicago, IL[1]	112.48	130.95	167.90	278.42	406.83
Detroit, MI[1]	110.55	132.92	177.67	356.67	535.66
Houston, TX[1]	93.90	107.97	123.57	236.14	348.71
Miami, FL[1]	80.53	94.73	123.12	262.95	402.78
Nashville, TN[1]	95.91	112.11	144.51	274.10	403.68
New York, NY[1]	188.15	221.78	289.04	558.10	827.16
Portland, OR[1]	92.13	107.87	139.36	298.17	456.98
San Francisco, CA[1]	156.22	209.04	276.94	699.49	1,122.04
Seattle, WA	68.13	86.87	124.37	274.32	424.28
AVERAGE	**98.66**	**117.11**	**152.05**	**303.02**	**453.55**

1) These bills have been estimated by Hydro-Québec and may differ from actual bills.
2) Newfoundland Power rates.

RESIDENTIAL

Average Prices on April 1, 2015
(in ¢/kWh)[1]

Consumption	625 kWh	750 kWh	1,000 kWh	2,000 kWh	3,000 kWh
Canadian Cities					
Montréal, QC	7.63	7.31	7.19	7.90	8.13
Calgary, AB	12.94	12.37	11.66	10.58	10.23
Charlottetown, PE[2]	17.09	16.44	15.62	14.39	13.05
Edmonton, AB	12.91	12.30	11.55	10.41	10.04
Halifax, NS	16.68	16.39	16.03	15.49	15.31
Moncton, NB	13.53	12.98	12.30	11.27	10.93
Ottawa, ON	15.44	15.18	14.86	14.38	14.22
Regina, SK	15.59	15.05	14.37	13.36	13.02
St. John's, NL[3]	12.41	12.03	11.55	10.84	10.60
Toronto, ON[2]	15.06	14.71	14.31	13.99	13.89
Vancouver, BC	9.27	9.54	10.29	11.42	11.80
Winnipeg, MB	8.55	8.35	8.11	7.75	7.62
American Cities					
Boston, MA	30.52	30.31	30.03	29.63	29.49
Chicago, IL[2]	18.00	17.46	16.79	13.92	13.56
Detroit, MI[2]	17.69	17.72	17.77	17.83	17.86
Houston, TX[2]	15.02	14.40	12.36	11.81	11.62
Miami, FL[2]	12.88	12.63	12.31	13.15	13.43
Nashville, TN[2]	15.35	14.95	14.45	13.70	13.46
New York, NY[2]	30.10	29.57	28.90	27.91	27.57
Portland, OR[2]	14.74	14.38	13.94	14.91	15.23
San Francisco, CA[2]	25.00	27.87	27.69	34.97	37.40
Seattle, WA	10.90	11.58	12.44	13.72	14.14
AVERAGE	**15.79**	**15.61**	**15.21**	**15.15**	**15.12**

1) In Canadian dollars.
2) These bills have been estimated by Hydro-Québec and may differ from actual bills.
3) Newfoundland Power rates.

RESIDENTIAL

Comparative Index on April 1, 2015
(Hydro-Québec = 100)

Consumption	625 kWh	750 kWh	1,000 kWh	2,000 kWh	3,000 kWh
Canadian Cities					
Montréal, QC	100	100	100	100	100
Calgary, AB	170	169	162	134	126
Charlottetown, PE[1]	224	225	217	182	161
Edmonton, AB	169	168	161	132	123
Halifax, NS	219	224	223	196	188
Moncton, NB	177	178	171	143	134
Ottawa, ON	202	208	207	182	175
Regina, SK	204	206	200	169	160
St. John's, NL[2]	163	165	161	137	130
Toronto, ON[1]	197	201	199	177	171
Vancouver, BC	121	131	143	145	145
Winnipeg, MB	112	114	113	98	94
American Cities					
Boston, MA	400	415	418	375	363
Chicago, IL[1]	236	239	233	176	167
Detroit, MI[1]	232	243	247	226	220
Houston, TX[1]	197	197	172	150	143
Miami, FL[1]	169	173	171	167	165
Nashville, TN[1]	201	205	201	174	166
New York, NY[1]	395	405	402	353	339
Portland, OR[1]	193	197	194	189	187
San Francisco, CA[1]	328	382	385	443	460
Seattle, WA	143	159	173	174	174
AVERAGE	**207**	**214**	**211**	**192**	**186**

1) These bills have been estimated by Hydro-Québec and may differ from actual bills.
2) Newfoundland Power rates.

04

DETAILED RESULTS

SMALL POWER

Monthly Bills

Average Prices

Comparative Index

SMALL POWER

Monthly Bills on April 1, 2015
(in CA$)

Power demand Consumption Load factor	6 kW 750 kWh 17%	14 kW 2,000 kWh 20%	40 kW 10,000 kWh 35%	100 kW 14,000 kWh 19%	100 kW 25,000 kWh 35%
Canadian Cities					
Montréal, QC	84.71	205.33	977.33	1,797.60	2,654.50
Calgary, AB	107.41	219.90	811.41	1,318.06	1,747.69
Charlottetown, PE[1]	146.45	349.57	1,630.17	2,855.57	4,009.47
Edmonton, AB	95.34	229.58	1,088.70	1,992.56	2,741.99
Halifax, NS	120.98	295.48	1,538.40	2,707.44	3,846.00
Moncton, NB	115.98	272.98	1,295.78	2,254.78	3,233.78
Ottawa, ON	117.97	287.96	1,481.62	2,147.04	2,990.64
Regina, SK	116.12	263.76	1,208.64	2,330.40	3,173.00
St. John's, NL[2]	104.40	269.07	1,162.20	2,053.79	2,978.85
Toronto, ON[1]	126.72	301.09	1,384.82	2,207.43	3,053.03
Vancouver, BC	91.71	232.54	1,074.53	1,836.41	2,658.48
Winnipeg, MB	77.87	174.77	794.93	1,588.37	2,079.69
American Cities					
Boston, MA	224.10	578.84	3,000.09	5,544.58	7,850.67
Chicago, IL[1]	129.94	302.63	1,457.10	2,381.18	3,584.45
Detroit, MI[1]	117.03	295.22	1,413.55	1,972.72	3,510.42
Houston, TX[1]	88.33	289.09	1,028.01	1,841.60	2,519.29
Miami, FL[1]	100.88	253.32	1,258.90	2,341.42	3,110.41
Nashville, TN[1]	139.96	319.87	1,471.29	3,034.43	4,016.74
New York, NY[1]	240.74	779.42	2,655.11	5,253.88	6,569.58
Portland, OR[1]	122.53	289.19	1,301.50	2,193.16	3,196.53
San Francisco, CA[1]	202.87	520.28	2,516.33	4,127.42	6,029.77
Seattle, WA	75.58	201.54	1,007.70	1,401.95	2,281.51
AVERAGE	**124.89**	**315.06**	**1,434.46**	**2,508.26**	**3,538.02**

1) These bills have been estimated by Hydro-Québec and may differ from actual bills.
2) Newfoundland Power rates.

SMALL POWER

Average Prices on April 1, 2015
(in ¢/kWh)[1]

Power demand Consumption Load factor	6 kW 750 kWh 17%	14 kW 2,000 kWh 20%	40 kW 10,000 kWh 35%	100 kW 14,000 kWh 19%	100 kW 25,000 kWh 35%
Canadian Cities					
Montréal, QC	11.29	10.27	9.77	12.84	10.62
Calgary, AB	14.32	11.00	8.11	9.41	6.99
Charlottetown, PE[2]	19.53	17.48	16.30	20.40	16.04
Edmonton, AB	12.71	11.48	10.89	14.23	10.97
Halifax, NS	16.13	14.77	15.38	19.34	15.38
Moncton, NB	15.46	13.65	12.96	16.11	12.94
Ottawa, ON	15.73	14.40	14.82	15.34	11.96
Regina, SK	15.48	13.19	12.09	16.65	12.69
St. John's, NL[3]	13.92	13.45	11.62	14.67	11.92
Toronto, ON[2]	16.90	15.05	13.85	15.77	12.21
Vancouver, BC	12.23	11.63	10.75	13.12	10.63
Winnipeg, MB	10.38	8.74	7.95	11.35	8.32
American Cities					
Boston, MA	29.88	28.94	30.00	39.60	31.40
Chicago, IL[2]	17.32	15.13	14.57	17.01	14.34
Detroit, MI[2]	15.60	14.76	14.14	14.09	14.04
Houston, TX[2]	11.78	14.45	10.28	13.15	10.08
Miami, FL[2]	13.45	12.67	12.59	16.72	12.44
Nashville, TN[2]	18.66	15.99	14.71	21.67	16.07
New York, NY[2]	32.10	38.97	26.55	37.53	26.28
Portland, OR[2]	16.34	14.46	13.01	15.67	12.79
San Francisco, CA[2]	27.05	26.01	25.16	29.48	24.12
Seattle, WA	10.08	10.08	10.08	10.01	9.13
AVERAGE	**16.65**	**15.75**	**14.34**	**17.92**	**14.15**

1) In Canadian dollars.
2) These bills have been estimated by Hydro-Québec and may differ from actual bills.
3) Newfoundland Power rates.

SMALL POWER

Comparative Index on April 1, 2015
(Hydro-Québec = 100)

Power demand Consumption Load factor	6 kW 750 kWh 17%	14 kW 2,000 kWh 20%	40 kW 10,000 kWh 35%	100 kW 14,000 kWh 19%	100 kW 25,000 kWh 35%
Canadian Cities					
Montréal, QC	100	100	100	100	100
Calgary, AB	127	107	83	73	66
Charlottetown, PE[1]	173	170	167	159	151
Edmonton, AB	113	112	111	111	103
Halifax, NS	143	144	157	151	145
Moncton, NB	137	133	133	125	122
Ottawa, ON	139	140	152	119	113
Regina, SK	137	128	124	130	120
St. John's, NL[2]	123	131	119	114	112
Toronto, ON[1]	150	147	142	123	115
Vancouver, BC	108	113	110	102	100
Winnipeg, MB	92	85	81	88	78
American Cities					
Boston, MA	265	282	307	308	296
Chicago, IL[1]	153	147	149	132	135
Detroit, MI[1]	138	144	145	110	132
Houston, TX[1]	104	141	105	102	95
Miami, FL[1]	119	123	129	130	117
Nashville, TN[1]	165	156	151	169	151
New York, NY[1]	284	380	272	292	247
Portland, OR[1]	145	141	133	122	120
San Francisco, CA[1]	239	253	257	230	227
Seattle, WA	89	98	103	78	86
AVERAGE	**147**	**153**	**147**	**140**	**133**

1) These bills have been estimated by Hydro-Québec and may differ from actual bills.
2) Newfoundland Power rates.

05

DETAILED RESULTS

MEDIUM POWER

Monthly Bills

Average Prices

Comparative Index

MEDIUM POWER

Monthly Bills on April 1, 2015
(in CA$)

Power demand Consumption Load factor	500 kW 100,000 kWh 28%	500 kW 200,000 kWh 56%	1,000 kW 200,000 kWh 28%	1,000 kW 400,000 kWh 56%	2,500 kW[1] 1,170,000 kWh 65%
Canadian Cities					
Montréal, QC	11,940.00	16,925.00	23,880.00	31,494.00	78,105.75
Calgary, AB	8,807.51	12,617.75	17,063.24	24,683.73	60,030.83
Charlottetown, PE[2]	17,248.97	27,738.97	34,453.97	55,433.97	156,351.97
Edmonton, AB[3]	12,754.38	18,242.31	23,497.56	34,473.41	92,496.24
Halifax, NS	17,089.50	25,651.50	34,179.00	51,303.00	132,544.65
Moncton, NB	13,928.78	22,828.78	27,853.78	45,653.78	129,258.78
Ottawa, ON	11,991.67	19,660.74	23,722.26	39,060.42	113,689.69
Regina, SK	14,182.75	20,911.75	28,348.75	41,806.75	101,998.34
St. John's, NL[4]	12,125.59	20,114.92	22,661.63	38,181.29	105,786.32
Toronto, ON[2]	13,076.50	20,763.69	25,833.51	41,068.16	113,641.17
Vancouver, BC	10,794.32	16,180.82	21,719.57	32,492.57	88,569.85
Winnipeg, MB	8,798.37	12,350.37	17,395.32	24,499.32	60,512.00
American Cities					
Boston, MA	24,491.24	35,077.76	48,772.29	69,945.32	190,887.08
Chicago, IL[2]	13,574.02	20,199.89	26,636.41	38,983.76	103,740.27
Detroit, MI[2]	13,994.78	21,800.32	27,973.92	43,167.63	110,172.33
Houston, TX[2]	11,818.90	17,979.73	25,930.68	38,252.35	99,790.70
Miami, FL[2]	14,018.88	20,389.20	27,962.71	40,703.35	109,937.28
Nashville, TN[2]	17,005.42	25,399.96	33,765.92	50,555.02	143,340.11
New York, NY[2]	29,675.84	41,636.81	59,306.22	83,228.16	218,987.60
Portland, OR[2]	13,561.53	20,840.93	25,874.50	39,758.90	101,562.75
San Francisco, CA[2]	29,526.54	41,601.10	56,550.30	79,334.24	161,567.52
Seattle, WA	9,408.55	17,404.56	18,322.55	34,097.47	97,218.93
AVERAGE	**14,991.55**	**22,559.86**	**29,622.91**	**44,462.57**	**116,826.83**

1) Supply voltage of 25 kV, customer-owned transformer.
2) These bills have been estimated by Hydro-Québec and may differ from actual bills.
3) Bills corresponding to consumption levels of 500 kW or more have been estimated by Hydro-Québec based on the applicable general rate.
4) Newfoundland Power rates.

MEDIUM POWER

Average Prices on April 1, 2015
(in ¢/kWh)[1]

Power demand Consumption Load factor	500 kW 100,000 kWh 28%	500 kW 200,000 kWh 56%	1,000 kW 200,000 kWh 28%	1,000 kW 400,000 kWh 56%	2,500 kW[2] 1,170,000 kWh 65%
Canadian Cities					
Montréal, QC	11.94	8.46	11.94	7.87	6.68
Calgary, AB	8.81	6.31	8.53	6.17	5.13
Charlottetown, PE[3]	17.25	13.87	17.23	13.86	13.36
Edmonton, AB[4]	12.75	9.12	11.75	8.62	7.91
Halifax, NS	17.09	12.83	17.09	12.83	11.33
Moncton, NB	13.93	11.41	13.93	11.41	11.05
Ottawa, ON	11.99	9.83	11.86	9.77	9.72
Regina, SK	14.18	10.46	14.17	10.45	8.72
St. John's, NL[5]	12.13	10.06	11.33	9.55	9.04
Toronto, ON[3]	13.08	10.38	12.92	10.27	9.71
Vancouver, BC	10.79	8.09	10.86	8.12	7.57
Winnipeg, MB	8.80	6.18	8.70	6.12	5.17
American Cities					
Boston, MA	24.49	17.54	24.39	17.49	16.32
Chicago, IL[3]	13.57	10.10	13.32	9.75	8.87
Detroit, MI[3]	13.99	10.90	13.99	10.79	9.42
Houston, TX[3]	11.82	8.99	12.97	9.56	8.53
Miami, FL[3]	14.02	10.19	13.98	10.18	9.40
Nashville, TN[3]	17.01	12.70	16.88	12.64	12.25
New York, NY[3]	29.68	20.82	29.65	20.81	18.72
Portland, OR[3]	13.56	10.42	12.94	9.94	8.68
San Francisco, CA[3]	29.53	20.80	28.28	19.83	13.81
Seattle, WA	9.41	8.70	9.16	8.52	8.31
AVERAGE	**14.99**	**11.28**	**14.81**	**11.12**	**9.99**

1) In Canadian dollars.
2) Supply voltage of 25 kV, customer-owned transformer.
3) These bills have been estimated by Hydro-Québec and may differ from actual bills.
4) Bills corresponding to consumption levels of 500 kW or more have been estimated by Hydro-Québec based on the applicable general rate.
5) Newfoundland Power rates.

MEDIUM POWER

Comparative Index on April 1, 2015
(Hydro-Québec = 100)

Power demand Consumption Load factor	500 kW 100,000 kWh 28%	500 kW 200,000 kWh 56%	1,000 kW 200,000 kWh 28%	1,000 kW 400,000 kWh 56%	2,500 kW[1] 1,170,000 kWh 65%
Canadian Cities					
Montréal, QC	100	100	100	100	100
Calgary, AB	74	75	71	78	77
Charlottetown, PE[2]	144	164	144	176	200
Edmonton, AB[3]	107	108	98	109	118
Halifax, NS	143	152	143	163	170
Moncton, NB	117	135	117	145	165
Ottawa, ON	100	116	99	124	146
Regina, SK	119	124	119	133	131
St. John's, NL[4]	102	119	95	121	135
Toronto, ON[2]	110	123	108	130	145
Vancouver, BC	90	96	91	103	113
Winnipeg, MB	74	73	73	78	77
American Cities					
Boston, MA	205	207	204	222	244
Chicago, IL[2]	114	119	112	124	133
Detroit, MI[2]	117	129	117	137	141
Houston, TX[2]	99	106	109	121	128
Miami, FL[2]	117	120	117	129	141
Nashville, TN[2]	142	150	141	161	184
New York, NY[2]	249	246	248	264	280
Portland, OR[2]	114	123	108	126	130
San Francisco, CA[2]	247	246	237	252	207
Seattle, WA	79	103	77	108	124
AVERAGE	**126**	**133**	**124**	**141**	**150**

1) Supply voltage of 25 kV, customer-owned transformer.
2) These bills have been estimated by Hydro-Québec and may differ from actual bills.
3) Bills corresponding to consumption levels of 500 kW or more have been estimated by Hydro-Québec based on the applicable general rate.
4) Newfoundland Power rates.

06

DETAILED RESULTS
LARGE POWER

Monthly Bills
Average Prices
Comparative Index

LARGE POWER

Monthly Bills on April 1, 2015
(in CA$)

Power demand	5,000 kW	5,000 kW	10,000 kW	30,000 kW	50,000 kW	50,000 kW
Consumption	**2,340,000 kWh**	**3,060,000 kWh**	**5,760,000 kWh**	**17,520,000 kWh**	**23,400,000 kWh**	**30,600,000 kWh**
Voltage[1]	**25 kV**	**25 kV**	**120 kV**	**120 kV**	**120 kV**	**120 kV**
Load factor	**65%**	**85%**	**80%**	**81%**	**65%**	**85%**
Canadian Cities						
Montréal, QC	134,845.50	158,317.50	287,919.00	871,581.00	1,263,555.00	1,498,275.00
Calgary, AB	117,881.06	145,597.96	276,667.29	837,905.62	1,172,789.24	1,449,958.28
Charlottetown, PE[2]	225,302.00	272,318.00	521,128.00	1,579,056.00	2,253,020.00	2,723,180.00
Edmonton, AB[3]	178,139.54	213,387.57	257,453.66	757,119.38	1,069,121.24	1,292,715.36
Halifax, NS	249,346.89	306,644.49	584,640.17	1,773,031.71	2,493,492.84	3,066,468.84
Moncton, NB	192,734.00	228,909.00	418,920.00	1,268,640.00	1,827,300.00	2,183,700.00
Ottawa, ON	230,926.30	284,692.47	593,906.01	1,209,150.68	1,598,682.31	1,875,065.61
Regina, SK	195,718.66	238,846.66	387,289.72	1,161,063.15	1,623,666.98	2,004,690.98
St. John's, NL[4]	208,937.34	264,808.12	495,683.65	844,435.20	1,194,184.00	1,458,856.00
Toronto, ON[2]	217,157.24	282,174.81	328,160.64	987,509.26	1,415,876.17	1,698,710.91
Vancouver, BC	177,268.66	215,469.72	341,362.23	1,034,937.20	1,462,863.48	1,788,147.60
Winnipeg, MB	118,763.00	142,804.00	235,211.00	712,861.00	1,013,582.00	1,230,230.00
American Cities						
Boston, MA	361,444.87	436,496.36	835,167.99	2,529,923.15	3,611,757.80	4,362,272.70
Chicago, IL[2]	206,709.90	251,160.35	458,078.04	1,273,740.57	1,764,100.97	2,208,605.46
Detroit, MI[2]	219,911.65	260,115.27	484,460.43	1,465,765.14	2,122,448.17	2,519,944.10
Houston, TX[2]	197,080.28	242,269.18	436,811.26	1,319,746.74	1,843,754.80	2,283,257.77
Miami, FL[2]	219,608.46	263,504.27	451,355.37	1,363,300.84	1,952,582.41	2,347,681.06
Nashville, TN[2]	288,178.17	348,055.91	564,175.62	1,689,218.49	2,512,011.92	2,886,134.28
New York, NY[2]	437,843.73	519,416.56	997,915.23	3,020,673.71	4,377,254.10	5,192,982.37
Portland, OR[2]	201,728.46	246,385.51	459,023.66	1,385,453.59	1,973,765.72	2,387,787.51
San Francisco, CA[2]	319,911.09	388,224.00	739,805.39	2,237,214.87	3,176,735.59	3,859,864.67
Seattle, WA	194,556.64	251,047.08	443,068.19	1,346,123.94	1,818,198.26	2,344,490.95
AVERAGE	**222,454.25**	**270,938.40**	**481,736.48**	**1,394,020.51**	**1,979,124.68**	**2,393,773.61**

1) Customer-owned transformer.
2) These bills have been estimated by Hydro-Québec and may differ from actual bills.
3) Bills corresponding to consumption levels of 500 kW or more have been estimated by Hydro-Québec based on the applicable general rate.
4) Newfoundland and Labrador Hydro rates for customers with a power demand of 30,000 kW or more; Newfoundland Power rates for all other customer categories.

LARGE POWER

Average Prices on April 1, 2015
(in ¢/kWh)[1]

Power demand	5,000 kW	5,000 kW	10,000 kW	30,000 kW	50,000 kW	50,000 kW
Consumption	2,340,000 kWh	3,060,000 kWh	5,760,000 kWh	17,520,000 kWh	23,400,000 kWh	30,600,000 kWh
Voltage[2]	25 kV	25 kV	120 kV	120 kV	120 kV	120 kV
Load factor	65%	85%	80%	81%	65%	85%
Canadian Cities						
Montréal, QC	5.76	5.17	5.00	4.97	5.40	4.90
Calgary, AB	5.04	4.76	4.80	4.78	5.01	4.74
Charlottetown, PE[3]	9.63	8.90	9.05	9.01	9.63	8.90
Edmonton, AB[4]	7.61	6.97	4.47	4.32	4.57	4.22
Halifax, NS	10.66	10.02	10.15	10.12	10.66	10.02
Moncton, NB	8.24	7.48	7.27	7.24	7.81	7.14
Ottawa, ON	9.87	9.30	10.31	6.90	6.83	6.13
Regina, SK	8.36	7.81	6.72	6.63	6.94	6.55
St. John's, NL[5]	8.93	8.65	8.61	4.82	5.10	4.77
Toronto, ON[3]	9.28	9.22	5.70	5.64	6.05	5.55
Vancouver, BC	7.58	7.04	5.93	5.91	6.25	5.84
Winnipeg, MB	5.08	4.67	4.08	4.07	4.33	4.02
American Cities						
Boston, MA	15.45	14.26	14.50	14.44	15.43	14.26
Chicago, IL[3]	8.83	8.21	7.95	7.27	7.54	7.22
Detroit, MI[3]	9.40	8.50	8.41	8.37	9.07	8.24
Houston, TX[3]	8.42	7.92	7.58	7.53	7.88	7.46
Miami, FL[3]	9.38	8.61	7.84	7.78	8.34	7.67
Nashville, TN[3]	12.32	11.37	9.79	9.64	10.74	9.43
New York, NY[3]	18.71	16.97	17.32	17.24	18.71	16.97
Portland, OR[3]	8.62	8.05	7.97	7.91	8.43	7.80
San Francisco, CA[3]	13.67	12.69	12.84	12.77	13.58	12.61
Seattle, WA	8.31	8.20	7.69	7.68	7.77	7.66
AVERAGE	**9.51**	**8.85**	**8.36**	**7.96**	**8.46**	**7.82**

1) In Canadian dollars.
2) Customer-owned transformer.
3) These bills have been estimated by Hydro-Québec and may differ from actual bills.
4) Bills corresponding to consumption levels of 500 kW or more have been estimated by Hydro-Québec based on the applicable general rate.
5) Newfoundland and Labrador Hydro rates for customers with a power demand of 30,000 kW or more; Newfoundland Power rates for all other customer categories.

LARGE POWER

Comparative Index on April 1, 2015
(Hydro-Québec = 100)

Power demand Consumption Voltage[1] Load factor	5,000 kW 2,340,000 kWh 25 kV 65%	5,000 kW 3,060,000 kWh 25 kV 85%	10,000 kW 5,760,000 kWh 120 kV 80%	30,000 kW 17,520,000 kWh 120 kV 81%	50,000 kW 23,400,000 kWh 120 kV 65%	50,000 kW 30,600,000 kWh 120 kV 85%
Canadian Cities						
Montréal, QC	100	100	100	100	100	100
Calgary, AB	87	92	96	96	93	97
Charlottetown, PE[2]	167	172	181	181	178	182
Edmonton, AB[3]	132	135	89	87	85	86
Halifax, NS	185	194	203	203	197	205
Moncton, NB	143	145	145	146	145	146
Ottawa, ON	171	180	206	139	127	125
Regina, SK	145	151	135	133	128	134
St. John's, NL[4]	155	167	172	97	95	97
Toronto, ON[2]	161	178	114	113	112	113
Vancouver, BC	131	136	119	119	116	119
Winnipeg, MB	88	90	82	82	80	82
American Cities						
Boston, MA	268	276	290	290	286	291
Chicago, IL[2]	153	159	159	146	140	147
Detroit, MI[2]	163	164	168	168	168	168
Houston, TX[2]	146	153	152	151	146	152
Miami, FL[2]	163	166	157	156	155	157
Nashville, TN[2]	214	220	196	194	199	193
New York, NY[2]	325	328	347	347	346	347
Portland, OR[2]	150	156	159	159	156	159
San Francisco, CA[2]	237	245	257	257	251	258
Seattle, WA	144	159	154	154	144	156
AVERAGE	**165**	**171**	**167**	**160**	**157**	**160**

1) Customer-owned transformer.
2) These bills have been estimated by Hydro-Québec and may differ from actual bills.
3) Bills corresponding to consumption levels of 500 kW or more have been estimated by Hydro-Québec based on the applicable general rate.
4) Newfoundland and Labrador Hydro rates for customers with a power demand of 30,000 kW or more; Newfoundland Power rates for all other customer categories.

A

APPENDIX
RATE ADJUSTMENTS

Average Adjustments

Adjustments by
Customer Category

RATE ADJUSTMENTS
All Categories

	Before April 2014		Between April 1, 2014 and April 1, 2015		
	Year	%	Date	%	Comments
Canadian Utilities					
Hydro-Québec, QC	2014	4.2	April 1, 2015	2.8	
ENMAX, AB	2014	22.6	January 1, 2015	3.11	Distribution component
Maritime Electric, PE	2014	2.2	March 1, 2015	2.2	Typical residential customer
EPCOR, AB	2014	n.a.	January 1, 2015	n.a.	
Nova Scotia Power, NS	2014	3.0	January 1, 2015	0.0	
NB Power, NB	2013	2.0	October 1, 2014	2.0	
Hydro Ottawa, ON	2014	n.a.	May 1, 2014 November 1, 2014 January 1, 2015	n.a. n.a. n.a.	
SaskPower, SK	2014	5.5	January 1, 2015	3.0	
Newfoundland Power, NL[1]	2013	-3.1	July 1, 2014	2.0	
Newfoundland and Labrador Hydro, NL[1]	2007	-18.3	—	—	
Toronto Hydro, ON	2013	n.a.	May 1, 2014	n.a.	
BC Hydro, BC	2014	9.0	April 1, 2015	6.0	
Manitoba Hydro, MB	2013	3.5	May 1, 2014	2.75	Interim increase

Data concerning American utilities not available.

n.a.: Not available.

1) Newfoundland and Labrador Hydro rates for customers with a power demand of 30,000 kW or more; Newfoundland Power rates for all other customer categories.

RATE ADJUSTMENTS (Between April 1, 2014, and April 1, 2015)

Adjustments by Customer Category

	Date	Residential %	General %	Industrial %	Average %
Canadian Utilities					
Hydro-Québec, QC	April 1, 2015	2.9	2.9[1] 2.7[2] 2.9[3]	2.5	2.8
ENMAX, AB	January 1, 2015	3.22	n.a.	n.a.	3.11[4]
Maritime Electric, PE	March 1, 2015	2.2	n.a.	n.a.	n.a.
EPCOR, AB	January 1, 2015	n.a.	n.a.	n.a.	n.a.
Nova Scotia Power, NS	January 1, 2015	0.0	-4.5[1] 0.0[2] 1.5[3]	0.0[5] 1.5[6] 1.5[7]	0.0
NB Power, NB	October 1, 2014	2.0	2.0	2.0	2.0
Hydro Ottawa, ON	May 1, 2014 November 1, 2014 January 1, 2015	2.48 1.69 1.22	2.61 1.78 1.33	0.09 9.88 -5.87	n.a. n.a. n.a.
SaskPower, SK	January 1, 2015	2.7	3.2	3.6	3.0
Newfoundland Power, NL[8]	July 1, 2014	1.9	2.2	2.6	2.0
Newfoundland and Labrador Hydro, NL[8]	—	—	—	—	—
Toronto Hydro, ON	May 1, 2014	n.a.	n.a.	n.a.	n.a.
BC Hydro, BC	April 1, 2015	6.0	6.0	6.0	6.0
Manitoba Hydro, MB	May 1, 2014	2.75	2.75	2.75	2.75

Data concerning American utilities not available.

n.a.: Not available.

1) Small power.
2) Medium power.
3) Large power.
4) Distribution component.
5) Small industrial.
6) Medium industrial.
7) Large industrial.
8) Newfoundland and Labrador Hydro rates for customers with a power demand of 30,000 kW or more; Newfoundland Power rates for all other customer categories.

Note: Because of adjustment clauses (see list in Appendix B), electricity bills issued by a utility may vary, even though base rates have not changed.

B

APPENDIX

TIME-OF-USE RATES

ADJUSTMENT CLAUSES

TIME-OF-USE RATES

The utilities listed below apply time-of-use rates for different consumption levels. For the purposes of this study, an annual average has been calculated for utilities whose rates vary according to the season or time of day (or both). In the case of utilities whose supply costs are determined by the market, the average for the month of March 2015 was used.

CenterPoint Energy, TX	All levels
Commonwealth Edison, IL	All levels
Consolidated Edison, NY	All levels
DTE Electric, MI	500–50,000 kW
ENMAX, AB	All levels
EPCOR, AB	All levels
Eversource Energy, MA	General: All levels
Hydro Ottawa, ON	All levels
Nashville Electric Service, TN	All levels
Newfoundland Power, NL	14–10,000 kW
Pacific Gas and Electric, CA	All levels
Pacific Power and Light, OR	1,000–50,000 kW
Seattle City Light, WA	Residential General: 1,000–50,000 kW
Toronto Hydro, ON	All levels

ADJUSTMENT CLAUSES

Below is a list of utilities whose rates include adjustment clauses that may cause fluctuations in the price of electricity even though base rates have not been adjusted.

BC Hydro, BC	Deferral Account Rate Rider
CenterPoint Energy, TX	Accumulated Deferred Federal Income Tax Credit Advanced Metering System Surcharge Energy Efficiency Cost Recovery Factor Nuclear Decommissioning Charge Rate Case Expenses Surcharge System Benefit Fund Charge Transition Charges Transmission Cost Recovery Factor
Commonwealth Edison, IL	Capacity Charge Energy Assistance Charge for the Supplemental Low-Income Energy Assistance Fund Energy Efficiency and Demand Response Adjustments Environmental Cost Recovery Adjustment Hourly Purchased Electricity Adjustment Factor Miscellaneous Procurement Components Charge PJM Services Charges Purchased Electricity Adjustment Factor Purchased Electricity Charges Renewable Energy Resources and Coal Technology Development Assistance Charge Residential Real Time Pricing Program Cost Recovery Charges Uncollectible Cost Factors
Consolidated Edison, NY	Adjustment Factors – MSC and MAC Delivery Revenue Surcharge Market Supply Charge Merchant Function Charge Monthly Adjustment Clause Renewable Portfolio Standard Program Revenue Decoupling Mechanism Adjustment Surcharge to collect PSL Section 18-a Assessments System Benefits Charge
DTE Electric, MI	Energy Optimization Surcharge Low Income Energy Assistance Fund Factor Nuclear Decommissioning Surcharge Power Supply Cost Recovery Clause Rate Realignment Adjustment (U-16472 RRA) Renewable Energy Plan Surcharge Securitization Bond Charge and Securitization Bond Tax Charge Vulnerable Household Warmth Fund Credit

ENMAX, AB	Balancing Pool Allocation Refund Rider Distribution Access Service Adjustment Rider Local Access Fee Transmission Access Charge Deferral Account Rider
EPCOR, AB	Balancing Pool Rider Local Access Fee SAS True-Up Rider Transmission Charge Deferral Account True-Up Rider
Eversource Energy, MA	Attorney General Consultant Expenses Provision Default Service Adjustment Demand-Side Management Charge Energy Efficiency Reconciliation Factor Long-Term Renewable Contract Adjustment Net Metering Recovery Surcharge Pension Adjustment Renewable Energy Charge Residential Assistance Adjustment Clause Smart Grid Adjustment Factor Storm Cost Recovery Adjustment Transition Cost Adjustment Transmission Service Cost Adjustment
Florida Power and Light, FL	Conservation Charge Capacity Payment Charge Environmental Charge Fuel Charge Storm Charge
Hydro Ottawa, ON	Debt Retirement Charge Ontario Clean Energy Benefit Smart Metering Entity Charge
Maritime Electric, PE	Energy Cost Adjustment Mechanism
Nashville Electric Service, TN	TVA Fuel Cost Adjustment
Newfoundland and Labrador Hydro, NL	Municipal Tax Adjustment Rate Stabilization Adjustment
Newfoundland Power, NL	Residential Energy Rebate
Nova Scotia Power, NS	Demand Side Management Cost Recovery Rider Fuel Adjustment Mechanism
Pacific Gas and Electric, CA	California Climate Credit Competition Transition Charges DWR Bond Energy Cost Recovery Amount Greenhouse Gas Volumetric Return New System Generation Charge Nuclear Decommissioning Public Purpose Programs Reliability Services Transmission Rate Adjustments

Pacific Power and Light, OR	Adjustment associated with the Pacific Northwest Electric Power Planning Conservation Act Energy Conservation Charge Generation Investment Adjustment Independent Evaluator Cost Adjustment Intervenor Funding Adjustment Klamath Dam Removal Surcharges Low Income Bill Payment Assistance Fund Oregon Solar Incentive Program Deferral Power Cost Adjustment Mechanism Property Sales Balancing Account Adjustment Public Purpose Charge Rate Mitigation Adjustment Renewable Adjustment Clause Renewable Resource Deferral TAM Adjustment for Other Revenues
Toronto Hydro, ON	Application of Tax Change Rate Rider Debt Retirement Charge Ontario Clean Energy Benefit Recovery of 2008-2010 Smart Meter Costs Rate Rider Recovery of Foregone Revenue Rate Rider Recovery of Incremental Capital Module Costs Rate Rider Recovery of Incremental Smart Meter Revenue Requirement Rate Rider Smart Metering Entity Charge Rate Rider

C

APPENDIX
APPLICABLE TAXES

Residential Sector

General Sector

Industrial Sector

TAXES APPLICABLE TO RESIDENTIAL SERVICE

On April 1, 2015

	Tax	% (or other)	Applicable
Canadian Cities			
Montréal, QC	Goods and services tax (GST)	5	To base amount of bill
	Québec sales tax	9.975	To base amount of bill
Calgary, AB	Goods and services tax	5	To base amount of bill
Charlottetown, PE	Harmonized sales tax	14	To base amount of bill
Edmonton, AB	Goods and services tax	5	To base amount of bill
Halifax, NS	Harmonized sales tax	5	To base amount of bill
Moncton, NB	Harmonized sales tax	13	To base amount of bill
Ottawa, ON	Harmonized sales tax	13	To base amount of bill
Regina, SK	Municipal tax	10	To base amount of bill
	Goods and services tax	5	To base amount of bill
St. John's, NL	Harmonized sales tax	13	To base amount of bill
Toronto, ON	Harmonized sales tax	13	To base amount of bill
Vancouver, BC	Regional transit levy	$1.90	Monthly
	Goods and services tax	5	To base amount of bill + regional transit levy
Winnipeg, MB	Provincial sales tax	8	To base amount of bill (heating other than electric)
		1.4	To base amount of bill (electric heating)
	Municipal tax	2.5	To base amount of bill (heating other than electric)
		0.5	To base amount of bill (electric heating)
	Goods and services tax	5	To base amount of bill + municipal tax
American Cities			
Boston, MA	None		
Chicago, IL	State tax	¢/kWh	Tax varies by energy block
	Municipal tax	¢/kWh	Tax varies by energy block
	Franchise cost	¢/kWh	Tax varies by energy block
Detroit, MI	State sales tax	6	To base amount of bill
	City of Detroit utility users' tax	5	To base amount of bill
Houston, TX	Municipal tax	1	To base amount of bill
Miami, FL	Gross receipts tax	2.5641	To base amount of bill
	Franchise fee	3	To base amount of bill + gross receipts tax
	Municipal tax	10	To a portion of base amount of bill
Nashville, TN	None		
New York, NY	Commodity gross receipts tax	2.4066	To commodity component
	Delivery gross receipts tax	5.0973	To other components
	Sales tax	4.5	To base amount of bill + gross receipts tax
Portland, OR	Multnomah County business income tax	0.15	To a portion of base amount of bill
	City of Portland franchise tax	1.5	To a portion of base amount of bill
San Francisco, CA	Energy Commission tax	0.029¢	To energy consumption
Seattle, WA	State utility tax	3.8734	Tax included in rate schedule prices
	Seattle occupation tax	6	Tax included in rate schedule prices

TAXES APPLICABLE TO GENERAL SERVICE
On April 1, 2015

	Tax	% (or other)	Applicable
Canadian Cities			
Montréal, QC	Goods and services tax (GST)	5	To base amount of bill (tax refundable)
	Québec sales tax	9.975	To base amount of bill (tax refundable)[1]
Calgary, AB	Goods and services tax	5	To base amount of bill
Charlottetown, PE	Harmonized sales tax	14	To base amount of bill (tax refundable)
Edmonton, AB	Goods and services tax	5	To base amount of bill
Halifax, NS	Harmonized sales tax	15	To base amount of bill (tax refundable)
Moncton, NB	Harmonized sales tax	13	To base amount of bill (tax refundable)
Ottawa, ON	Harmonized sales tax	13	To base amount of bill
Regina, SK	Municipal tax	10	To base amount of bill
	Provincial sales tax	5	To base amount of bill + municipal tax
	Goods and services tax	5	To base amount of bill
St. John’s, NL	Harmonized sales tax	13	To base amount of bill (tax refundable)
Toronto, ON	Harmonized sales tax	13	To base amount of bill (tax refundable)
Vancouver, BC	Goods and services tax	5	To base amount of bill
	Provincial sales tax	7	To base amount of bill
Winnipeg, MB	Provincial sales tax	8	To base amount of bill (industries other than mining and manufacturing)
		1.6	To base amount of bill (mining and manufacturing industries)
	Municipal tax	5	To base amount of bill (heating other than electric)
		1	To base amount of bill (electric heating)
	Goods and services tax	5	To base amount of bill + municipal tax (tax refundable)
American Cities			
Boston, MA	State sales tax	6.25	To a portion of base amount of bill
Chicago, IL	State tax	¢/kWh	Tax varies by energy block
	Municipal tax	¢/kWh	Tax varies by energy block
	Franchise cost	¢/kWh	Tax varies by energy block
Detroit, MI	State sales tax	6	To base amount of bill
	City of Detroit utility users’ tax	5	To base amount of bill
Houston, TX	State tax	6.25	To base amount of bill
	Municipal tax	1	To base amount of bill
	Transit tax	1	To base amount of bill
	County tax	0.5	To base amount of bill
Miami, FL	Gross receipts tax	2.5641	To base amount of bill
	Franchise fee	3	To base amount of bill + gross receipts tax
	Municipal tax	10	To a portion of base amount of bill
	State sales tax	7	To base amount of bill + gross receipts tax + franchise fee
	Local tax	1	To base amount of bill + gross receipts tax + franchise fee
Nashville, TN	State sales tax	7	To base amount of bill

1) Commercial customers with revenue below $10 million and customers in the manufacturing sector are entitled to a refund of this tax.

TAXES APPLICABLE TO GENERAL SERVICE (cont'd)

On April 1, 2015

	Tax	% (or other)	Applicable
New York, NY	Commodity gross receipts tax	2.4066	To commodity component
	Delivery gross receipts tax	2.5642	To other components
	Sales tax	8.875	To base amount of bill + gross receipts tax
Portland, OR	Multnomah County business income tax	0.15	To a portion of base amount of bill
	City of Portland franchise tax	1.5	To a portion of base amount of bill
San Francisco, CA	Energy Commission tax	0.029¢	To energy consumption
	San Francisco utility users' tax	7.5	To base amount of bill
Seattle, WA	State utility tax	3.8734	Tax included in rate schedule prices
	Seattle occupation tax	6	Tax included in rate schedule prices

TAXES APPLICABLE TO INDUSTRIAL SERVICE

On April 1, 2015

	Tax	% (or other)	Applicable
Canadian Cities			
Montréal, QC	Goods and services tax (GST)	5	To base amount of bill (tax refundable)
	Québec sales tax	9.975	To base amount of bill (tax refundable)[1]
Calgary, AB	Goods and services tax	5	To base amount of bill
Charlottetown, PE	Harmonized sales tax	14	To base amount of bill (tax refundable)
Edmonton, AB	Goods and services tax	5	To base amount of bill
Halifax, NS	Harmonized sales tax	15	To base amount of bill (tax refundable)
Moncton, NB	Harmonized sales tax	13	To base amount of bill (tax refundable)
Ottawa, ON	Harmonized sales tax	13	To base amount of bill
Regina, SK	Municipal tax	10	To base amount of bill
	Provincial sales tax	5	To base amount of bill + municipal tax
	Goods and services tax	5	To base amount of bill
St. John's, NL	Harmonized sales tax	13	To base amount of bill (tax refundable)
Toronto, ON	Harmonized sales tax	13	To base amount of bill (tax refundable)
Vancouver, BC	Goods and services tax	5	To base amount of bill
	Provincial sales tax	7	To base amount of bill
Winnipeg, MB	Provincial sales tax	8	To base amount of bill (industries other than mining and manufacturing)
		1.6	To base amount of bill (mining and manufacturing industries)
	Municipal tax	5	To base amount of bill (heating other than electric)
		1	To base amount of bill (electric heating)
	Goods and services tax	5	To base amount of bill + municipal tax (tax refundable)
American Cities			
Boston, MA	State sales tax	6.25	To a portion of base amount of bill
Chicago, IL	State tax	¢/kWh	Tax varies by energy block
	Municipal tax	¢/kWh	Tax varies by energy block
	Franchise cost	¢/kWh	Tax varies by energy block
Detroit, MI	State sales tax	6	To base amount of bill
	City of Detroit utility users' tax	5	To base amount of bill
Houston, TX	State tax	6.25	To base amount of bill
	Municipal tax	1	To base amount of bill
	Transit tax	1	To base amount of bill
	County tax	0.5	To base amount of bill
Miami, FL	Gross receipts tax	2.5641	To base amount of bill
	Franchise fee	3	To base amount of bill + gross receipts tax
	Municipal tax	10	To a portion of base amount of bill
	State sales tax	7	To base amount of bill + gross receipts tax + franchise fee
	Local tax	1	To base amount of bill + gross receipts tax + franchise fee

1) Commercial customers with revenue below $10 million and customers in the manufacturing sector are entitled to a refund of this tax.

TAXES APPLICABLE TO INDUSTRIAL SERVICE (cont'd)

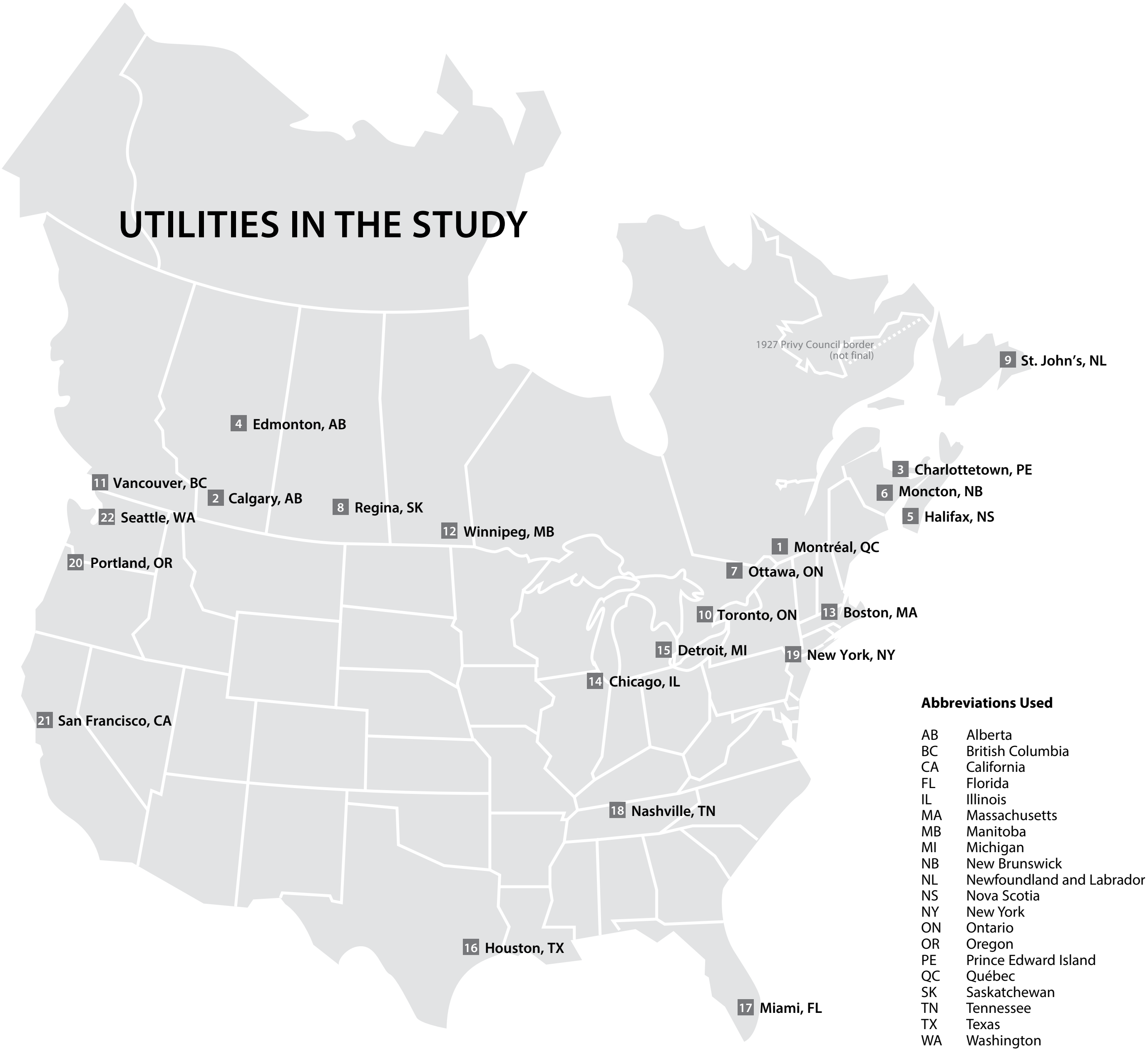
On April 1, 2015

	Tax	% (or other)	Applicable
Nashville, TN	State sales tax	7	To base amount of bill (companies other than manufacturing)
	State sales tax	1.5	To base amount of bill (manufacturing companies)
New York, NY	Commodity gross receipts tax	2.4066	To commodity component
	Delivery gross receipts tax	2.5642	To other components
	Sales tax	8.875	To base amount of bill + gross receipts tax
Portland, OR	Multnomah County business income tax	0.15	To a portion of base amount of bill
	City of Portland franchise tax	1.5	To a portion of base amount of bill
San Francisco, CA	Energy Commission tax	0.029¢	To energy consumption
	San Francisco utility users' tax	7.5	To base amount of bill
Seattle, WA	State utility tax	3.8734	Tax included in rate schedule prices
	Seattle occupation tax	6	Tax included in rate schedule prices

D

APPENDIX

UTILITIES IN THE STUDY



CANADIAN UTILITIES

1- Hydro-Québec
2- ENMAX
3- Maritime Electric
4- EPCOR
5- Nova Scotia Power
6- NB Power
7- Hydro Ottawa
8- SaskPower
9- Newfoundland and Labrador Hydro (customers with a power demand of 30,000 kW or more)
Newfoundland Power (all other customer categories)
10- Toronto Hydro
11- BC Hydro
12- Manitoba Hydro

AMERICAN UTILITIES

13- Eversource Energy
14- Commonwealth Edison
15- DTE Electric
16- CenterPoint Energy
17- Florida Power and Light
18- Nashville Electric Service
19- Consolidated Edison
20- Pacific Power and Light
21- Pacific Gas and Electric
22- Seattle City Light

CANADIAN UTILITIES

HYDRO-QUÉBEC
Montréal, Québec

A government-owned company whose lines of business have been unbundled, Hydro-Québec is one of the largest electric utilities in North America, with an installed capacity of 36,643 MW; 99% of electricity is generated using waterpower. Its transmission and distribution activities are regulated. The utility distributes electricity to more than 4 million residential, commercial, institutional and industrial customer accounts throughout Québec and delivers electricity to nine municipal systems and one regional cooperative. Hydro-Québec also does business with many electric utilities in the Northeastern United States, Ontario and New Brunswick.

The *Act respecting the Régie de l'énergie* (Québec energy board) established an annual maximum heritage pool of 165 TWh that Hydro-Québec Production must supply to Hydro-Québec Distribution. For demand beyond that volume, needs have to be met through purchases on the market. The average supply cost of heritage pool electricity, set at a fixed price of 2.79¢/kWh since 1998, is indexed on January 1st since 2014 at a rate corresponding to the annual variation in the all-item consumer price index for Québec.

The Régie de l'énergie approved an average increase of 2.9% in the rates of Hydro-Québec Distribution, effective April 1, 2015, with the exception of Rate L, for which the increase is 2.5%.

MARITIME ELECTRIC
Charlottetown, Prince Edward Island

A subsidiary of Fortis Inc., Maritime Electric is the principal supplier of electricity on Prince Edward Island, with some 78,000 customers. Since its two power plants (with a total capacity of 150 MW) are operated strictly for reserve purposes, it purchases most of its electricity from NB Power, with which it has long-term contracts, and through additional short-term contracts on the New England wholesale market. Maritime Electric also purchases nearly 52 MW of wind-generated electricity from private producers.

Since the adoption of the *Electric Power Act* on January 1, 2004, Maritime Electric has had to submit all requests for rate increases to the Island Regulatory and Appeals Commission. In December 2012, the Act was amended to reflect the terms of maintaining the *PEI Energy Accord* for the next three years, from March 1, 2013, to February 29, 2016. The rate increase for residential customers and business customers in the General – Small power category was set at 2.2% per year during this period.

ENMAX
EPCOR
Calgary, Alberta
Edmonton, Alberta

ENMAX Corporation is a wholly owned subsidiary of the City of Calgary. It generates, transmits and distributes electricity to approximately 835,000 customers throughout the province. In addition to its active participation in Alberta's restructured electricity industry, ENMAX serves customers who are eligible for the City of Calgary's regulated rate option tariff.

EPCOR Utilities, whose sole shareholder is the City of Edmonton, transmits and distributes electricity to 369,000 residential and business customers in Edmonton. It also supplies more than 600,000 customers throughout the province who are eligible for a regulated rate option tariff.

Since July 1, 2010, prices under the regulated rate option tariff have fluctuated monthly with market forecasts, so customers' electricity bills have varied more.

NOVA SCOTIA POWER
Halifax, Nova Scotia

Nova Scotia Power, a subsidiary of Emera, is the principal supplier of electricity in Nova Scotia, meeting most of the province's needs for electricity generation, transmission and distribution. It supplies electricity to 500,000 customers. Its generating facilities have an installed capacity in excess of 2,400 MW.

The open access transmission tariff came into effect on November 1, 2005. Under the province's energy policy, eligible customers have nondiscriminatory access to the utility's transmission system.

NB POWER

Moncton, New Brunswick

A subsidiary of provincial Crown corporation NB Power Group, NB Power Distribution and Customer Service Corporation directly serves more than 349,000 customers and sells electricity to the province's municipal systems, which supply nearly 42,000 customers. NB Power has a generating capacity of about 3,500 MW under the management of NB Power Generation and NB Power Nuclear.

The New Brunswick electricity market has been partially open to competition since October 1, 2004. Large industrial customers and three municipal electricity distribution utilities are free to choose their supplier. However, other retail market customers continue to be served by NB Power.

SASKPOWER

Regina, Saskatchewan

Crown utility SaskPower directly serves more than 500,000 customers and sells wholesale electricity to municipal systems in Saskatchewan. The utility operates 18 power plants, with a net generating capacity of some 4,100 MW.

In Saskatchewan, the wholesale electricity market has been open to competition since 2001.

NEWFOUNDLAND AND LABRADOR HYDRO

(customers with a power demand of 30,000 kW or more)

NEWFOUNDLAND POWER (all other customer categories)

St. John's, Newfoundland and Labrador

Newfoundland Power, a subsidiary of Fortis Inc., serves about 259,000 customers on the island of Newfoundland. Since it operates only small generating stations with a total installed capacity of less than 140 MW, it purchases 90% of its electricity from Newfoundland and Labrador Hydro (NLH), a subsidiary of Nalcor Energy that operates generating facilities with an installed capacity of 1,626 MW and a transmission system that serves the whole province. NLH also supplies remote regions, Labrador and large industrial customers. Aside from Newfoundland and Labrador Hydro, Nalcor Energy operates generating facilities with an installed capacity in excess of 5,600 MW.

TORONTO HYDRO
HYDRO OTTAWA

Toronto, Ontario
Ottawa, Ontario

A subsidiary of Hydro Ottawa Holding, whose sole shareholder is the City of Ottawa, Hydro Ottawa serves some 315,000 customers. Toronto Hydro-Electric System is a subsidiary of city-owned Toronto Hydro Corporation and serves about 740,000 customers, or 18% of Ontario electricity consumers.

In Ontario, the wholesale and retail markets have been open to competition since May 2002. Electricity generation is the responsibility of Ontario Power Generation while transmission service is supplied by Hydro One.

Following the adoption of the *Electricity Restructuring Act* in December 2004, the Ontario Energy Board was given the mandate to regulate the supply of electricity and has produced a plan in this regard (Regulated Price Plan or RPP). Prices have been reviewed on May 1 each year since 2006 and adjusted six months later, if necessary.

BC HYDRO

Vancouver, British Columbia

BC Hydro, a provincial Crown corporation, operates generating facilities with a total capacity of more than 12,000 MW. About 90% of electricity is generated using waterpower. The utility distributes electricity to about 1.9 million customers.

The wholesale market in British Columbia is open to competition, as is the retail market for some large industrial companies. When the market was opened up, generation, transmission and distribution were made into separate entities. The *Clean Energy Act* grouped transmission and distribution in July 2010 to ensure coordinated supply planning for the province. In November 2013, the government published a 10-year plan which provides for upgrading aging infrastructure, implementing new generation projects to meet growing demand and minimizing the impact of these activities on electricity rates.

MANITOBA HYDRO

Winnipeg, Manitoba

Manitoba Hydro is a Crown utility serving nearly 555,000 customers throughout the province. Virtually all the electricity it generates and distributes comes from its 15 hydropower plants, which have a total capacity of 5,600 MW.

The wholesale electricity market has been open to competition since 1997 and Manitoba Hydro joined Midwest ISO, a regional transmission organization, in 2001.

AMERICAN UTILITIES

EVERSOURCE ENERGY

Boston, Massachusetts

Eversource, a merger between NSTAR Electric and Northeast Utilities, serves 3.1 million residential, commercial and industrial customers in the states of Massachusetts, Connecticut and New Hampshire. The utility purchases electricity on the market and concentrates on transmission and distribution.

Since March 1, 2005, the basic service rates are applied to customers in Boston to the electricity commodity component for those who have chosen not to purchase electricity from a competitor. These rates are adjusted every six months, or every three months in the case of large industrial customers. The rates reflect the average market price of electricity.

COMMONWEALTH EDISON (ComEd)

Chicago, Illinois

ComEd, a subsidiary of Exelon Corporation, purchases, transmits and distributes electricity on the wholesale and retail markets. On the retail market, it serves more than 3.8 million customers in northern Illinois, or 70% of the state's population.

Since May 1, 2002, the retail market has been fully open for residential, commercial and industrial customers. However, it is only since 2011 that residential customers have actually exercised their right to choose distributors other than the two companies that were in place when deregulation was implemented: ComEd and Ameren.

DTE ELECTRIC

Detroit, Michigan

DTE Electric operates generating facilities with a total installed capacity of almost 11,100 MW. A subsidiary of DTE Energy, it serves 2.1 million customers in southeastern Michigan.

Under the June 2000 legislation that restructured the electricity industry, all retail market customers in Michigan have been able to choose their electricity supplier since January 1, 2002.

CENTERPOINT ENERGY

Houston, Texas

CenterPoint Energy concentrates on electricity transmission and distribution and delivering natural gas. It sells electricity to approximately 2.1 million customers in the Houston area.

The majority of Texas consumers have had access to an open retail market since January 1, 2002. As of January 2007, electricity distributors with effective monopolies are no longer obliged to maintain their rates above the "price to beat" designed to encourage new market entrants. Customers who have opted to continue doing business with the same distributor pay a monthly rate that varies according to the market price.

CONSOLIDATED EDISON (ConEd)

New York, New York

ConEd of New York delivers electricity to 3.4 million customers and natural gas to nearly 1.1 million customers in and around New York City and Westchester County. This ConEd subsidiary operates the largest underground system in the world, which represents 72% of its distribution system.

When the electricity market was opened to competition in 1998, ConEd had to dispose of a large part of its generating capacity, which is now limited to about 700 MW. Rates, which continue to be regulated by the New York State Public Service Commission, are adjusted monthly to reflect the market price of electricity.

FLORIDA POWER AND LIGHT (FPL)

Miami, Florida

FPL's vast transmission and distribution system supplies more than 4.7 million customers. A subsidiary of NextEra Energy, the utility operates generating facilities with an installed capacity of 24,100 MW.

On April 1, 2010, FPL released its 2010–2019 strategic plan, in which it proposes to upgrade some of its nuclear plants and add new generating facilities using thermal and renewable energy. It will also rely on energy efficiency measures to meet the demand for power during the strategic plan time frame.

PACIFIC POWER AND LIGHT

Portland, Oregon

Pacific Power and Light, a subsidiary of PacifiCorp, serves some 735,000 customers across three states, including more than 562,000 in Oregon. PacifiCorp operates generating facilities with an installed capacity of over 10,600 MW.

On March 1, 2002, the Oregon state government opened its retail market to competition for large commercial and industrial customers. Residential and small commercial customers have fewer suppliers to choose from, but they do have a range of options, including market-based rates, regulated rates or rates applicable to green energy.

NASHVILLE ELECTRIC SERVICE

Nashville, Tennessee

Nashville Electric Service, whose sole shareholder is the City of Nashville, distributes the electricity that it purchases from the Tennessee Valley Authority (TVA) to more than 360,000 customers. A federal agency, the TVA supplies 155 distributors and nearly 60 large industrial and federal customers.

Close to 40% of the electricity produced by the TVA comes from its 10 coal-fired plants, with the rest from gas, nuclear and hydro plants. The TVA has also included renewables, including solar, wind and biomass, into its generation portfolio.

PACIFIC GAS AND ELECTRIC (PG&E)

San Francisco, California

Pacific Gas and Electric concentrates on the transmission and distribution of electricity and natural gas. A subsidiary of PG&E Corporation, it has 5.1 million electric customer accounts.

In 2001, California adopted emergency measures to mitigate the price volatility that followed the opening of the electricity market. Those measures allowed it to reinstate regulatory authority over production costs and to give responsibility for electricity purchases to the California Department of Water and Resources. Since January 1, 2003, PG&E has been authorized to again purchase energy and directly supply its customers.

SEATTLE CITY LIGHT
Seattle, Washington

Seattle City Light, whose shareholder is the City of Seattle, serves about 400,000 customers. It produces nearly 50% of the electricity it needs and purchases the rest from the Bonneville Power Administration (BPA), a northwestern U.S. federal agency that wholesales electricity produced by some 30 hydropower stations.

Six electric utilities in the Pacific Northwestern states, including Seattle City Light and BPA, got together in early 2006 to form the nonprofit ColumbiaGrid. The group's objective is to develop an integrated approach to the use and expansion of the region's interconnected transmission system.

Sources:
Annual reports and Web sites of the Canadian and American utilities in the study.

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www.hydroquebec.com/publications/en

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Hydro Québec

2015G1314A

100 %

Fiscal 2017 to Fiscal 2019

Revenue Requirements Application

Appendix FF

BC Hydro Safety Strategy

Attachment 1 – Five-Year Safety Plan

With a phased approach, BC Hydro is following a five year safety plan to develop and deliver programs and tools to help us achieve our safety vision and goals. The following illustration shows the progress being made across our suite of priorities. Fiscal 2016 is the first year of the Five-Year Safety Plan.

Goal 1: Zero Fatalities and Zero Disabling Injuries

Goal 2: Year-over-Year Reduction in LTI and Medical Aid Injuries

Goal 3: Achieve Regulatory Compliance

Goal 4: Build Culture to Achieve Excellence in Safety

Goal 5: Build Corporate Systems & Tools Supporting Excellence in Safety

1 YEAR

- **G1: Improve Job Planning, Identification of Critical Hazards and Use of Multiple Barriers:** We have implemented the corrective actions resulting from the New West incident
- **G2: Safe Start:** We have re-introduced the Safe Start program for our field crews. All 17 planned sessions completed in F16.
- **G2: Knife Injury Reduction:** We have established a new requirement that cut resistant gloves are worn and proper cutting tools used on all jobs
- **G4: Strengthen Seen and Felt Safety Leadership:** We have improved safety awareness at all levels of the organization: Safety moments are at the start of all meetings; safe work observations completed; consolidated Safety team and increased field safety support; All guest to corporate offices require to complete safety orientation; Effectiveness of Safety program included in employee engagement survey
- **G5: Streamline Investigation and CAPs**: We have implemented a process to improve the timeliness and effectiveness of our safety incident investigations and corrective action plans
- **G5: Learning from Safety Analytics:** New Analytical tools have been implemented and are being used to identify Safety trends/areas of concern, increase Safety awareness and inform the basis of Safety improvement projects. Senior leaders in operating lines of business review safety performance on a monthly basis

3 YEAR

- **G1: Competency Training (Life Saving Rules 1-4):** We will have completed LSR 1- 4 training and competency assessment of all PLTs and Electricians by the end of F18
- **G1: PSSP Sustainment:** Training material for Power System Safety Protection (PSSP) updated for Category 3 and 4. Employee PSSP manuals revised and published
- **G1: Safety Practice Regulations Refresh:** Revisions to Safety Practice Regulations will be completed
- **G1: Use of Rubber Gloves:** Evaluation of effectiveness of rubber gloves to prevent fatalities and serious injuries and industry best practices evaluation will be completed
- **G3: Asbestos:** We will have accurate asbestos inventories and proper labelling of asbestos containing materials in all our facilities
- **G3: Confined Space:** All confined spaces in BC Hydro system will have been identified. Hazard and risk assessments, safe work procedures, employee training, rescue requirements and documentation will be complete
- **G5: Field Access to Safety Info**: We will have implemented new technology to enable easier access to safety information by field staff. This includes ensuring all safety documents are current and accurate
- **G5: Contractor Safety Management:** We will have implemented new processes and procedures to ensure the safety of all contractors working for BC Hydro

5 YEAR

- **G1: Worker Protection Practices for Substations:** We will have completed assessment of use of WPP in substations to provide safe work isolation
- **G1: ARC Flash:** We will completed assessment of worker exposure to ARC flash hazards in all BC Hydro facilities and put in place procedures, training and PPE to mitigate this hazard
- **G2: Ergonomics**: Ergonomic programs will put in place across all field, plant and offices to reduce high frequency musculoskeletal injuries
- **G4: Electrical Public Safety:** We will continue our school and public safety awareness programs. This also includes offering electrical awareness training to first responders and contractors
- **G5: Safety Management Framework:** We will have implemented a Safety Management framework that ensures continuous safety improvement; defines governance and accountabilities; clearly identifies roles, responsibilities, goals and objectives; identifies safety hazards, barriers and controls; incident management; training and competency requirements; information and records management; and audits and management review

Attachment 2 – Safety Policy

In fiscal 2016 BC Hydro revised its safety policy making it clearer for all workers to understand and follow. The policy sets the stage for all our work and decision-making and demonstrates that BC Hydro is committed to integrating safety in all we do. The policy directs our operations to minimize the chance of injury to employees, contractors and the public and challenges us to work for continual improvement in safety performance, driving to our vision of zero serious injuries and fatalities.

CORPORATE POLICY STATEMENT (CPS)

SAFETY AND HEALTH POLICY

BC Hydro
Power smart

Issue Date: 12 May 1998

Revision 8 (24 February 2016)

Executive Sponsor

President & CEO, Jessica McDonald

Senior Vice-President, Safety, Security & Emergency Management, Hugo Shaw

Contact for Policy Interpretation and Clarification

Manager, Safety Regulation, Policy & Standards, Donald Bauerfind

To ensure the safety of our employees, contractors and the public, this policy outlines the expectations of all employees for safety performance and prevention of injuries.

POLICY

Safety is core to everything we do, all the time and at every level of our organization. It shapes our decision-making, how we think and talk about our work and how we act each day. For us, even one injury is unacceptable. All our employees and our contractors must go home safe every day. Safety at BC Hydro is everyone's responsibility.

Our mission reflects our safety value "to provide our customers with reliable, affordable, clean electricity throughout B.C., safely".

Safety starts with leadership. We set clear expectations, taking the guess work out of how a person's role and its responsibilities contribute to safety. We ensure that our plans, designs and how we resource all our work removes hazards or puts in place effective barriers and minimizes safety risks. We provide the necessary rules, procedures, structures, training and tools to ensure everyone can work safely. We enable and require our managers, supervisors, employees and contractors to be accountable for safety. We will comply with all safety rules and applicable regulations and strive to meet or exceed industry best practice.

Our employees are involved in work plans and decisions that impact their safety. Our culture encourages employees to raise concerns or stop work any time they feel their safety may be at risk. We measure our safety performance and learn from our failures and our successes. Learning from our near misses is as important as learning from our injuries as we believe 100% of all injuries can be prevented.

Our goal is zero injuries and we challenge every person to achieve this.

Jessica McDonald
President & CEO

Hugo Shaw
Senior Vice President, Safety, Security and Emergency Management

CPS Safety & Health Policy — Printed Copies are Uncontrolled — Page **1** of **2**

BC Hydro
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YOUR ROLE IN FULFILLING THIS POLICY

- All employees are required to:
  - be responsible for their own safety and the safety of their co- workers, contractors, and the public to the extent of their knowledge and control;
  - work safely and know and follow all applicable safety rules and work procedures;
  - intervene when they see unsafe work or conditions and immediately correct or report to their manager or supervisor unsafe conditions, equipment and activities;
  - refuse work if they believe it is unsafe for them or others; and,
  - work cooperatively toward the prevention of incidents and occupational diseases.
- Managers, supervisors and any other BC Hydro employee who oversees, instructs, directs or controls others in the conduct of work, are responsible for:
  - ensuring that workers are properly trained, instructed and qualified to work safely;
  - ensuring that workers have the tools, resources and information to work safely;
  - enforcing safe work procedures, rules, standards and regulations and correcting all unsafe conditions, equipment and activities;
  - ensuring all work is planned and designed to remove hazards or have effective barriers in place to minimize safety risks;
  - being open and responsive to safety issues raised by employees or that arise from the work being overseen, and providing timely follow-up;
  - acknowledging and recognizing good safety performance and behaviour; and,
  - ensuring that consequences for non-compliance with safety expectations are managed in a manner consistent with our Just Culture principles.
- The Executive are:
  - accountable for BC Hydro ensuring the health and safety of all workers and ensuring compliance with the Workers Compensation Act, regulations and applicable orders;
  - responsible for setting safety direction, including assessment of safety risk tolerance, based on the input and recommendations of management and external advisors as required; and,
  - accountable for regularly monitoring regulatory compliance and safety performance across BC Hydro.
- The Board of Directors, via the Board Governance Manual, delegate specific authorities and responsibilities to the Chief Executive Officer and the Senior Vice President, Safety, Security and Emergency Management and establish policies that support BC Hydro's safety performance and ensure that the corporation complies with the Workers Compensation Act, regulations and applicable orders.

Attachment 3 – Safety Taskforce Recommendations

The Safety Taskforce was formed in the fall of 2010 after a worker fatality occurred at the Cranbrook Substation. The Safety Taskforce was comprised of front-line workers and managers and they were charged with determining what we needed to do to improve safety for our workers and contractors. After talking to over 4000 employees in the company, visiting 17 external organizations with exemplary safety performance and researching best practices across several industries and the world, they developed a suite of 21 recommendations. There are four recommendations remaining to be implemented and they have been incorporated into the Five-Year Safety Plan.

Safety Taskforce Recommendations - Status Update

Taskforce Recommendations in Sustainment
1. **Employee Engagement Principles** – Engage workforce in any initiatives that affect their day to day activities. This practice must be embedded into our culture with continuous communication of progress and updates. Corporate and Field Business Units need to incorporate engagement of the frontline/end users as a matter of course in the roll out of initiatives. 2. **Safe Crew Complement** - Prevent short cuts in completing high hazard work activities and ensure the work is done safely - we must review and determine the required resources. This may require a headcount review, delays in work, or budget reallocation around completing any high hazard work activities. 3. **Courage to Intervene** - Develop a module that becomes a core training requirement for all employees to ensure that all employees have the skills and confidence to intervene regardless of the situation in order to ensure safety is first and disrespectful behaviour stopped. 4. **Job Planning for Stations** - Develop a job planning approach for substations to increase awareness of hazards and develop and apply more/better barriers. 5. **Safety Advocates** – Develop Safety Advocate role is part of the Union Management Partnership recommendation from the BC Hydro Safety Taskforce Report of September 2011. The recommendation specifically outlined the need to “develop a Safety Advocate Role,” whose scope could include the following duties/responsibilities: • Help to interpret current rules and their intent; • Provide feedback on how rules are being used in the field; • Are another source of expertise to change rules and procedures;

- Help to maintain a high sense of awareness through communication of critical safety information, procedure updates, and outcomes of investigations through their communications with the field and travels to the headquarters; and,
- Coach and mentor employees on the job in safety leadership, job planning, rule and procedure application.

6. **Joint Health and Safety Committee Structure** - Re-establish a consistent approach to the JHSCs to ensure that each and every employee had representation on a committee and knew how to raise issues and concerns with the committee for resolution.

7. **WPP / Lock out for Non-Integrated Areas** – Implement "Work Protection Practices" which is a lock out system that is already used in generation stations and in some stations associated with generation plants. It provides a method of worker isolation and where each worker understands the isolation they require for their specific tasks, isolation points are controlled through physical locks.

8. **Ensuring Right Fits** - Develop a collaborative approach in a Union Management partnership for dealing with wrong fits – Union M&P.

9. **T&D Work Planning Process** - Review the current state of the work planning and management process in T&D, and expedite the Plan Schedule Work (PSW) project and resource allocation process where it makes sense.

10. **M1 Attraction Strategy** - Develop a strategy to attract frontline managers from the trade or with suitable technical background.

11. **Safety Reporting system** - Revise our safety reporting process and associated tools (e.g. IMS) to allow safety concerns, alerts, etc to be raised and communicated by anyone. This needs to be simple to use, allow for confidential reporting, and feedback to the person reporting a concern or incident on what actions are being taken. Reporting should be possible through different avenues – paper, phone call, or computer.

12. **Life Saving Rules / Just Culture** - Redevelop the cardinal rules into a set of "Life Saving Rules", based on engagement of employees from the frontline/end users, and across the company. Develop "Just Culture" principles ensuring consistency and fairness in the application of the Rules.

13. **Rubber Work Methods** – Investigate the practicality and benefit of using rubber work methods in Distribution Field Operations as an option in their toolkit, training and equipment, ongoing rigorous testing of gloves, cover up and bucket liners, etc. Implement as appropriate.

14. **Tailored Leadership** - Design a tailored leadership development program with an effective coaching and mentoring sustainment program that addresses leadership

competencies centred around safety, technical, and people. The tailored format will be modularized to meet the needs of the safety critical roles of crew leaders, team leads, construction officers, and all managers (including project managers). This training must be sustained over the long term as a "basic" training requirement before new crew leaders, team leads, or managers take over leadership duties.

15. **Develop ALARP (As Low As Reasonably Practicable) Framework** - Establish an ALARP framework for BC Hydro under guidance of Corporate Safety Health and Environment. This needs to happen in an integrated way at all levels in the organization, including an engineering framework, embedding in work procedures and higher level job planning, and more effective and relevant job planning at the front line.

16. **Design & Maintenance** – Recommend that maintenance budgets should be protected and the work associated with those budgets should be made a high priority. In addition, Safety by Design needs to be continually developed/improved and integrated throughout all aspects of the company's hazardous activities. It is recognized that Safety by Design bears significant impact on overall safety as well as the ease of maintenance of our assets. There needs to be teamwork between engineering, operations and maintenance workers to achieve best results.

17. **Competency Training** - Develop a rigorous training program for critical safety competency training for critical tasks in hazardous work area skills for all frontline employees. Training needs to include familiarity with the area that they are to work in.

Remaining Recommendations (incorporated in 5-year Safety Plan)
18. **Safety Management Framework** - Improve the current Safety Management Framework so it is effective and enables operations to effectively manage risks. Address the concerns raised within the report prepared by the Operations Safety Practitioners which specifically relate to a more effective Safety Health & Environment Management System. 19. **Contractor Safety Management** - Perform a comprehensive review of the state of contract management in BC Hydro. Determine risks that are transferred to contractors and whether quality control is appropriate and standards are followed. Develop partnership with contractors to track and report safety incidents to facilitate learning for both parties. 20. **WPP for Stations** – Implement "Work Protection Practices" which is a lock out system that is already used in generation stations and in some stations associated with generation plants. It provides a method of worker isolation and where each worker understands the isolation they require for their specific tasks, isolation points are controlled through physical locks. The practicality and benefit of using WPP in all substations will be investigated by a knowledgeable team from the field and Grid operations. 21. **Rules and Procedures** - Review, simplify and clarify the current structure of all the rules and procedures that apply to frontline work

Attachment 4 – Measures of Success

The following are the key Safety Performance Measures tracked in BC Hydro's Annual Service Plan. BC Hydro's Operating Lines of Business have dashboard targets that reflect these overall corporate targets.

Performance Measure	4 Year Avg	Actual F14	Actual F15	Actual F16	Target F16	Target F17	Target F18	Target F19
Zero Fatality & Serious Injury [Loss of life or the injury has resulted in a permanent disability]	0.75	0	1	0	0	**0**	**0**	**0**
Lost Time Injury Frequency [Number of employee injury incidents resulting in lost time (beyond the day of the injury) per 200,000 hours worked]	1.1	1.1	1.0	1.1	1.0	**1.0**	**0.9**	**0.8**
Timely Completion of Corrective Actions (%)	84%	84%	78%	80%	N/A	**85%**	**90%**	**95%**

Fiscal 2017 to Fiscal 2019

Revenue Requirements Application

Appendix GG

Glossary of Terms and Abbreviations

Abbreviations and Glossary of Terms

A

Avoided costs	The electricity supply costs that could be avoided by pursuing DSM. Includes generation, regional transmission, substation and distribution capacity costs

B

BC Hydro	British Columbia Hydro and Power Authority
BC Hydro Costs	BC Hydro's DSM costs, including capital, deferred operating and specific capital costs
BCTC	British Columbia Transmission Corporation

C

Capacity	1. The instantaneous power output of a generator at any given time, normally measured in kilowatts (kW) or megawatts (MW), of a power plant 2. The instantaneous *electricity* demand at any given time, normally measured in *kilowatts* (kW) or *megawatts* (MW) 3. A *transmission* facility's ability to transmit electricity, at any instant
CBL	Customer Baseline Load – a measure of historical consumption used for BC Hydro's TSR stepped rate, expressed in kWh
CEA	*Clean Energy Act*
CGAAP	Canadian Generally Accepted Accounting Principles
Cross Effects	The effect of an energy efficient action on one energy use causing a change in another energy use. For example, more efficient lighting products typically release less waste heat and thereby reduce air-conditioning load
CSA	Canadian Standards Association

Customer Costs	The full cost to the customer of an energy efficiency improvement or the incremental cost of the energy efficient option relative to the standard option where applicable

D

Demand	Refer to Capacity
Direct Rebound Effect	The increased usage of a device or system because it is more energy efficient
Demand Side Measures (DSM)	The definition is the same as the definition of "demand-side measures" set out in section 1 of the *Clean Energy Act*, which is "a rate, measure, action or program undertaken; (a) to conserve energy or promote energy efficiency, (b) to reduce the energy demand a public utility must serve, or (c) to shift the use of energy to periods of lower demand, but does not include (d) a rate, measure, action or program the main purpose of which is to encourage a switch from the use of one kind of energy to another such that the switch would increase greenhouse gas emissions in British Columbia, or (e) any rate, measure, action or program prescribed."
DSM Regulation	B.C. Regulation 326/2008 (Ministerial Order M 271), subsequently amended by B.C. Regulation 228/2011 and B.C. Regulation 141/2014.

E

EC&E	Energy Conservation and Efficiency Committee
ECAP	Energy Conservation Assistance Program, a component of the residential Low Income Program
Electricity	A term defined as the combination of energy and capacity
EM&V	Evaluation, Measurement and Verification
Energy	The amount of electricity consumed (or produced) over a certain time period, measured in multiples of watt-hours

ESK	Energy Savings Kit, a kit of energy savings measures provided to customers in the residential Low Income Program
EOC	Evaluation Oversight Committee

F

Fiscal 2015 Plan	BC Hydro's F2015 to F2016 Revenue Requirements Rates Application, Fiscal 2015 Plan
Fiscal 2016 Plan	BC Hydro's F2015 to F2016 Revenue Requirements Rates Application, Fiscal 2015 Plan
FortisBC Energy Inc.	FortisBC gas distribution utility
FortisBC Inc.	FortisBC integrated electricity utility serving customers in the southern interior of B.C.
Free-riders	Customers who participate in a DSM program but who would have undertaken the energy efficiency improvement at the same time in the absence of the program
FTE	Full Time Equivalent

G

GAAP	Generally Accepted Accounting Principles
GDP	Gross Domestic Product
Generation System Reserve Margin	Generation capacity beyond that required to meet forecast peak load that is planned and constructed or contracted to ensure reliable electricity supply in the event of operational contingencies
GHG	Greenhouse gas – any of the atmospheric gases that contribute to climate change such as water vapour, methane, or carbon dioxide
GWh	Gigawatt-hour – one billion watt-hours or one million kilowatt hours of Electric Energy being an amount of Electric Energy that will serve about 100 residential customers for one year
GBL	Generator Baseline Load

I

IBEW	International Brotherhood of Electrical Workers
IFRS	International Financial Reporting Standards
IPP	Independent Power Producer
IRP	Integrated Resource Plan, to be presented to the B.C. Provincial Government pursuant to the *Clean Energy Act*
IPMVP	International Performance Measurement and Verification Protocol

K

kV	Kilovolt
kW	Kilowatt
kWh	Kilowatt-hour

L

LED	Light emitting diode
LGS	Large General Service, refers to the rate class of large commercial and small industrial customers with demand greater than 150 kilowatts
Line Losses	Reduction in capacity and energy transferred as resistance converts electricity to heat in electrical equipment and along transmission lines. Used to calculate DSM energy and capacity savings at different points in BC Hydro’s system
LNG	Liquefied Natural Gas
LTAP	Long Term Acquisition Plan – BC Hydro’s plan of resource development actions that will allow it to meet its customers’ future electricity requirements

M

M&V	Measurement and Verification
Market Effects	Refers to a change in the structure or functioning of a market or the behaviour of participants in a market that result from one or more program efforts. Typically these efforts are designed to increase the adoption of energy efficient products, services, or practices and are causally related to market interventions. Market effects may include participant and non-participant spillover and market transformation
Market Transformation	Refers to a permanent change in the structure or functioning of markets, including more energy efficient behaviour among customers and higher market penetration of energy-efficient products, as a result of demand-side management (DSM) programs that reduce barriers to energy efficiency. These market changes are likely to persist in the absence of continued program activity
MGS	Medium General Service, refers to the rate class of commercial customers with electricity demand of greater than 35 kilowatts and less than 150 kilowatts
MoveUP	Movement of United Professionals (Formally Canadian Office and Professional Employees Union)
MW	Megawatt – one million watts or one thousand kilowatts

N

Non-Participant Cost Test	A DSM benefit-cost test that indicates the impact of a DSM initiative or portfolio from the perspective of BC Hydro customers who do not participate in that program or portfolio (also referred to as the Ratepayer Impact Measure).The benefit-cost ratio is calculated as follows: PV (Avoided electric energy costs + avoided electric capacity costs) / PV (BC Hydro program costs + BC Hydro incentive costs + BC Hydro allocated supporting initiative costs + BC Hydro lost revenues)

O

OATT	Open Access Transmission Tariff

P

Persistence	The timeframe during which DSM measures produce electricity savings that are attributable to the utility's actions

R

Ratepayer Impact Measure (RIM)	Refer to Non-Participant Test
Rebound Effect	Refer to Direct Rebound Effect
RIB	Residential Inclining Block, refers to the rate class for residential customers
RRA	Revenue Requirement Application

S

Self-Sufficiency	BC Hydro is required by section 6 of the CEA to achieve electricity self-sufficiency by holding, by the year 2016 (BC Hydro's F2017), the rights to an amount of electricity that meets its electricity supply obligations, taking into account demand-side measures. Further, BC Hydro must use the planning criteria that the annual energy produced by the heritage hydroelectric facilities is no more than the maximum amount produced under average water conditions, and Burrard Thermal may be relied on for no energy and no capacity, except as authorized by regulation (B.C. Regulation 319/201; B.C. Regulation 315/2010). Electricity self-sufficiency must be achieved solely from DSM and electricity generating facilities in the province

Spillover	Refers to program participants and non-participants whose energy savings measures occur through actions that are not part of a program, but which were influenced by the program (also called free drivers or tag-ons). Participant spillover is the additional energy savings that occur when a program participant independently installs additional energy efficiency measures or applies additional energy savings practices after having participated in the efficiency program, as a result of the program's influence. Non-participant spillover refers to energy savings that occur when a program non-participant installs energy efficiency measures or applies energy savings practices as a result of a program's influence

T

Test Period	The fiscal 2017 to fiscal 2019 period
Total Resource Cost Test	A DSM benefit-cost test that indicates the impact of a DSM initiative or portfolio from the perspective of all utility customers (also referred to as the All Ratepayers Test). The benefit-cost ratio is calculated as follows: PV (Avoided electric energy costs + avoided electric capacity costs + avoided non-electric fuel costs + customer non-energy benefits) / PV (BC Hydro program costs + BC Hydro allocated supporting initiative costs + customer costs + partner organization program costs)
TRC	Total Resource Cost
TSR	Transmission Service Rate, applies to large industrial customers supplied with electricity at transmission voltage (60,000 volts or more)

U

UC	Utility Cost
UCA	*Utilities Commission Act*

Utility Cost Test	A DSM benefit-cost test that indicates the impact of a DSM initiative or portfolio from the utility's perspective. The benefit-cost ratio is calculated as follows: PV (Avoided electric energy costs + avoided electric capacity costs) / PV (BC Hydro program costs + BC Hydro incentive costs + BC Hydro allocated supporting initiative costs)
Utility Costs	Refer to BC Hydro Costs