BC Hydro
Power smart

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August 22, 2019

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

Dear Mr. Wruck:

RE: Project No. 1598990
British Columbia Utilities Commission (BCUC or Commission)
British Columbia Hydro and Power Authority (BC Hydro)
Fiscal 2020 to Fiscal 2021 Revenue Requirements Application
Evidentiary Update

BC Hydro writes to file an Evidentiary Update to our Fiscal 2020 to Fiscal 2021 Revenue Requirements Application.

As described in detail in this filing, the updated revenue requirements in the Evidentiary Update result in a favourable impact on customers. BC Hydro is forecasting a reduction of $122.4 million to our total revenue requirements over the test period. We are proposing to reflect this reduction through a rate decrease of 0.99 per cent on April 1, 2020, with no change to the fiscal 2020 rates approved by the BCUC on an interim basis.

The Evidentiary Update also increases the Transmission Revenue Requirement by $43.4 million in fiscal 2020 and $42.2 million in fiscal 2021, which impacts BC Hydro's Open Access Transmission Tariff rates. Further information is provided in Appendix E of the Evidentiary Update.

The public version of the Evidentiary Update redacts certain components of BC Hydro's updated Cost of Energy forecast, in accordance with BCUC Order G-146-19. An un-redacted version is being filed in confidence with the BCUC and will be filed publicly on Friday, October 18, 2019, as contemplated by the regulatory timetable.

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

Yours sincerely,

Fred James
Chief Regulatory Officer

cs/rh

Enclosure

BC Hydro Fiscal 2020 to Fiscal 2021
Revenue Requirements Application

Evidentiary Update

August 22, 2019

PUBLIC

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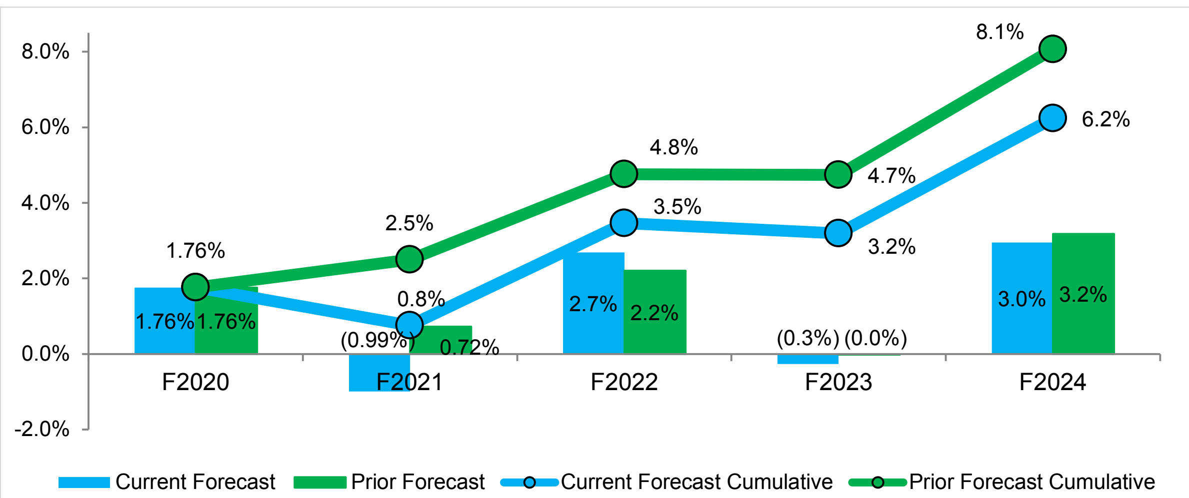
1 Evidentiary Update Has a Favourable Impact on Customers

On February 25, 2019, BC Hydro filed its Fiscal 2020 to Fiscal 2021 Revenue Requirements Application (**Application**) to request various approvals from the BCUC. BC Hydro now files this Evidentiary Update to the Application (**Evidentiary Update**). Based on the approvals BC Hydro is seeking, the Evidentiary Update has a favourable impact on customers. It reduces BC Hydro's total revenue requirement over the test period by $122.4 million. BC Hydro proposes to reflect this favourable impact through a rate decrease of 0.99 per cent on April 1, 2020, with no change to the fiscal 2020 rates approved by the BCUC on an interim basis.[1]

Figure 1 below provides an updated five-year net bill increases forecast, based on the Evidentiary Update. As shown, the forecast cumulative net bill increase from fiscal 2020 to fiscal 2024 has decreased from 8.1 per cent to 6.2 per cent.

Figure 1 Five Year Net Bill Increases Forecast



[1] As discussed in section 1.2 below, BC Hydro is proposing to amortize a higher amount of the credit balance in the Cost of Energy Variance accounts in fiscal 2020 and a lower amount in fiscal 2021 so that BC Hydro's required rate increase for fiscal 2020 remains unchanged, avoiding the need for a retrospective adjustment to fiscal 2020 interim rates and customer bills. This is shown on line 26 of Schedule 2.1 of Appendix A of the Evidentiary Update.

The reduction in BC Hydro's revenue requirements over the test period is the product of updated information. Specifically, the Evidentiary Update:

- **Reflects Actual Financial Results from Fiscal 2019:** The Evidentiary Update replaces the fiscal 2019 forecast with actual fiscal 2019 results. Fiscal 2019 actual results impact the test period because they impact the amortization of BC Hydro's regulatory accounts in fiscal 2020 and fiscal 2021. Among other things, this includes actual Powerex Net Income for fiscal 2019 which was $230.4 million higher than forecast in the Application, increasing the credit balance in the Cost of Energy Variance Accounts, which BC Hydro has proposed to refund to ratepayers over the test period. Further information is provided in section 1.6 below;
- **Updates the Cost of Energy Forecast:** The Evidentiary Update replaces the October 2018 Energy Study forecast in the Application with the June 2019 Energy Study forecast, which includes actual costs for April and May 2019. Dry conditions and lower water inflows have decreased planned hydroelectric generation (water rentals) and purchases from IPPs and Long-Term Commitments, resulting in lower planned surplus sales and higher planned market electricity purchases. Further information is provided in section 1.2 below;
- **Updates the Discount Rate for Pension Costs:** The Evidentiary Update replaces the forecast discount rate of 3.83 per cent used to forecast BC Hydro's pension costs in the Application with the actual discount rate of 3.33 per cent as of April 1, 2019. The lower discount rate has an unfavourable impact on operating costs, as discussed in section 1.3 below;
- **Updates Interest and Foreign Exchange Rates:** The Evidentiary Update replaces the October 2018 Government of B.C. interest and foreign exchange rates forecast in the Application with the January 2019 Government of B.C.

forecasts. It also replaces the September 30, 2018 forward interest rates used for future debt hedges in the Application with interest rates as of May 31, 2019. This has a favourable impact on Finance Charges, as discussed in section 1.5 below;

- **Reflects the Full Implementation of the new Leasing Standard (IFRS 16):** In the Application, BC Hydro estimated the impact of IFRS 16 on Electricity Purchase Agreements based on its preliminary assessment. We noted that the actual impacts from the implementation of the standard may vary from these estimates. The Evidentiary Update reflects BC Hydro's completed assessment. The difference between the estimates in the Application and those of the completed assessment in the Evidentiary Update result in:
  - ▶ An increase of $82.8 million to the Non-Heritage Deferral Account; and
  - ▶ A decrease to Cost of Energy and an increase to Amortization and to Finance Charges, resulting in a net increase to BC Hydro's revenue requirement of $16.6 million in fiscal 2020 and $15.5 million in fiscal 2021.

  The impact to the test period revenue requirements is not net neutral because if an Electricity Purchase Agreement is determined to be a lease under IFRS 16, more costs are recognized in the earlier years of the agreement and fewer costs are recognized in the later years of the agreement. Further information is provided in Appendix F of the Evidentiary Update;

- **Updates for April and May Actuals:** The Evidentiary Update replaces BC Hydro's forecasts in the Application for April and May 2019 with the actual financial results for those months. This includes an update to domestic sales revenue. Domestic sales revenue for the remainder of fiscal 2020 and all of fiscal 2021 remains based on the October 2018 Load Forecast. In accordance with the regulatory timetable for this proceeding, BC Hydro will file a 20-year load forecast on October 3, 2019. This forecast was completed after the financial inputs into the Evidentiary Update were finalized and is not reflected in the Evidentiary Update. As BC Hydro will explain further in its October 3, 2019 filing, the difference in the test period between the October 2018 Load Forecast volumes and the Load Forecast BC Hydro will file in October 2019 is less than 0.5 per cent. Therefore, BC Hydro has not updated its financial schedules based on the updated Load Forecast.[2]

Overall, actual domestic sales revenue in April and May 2019 was lower than forecast due to warm weather, reduced use per account and lower consumption at the step two rate, which resulted in lower residential revenue. Large industrial revenue was also lower due to delayed commercial operation dates for new cryptocurrency customers and lower production in the oil and gas sector because of poor market conditions.

As discussed in section 1.2, BC Hydro's planned market electricity purchases have increased for fiscal 2020 and fiscal 2021. As actual sales in April and May 2019 were lower than forecast, BC Hydro's market electricity purchases were also lower than they otherwise would have been; and

- **Updates the Demand-Side Management Expenditure Schedule:** In the Application, BC Hydro requested BCUC approval of a Demand-Side Management (**DSM**) expenditure schedule of $90.8 million in fiscal 2020 and $116.3 million in fiscal 2021. The Evidentiary Update reduces BC Hydro's DSM expenditure request by $27.2 million in fiscal 2021 from $116.3 million to $89.1 million because two projects that BC Hydro expected to proceed under the Thermo-Mechanical Pulp (**TMP**) Program did not submit applications by the required deadline. As this update is limited to expenditures in fiscal 2021 which

2 In the June 24, 2019 Procedural Conference, BC Hydro stated that the impetus for filing the 20-year load forecast in this proceeding was for information purposes only, in response to certain Round 1 information requests. The 20-year load forecast was not expected to update the test period itself. For further information, refer to page 209 to 210 of Transcript Volume 2.

are amortized into rates starting in fiscal 2022, it does not impact BC Hydro's revenue requirements in the test period.

1.1 Overview of BC Hydro's Updated Revenue Requirements

This section summarizes BC Hydro's updated revenue requirements, based on the Current View[3], for fiscal 2020 and fiscal 2021. A reconciliation of the Gross View[4] and the Current View for each component of the revenue requirements is provided in Schedule 3.0 of Appendix A. The Current View is used because it shows the actual costs being recovered from customers in rates in fiscal 2020 and fiscal 2021.

Table 1 Revenue Requirement - Application vs. Evidentiary Update - Current View

Cost Component	Appendix A Reference	Fiscal 2020 Difference ($ million)	Fiscal 2021 Difference ($ million)	Explanation
Cost of Energy	Schedule 4.0 Line 51	(45.9)	(155.4)	See section 1.2 below
Operating Costs	Schedule 5.0 Line 122	62.9	63.9	See section 1.3 below
Taxes	Schedule 6.0 Line 24	0.0	0.0	
Amortization	Schedule 7.0 Line 32	60.3	59.7	See section 1.4 below
Finance Charges	Schedule 8.0 Line 32	38.3	33.7	See section 1.5 below
Return on Equity	Schedule 9.0 Line 36	0.0	0.0	
Miscellaneous Revenue	Schedule 15.0 Line 42	0.1	0.1	
Inter-Segment Revenue	Schedule 3.0 Line 51	4.1	0.7	Lower transmission charges due to lower Surplus Sales, as discussed in section 1.2

3 The Current View shows the total costs for each component of the revenue requirements after any forecast transfers to regulatory accounts. In other words, the "Current View" shows the actual costs being recovered from customers in rates in fiscal 2020 and fiscal 2021.

4 The Gross View shows the total costs for each component of the revenue requirements before any forecast transfers to regulatory accounts and then shows the regulatory account transfers as a separate total. In other words, "Gross View" shows the total costs incurred in fiscal 2020 and fiscal 2021.

Cost Component	Appendix A Reference	Fiscal 2020 Difference ($ million)	Fiscal 2021 Difference ($ million)	Explanation
Subsidiary Net Income	Schedule 3.0 Lines 55/56	(151.6)	(92.6)	As discussed further in section 1.6 below, Subsidiary Net Income is higher in fiscal 2020 and fiscal 2021 because, in the Current View, the favourable difference between forecast and actual Powerex Net Income in fiscal 2019 is recovered in fiscal 2020 and fiscal 2021.
Other Utilities Revenue	Schedule 14.0 Line 18	(0.2)	0.0	
Liquefied Natural Gas Revenue	Schedule 14.0 Line 19	(0.6)	0.0	
Deferral Account Rate Rider Revenue	Schedule 14.0 Line 21	0.0	0.0	
Total	Schedule 1.0 Line 35	**(32.5)**	**(89.9)**	Numbers may not add due to rounding
		122.4		

The sub-sections below provide further details on the differences shown in the table above.

Appendix A contains the detailed financial schedules reflecting our updated revenue requirements. The working revenue requirements model that produces these schedules is also provided in electronic form as part of the Evidentiary Update.

Appendix B contains a Draft Order that sets out our requests, as updated by the Evidentiary Update. The following updates are reflected in this Draft Order:

- A rate decrease of 0.99 per cent, effective April 1, 2020;
- Updated Open Access Transmission Tariff Rates (**OATT**) for fiscal 2020 and fiscal 2021;
- Amortizing into rates, over the fiscal 2020 to fiscal 2021 test period, the fiscal 2019 net closing balance and the forecast fiscal 2020 and fiscal 2021 net

additions and net interest applied to the Cost of Energy Variance Accounts, such that fiscal 2020 rates remain the same.[5]

- An updated Demand Side Management (**DSM**) expenditure schedule of $90.8 million in fiscal 2020 and $89.1 million in fiscal 2021;[6] and
- Closure of the Arrow Water Systems Provision Regulatory Account and the Arrow Water Systems Regulatory Account in fiscal 2020.[7]

Appendix C provides detailed information on BC Hydro's updated Cost of Energy forecast.

Appendix D provides BC Hydro's updated regulatory account balances.

Appendix E provides BC Hydro's updated Transmission Revenue Requirement and OATT rates.

Appendix F provides a more detailed explanation of the difference between the estimated impacts from the implementation of IFRS 16 in the Application and the actual impacts shown in the Evidentiary Update.

Appendix G provides explanations for variances between fiscal 2019 RRA plan and fiscal 2019 actual amounts.

1.2 Cost of Energy Has Decreased While Dry Conditions and Lower IPP Purchases Have Increased Market Purchases

The Cost of Energy forecast in the Application was based on BC Hydro's October 2018 energy study. The Cost of Energy forecast in the Evidentiary Update is based on the June 2019 energy study.

[5] Refer to section 1.2 for further discussion.
[6] Refer to BC Hydro's response to BCUC IR 1.182.1.
[7] Refer to BC Hydro's response to BCUC IR 1.40.3.1.

Dry conditions and lower water inflows have decreased planned hydroelectric generation (water rentals) and purchases from IPPs and Long-Term Commitments. In addition, purchases from IPPs and Long-Term Commitments have decreased due to delayed IPP commercial operation dates and due to lower forecast IPP deliveries, based on updated historical delivery averages. The decrease in hydroelectric generation and purchases from IPPs and Long-Term Commitments results in lower planned surplus sales and higher planned market electricity purchases. This shift in volumes is shown in Figure 2 and Figure 3 below.[8] The references in brackets show the line numbers and schedules in Appendix A (e.g., L1, S4 relates to line 1 of Schedule 4 of Appendix A of the Evidentiary Update).

Figure 2 Volumes of Supply - Fiscal 2020 Plan vs. Fiscal 2020 Update (GWh)

[redacted]

[8] For further information, refer to lines 1 to 12 of Schedule 4.0 of Appendix A of the Evidentiary Update.

Figure 3 Volumes of Supply - Fiscal 2021 Plan vs. Fiscal 2021 Update (GWh)

[redacted]

The primary driver of the decreased cost of energy is lower costs for IPPs and Long-Term Commitments. These costs have decreased for two reasons:

- First, as shown in Figure 2 and Figure 3 above, supply from IPPs and Long-Term Commitments is lower. This is due to:
  - dry conditions and low water inflows, which decrease hydro generation; and
  - lower forecast deliveries, based on updated historical delivery averages and delayed commercial operation dates.
- Second, the full implementation of IFRS 16, discussed further in Appendix F, shifts costs from IPPs and Long-Term Commitments (Cost of Energy) to Amortization and Finance Charges.

In the Application, BC Hydro proposed to refund the forecast fiscal 2019 net closing balance and the forecast fiscal 2020 and fiscal 2021 net additions and net interest applied to the Cost of Energy Variance Accounts, over the fiscal 2020 to fiscal 2021 test period with equal amounts being amortized in fiscal 2020 and fiscal 2021. In the Evidentiary Update, BC Hydro is proposing to amortize a higher amount of the credit balance in the Cost of Energy Variance accounts in fiscal 2020 and a lower amount in fiscal 2021. The result is that BC Hydro's requested rate increase for fiscal 2020 remains unchanged, avoiding the need for a retrospective adjustment to fiscal 2020 interim rates and customer bills.

As a result of this proposal and the difference between forecast and actual fiscal 2019 closing account balances, net recoveries from the Heritage Deferral Account and Non-Heritage Deferral Account are higher than planned in fiscal 2020 and lower than planned in fiscal 2021.

The increases and decreases to the components of the Cost of Energy in fiscal 2020 and fiscal 2021 are shown in Figure 4 and Figure 5 below.[9]

[9] For further information, refer to lines 23 to 39 of Schedule 4.0 of Appendix A of the Evidentiary Update.

Figure 4 Cost of Energy - Fiscal 2020 Plan vs. Fiscal 2020 Update – Current View ($ millions)

[redacted]

Figure 5 Cost of Energy - Fiscal 2021 Plan vs. Fiscal 2021 Update – Current View ($ millions)

[redacted]

For more detailed information on BC Hydro's updated Cost of Energy forecast, please refer to Appendix C.

1.3 Operating Costs Have Increased Due to Uncontrollable Factors

Operating costs have increased due to two factors that are outside of BC Hydro's control:

- First, the discount rate used to value BC Hydro's pension liability has decreased from 3.83 per cent as of September 30, 2018 to 3.33 per cent as of April 1, 2019. The discount rate is driven by market conditions and is determined by BC Hydro's external actuary. It is not controllable by BC Hydro as it is based on 'AA' Canadian Corporate bonds. A decrease in the discount rate results in a higher present value of BC Hydro's pension liability. This increases BC Hydro's current service pension costs by $15.9 million in fiscal 2020 and $17.1 million in fiscal 2021.

  The lower discount rate also increased BC Hydro's fiscal 2019 non-current pension costs. This increase is deferred to the Non-Current Pension Cost Regulatory Account and amortized into rates over a 13-year period, which increases the required recovery by $40.8 million in both fiscal 2020 and fiscal 2021.

- Second, storm restoration costs were higher than planned in fiscal 2019 due to more severe storms, including the December 2019 storm. These costs were deferred to the Storm Restoration Costs Regulatory Account and are amortized over the test period, which increases the required recovery in fiscal 2020 and fiscal 2021.

These cost increases are summarized in Figure 6 and Figure 7 below.[10]

[10] For further information, refer to lines 1 to 122 of Schedule 5.0 of Appendix A of the Evidentiary Update.

Figure 6 Operating Costs - Fiscal 2020 Plan vs. Fiscal 2020 Update – Current View ($ millions)

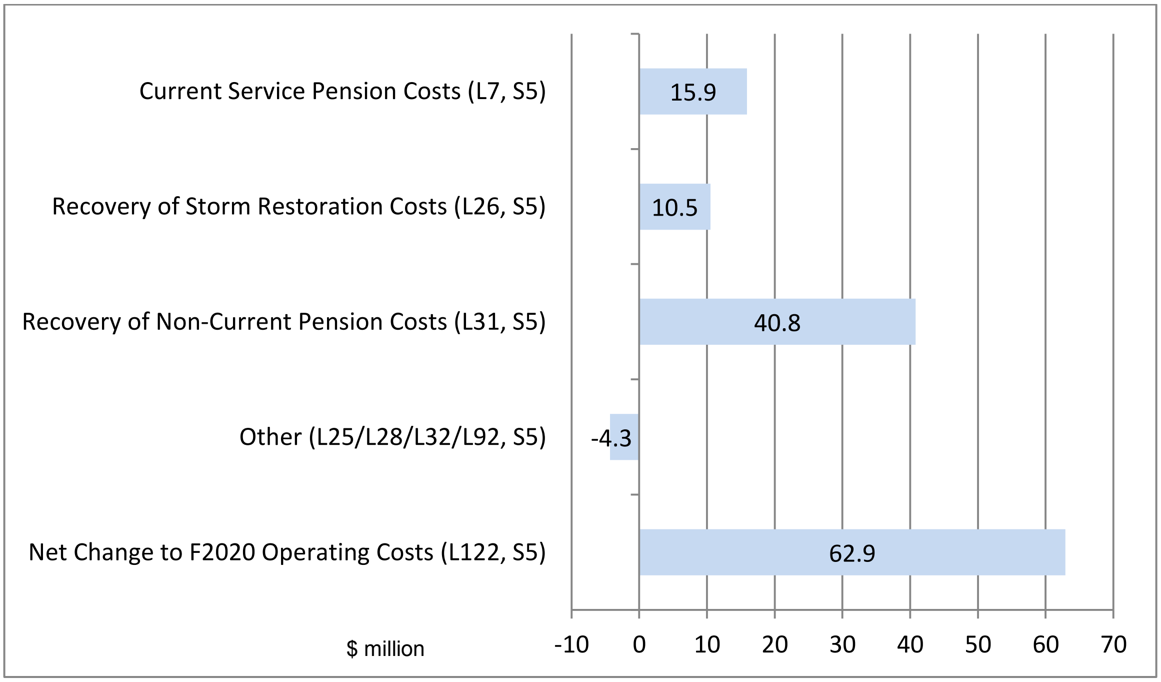
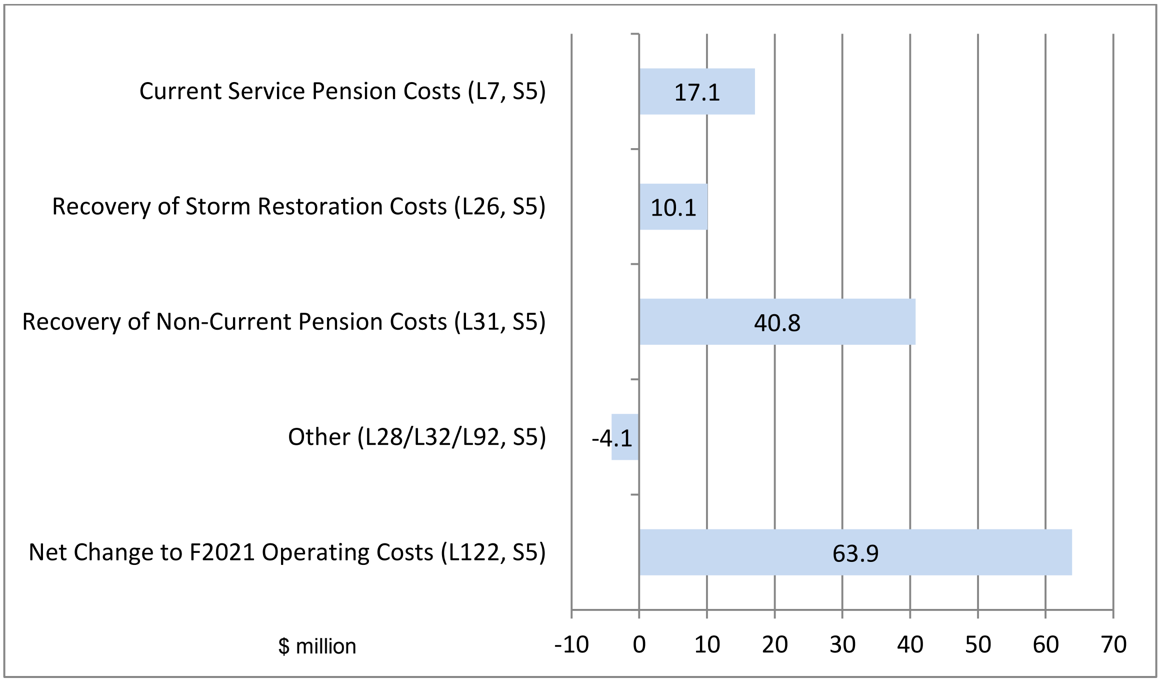


Figure 7 Operating Costs - Fiscal 2021 Plan vs. Fiscal 2021 Update – Current View ($ millions)



1.4 Amortization Has Increased Due to the Full Implementation of IFRS 16

As discussed above, the Evidentiary Update reflects the impacts resulting from the full implementation of IFRS 16, following the completion of BC Hydro's assessment, and subject to the completion of the fiscal 2020 financial statement audit. The implementation of IFRS 16 decreases Cost of Energy while increasing Amortization and Finance Charges. The impact to Amortization is an increase of $58.8 million in fiscal 2020 and $59.9 million in fiscal 2021. Amortization is also increasing because actual capital additions in fiscal 2019 were slightly higher than planned. There were no changes to the capital plan as part of the Evidentiary Update.

1.5 Finance Charges Have Increased Due to the Full Implementation of IFRS 16

Finance Charges are also increasing due to the impacts resulting from the full implementation of IFRS 16. The resulting impact to Finance Charges is an increase of $44.3 million in fiscal 2020 and $43.3 million in fiscal 2021. This increase is partially offset by lower finance charges on debt that was hedged subsequent to the filing of the Application, at interest rates that were lower than forecast in the Application.

1.6 Actual Fiscal 2019 Powerex Net Income Was Higher Than Planned

In the Application, Powerex Net Income was forecast to be $205.3 million in fiscal 2019. Actual Powerex Net Income in fiscal 2019 was $435.7 million or $230.4 million higher than the forecast. This difference increases the credit balance in the Cost of Energy Variance Accounts, which BC Hydro has proposed to refund to ratepayers over the test period. In the Current View, this refund is reflected in BC Hydro's revenue requirements as Subsidiary Net Income. As a result, Subsidiary Net Income is $151.6 million higher in fiscal 2020 and $92.6 million higher in fiscal 2021, which decreases BC Hydro's revenue requirements.[11]

[11] The total increase in refunds in fiscal 2020 and fiscal 2021 is greater than the difference between forecast and actual Powerex Net Income in fiscal 2019, primarily due to variances in interest accrual amounts on the balance in the Trade Income Deferral Account. The refund amount is higher in fiscal 2020 than fiscal 2021 so that BC Hydro's requested rate increase in fiscal 2020 remains unchanged. For further information, refer to section 1.2 above.

BC Hydro
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BC Hydro Fiscal 2020 to Fiscal 2021
Revenue Requirements Application

Appendix A

Financial Schedules

PUBLIC

REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

(Accessible by opening the Attachments Tab in Adobe)

BC Hydro Fiscal 2020 to Fiscal 2021
Revenue Requirements Application

Appendix B

Draft Order

BC Hydro Fiscal 2020 to Fiscal 2021
Revenue Requirements Application

Appendix B-1

Draft Order
Clean Version

Suite 410, 900 Howe Street
Vancouver, BC Canada V6Z 2N3
P: 604.660.4700
TF: 1.800.663.1385
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ORDER NUMBER
G-xx-xx

IN THE MATTER OF
the *Utilities Commission Act*, RSBC 1996, Chapter 473

and

British Columbia Hydro and Power Authority (BC Hydro)
Fiscal 2020 to Fiscal 2021 Revenue Requirements Application

BEFORE:
Commissioner
Commissioner
Commissioner

on Date

ORDER

WHEREAS:

A. On February 25, 2019, the British Columbia Hydro and Power Authority (BC Hydro) filed its Fiscal 2020 to Fiscal 2021 (F2020-F2021) Revenue Requirements Application (Application) with the British Columbia Utilities Commission (BCUC) pursuant to sections 44.2, 58 to 61 and 99 of the *Utilities Commission Act* (UCA) requesting, among other things:

   (i) Approval of a reduction of the Deferral Account Rate Rider (DARR) from 5 per cent to 0 per cent effective April 1, 2019;

   (ii) Approval of an increase in rates by 6.85 percent effective April 1, 2019;

   (iii) Approval of an increase in rates by 0.72 percent effective April 1, 2020; and

   (iv) Approval of the F2020-F2021 Open Access Transmission Tariff (OATT) rates as set out in Table 9-8 of the Application effective April 1, 2019 and April 1, 2020, respectively.

B. BC Hydro requested that these changes be made effective on an interim basis, pending a final BCUC decision on the Application and proposed a regulatory review process for the Application;

C. On February 26, 2019, BC Hydro filed a letter requesting that certain information in Appendix I, J, K and Y be held confidential due to the commercially sensitive nature of the information, in accordance with Part IV of the BCUC's Rules of Practice and Procedure attached to Order G-15-19;

…/2

D. On March 1, 2019, the BCUC issued Order No. G-45-19 approving the changes to the DARR and rates sought in the Application on an interim basis effective April 1, 2019, pending a final BCUC decision on the Application, establishing the Regulatory Timetable for the initial review of the Application, including a Procedural Conference on June 24, 2019, and granting the request to hold certain information in Appendix I, J, K and Y in the Application as confidential on an interim basis, pending further review;

E. On May 22, 2019, the Panel completed its review of BC Hydro's request to hold certain information in the Application as confidential. The Panel found that the request, as clarified by information provided by BC Hydro on April 3, 2019, was reasonable for the reasons stated in BC Hydro's letter dated February 26, 2019, and granted BC Hydro's request that certain information in Appendix I, J, K, Y and BB be held confidential;

F. On June 28, 2019, following the June 24, 2019 Procedural Conference, the BCUC issued Order No. G-146-19, establishing a further regulatory timetable and approving BC Hydro's request to temporarily hold certain information in its pending Evidentiary Update as confidential;

G. On August 22, 2019, BC Hydro filed an Evidentiary Update to the Application (Evidentiary Update) with the BCUC pursuant to sections 44.2, 58 to 61 and 99 of the UCA requesting, among other things, the following amendments to the relief sought:

    (i) Approval of a decrease in rates by 0.99 per cent effective April 1, 2020; and

    (ii) Approval of the revised F2020-F2021 OATT rates as set out in Table E2 of Appendix E of the Evidentiary Update effective April 1, 2019 and April 1, 2020, as applicable;

H. [Other recitals as required.];

I. The BCUC has considered the Application and the evidence and submissions filed in the proceeding and makes the following determinations.

NOW THEREFORE pursuant to sections 44.2, 58 to 61 and 99 of the *Utilities Commission Act*, and for the reasons outlined in the decision issued concurrently with this order, the BCUC orders as follows:

1. The requested final reduction of the DARR from 5 percent to 0 percent is approved effective April 1, 2019.

2. The requested final rate increase of 6.85 percent to be applied as set out in Appendix EE of the Application is approved effective April 1, 2019.

3. The requested final rate decrease of 0.99 per cent, is approved effective April 1, 2020.

4. The following requested changes to deferral and regulatory accounts and the associated financial treatment are approved:

    (a) Amortize into rates, over the fiscal 2020 to fiscal 2021 test period, the fiscal 2019 net closing balance and the forecast fiscal 2020 and fiscal 2021 net additions and net interest applied to the Cost of Energy Variance Accounts;

    (b) Defer any variances related to the accounting for EPAs determined to be leases under International Financial Reporting Standard (IFRS) 16, which are not eligible for deferral treatment under existing orders, to the Non-Heritage Deferral Account;

Filepath

(c) Defer any variances between forecast and actual amounts related to the Biomass Energy Program, which are not eligible for deferral treatment under existing orders, to the Non-Heritage Deferral Account;

(d) Continue to defer, on an annual and ongoing basis, any variances between forecast and actual dismantling costs to the Dismantling Cost Regulatory Account, continue to apply interest to the balance of the account and recover the forecast interest charged to the account each year, and continue to recover the forecast account balance at the end of a test period over the next test period;

(e) Defer low-carbon electrification expenditures to the Demand-Side Management Regulatory Account;

(f) Remove the reference to the "Prescribed Standards" from the description of what may be deferred to the Site C Regulatory Account;

(g) Closure of the Capital Project Investigation Costs Regulatory Account at the end of fiscal 2021;

(h) Closure of the Rate Smoothing Regulatory Account in fiscal 2020;

(i) Closure of the Arrow Water Systems Provision Regulatory Account in fiscal 2020; and

(j) Closure of the Arrow Water Systems Regulatory Account in fiscal 2020.

5. The requested depreciation rates for the Burrard synchronous condense facility, for new Water Rights, Infrastructure Rights and LED Streetlights asset classes and for three new asset classes for agreements recognized as leases under IFRS 16, *Leases* are approved on an ongoing basis.

6. The requested final OATT rates for fiscal 2020 and fiscal 2021 in Table E2 of Appendix E of the Evidentiary Update are approved effective April 1, 2019 and April 1, 2020, as applicable.

7. The requested demand side management (DSM) expenditure schedule of $90.8 million in fiscal 2020 and $89.1 million in fiscal 2021 is accepted.

8. The request for reconsideration of Directive 3 of the BCUC's Decision on BC Hydro's Fiscal 2017 to Fiscal 2019 Revenue Requirements Application which directs BC Hydro to file a certificate of public convenience and necessity (CPCN) application for the Northwest Substation Upgrade project is allowed, and Directive 3 is varied to no longer require BC Hydro to file a CPCN for the project.

9. The requested reconsideration is allowed with respect to the following directives, which are rescinded:

(a) Directive 61 of the BCUC's Decision on BC Hydro's Fiscal 2005 to Fiscal 2006 Revenue Requirements Application which directed that a prorated amount of costs from portfolio-level initiatives be added to the cost of each DSM program to assess cost effectiveness; and

(b) Directive 57 of the BCUC's Decision on BC Hydro's Fiscal 2009 to Fiscal 2010 Revenue Requirements Application which directed that BC Hydro revenue requirement applications filed after January 1, 2011 contain financial information that follows the Uniform System of Accounts.

10. BC Hydro is directed to comply with all other directives in the Decision accompanying this order.

DATED at the City of Vancouver, in the Province of British Columbia, this (XX) day of (Month Year).

BY ORDER

(X. X. last name)
Commissioner

Attachment Options

BC Hydro Fiscal 2020 to Fiscal 2021
Revenue Requirements Application

Appendix B-2

Draft Order
Black-lined Version

Suite 410, 900 Howe Street
Vancouver, BC Canada V6Z 2N3
P: 604.660.4700
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ORDER NUMBER
G-xx-xx

IN THE MATTER OF
the *Utilities Commission Act*, RSBC 1996, Chapter 473

and

British Columbia Hydro and Power Authority (BC Hydro)
Fiscal 2020 to Fiscal 2021 Revenue Requirements Application

BEFORE:
Commissioner
Commissioner
Commissioner

on Date

ORDER

WHEREAS:

A. On February 25, 2019, the British Columbia Hydro and Power Authority (BC Hydro) filed its Fiscal 2020 to Fiscal 2021 (F2020-F2021) Revenue Requirements Application (Application) with the British Columbia Utilities Commission (BCUC) pursuant to sections 44.2, 58 to 61 and 99 of the *Utilities Commission Act* (UCA~~Act~~) requesting, among other things:~~,~~

(i) ~~effective April 1, 2019,~~ Approval of a reduction of the Deferral Account Rate Rider (DARR) from 5 per cent to 0 per cent effective April 1, 2019;

(ii) ~~and~~ Approval of an increase in rates by 6.85 percent effective April 1, 2019~~, resulting in an average net bill increase of 1.76 percent~~;

(iii) ~~effective April 1, 2020,~~ Approval of an increase in rates by 0.72 percent effective April 1, 2020; and

(iv) ~~approval~~ Approval of the ~~fiscal 2020 and fiscal 2021~~ F2020-F2021 Open Access Transmission Tariff (OATT) rates as set out in Table 9-8 of the Application effective April 1, 2019 and April 1, 2020, respectively.~~; and~~

~~(v) acceptance of a demand-side management expenditure schedule of $207.1 million in fiscal 2020 and fiscal 2021 as set out in Table 10-1 of the Application.~~

B. BC Hydro requested that these changes be made effective on an interim basis, pending a final BCUC decision on the Application and proposed a regulatory review process for the Application;

C. On February 26, 2019, BC Hydro filed a letter requesting that certain information in Appendix I, J, K and Y be held confidential due to the commercially sensitive nature of the information, in accordance with Part IV of the BCUC's Rules of Practice and Procedure attached to Order G-15-19;

.../2

~~B.~~D. On March ~~XX~~1, 2019, the BCUC issued Order No. G-~~XX~~45-19 approving ~~BC Hydro's request that~~ the changes to the DARR and rates sought in the Application ~~be approved~~ on an interim basis effective April 1, 2019, pending a final BCUC decision on the Application, establishing the Regulatory Timetable for the initial review of the Application, including a Procedural Conference on June 24, 2019, and granting the request to hold certain information in Appendix I, J, K and Y in the Application as confidential on an interim basis, pending further review~~.~~;

~~C. On XX, 2019, the BCUC issued Order No. G-XX-19 establishing a regulatory timetable for the review of the Application.~~

E. On May 22, 2019, the Panel completed its review of BC Hydro's request to hold certain information in the Application as confidential. The Panel found that the request, as clarified by information provided by BC Hydro on April 3, 2019, was reasonable for the reasons stated in BC Hydro's letter dated February 26, 2019, and granted BC Hydro's request that certain information in Appendix I, J, K, Y and BB be held confidential;

F. On June 28, 2019, following the June 24, 2019 Procedural Conference, the BCUC issued Order No. G-146-19, establishing a further regulatory timetable and approving BC Hydro's request to temporarily hold certain information in its pending Evidentiary Update as confidential;

G. On August 22, 2019, BC Hydro filed an Evidentiary Update to the Application (Evidentiary Update) with the BCUC pursuant to sections 44.2, 58 to 61 and 99 of the UCA requesting, among other things, the following amendments to the relief sought:

(i) Approval of a decrease in rates by 0.99 per cent effective April 1, 2020; and

(ii) Approval of the revised F2020-F2021 OATT rates as set out in Table E2 of Appendix E of the Evidentiary Update effective April 1, 2019 and April 1, 2020, ~~respectively~~as applicable;

~~D.~~H. [Other recitals as required.];

~~E.~~I. The BCUC has considered the Application and the evidence and submissions filed in the proceeding and makes the following determinations.

NOW THEREFORE pursuant to sections 44.2, 58 to 61 and 99 of the *Utilities Commission Act*, and for the reasons outlined in the decision issued concurrently with this order, the BCUC orders as follows:

1. The requested final reduction of the DARR from 5 percent to 0 percent is approved effective April 1, 2019.

2. The requested final rate increase~~s~~ of 6.85 percent ~~and 0.72 percent,~~ to be applied as set out in Appendix EE of the Application~~,~~ ~~are~~is approved effective April 1, 2019 ~~and April 1, 2020, respectively~~.

~~2.~~3. The requested final rate decrease of 0.99 per cent, is approved effective April 1, 2020.

~~3.~~4. The following requested changes to deferral and regulatory accounts and the associated financial treatment are approved:

(a) Amortize into rates, over the fiscal 2020 to fiscal 2021 test period, the ~~forecast~~ fiscal 2019 net closing balance and the forecast fiscal 2020 and fiscal 2021 net additions and net interest applied to the Cost of Energy Variance Accounts;

(b) Defer any variances related to the accounting for EPAs determined to be leases under International Financial Reporting Standard (IFRS) 16, which are not eligible for deferral treatment under existing orders, to the Non-Heritage Deferral Account;

(c) Defer any variances between forecast and actual amounts related to the Biomass Energy Program, which are not eligible for deferral treatment under existing orders, to the Non-Heritage Deferral Account;

(d) Continue to defer, on an annual and ongoing basis, any variances between forecast and actual dismantling costs to the Dismantling Cost Regulatory Account, continue to apply interest to the balance of the account and recover the forecast interest charged to the account each year, and continue to recover the forecast account balance at the end of a test period over the next test period;

(e) Defer low-carbon electrification expenditures to the Demand-Side Management Regulatory Account;

(f) Remove the reference to the "Prescribed Standards" from the description of what may be deferred to the Site C Regulatory Account;

(g) Closure of the Capital Project Investigation Costs Regulatory Account at the end of fiscal 2021; ~~and~~

(h) Closure of the Rate Smoothing Regulatory Account in fiscal 2020;~~.~~

(i) Closure of the Arrow Water Systems Provision Regulatory Account in fiscal 2020; and

~~(i)~~(j) Closure of the Arrow Water Systems Regulatory Account in fiscal 2020.

~~4.~~5. The requested depreciation rates for the Burrard synchronous condense facility, for new Water Rights, Infrastructure Rights and LED Streetlights asset classes and for three new asset classes for agreements recognized as leases under IFRS 16, *Leases* are approved on an ongoing basis.

~~5.~~6. The requested final OATT rates for fiscal 2020 and fiscal 2021 in Table ~~9-8X~~E2 of Appendix E of the ~~Application~~ Evidentiary Update are approved effective April 1, 2019 and April 1, 2020, as applicable.

~~6.~~7. The requested demand side management (DSM) expenditure schedule of $90.8~~207.1~~ million in fiscal 2020 and $89.1 million in fiscal 2021 ~~as set out in Table 10-1 of the Application~~ is accepted.

~~7.~~8. The request for reconsideration of Directive 3 of the BCUC's Decision on BC Hydro's Fiscal 2017 to Fiscal 2019 Revenue Requirements Application which directs BC Hydro to file a certificate of public convenience and necessity (CPCN) application for the Northwest Substation Upgrade project is allowed, and Directive 3 is varied to no longer require BC Hydro to file a CPCN for the project.

~~8.~~9. The requested reconsideration is allowed with respect to the following directives, which are rescinded:

(a) Directive 61 of the BCUC's Decision on BC Hydro's Fiscal 2005 to Fiscal 2006 Revenue Requirements Application which directed that a prorated amount of costs from portfolio-level initiatives be added to the cost of each DSM program to assess cost effectiveness; and

(b) Directive 57 of the BCUC's Decision on BC Hydro's Fiscal 2009 to Fiscal 2010 Revenue Requirements Application which directed that BC Hydro revenue requirement applications filed after January 1, 2011 contain financial information that follows the Uniform System of Accounts.

~~9.~~10. BC Hydro is directed to comply with all other directives in the Decision accompanying this order.

DATED at the City of Vancouver, in the Province of British Columbia, this (XX) day of (Month Year).

BY ORDER

(X. X. last name)
Commissioner

Attachment Options

Filepath

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BC Hydro Fiscal 2020 to Fiscal 2021
Revenue Requirements Application

Appendix C

Updated Cost of Energy Forecast

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1 Updated Cost of Energy Forecast

The Cost of Energy forecast has been updated based on the June 2019 Energy Study (previously October 2018 Energy Study), and is found in Appendix A, Schedule 4.0. Consistent with the Application, the updated Cost of Energy forecast is presented in the Gross View,[1] for the test period and summarized in Table C-1 below. This table updates Table 4-2 of Chapter 4 of the Application.

Table C-1 Cost of Energy Forecast (Integrated System and Non-Integrated Areas)

	Cost of Energy ($millions)	Schedule Reference	F2020 Plan	F2020 EU	Diff	F2021 Plan	F2021 EU	Diff
			1	2	3=2-1	4	5	6=5-4
1	Heritage Energy	4.0L28	350.9	[redacted]	[redacted]	350.8	[redacted]	[redacted]
2	Non-Heritage Energy	4.0L33	1,576.3	[redacted]	[redacted]	1,641.1	[redacted]	[redacted]
3	Market Energy	4.0L38	(40.2)	[redacted]	[redacted]	(71.7)	[redacted]	[redacted]
4	Total	4.0L39	1,887.0	1,928.9	41.9	1,920.2	1,734.6	(185.6)

In fiscal 2020, BC Hydro's total Cost of Energy is forecast to increase by $41.9 million from the fiscal 2020 Plan. In fiscal 2021, total Cost of Energy is forecast to decrease by $185.6 million from the fiscal 2021 Plan. Overall, the updated Cost of Energy forecast in the test period represents a decrease of $143.7 million compared to the forecast in the Application.

One of the drivers of the change in BC Hydro's Cost of Energy forecast is the continuing dry conditions from fiscal 2019 through to fiscal 2020, with low reservoir levels recorded at the end of fiscal 2019 and a reduction in the water supply forecast for fiscal 2020. These dry conditions impact hydro facilities owned by Independent Power Producers (**IPPs**), as well as facilities owned by BC Hydro. This results in higher cost of Market Energy, with market electricity purchases forecast to increase

[1] The Gross View shows the total costs for each component of the revenue requirements before any forecast transfers to regulatory accounts. In other words, "Gross View" shows the total costs incurred in fiscal 2020 and fiscal 2021.

and surplus sales forecast to decrease. The forecast increase in cost of Market Energy is mitigated by a decrease in costs for IPPs and Long-Term commitments and Water Rentals. Further information is provided in the sections below.

1.1 Cost of Heritage Energy

Cost of Heritage Energy is forecast to increase by [redacted] million in fiscal 2020 and decrease by [redacted] million in fiscal 2021, compared to the Application. This is largely driven by lower water rentals during the test period, and lower Non-Treaty Storage and Libby Coordination Agreement costs in fiscal 2021, partially offset by higher Non-Treaty Storage and Libby Coordination Agreement costs in fiscal 2020.

Water rental fees are calculated based on generation volumes from the prior calendar year multiplied by the current year water rental rates. Total water rentals are forecast to be [redacted] million in fiscal 2020 and [redacted] million in fiscal 2021, a decrease of [redacted] million in fiscal 2020 and [redacted] million in fiscal 2021 compared to the Application. This difference is primarily due to lower hydro generation output in fiscal 2019 and fiscal 2020 than forecast in the Application. Actual hydro generation output in fiscal 2019 was 4,027 GWh lower than the fiscal 2019 Plan, and hydro generation output in fiscal 2020 is expected to decrease by [redacted] GWh compared to the fiscal 2020 Plan in the Application. This is mainly driven by lower inflows constraining hydro generation during the winter of fiscal 2019 and fiscal 2020.

Total costs for Non-Treaty Storage and Libby Coordination Agreements are forecast to be [redacted] million higher in fiscal 2020 and [redacted] million lower in fiscal 2021, compared to the Application. Higher water releases occurred during the winter of fiscal 2019 which drew down BC Hydro's storage accounts under these agreements. As a result, BC Hydro needs to store water back into the accounts during fiscal 2020, which increases forecast costs. Higher water releases and lower costs are expected to occur in fiscal 2021.

1.2 Cost of Non-Heritage Energy

Cost of Non-Heritage Energy is forecast to decrease by [redacted] million in fiscal 2020 and [redacted] million in fiscal 2021, compared to the Application. This is primarily due to lower costs for IPPs and Long-Term Commitments.

Total costs for IPPs and Long-Term Commitments are forecast to be [redacted] million in fiscal 2020 and [redacted] million in fiscal 2021. This represents a decrease of [redacted] million in fiscal 2020 and [redacted] million in fiscal 2021, compared to the forecast in the Application. This reduction is due to a number of factors, such as:

- A change in accounting treatment under IFRS 16 (capital leases) for two Electricity Purchase Agreements not previously identified as capital leases (please refer to Appendix F for further discussion on the adoption of IFRS 16 and its implications);
- Lower forecast inflows for hydro IPPs due to dry weather conditions, as described above;
- Updates to historical average deliveries to incorporate the fiscal 2019 actual deliveries for operating projects, which resulted in a lower IPP forecast compared to the Application; and
- Delays in projects reaching commercial operation.

1.3 Cost of Market Energy

Cost of Market Energy is forecast to increase by [redacted] million in fiscal 2020 and [redacted] million in fiscal 2021, compared to the Application. As discussed above, dry weather conditions during the winter of fiscal 2019 have continued into fiscal 2020, increasing the potential need for market electricity purchases and decreasing surplus sales and domestic transmission costs.

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Appendix D

Updated Regulatory Account Balances

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1 Updated Regulatory Account Balances

Table D-1 below provides BC Hydro's updated forecast fiscal 2020 and fiscal 2021 regulatory account balances as a result of the Evidentiary Update. Updated financial schedules for each of BC Hydro's regulatory accounts are provided in Schedules 2.1 and 2.2 of Appendix A.

Table D-1 Regulatory Account Balances Fiscal 2020 to Fiscal 2021 Forecast

	End of Year Balance ($ million)	Schedule Reference	F2020 Plan	F2020 EU	Diff	F2021 Plan	F2021 EU	Diff
			1	2	3 = 2 - 1	4	5	6 = 5 - 4
	Cost of Energy Variance Accounts							
1	Heritage Deferral Account	2.1L20	(198)	(218)	(20)	0	0	0
2	Non-Heritage Deferral Account	2.1L21	52	101	49	(0)	0	0
3	Trade Income Deferral Account	2.1L22	(12)	(103)	(91)	(0)	(0)	(0)
4	Total		(158)	(219)	(61)	(0)	0	0
5	Non-Current Pension Costs	2.2 L187	(19)	359	378	(35)	302	337
6	Debt Management	2.2 L199	(248)	276	524	(235)	289	524
7	Other Regulatory Accounts		4,057	4,070	13	3,928	3,893	(35)
8	**Total**	2.1L23+2.2 L203	**3,632**	**4,486**	**854**	**3,658**	**4,484**	**826**

Approximately two-thirds of the $854 million increase in the forecast fiscal 2020 ending regulatory account balance is driven by variances for fiscal 2019 (i.e., actual results compared to the fiscal 2019 forecast in the Application). This variance was largely driven by increases in the Debt Management and Non-Current Pension Costs regulatory accounts, as discussed further below.

Heritage Deferral Account - the forecast fiscal 2020 credit balance in the Heritage Deferral Account is higher than in the Application. This is primarily due to higher than forecast reductions to the account in fiscal 2019 resulting from higher recoveries associated with Non-Treaty Storage and Libby Coordination agreements. The higher than forecast reductions are partially offset by higher than forecast market electricity purchases in fiscal 2019.

Non-Heritage Deferral Account - the forecast fiscal 2020 balance in the Non-Heritage Deferral Account is higher than in the Application, primarily due to impacts from the full implementation of IFRS 16 at April 1, 2019, following BC Hydro's completed accounting assessment, as discussed further in Appendix F. This was partially offset by higher than forecast reductions to the account in fiscal 2019 resulting from lower than forecast cost of energy for IPPs are Long-Term commitments.

Trade Income Deferral Account - the forecast fiscal 2020 credit balance in the Trade Income Deferral Account is higher than in the Application, primarily due to higher than forecast Powerex Net Income in fiscal 2019, as discussed further in section 1.6 of the Evidentiary Update.

Non-Current Pension Costs Regulatory Account - the forecast fiscal 2020 and fiscal 2021 balance in the Non-Current Pension Costs Regulatory Account is higher than in the Application, primarily due to a non-cash actuarial loss in fiscal 2019 due to a decrease in the discount rate. The discount rate is driven by market conditions and is determined by BC Hydro's external actuary. It is not controllable by BC Hydro as it is based on 'AA' Canadian Corporate bonds. A 1 per cent change in discount rates results in a $500 million to $600 million actuarial gain/loss. These gains/losses are amortized over 13 years, which is the expected average remaining service life of employees.

Debt Management Regulatory Account - the forecast fiscal 2020 and fiscal 2021 balance in the Debt Management Regulatory Account is higher than in the Application, primarily due to a decrease in forward interest rates, resulting in a decrease in the fair value of financial contracts that hedge the interest rate on future debt issuances. The increase is mostly non-cash (only a small portion relates to hedges that have realized and were settled in cash) and will be offset by lower finance charges when the hedged future debt is issued at lower interest rates. A

1 per cent change in forward interest rates results in an $800 million to $900 million increase/decrease in the fair value of the financial contracts that hedge interest rates on future debt issuances. Any realized gains or losses on interest rate hedges are amortized starting in the next test period over the remaining term of the underlying debt (e.g., 10 to 30 years). These financial contracts were not settled prior to the start of the test period. Therefore, the amortization of the Debt Management Regulatory Account for the test period is unchanged from the Application.

Table D-2 below provides a more detailed view of the regulatory account balances to the end of fiscal 2024. This table updates Table 7-2 of Chapter 7 of the Application.

Table D-2 Regulatory Account Balances Fiscal 2017 to Fiscal 2019 Actual and Fiscal 2020 to Fiscal 2024 Forecast

	($ million)	Schedule Reference	F2017 Actual	F2018 Actual	F2019 Actual	F2020 Update	F2021 Update	F2022 Forecast	F2023 Forecast	F2024 Forecast
			1	2	3	4	5	6	7	8
	Cost of Energy Variance Accounts									
1	Heritage Deferral Account	2.1L20	(53)	(104)	(485)	(218)	0	(0)	(0)	(0)
2	Non-Heritage Deferral Account	2.1L21	756	463	76	101	0	(16)	(22)	(24)
3	Trade Income Deferral Account	2.1L22	194	127	(259)	(103)	(0)	0	0	0
	Total	2.1L23	897	487	(668)	(219)	0	(16)	(22)	(24)
	Other Cash Variance Accounts									
4	Storm Restoration Costs	2.2 L180	39	46	58	29	0	(0)	(0)	0
5	Amortization of Capital Additions	2.2 L183	(9)	(5)	18	9	0	0	0	0
6	Total Finance Charges	2.2 L184	(215)	(139)	20	10	(0)	0	0	0
7	Rock Bay Remediation	2.2 L190	(23)	(20)	(21)	(10)	(0)	(0)	(0)	(0)
8	Arrow Water Systems	2.2 L193	0	0	0	0	0	(0)	(0)	(0)
9	Remediation	2.2 L195	(16)	(29)	(31)	(15)	(0)	(0)	(0)	(0)
10	Real Property Sales	2.2 L197	28	38	49	42	34	26	18	9
11	Dismantling Cost	2.2 L200	0	35	48	24	0	(0)	(0)	(0)
12	Customer Crisis Fund	2.2 L202	0	0	(3)	(3)	(3)	(4)	(4)	(4)
13	Mining Customer Payment Plan		0	0	0	0	0	0	0	0
	Total		(196)	(73)	140	86	31	22	14	5
	Non-Cash Variance Accounts									
14	Foreign Exchange Gains/Losses	2.2 L178	(66)	(31)	12	9	8	8	7	6
15	Non-Current Pension Costs	2.2 L187	511	303	485	359	302	251	199	148
16	PEB Current Pension Costs	2.2 L201	0	3	(2)	(1)	0	0	0	0
17	Debt Management	2.2 L199	(187)	(158)	163	276	289	296	298	294
	Total		258	118	659	643	599	555	504	448
	Benefit Matching Accounts									
18	DSM	2.2 L173	916	902	915	920	912	896	869	841
19	First Nations Costs	2.2 L174	124	104	85	71	56	38	25	14
20	Site C	2.2 L176	453	472	491	508	525	540	551	556
21	Future Removal and Site Restoration (closed)	2.2 L177	3	(0)	0	0	0	0	0	0
22	Pre-1996 Contributions in Aid of Construction	2.2 L179	91	88	83	78	73	68	63	58
23	Capital Project Investigation Costs	2.2 L181	20	15	10	5	0	0	0	0
24	SMI	2.2 L185	261	239	217	196	174	152	130	109
	Total		1,868	1,821	1,802	1,779	1,739	1,694	1,638	1,577
	Non-Cash Provisions									
25	First Nations Provisions	2.2 L175	409	414	420	423	428	433	432	428
26	Environmental Provisions	2.2 L189	333	310	279	236	196	172	149	131
27	Arrow Water Systems Provision	2.2 L194	4	3	0	0	0	(0)	(0)	(0)
	Total		746	727	699	659	624	605	581	559
	Rate Smoothing Accounts									
28	Rate Smoothing	2.2 L196	489	815	0	0	0	0	0	0
	Total		489	815	0	0	0	0	0	0
	IFRS Transition Accounts									
29	IFRS Property, Plant and Equipment	2.2 L191	962	1,025	1,064	1,079	1,071	1,039	1,007	976
30	IFRS Pension	2.2 L192	574	535	497	459	421	382	344	306
	Total		1,535	1,561	1,561	1,538	1,491	1,421	1,352	1,282
	Total	2.1L23+2.2 L203	**5,597**	**5,454**	**4,193**	**4,486**	**4,484**	**4,282**	**4,066**	**3,847**

Table D-3 below sets out the updated baseline forecast amounts for regulatory accounts and provides the differences between the amounts in the Evidentiary Update and the amounts in the Application. The variances deferred to BC Hydro's regulatory accounts will be determined from these updated baseline forecast amounts. This table updates Table 7-3 of Chapter 7 of the Application.

Table D-3 Fiscal 2020 to Fiscal 2021 Baseline Forecast Amounts for Regulatory Accounts

Line	($ million)	Schedule Reference	F2020 Plan	F2020 EU	Diff	F2021 Plan	F2021 EU	Diff
			1	2	3 = 2 - 1	4	5	6 = 5 - 4
	Heritage Deferral Account							
1	COE Subject to Deferral to HDA	4.0 L66	327.7	[redacted]		294.2	[redacted]	
	Non-Heritage Deferral Account							
2	COE Subject to Deferral to NHDA	4.0 L80	1,571.0	[redacted]		1,637.2	[redacted]	
3	Total Rate Revenue	1.0 L23	5,256.5	5,223.9	(32.6)	5,288.3	5,198.4	(89.9)
4	External OATT	15.0 L4	15.4	15.9	0.5	15.4	15.9	0.5
5	NTL Supplemental Charge Revenue	15.0 L9	2.3	2.3	0.0	2.3	2.3	0.0
	Trade Income Deferral Account							
6	Trade Income	1.0 L17	120.6	120.6	0.0	120.6	120.6	0.0
	Other Regulatory Accounts							
7	Non-Current PEB - Pension	8.0 L17	(33.2)	(36.5)	(3.3)	(36.7)	(42.2)	(5.5)
8	Current PEB - Operating Cost	N/A	62.1	78.0	15.9	63.4	79.5	16.1
9	Storm Restoration Costs	N/A	17.8	17.8	0.0	17.8	17.8	0.0
10	Total Finance Charges	8.0 L32-L16-L17	729.5	770.9	41.4	697.8	736.8	39.0
11	Amortization of Capital Additions	13.0 L35	28.6	28.6	0.0	80.7	80.7	0.0
12	Net Gain on Property Sales	5.0 L76	10.0	10.0	0.0	10.0	10.0	0.0
13	Dismantling Cost	5.0 L72:L75	67.0	67.0	0.0	43.0	43.0	0.0

BC Hydro Fiscal 2020 to Fiscal 2021
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Appendix E

Updated Transmission Revenue Requirement

1 Transmission Revenue Requirement

In the Evidentiary Update, BC Hydro is updating the Open Access Transmission Tariff (**OATT**) rates required to recover its Transmission Revenue Requirement. The Transmission Revenue Requirement and OATT Rates are summarized in Schedule 3.4 of Appendix A of the Evidentiary Update.

The table below updates the cost components which comprise the Transmission Revenue Requirement, based on the Evidentiary Update. This table updates Table 9-1 of Chapter 9 of the Application. As shown in the table below, the Transmission Revenue Requirement has increased by $43.4 million or 4.1 per cent in fiscal 2020 and $42.2 million or 4.0 per cent in fiscal 2021, compared to the amounts in the Application. These increases are primarily due to the increases in finance charges directly assigned to Transmission, an increase in the return on equity assigned to Transmission, and an increase in business support cost assigned to Transmission. These changes are described in greater detail below.

Table E-1 Transmission Revenue Requirement

		F2020			F2021		
		Plan	Evidentiary Update	Diff	Plan	Evidentiary Update	Diff
		1	2	3	4	5	6
1	Operating Cost	252.1	252.7	0.6	256.5	257.1	0.6
2	Taxes	157.6	157.6	-	163.7	163.7	-
3	Amortization	235.0	233.5	(1.4)	237.3	236.1	(1.2)
4	Finance Charges	223.3	243.9	20.7	209.0	227.6	18.6
5	Return on Equity	227.9	236.1	8.1	224.7	232.9	8.1
6	Business Support Cost	188.2	205.1	17.0	195.2	212.1	16.9
7	Internal Allocations to Transmission						
8	Generation Ancillary Services	2.8	2.8	-	2.8	2.8	-
9	Transmission Capitalized Overhead	(16.1)	(16.1)	-	(16.3)	(16.3)	-
10	Transmission RSRA Writeoff	-	-	-	-	-	-
11	Gross Transmission Costs	1,270.8	1,315.7	44.9	1,273.0	1,316.1	43.1
12	Less Internal Allocations from Transmission						
13	Generation Related Transmission Assets	(43.3)	(43.3)	-	(43.3)	(43.3)	-
14	Generation Real Time Dispatch	(2.3)	(2.4)	(0.1)	(2.3)	(2.4)	(0.1)
15	Distribution Real Time Dispatch	(20.0)	(20.7)	(0.7)	(20.4)	(21.1)	(0.7)
16	Substation Distribution Assets	(126.5)	(127.4)	(1.0)	(128.1)	(128.5)	(0.4)
17	Less Miscellaneous Revenues						
18	Fortis General Wheeling Agreement	(5.2)	(5.2)	-	(5.3)	(5.3)	-
19	Secondary Revenues	(6.0)	(6.0)	-	(6.2)	(6.2)	-
20	Interconnections	(2.2)	(2.2)	-	(2.2)	(2.2)	-
21	Amortization of Contributions	(14.8)	(14.6)	0.3	(15.3)	(15.0)	0.3
22	NTL Supplemental Charge	(2.3)	(2.3)	-	(2.3)	(2.3)	-
23	Subtotal	(222.5)	(224.0)	(1.5)	(225.4)	(226.3)	(0.9)
24	Transmission Revenue Requirement	1,048.3	1,091.7	43.4	1,047.6	1,089.9	42.2

As shown on line 38 of Schedule 8.0 of Appendix A, the finance charges allocated to Transmission increased by $20.7 million in fiscal 2020 and $18.6 million in fiscal 2021. This increase is due to an overall increase in finance charges (see section 1.5 of the Evidentiary Update) as well as an increase to the proportion of finance charges assigned to Transmission. Finance charges are allocated based on a rate base. As shown on line 34 of Schedule 8.0 of Appendix A, the proportion of Rate Base allocated to Transmission increased by 1.1 per cent in both fiscal 2020 and fiscal 2021. This increase results from a reclassification of the Altagas contribution to the Northwest Transmission Line due to transition to IFRS. Contributions to aid in the construction of the Transmission system have been reclassified from Transmission contribution in aid of construction to other non-current liabilities and accounts payable for the current portion.

As shown on line 42 of Schedule 9.0 of Appendix A of the Evidentiary Update, the increase to the proportion of Rate Base allocated to Transmission also results in an increase to return on equity allocated to Transmission of $8.1 million in both fiscal 2020 and fiscal 2021.

As shown on line 45 of Schedule 3.1 of Appendix A, Business Support costs allocated to transmission have increased by $17.0 million in fiscal 2020 and $16.9 million in fiscal 2021. This is primarily due to increases in current pension service costs (see section 1.3 of the Evidentiary Update) and higher recoveries from the Non-Current Pension Costs Regulatory Account (see Appendix D).

The table below provides BC Hydro's updated proposed OATT Rates, based on the updated Transmission Revenue Requirement. This table updates Table 9-8 of Chapter 9 of the Application.

Table E-2 Proposed OATT Rates Fiscal 2020 to Fiscal 2021

				F2020			F2021		
	Rate Schedule	Rate Class	Ref	Plan	Evidentiary Update	Diff	Plan	Evidentiary Update	Diff
				1	2	3	4	5	6
1	Attachment H	NITS Revenue Requirement ($)	Schedule 3.4 L32	928,236,000	967,788,000	39,552,000	926,484,000	965,040,000	38,556,000
2	RS 00	NITS Monthly Rate ($)	Schedule 3.4 L33	77,353,000	80,649,000	3,296,000	77,207,000	80,420,000	3,213,000
3	RS 01	Long Term Firm Point-to-Point							
4		Yearly - $/MW of Reserved Capacity per year	Schedule 3.4 L41	78,433	81,695	3,262	78,375	81,546	3,171
5		Short Term Firm and Non-Firm Maximum Price for Delivery							
6		Monthly - $/MW of Reserved Capacity per month	Schedule 3.4 L42	6,536.12	6,807.92	271.80	6,531.23	6,795.47	264.24
7		Weekly - $/MW of Reserved Capacity per week	Schedule 3.4 L43	1,508.34	1,571.06	62.72	1,507.21	1,568.19	60.98
8		Daily - $/MW of Reserved Capacity per day	Schedule 3.4 L44	214.89	223.82	8.93	214.73	223.41	8.68
9		Hourly - $/MW of Reserved Capacity per hour	Schedule 3.4 L45	8.95	9.33	0.38	8.95	9.31	0.36
10	RS 03	Scheduling, System Control & Dispatch Service ($)							
11		per MW of Reserved Capacity per hour	Schedule 3.4 L48	0.133	0.137	0.004	0.136	0.140	0.004

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Appendix F

Implementation of IFRS 16 Update

As discussed in section 8.13.3 of Chapter 8 of the Application, the IFRS 16 lease impacts included in the Application were estimates as the standard was not effective until April 1, 2019 and BC Hydro had not completed its impact assessment.

BC Hydro has now completed its implementation of IFRS 16 and the revised impact of the adoption at April 1, 2019 compared to the estimate provided in the Application is shown in Table F-1. The resulting net change of $82.8 million has been included as an addition to the Non-Heritage Deferral Account.

Table F-1 Electricity Purchase Agreements – Comparison of Forecast Adjustment to Actual Impact

Financial Statement Item Debit/(Credit)	IFRS 16 Adjustment at April 1, 2019 ($ million)	
	Application Forecast	**Actual**
Prepaid Lease	(17.7)	(17.7)
Property, Plant and Equipment	(617.7)	(617.7)
Right-of-Use Assets	93.1	1,428.4
Lease Obligations	560.4	(857.8)
Net Change	**(18.0)**	**64.8**

Table F-2 below shows the net impact of the completion of IFRS 16 implementation on BC Hydro's revenue requirements in fiscal 2020 and fiscal 2021, compared to the Application.

Table F-2 IFRS 16 Expenses – Forecast Compared to Actual

($ million)	Fiscal 2020	Fiscal 2021
Cost of Energy	(86.4)	(87.7)
Amortization	58.8	59.9
Finance Charges	44.3	43.3
Net Impact	**16.6**	**15.5**

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Appendix G

Fiscal 2019 Variance Explanations

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1 Introduction

This appendix provides variance explanations between the plan amounts in the Fiscal 2017 to Fiscal 2019 Revenue Requirements Application (**Previous Application**) and the actual results for fiscal 2019.

2 Energy Sales and Revenue Variance Explanations

Chapter 3 of the Application addresses BC Hydro's load and revenue forecast for the test period. This section compares domestic energy sales and revenue actual amounts for fiscal 2019 with the fiscal 2019 amounts from the Previous Application (**fiscal 2019 RRA Plan**).

Load and revenues always have a degree of variability between forecast and actual amounts, as described below. These variances are captured by the Cost of Energy Variance Regulatory accounts, so that customers only pay actual costs.

2.1 Domestic Energy Sales Variance Explanations – Fiscal 2019

Table G-1 compares fiscal 2019 domestic energy sales actual amounts (in GWh) against the fiscal 2019 RRA Plan, with variance explanations provided below the table.

Table G-1 Fiscal 2019 Domestic Energy Sales Variance

		Schedule	F2019			
	(GWh)	Reference	RRA	Actual	Diff	% Diff
			1	2	3 = 2 -1	4 = 3 / 1
1	Residential	14.0 L1	18,250	18,000	(250)	-1.4%
2	Light Industrial and Commercial	14.0 L2	18,899	19,007	108	0.6%
3	Large Industrial	14.0 L3+L9	13,882	13,896	15	0.1%
4	Other	14.0 L4 to L8	1,634	1,510	(124)	-7.6%
5	Total	14.0 L10	52,664	52,413	(251)	-0.5%

Overall, actual domestic energy sales in fiscal 2019 were 251 GWh (or 0.5 per cent) lower than fiscal 2019 RRA Plan.

Actual residential sales were 250 GWh (or 1.4 per cent) lower than the fiscal 2019 RRA Plan. The residential sales forecast is based on three main variables:

- Number of accounts;
- Electricity sales per account (use per account); and
- Temperature.

The residential sales variance was related to a lower than expected usage per residential account. The lower usage per account is likely due to a number of factors including higher Demand-Side Management savings, denser housing development (more multiple unit dwellings), fewer people per account, and changes in appliance mix resulting in more efficient appliances (appliance stock turnover). The total number of residential accounts was 2,000 (or 0.1 per cent) higher than forecast in fiscal 2019 and temperatures were slightly colder than normal during the year. As such, temperature and the number of accounts do not account for the negative sales variance.

Actual light industrial and commercial sales were 108 GWh (or 0.6 per cent) higher than forecast due to higher sales in the light industrial sector. This variance in the light industrial sector reflects continued strong growth in the B.C. economy, which has been reflected in other economic indicators such as low unemployment and consistent GDP growth. The commercial sector had a small negative variance.

Actual large industrial sales were 15 GWh (or 0.1 per cent) higher than the fiscal 2019 RRA Plan.

Actual energy sales to the Other customer sector were 124 GWh (or 7.6 per cent) lower than the fiscal 2019 RRA Plan, primarily due to lower than expected sales to FortisBC.

2.2 Domestic Revenue Variance Explanations – Fiscal 2019

Table G-2 compares fiscal 2019 domestic revenue actual amounts against the fiscal 2019 RRA Plan, with variance explanations provided below the table.

Table G-2 Fiscal 2019 Domestic Revenues – Variance

($ million)	Schedule Reference	F2019			
		RRA	Actual	Diff	% Diff
		1	2	3 = 2 - 1	4 = 3 / 1
Residential	14.0 L11	2,067.9	2,025.2	(42.7)	-2.1%
Light Industrial and Commercial	14.0 L12	1,821.9	1,832.3	10.4	0.6%
Large Industrial	14.0 L13+L19	840.9	831.4	(9.5)	-1.1%
Other	14.0 L14 to L18	129.1	137.7	8.6	6.7%
Subtotal	14.0 L20	4,859.8	4,826.6	(33.2)	-0.7%
Revenue from Deferral Rider	14.0 L21	241.8	240.6	(1.2)	-0.5%
Total	14.0 L22	5,101.6	5,067.2	(34.4)	-0.7%

Actual domestic revenues in fiscal 2019 were $34 million (or 0.7 per cent) lower than the fiscal 2019 RRA Plan, with lower residential revenues and slightly lower large industrial revenues partially offset by higher light industrial and commercial revenue and higher other revenue. Lower residential revenue was driven by lower load, as described in section 2.1 above. Light industrial and commercial revenue was higher due to higher load, as described in section 2.1 above. Lower large industrial revenue was driven by a lower average rate, due to a different mix of customer rates than was projected in the fiscal 2019 Plan. Other revenue was higher mainly due to the adoption of IFRS 15, Revenue from Contracts with Customers, as described in section 8.13 of Chapter 8 of the Application. The adoption of IFRS 15 resulted in a higher price per MWh for sales to the City of Seattle and was partially offset by lower sales to FortisBC.

3 Cost of Energy Variance Explanations (Schedule 4.0)

Table G-3 Fiscal 2019 Cost of Energy Variances

	($ million)	Schedule Reference	F2019 RRA	Actual	Diff	% Diff
			1	2	3=2-1	4=3/1
	Heritage Energy					
1	Water Rentals	4.0 L1	356.4	363.1	6.7	2%
2	Natural Gas for Thermal Generation	4.0 L2	10.7	7.6	(3.1)	-29%
3	Domestic Transmission - Other	4.0 L3	22.1	22.3	0.2	1%
4	Non-Treaty Storage and Libby Coordination Agreements	4.0 L4	(7.2)	(181.9)	(174.7)	2431%
5	Remissions and Other	4.0 L5	(33.1)	(33.9)	(0.8)	2%
6	**Subtotal**	4.0 L6	**349.0**	**177.2**	(171.8)	-49%
	Non-Heritage Energy					
7	IPPs and Long-Term Commitments	4.0 L7	1,439.3	1,247.2	(192.1)	-13%
8	Non-Integrated Area	4.0 L8	31.1	28.9	(2.2)	-7%
9	Gas & Other Transportation	4.0 L9	6.1	9.4	3.3	54%
10	Water Rentals (Waneta 2/3)	4.0 L10	0.0	2.4	2.4	N/A
11	**Subtotal**	4.0 L11	**1,476.5**	**1,287.9**	(188.6)	-13%
	Market Energy					
12	Market Electricity Purchases	4.0 L12	35.9	125.0	89.1	248%
13	Surplus Sales	4.0 L13	(129.2)	(115.0)	14.2	-11%
14	Net Purchases (Sales) from Powerex	4.0 L14	0.7	25.0	24.3	3276%
15	Domestic Transmission - Export	4.0 L15	29.9	18.5	(11.4)	-38%
16	**Subtotal**	4.0 L16	(62.6)	53.5	116.1	-185%
17	**Total Gross Cost of Energy**	1.0 L1	**1,762.9**	**1,518.7**	(244.2)	-14%

Fiscal 2019 actual gross Cost of Energy was $244.2 million or 14 per cent lower than the fiscal 2019 RRA Plan. This was primarily due to:

- Line 4 - Higher recoveries from water transactions associated with Non-Treaty Storage and Libby Coordination agreements due to high water releases that primarily occurred in July 2018, August 2018, and February 2019 when market prices were high;
- Line 7 - Lower costs from Independent Power Producers primarily resulting from lower deliveries from hydro projects due to low water inflows, delayed Commercial Operation Date for several projects, suspension of the Standing Offer Program, lower deliveries from wind projects, and the termination of several Electricity Purchase Agreements; and
- Line 15 - Lower domestic transmission charges as a result of fewer surplus sales during the year.

Partially offset by:

- Line 12 - Higher market electricity purchases required to meet domestic load requirements due to lower water inflows;
- Line 13 - Lower revenues from surplus sales primarily due to lower water inflows and lower purchases from Independent Power Producers, as discussed above; and
- Line 14 - Higher net purchases from Powerex due to limited opportunities to export energy because of low water levels.

4 Operating Costs and Provisions Variance Explanations (Schedule 5.0)

Table G-4 Fiscal 2019 Operating Costs and Provisions Variances

	($ million)	Schedule Reference	F2019 RRA	Actual	Diff	% Diff
			1	2	3=2-1	4=3/1
1	Integrated Planning	5.0 L1	270.1	285.9	15.8	6%
2	Capital Infrastructure Project Delivery	5.0 L2	81.9	85.9	4.0	5%
3	Operations	5.0 L3	216.2	215.6	(0.6)	0%
4	Safety	5.0 L4	54.9	53.6	(1.3)	-2%
5	Finance, Technology, Supply Chain	5.0 L5	265.0	261.2	(3.8)	-1%
6	People, Customer, Corporate Affairs	5.0 L6	122.5	105.5	(17.0)	-14%
7	Other	5.0 L7	(251.6)	(250.5)	1.0	0%
8	F17-F19 RRA Compliance Filing Adjustment	5.0 L8	10.4	-	(10.4)	-100%
9	**Base Operating Costs**	5.0 L9	**769.5**	**757.2**	(12.2)	-2%
10	IFRS Ineligible Capitalized Costs	5.0 L10	147.7	147.7	-	0%
11	Independent Power Producer Capital Leases	5.0 L11	54.3	54.4	0.0	0%
12	Waneta 2/3	5.0 L12	-	3.7	3.7	N/A
13	Customer Crisis Fund	5.0 L13	-	4.1	4.1	N/A
14	**Net Operating Costs**	5.0 L14	**202.0**	**209.8**	7.8	4%
15	Deferred Account Additions	5.0 L18	-	(0.7)	(0.7)	N/A
16	Regulatory Account Additions	5.0 L29	197.9	198.7	0.8	0%
17	**Subtotal**		**197.9**	**198.0**	0.1	0%
18	**Total Gross Operating Costs**	5.0 L30	**1,169.4**	**1,165.1**	(4.3)	0%
19	Net Provisions & Other	5.0 L43	65.7	95.9	30.2	46%
20	Deferral Account Additions - Provisions & Other	5.0 L45	-	-	-	N/A
21	Regulatory Account Additions - Provisions & Other	5.0 L52	(14.0)	16.0	30.0	-215%
22	**Total Gross Provisions & Other**	5.0 L53	**51.7**	**111.9**	60.3	117%
23	**Total Gross Operating Costs and Provisions**	1.0 L2	**1,221.0**	**1,277.0**	56.0	5%

Fiscal 2019 actual gross Operating Costs and Provisions were $56.0 million or 5 per cent higher than fiscal 2019 RRA Plan. Of this amount, $30.2 million (line 19 in

Table G-4 above) was related to higher net provisions, $30.0 million (line 21 in Table G-4 above) was related to higher regulatory account additions for provisions. These amounts were partially offset by $12.2 million (line 9 in Table G-4 above) related to lower base operating costs.

Variances of $30.2 million related to net provisions and other were primarily due to:

- Higher capital asset retirements and project write-offs of $21 million primarily due to partial project costs being written off as a result of scope changes or revisiting leading alternatives on certain projects based on higher project cost estimates. This included $4.6 million related to the Ruskin Dam and Powerhouse Upgrade Project for the costs of an engineering study, which concluded that $50 million in crest block reinforcement works were not required and could be removed from the project scope. As the scope was not proceeding, the costs that were already incurred related to it were not capital in nature and needed to be written off;
- Higher litigation costs of $5.2 million related to a capital project; and
- Other variances, totalling $4.0 million.

Variances of $30.0 million related to regulatory account additions for provisions and other were primarily due to:

- An increase in the Real Property Sales Regulatory Account of $23.4 million due to surplus property sales being delayed to future years;
- An increase in the Dismantling Costs Regulatory Account of $11.3 million primarily due to higher transmission and distribution work programs and the associated removal of end of life plant and equipment; and
- Other variances, totalling $2.4 million.

Partially offset by:

- A decrease in the Environmental Provisions Regulatory Account of $7.1 million, resulting from a decrease to the Rock Bay provision of $8.8 million and a decrease in Asbestos Remediation provision of $3.1 million due to changes in project cost estimates. This was partially offset by an increase in the Polychlorinated Biphenyl provision of $4.8 million mainly due to a decrease in the discount rate (resulting in an increase in the present value of the forecast remediation expenditures).

Variances of $12.2 million related to base operating costs were primarily due to lower than planned expenditures on external services, and higher external recoveries from contributions to the maintenance of the power system for poles that are jointly-owned.

Individual variances within the Business Groups (lines 1 through 7 in Table G-4 above) include reallocation of costs related to a reorganization which had a net zero impact to BC Hydro (line 9 in Table G-4 above).

5 Capital Expenditures and Capital Additions Variance Explanations

The following tables and discussion provide information on the variances for BC Hydro's fiscal 2019 actual capital expenditures and capital additions compared to the fiscal 2019 RRA Plan. The fiscal 2019 RRA Plan filed in the Fiscal 2017 to Fiscal 2019 Revenue Requirements Application was based on a Currency Date of March 31, 2016.

On an annual basis, BC Hydro manages over 900 projects and programs in various project and program phases. 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 progression and timing, potential changes in scope to meet business requirements, and cost changes due to market conditions or other factors.

In addition, capital projects frequently take several years to complete, and any variances from plan in a particular year may be offset by project expenditures and additions in a subsequent year. While year-over-year capital project cash flows may vary from annual plan amounts, overall BC Hydro is delivering its projects on budget as reported in BC Hydro's Service Plan Budget to Actual Cost performance metric.

In general, 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 and variance explanations are provided in the sub-sections below for each main asset category.

The actual capital additions information has been presented using the same classification as the planned capital additions as presented in the tables in Chapter 6 of BC Hydro's Fiscal 2020 to Fiscal 2021 Revenue Requirements Application.

5.1 Overall Capital Expenditures and Additions Variance Explanations

Table G-5 and Table G-6 below provide BC Hydro's fiscal 2019 capital expenditures and capital additions by main asset category, including the Site C Project and the Waneta 2/3 Interest Acquisition.

Overall, the fiscal 2019 capital expenditures and capital additions were above the fiscal 2019 RRA Plan primarily due to:

- The Waneta 2/3 Interest Acquisition which was not included in BC Hydro's Fiscal 2019 RRA Plan as it was not contemplated at the time of filing; and

- An increase in Site C Project expenditures based on the revised budget of $10.7 billion, including project reserve, approved by BC Hydro's Board of Directors in February 2018.

Table G-5 Fiscal 2019 Capital Expenditures Variances

($ million)	F2019			
	RRA	Actual	Diff	% Diff
	1	2	3=2-1	4=3/1
Generation	425.0	370.3	(54.7)	-13%
Site C Project	829.2	1,116.7	287.5	35%
Waneta 2/3 Interest Acquisition	-	1,218.8	1,218.8	-
Transmission & Distribution	963.7	920.0	(43.7)	-5%
Business Support				
Technology	78.8	84.3	5.5	7%
Properties	88.3	48.4	(39.9)	-45%
Fleet/Other	39.6	58.2	18.6	47%
Total Gross	**2,424.6**	**3,816.8**	**1,392.2**	**57%**
Less: Contribution in Aid	(106.5)	(185.3)	(78.8)	74%
Total	**2,318.1**	**3,631.5**	**1,313.4**	**57%**

Table G-6 Fiscal 2019 Capital Additions Variances

($ million)	F2019			
	RRA	Actual	Diff	% Diff
	1	2	3=2-1	4=3/1
Generation	1,332.3	1,185.5	(146.8)	-11%
Site C Project	-	-	-	-
Waneta 2/3 Interest Acquisition	-	1,220.3	1,220.3	-
Transmission & Distribution	871.8	977.6	105.8	12%
Business Support				
Technology	112.6	64.1	(48.5)	-43%
Properties	25.5	33.0	7.6	30%
Fleet/Other	45.7	72.5	26.8	59%
Total Gross	**2,387.8**	**3,553.0**	**1,165.1**	**49%**
Less: Contribution in Aid	(84.6)	(135.0)	(50.4)	60%
Total	**2,303.2**	**3,418.0**	**1,114.7**	**48%**

5.2 Generation Capital Expenditures and Additions Variance Explanations

Generation capital expenditures and capital additions in fiscal 2019 are presented in Table G-7 and Table G-8 below. Results exclude amounts for the Site C Project and the Waneta 2/3 Interest Acquisition, which are presented separately in sections 5.6 and 5.7 below.

Table G-7 Fiscal 2019 Generation Capital Expenditures Variances (excluding Site C Project and Waneta 2/3 Interest Acquisition)

($ million)	F2019			
	RRA	**Actual**	**Diff**	**% Diff**
	1	2	3=2-1	4=3/1
Hydroelectric Generation				
Growth	0.7	5.6	4.9	693%
Redevelopment / Rehabilitation	121.9	104.5	(17.4)	-14%
Dam Safety	124.3	35.6	(88.7)	-71%
Sustaining - Other	238.6	217.9	(20.7)	-9%
Total Hydroelectric Generation	485.5	363.6	(122.0)	-25%
Total Non-Integrated Areas	6.6	1.3	(5.3)	-80%
Total Thermal Generation	6.8	5.5	(1.4)	-20%
Less: Portfolio Risk Adjustment	(74.0)	-	74.0	-
Total Gross	**425.0**	**370.3**	**(54.7)**	**-13%**
Less: Contribution in Aid	-	(0.4)	(0.4)	-
Total	**425.0**	**369.9**	**(55.1)**	**-13%**

Table G-8 Fiscal 2019 Generation Capital Additions Variances (excluding Site C Project and Waneta 2/3 Acquisition)

($ million)	F2019			
	RRA	**Actual**	**Diff**	**% Diff**
	1	2	3=2-1	4=3/1
Hydroelectric Generation				
Growth	0.2	(0.3)	(0.5)	-250%
Redevelopment / Rehabilitation	955.5	951.8	(3.7)	0%
Dam Safety	87.5	52.5	(35.0)	-40%
Sustaining - Other	268.1	153.6	(114.5)	-43%
Total Hydroelectric Generation	1,311.3	1,157.6	(153.7)	-12%
Total Non-Integrated Areas	4.2	11.1	6.9	164%
Total Thermal Generation	16.8	16.8	-	-
Less: Portfolio Risk Adjustment	-	-	-	-
Total Gross	**1,332.3**	**1,185.5**	**(146.8)**	**-11%**
Less: Contribution in Aid	-	(0.4)	(0.4)	-
Total	**1,332.3**	**1,185.1**	**(147.2)**	**-11%**

Growth Capital

In general, when excluding the Site C Project and the Waneta 2/3 Interest Acquisition, planned capital expenditures and additions for Generation Growth Capital are a small component of the annual capital plan. The majority of the capital investments in the Generation portfolio are driven by the need to address issues and risks associated with existing facilities.

Fiscal 2019 capital expenditures were $4.9 million or 693 per cent above the fiscal 2019 RRA Plan. This was primarily because:

- The Mica Unit 5 and Unit 6 Project was $2.8 million above plan due to remaining work being delayed from fiscal 2018 to fiscal 2019; and
- The Revelstoke Unit 6 Installation Project was $2 million above plan due to spending related to the Environmental Assessment Certificate and additional Water Licence being delayed to fiscal 2019 because the Environmental

Assessment Office and Comptroller of Water Rights required additional time to review the applications.

Fiscal 2019 capital additions were comparable to the fiscal 2019 RRA Plan.

Redevelopment/ Rehabilitation

Fiscal 2019 capital expenditures were $17.4 million or 14 per cent below the fiscal 2019 RRA Plan. This was primarily because:

- The John Hart Generating Station Replacement project was $53.3 million below plan due to more work than planned being completed in fiscal 2017 and fiscal 2018;
- The Ruskin Dam and Powerhouse Upgrade project was $21.5 million above plan due to contractor delays related to construction work on the generating units which had been planned to occur in previous fiscal years and trailing work; and
- The remaining variance of $14.4 million is due to smaller variances on various projects.

Fiscal 2019 capital additions were comparable to the fiscal 2019 RRA Plan.

Dam Safety

Fiscal 2019 capital expenditures were $88.7 million or 71 per cent below the fiscal 2019 RRA Plan. This was primarily because:

- The WAC Bennett Dam Rip Rap Upgrade project was $31.6 million below plan because the project was under budget and put in-service ahead of schedule;
- The Ladore Spillway Seismic Upgrade project was $7.4 million below plan because the project schedule was revised and construction has moved into future years;

- The Peace Canyon Flood Discharge Gates Reliability Improvement project was $7.5 million below plan because the project was cancelled due to escalating costs and declining expected benefits. It was determined that the work originally planned in the project could be deferred and incorporated into upcoming gates and seismic upgrade projects at Peace Canyon without retaining an unreasonable level of risk in the interim;
- The Puntledge Flow Control Improvement project was $7.3 million below plan due to more time being required to complete design work for telecommunications, various control system components and Constructability Reviews;
- The GM Shrum Seal Low Level Outlets project was $5.3 million below plan because the fiscal 2019 RRA Plan amount was based on preliminary planning information prior to specific scope finalization. The scope has since been revised; and
- Alouette Improve Headworks and Surge Tower Seismic Stability project was $4.4 million below plan as the field investigations (to inform the Feasibility Design) at the Alouette Surge Tower and the Power Tunnel were delayed, resulting in delayed completion of the Identification-Feasibility Design Stage and Definition and Implementation Phases.

The remaining variance of $25.2 million is due to smaller variances on various projects.

Fiscal 2019 capital additions were $35 million or 40 per cent below the fiscal 2019 RRA Plan. This was primarily because:

- The WAC Bennett Dam Rip Rap Upgrade project was $8.9 million below plan because the project was partially placed into service ahead of schedule;

- The Peace Canyon Flood Discharge Gates Reliability Improvement project was $13 million below plan because the project was cancelled (as discussed in the preceding section); and
- The Revelstoke Improve Left Bank Slope Stability project was $5.9 million below plan due to rescheduling of construction. The majority of the re-scheduled construction work is now planned for fiscal 2021.

Sustaining – Other

Fiscal 2019 capital expenditures were comparable with the fiscal 2019 RRA Plan.

Fiscal 2019 capital additions were $114.5 million or 43 per cent below the fiscal 2019 RRA Plan. This was primarily because:

- The Puntledge Recoat Penstock project was $23 million below plan because an extended procurement process delayed the start of the Implementation Phase;
- The Kootenay Canal Upgrade Powerhouse Crane project was $15.3 million below plan because the fiscal 2019 RRA Plan amount was based on fiscal 2016 preliminary planning allowances and schedule. The scope has since been revised and the updated In-Service date is fiscal 2020;
- The Bridge River 2, Unit 5 and 6 Upgrade project was $25.9 million below plan because the installation of Unit 6 was delayed to fiscal 2020 and due to labour cost savings on the balance of plant work;
- The Cheakamus Unit 1 and 2 Generator Replacement project was $34.2 million below plan because the capital addition for the first unit was reported after the fiscal 2019 year end was completed; and
- The Mica 600 v Circuit Breaker Upgrades project was $9.4 million below plan because the scope was revised to include the replacement and re-location of the existing 600 v diesel generators and diesel fuel storage tanks as well as the

upgrade of the 600 v essential bus to accommodate additional loads. This change in scope delayed the start of the Implementation Phase.

Non-Integrated Areas and Diesel and Thermal Generation

Fiscal 2019 capital expenditures and additions for Non-Integrated Areas and Diesel and Thermal Generation were comparable to the fiscal 2019 RRA Plan.

Portfolio Risk Adjustment

The fiscal 2019 RRA Plan Portfolio Risk Adjustment amount was $(74.0) million. The Portfolio Risk Adjustment is meant to account for the uncertainty in the schedule and cost of projects. The Portfolio Risk Adjustment amount is calculated using a Monte Carlo simulation. A probability distribution is determined, based on historical project delivery performance information. The calculated Portfolio Risk Adjustment amount represents the difference (by fiscal year) between the expected value of the simulated portfolio forecast and the sum of individual project forecasts in the baseline Capital Plan.

5.3 Transmission Capital Expenditures and Additions Variance Explanations

Transmission fiscal 2019 capital expenditures and capital additions are provided in Table G-9 and Table G-10, below.

Table G-9 Fiscal 2019 Transmission Capital Expenditures Variances

($ million)	F2019			
	RRA	**Actual**	**Diff**	**% Diff**
	1	2	3=2-1	4=3/1
Transmission Growth				
Regional System Reinforcement	66.4	176.4	110.0	166%
Bulk System Reinforcement	24.4	(0.6)	(25.0)	-103%
Station Expansion & Modification	59.2	22.3	(36.9)	-62%
Feeder Positions / Section Additions	-	1.7	1.7	-
Generator Interconnections	15.1	10.7	(4.3)	-29%
Transmission Load Interconnection	27.7	13.8	(13.9)	-50%
Total Growth	192.7	224.3	31.6	16%
Transmission Sustain - Stations				
Circuit Breakers	12.8	29.6	16.8	132%
Other Power Equipment	143.3	28.4	(114.8)	-80%
Protection and Control	21.7	16.7	(5.0)	-23%
Stations Auxiliary Equipment	22.8	20.8	(2.0)	-9%
Stations Risk Mitigation	8.7	4.1	(4.6)	-53%
Telecommunications	12.4	13.5	1.1	9%
Total Sustain - Stations	221.6	113.1	(108.5)	-49%
Transmission Sustain - Lines				
Cable Sustainment	21.5	2.4	(19.1)	-89%
O/H Lines Life Extension	89.9	45.1	(44.8)	-50%
O/H Lines Performance Improvement	4.3	2.0	(2.3)	-52%
O/H Lines Risk Mitigation	20.9	12.6	(8.3)	-40%
ROW Sustainment	10.5	10.8	0.3	3%
Third Party Requested Transmission Line Relocations	5.2	6.9	1.7	33%
Total Sustain - Lines	152.3	79.9	(72.4)	-48%
Total Gross	**566.6**	**417.3**	**(149.3)**	**-26%**
Less: Contribution in Aid	(26.2)	(15.8)	10.4	-40%
Total	**540.5**	**401.5**	**(138.9)**	**-26%**

Table G-10 Fiscal 2019 Transmission Capital Additions Variances

($ million)	F2019			
	RRA	**Actual**	**Diff**	**% Diff**
	1	2	3=2-1	4=3/1
Transmission Growth				
Regional System Reinforcement	129.7	122.6	(7.1)	-5%
Bulk System Reinforcement	0.8	121.0	120.2	15025%
Station Expansion & Modification	74.2	86.8	12.6	17%
Feeder Positions / Section Additions	1.2	2.4	1.2	100%
Generator Interconnections	-	1.1	1.1	-
Transmission Load Interconnection	7.9	10.1	2.2	28%
Total Growth	213.8	344.0	130.2	61%
Transmission Sustain - Stations				
Circuit Breakers	13.5	47.4	33.9	251%
Other Power Equipment	58.6	24.1	(34.5)	-59%
Protection and Control	21.8	6.0	(15.8)	-72%
Stations Auxiliary Equipment	22.6	14.5	(8.1)	-36%
Stations Risk Mitigation	8.6	0.3	(8.3)	-97%
Telecommunications	12.5	2.2	(10.3)	-82%
Total Sustain - Stations	137.6	94.5	(43.1)	-31%
Transmission Sustain - Lines				
Cable Sustainment	8.6	-	(8.6)	-100%
O/H Lines Life Extension	52.4	51.1	(1.3)	-2%
O/H Lines Performance Improvement	4.2	4.8	0.6	14%
O/H Lines Risk Mitigation	19.8	9.8	(10.0)	-51%
ROW Sustainment	10.5	16.2	5.7	54%
Third Party Requested Transmission Line Relocations	11.9	8.8	(3.1)	-26%
Total Sustain - Lines	107.4	90.7	(16.7)	-16%
Total Gross	**458.8**	**529.2**	**70.4**	**15%**
Less: Contribution in Aid	(4.4)	(10.6)	(6.2)	141%
Total	**454.4**	**518.6**	**64.2**	**14%**

Transmission Growth - Regional System Reinforcement

Fiscal 2019 capital expenditures were $110 million or 166 per cent above the fiscal 2019 RRA Plan primarily due to a property purchase that was planned in fiscal 2017 but completed in fiscal 2019 and due to the advancement of definition phase activities related to the Peace Region Electrical Supply project from later years into fiscal 2019.

Fiscal 2019 capital additions were comparable with the fiscal 2019 RRA Plan.

Bulk System Reinforcement

Fiscal 2019 capital expenditures were $25 million or 103 per cent below the fiscal 2019 RRA Plan primarily due to a significant change in the scope of work required to interconnect LNG Canada's phase 1 project which resulted in the cancellation of the Northwest Substation Upgrade Project and the introduction of a new interconnection project, (the MIN to LNG Canada Interconnection project) with a reduced scope of work.

Fiscal 2019 capital additions were $120.2 million or 15,025 per cent above the fiscal 2019 RRA Plan. This was primarily because:

- The Interior to Lower Mainland Transmission project was $96.7 million above plan due to an arbitrator decision on a contractor claim; and
- The Peace Region Load Shedding Remedial Action Scheme project was $25.7 million above plan because the project was put into service in fiscal 2018 but the capital expenditures were not recognized as capital additions until fiscal 2019.

Station Expansion & Modification

Fiscal 2019 capital expenditures were $36.9 million or 62 per cent below the fiscal 2019 RRA Plan. This was primarily because:

- The Mount Lehman Substation Upgrade project was $13.3 million below plan because the Identification and Definition phases were extended to study potential design alternatives due to the discovery of two species listed under the *Federal Species at Risk Act* in the planned expansion area. This discovery required additional design and field work to confirm the current plan to expand on the West side of the facility which eliminated the impact to these species;

- The Capilano Substation 25kv Conversion project was $8.7 million below plan because the Identification and Definition phases were extended to address required engineering and geotechnical studies; and
- The Westbank Substation Upgrade project was $12.5 million below plan because the Identification phase was deferred pending confirmation of the project scope.

Fiscal 2019 capital additions were $12.6 million or 17 per cent above the fiscal 2019 RRA Plan. This was primarily because:

- The Arnott Capacity Upgrade project was $4.5 million above plan because some of the construction work was delayed until fiscal 2019 due to outage constraints;
- The Campbell River Substation Capacity Upgrade project was $26 million above plan due to additional planning and construction time required to address seismic risks which delayed the project's In-Service date; and
- The Westbank Substation Upgrade project was $23 million below plan (as discussed further in the preceding section).

Transmission Load Interconnection

Fiscal 2019 capital expenditures were $13.9 million or 50 per cent below the fiscal 2019 RRA Plan. These capital expenditures are third-party driven and, as a result, the timing and scope of these projects is highly uncertain. Variances from plan are due to changes in scope and timing of planned projects as well as the addition of new projects.

Fiscal 2019 additions were comparable to the fiscal 2019 RRA Plan.

Transmission Sustain-Stations - Circuit Breakers

Fiscal 2019 capital expenditures were $16.8 million or 132 per cent above the fiscal 2019 RRA Plan primarily due to the advancement of the 60 kV Circuit Breaker Replacement and 138kV Circuit Breaker Replacement programs to manage system risks.

Fiscal 2019 capital additions were $33.9 million or 251 per cent above the fiscal 2019 RRA Plan primarily due to the addition of the Barnard 60 kV Circuit Breaker Relay Building Replacement project and advancement of the 60 kV Circuit Breaker Replacement and 138 kV Circuit Breaker Replacement programs to manage system risks.

Other Power Equipment

Fiscal 2019 capital expenditures were $114.8 million or 80 per cent below the fiscal 2019 RRA Plan. This was primarily because:

- The Esquimalt Feeder Section Replacement project was $9.5 million below plan because it was deferred until fiscal 2021 to be managed within the Substation 12/25 kV Circuit Breaker Replacement program;
- The CAP14UPG Capacitor Protection Control Underground project was $7.8 million below plan because of a reduction to the scope of the project and delays due to resource constraints and design complexity;
- The Mainwaring Station Upgrade project was $40.6 million below plan because the start of the Definition phase was delayed to re-evaluate project alternatives;
- The Newell Substation Upgrade project was $16.3 million below plan because the project was temporarily put on hold while the substation plan was re-evaluated due to updates to the load forecast for the distribution area served by the station;

- The Horsey Outdoor 12 kV Feeder Section Replacement project was $7.0 million below plan because the project was deferred until fiscal 2021 to be managed within the Substation Feeder Section Upgrade program; and
- The Barnard 50/60 Feeder Section Replacement project was $7.8 million below plan because the project was delayed until fiscal 2020 due to prioritization against other planned work at the Barnard Substation, based on a detailed asset study.

The remaining variance of $25.8 million is due to smaller variances on various projects.

Fiscal 2019 capital additions were $34.5 million or 59 per cent below the fiscal 2019 RRA Plan. This was primarily because:

- The CAP14UPG Capacitor Protection Control Underground project was $7.1 million below plan due to delays related to resource constraints and design complexity. The revised target In-Service date is fiscal 2022; and
- The Horsey Outdoor 12 kV Feeder Section Replacement project was $6.2 million below plan because the project was deferred until fiscal 2021 to be managed within the Substation Feeder Section Upgrade program.

The remaining variance of $21.2 million is due to smaller variances on various projects.

Protection and Control

Fiscal 2019 capital expenditures were comparable with the fiscal 2019 RRA Plan.

Fiscal 2019 capital additions were $15.8 million or 72 per cent below the fiscal 2019 RRA Plan primarily due to schedule changes related to the NERC CIPv5 Compliance at Medium Impact T&D Stations project. The original schedule was based on planning assumptions developed in June 2015 which assumed that the project would be completed and put in-service on a partial basis in fiscal 2017 and fiscal 2018 and completed prior to fiscal 2019. Under the updated schedule, the project will be put in-service at full completion, which is expected in fiscal 2023.

Telecommunications

Fiscal 2019 capital expenditures were comparable with the fiscal 2019 RRA Plan.

Fiscal 2019 capital additions were $10.3 million or 82 per cent below the fiscal 2019 RRA Plan primarily due to schedule delays associated with the Vancouver Radio System project due to revisions to the system architecture and cutover strategy in response to issues with new standardized equipment.

Transmission Sustain-Lines - Cable sustainment

Fiscal 2019 capital expenditures were $19.1 million or 89 per cent below the fiscal 2019 RRA Plan primarily due to the suspension of construction work on the South Fraser Transmission Relocation Project, pending a government decision on the George Massey Tunnel replacement.

Fiscal 2019 additions were comparable to the fiscal 2019 RRA Plan.

O/H Lines Life Extension

Fiscal 2019 capital expenditures were $44.8 million or 50 per cent below the fiscal 2019 RRA Plan. This was primarily because:

- The Terrace to Kitimat Transmission project was $30.7 million below plan because the leading alternative to construct a new line was revised to a refurbishment of the existing line in response to updates to the load forecast, increases in the total project cost for a new line and updated asset health information for the existing line; and

- The 5L63 Telkwa Relocation project was $8.2 million below plan because BC Hydro decided to complete a project investment value study prior to the proceeding to Feasibility Design phase. While the investment value study was ongoing, BC Hydro only proceeded with critical summer/fall 2018 field work. The project moved into Feasibility Design phase in April 2019.

Fiscal 2019 additions were comparable to the fiscal 2019 RRA Plan.

O/H Lines Risk Mitigation

Fiscal 2019 capital expenditures were comparable with the fiscal 2019 RRA Plan.

Fiscal 2019 capital additions were $10 million or 51 per cent below the fiscal 2019 RRA Plan primarily due to the deferral of the Pitt River Crossing Tower Refurbishment project as a result of prioritization against other planned capital work.

5.4 Distribution Capital Expenditures and Additions Variance Explanations

Distribution fiscal 2019 actual to fiscal 2019 RRA Plan capital expenditures and capital additions are provided in Table G-11 and Table G-12, below.

Table G-11 Fiscal 2019 Distribution Capital Expenditures Variances

($ million)	F2019			
	RRA	**Actual**	**Diff**	**% Diff**
	1	2	3=2-1	4=3/1
Distribution Growth				
Customer Driven	164.6	232.4	67.8	41%
System Expansion and Improvement	44.4	63.2	18.8	42%
Uneconomic Extension Assistance	0.5	0.4	(0.1)	-13%
Total Growth	209.5	296.0	86.5	41%
Distributon Sustain				
System Expansion and Improvement	55.1	64.3	9.2	17%
Asset Replacement				
Poles	74.0	74.8	0.9	1%
Overhead Equipment	15.8	11.5	(4.3)	-27%
Underground Equipment	30.3	28.7	(1.6)	-5%
Trouble	11.0	24.0	13.0	118%
Asset Replacement sub-total	131.0	139.0	8.0	6%
Beautification	1.5	3.3	1.8	122%
Total Sustain	187.6	206.7	19.1	10%
Total Gross	**397.1**	**502.7**	**105.6**	**27%**
Less: Contribution in Aid	(80.3)	(169.0)	(88.7)	111%
Total	**316.8**	**333.6**	**16.8**	**5%**

Table G-12 Fiscal 2019 Distribution Capital Additions Variances

($ million)	F2019			
	RRA	Actual	Diff	% Diff
	1	2	3=2-1	4=3/1
Distribution Growth				
Customer Driven	164.5	190.0	25.5	15%
System Expansion and Improvement	64.0	49.3	(14.8)	-23%
Uneconomic Extension Assistance	0.5	0.3	(0.2)	-40%
Total Growth	229.0	239.5	10.5	5%
Distributon Sustain				
System Expansion and Improvement	51.9	81.6	29.7	57%
Asset Replacement				
Poles	74.6	53.1	(21.5)	-29%
Overhead Equipment	14.9	12.2	(2.7)	-18%
Underground Equipment	30.1	33.2	3.1	10%
Trouble	10.9	27.9	17.0	156%
Asset Replacement sub-total	130.6	126.4	(4.2)	-3%
Beautification	1.5	0.9	(0.6)	-40%
Total Sustain	184.0	208.9	24.9	14%
Total Gross	**413.0**	**448.4**	**35.4**	**9%**
Less: Contribution in Aid	(80.2)	(123.9)	(43.7)	54%
Total	**332.8**	**324.5**	**(8.3)**	**-3%**

Distribution Growth – Customer Driven

Fiscal 2019 capital expenditures were $67.8 million or 41 per cent above the fiscal 2019 RRA Plan due to an increase in distribution customer connection requests as a result of increased economic activity including housing starts and multi-year provincial infrastructure investments. This work is difficult to plan as it is dependent on customer requests and their related timing.

Fiscal 2019 capital additions were $25.5 million or 15 per cent above the fiscal 2019 RRA Plan primarily due to the increase in capital expenditures discussed above.

Distribution Growth - System Expansion and Improvement

Fiscal 2019 capital expenditures were $18.8 million or 42 per cent above the fiscal 2019 RRA Plan. Growth-driven system expansion and improvement expenditures address existing capacity constraints to meet the anticipated customer load growth.

The priority of growth-driven system upgrades is influenced by new customer load connections and general load growth of existing customers. This category of expenditures is subject to year over year fluctuations from plan as a result of changes in scope, cost and schedule for projects as well as variances between forecast and actual customer load growth. The variance is made up of unplanned projects under $5 million.

Fiscal 2019 capital additions were $14.8 million or 23 per cent below the fiscal 2019 RRA Plan primarily due to the delayed in-service date for the Horne Payne 12F54 Voltage Conversion which was primarily due to delays in getting access to separate customer vaults fed by the existing 12 kV circuit.

Distribution Sustain - System Expansion and Improvement

Fiscal 2019 capital expenditures were comparable with the fiscal 2019 RRA Plan.

Fiscal 2019 capital additions were $29.7 million or 57 per cent above fiscal 2019 RRA Plan primarily due to higher than planned expenditures in the minor capital program to address system performance deficiencies and opportunity based improvements.

Distribution Sustain - Asset Replacement

Fiscal 2019 capital expenditures were comparable to the fiscal 2019 RRA Plan.

Fiscal 2019 capital additions were comparable to the fiscal 2019 RRA Plan.

Contribution in Aid

Fiscal 2019 contribution in aid related to capital expenditures was $88.7 million or 111 per cent above the fiscal 2019 RRA Plan primarily due to the higher than planned expenditures for Distribution Customer Driven work, which is dependent on customer requests, as well as Contribution in Aid for several large major distribution projects being received in advance of project commencement.

Fiscal 2019 capital additions were $43.7 million or 54 per cent above the fiscal 2019 RRA Plan due to higher than planned volume for Distribution Customer Driven work.

5.5 Business Support Capital Expenditures and Additions Variance Explanations

Business Support includes capital expenditures and additions for Technology, Properties and Fleet / Other categories. Business Support fiscal 2019 capital expenditures and capital additions are presented by category in the tables below.

Table G-13 Fiscal 2019 Business Support Capital Expenditures Variances

($ million)	F2019			
	RRA	**Actual**	**Diff**	**% Diff**
	1	2	3=2-1	4=3/1
Business Support				
Technology	78.8	84.3	5.5	7%
Properties	88.3	48.4	(39.9)	-45%
Fleet/Other	39.6	58.2	18.6	47%
Total	**206.7**	**191.0**	(15.7)	-8%

Table G-14 Fiscal 2019 Business Support Capital Additions Variances

($ million)	F2019			
	RRA	Actual	Diff	% Diff
	1	2	3=2-1	4=3/1
Business Support				
Technology	112.6	64.1	(48.5)	-43%
Properties	25.5	33.0	7.6	30%
Fleet/Other	45.7	72.5	26.8	59%
Total	**183.8**	**169.6**	(14.2)	-8%

Technology Fiscal 2019 Capital Expenditures and Additions Variances

Table G-15 Fiscal 2019 Technology Capital Expenditures Variances

($ million)	F2019			
	RRA	Actual	Diff	% Diff
	1	2	3=2-1	4=3/1
Technology	76.2	83.6	7.4	10%
Other Technology	2.6	0.8	(1.8)	-71%
Total	**78.8**	**84.3**	5.5	7%

Table G-16 Fiscal 2019 Technology Capital Additions Variances

($ million)	F2019			
	RRA	Actual	Diff	% Diff
	1	2	3=2-1	4=3/1
Technology	110.0	61.5	(48.5)	-44%
Other Technology	2.6	2.6	-	0%
Total	**112.6**	**64.1**	(48.5)	-43%

Fiscal 2019 capital expenditures were comparable with the fiscal 2019 RRA Plan.

Fiscal 2019 capital additions were $48.5 million or 44 per cent below the fiscal 2019 RRA Plan. This was primarily because:

- The Supply Chain Applications project was $71 million below plan primarily due to the In-Service date being updated to fiscal 2020;

- The transfer of the Telecommunications, Protection and Control Department to the Integrated Planning Business Group which resulted in fiscal 2019 actual additions that were $10.7 million below plan within Technology, but resulted in an overage in fiscal 2019 in Fleet/Other capital additions as described below; and
- Schedule changes for a number of business-driven projects resulted in fiscal 2019 actual additions that were $7.0 million below plan.

The reductions to capital additions outlined above were partially offset by emergent needs, delayed in-service dates, higher than expected storage costs, and other actual additions that were above plan amounts, totalling $40.2 million.

Properties Fiscal 2019 Capital Expenditures and Additions Variances

Table G-17 Fiscal 2019 Properties Capital Expenditures Variances

($ million)	F2019			
	RRA	Actual	Diff	% Diff
	1	2	3=2-1	4=3/1
Building Development	69.5	14.7	(54.8)	-79%
Building Improvements and Others	18.8	30.4	11.6	62%
Other Properties	-	3.3	3.3	
Total	**88.3**	**48.4**	**(39.9)**	-45%

Table G-18 Fiscal 2019 Properties Capital Additions Variances

($ million)	F2019			
	RRA	Actual	Diff	% Diff
	1	2	3=2-1	4=3/1
Building Development	6.7	5.9	(0.8)	-12%
Building Improvements and Others	18.8	27.1	8.4	45%
Other Properties	-	-	-	-
Total	**25.5**	**33.0**	7.6	30%

Fiscal 2019 capital expenditures were $39.9 million or 45 per cent below the fiscal 2019 RRA Plan. This was primarily because:

- The Construction Services/Lower Mainland Transmission Building was deferred to fiscal 2025;
- The Dawson Creek Building was deferred to fiscal 2025;
- The Material Classification Facility Building Redevelopment was temporarily deferred during the test period which has delayed the project schedule and related spend in each year of the test period;
- The Chilliwack Facility was delayed due to difficulties in securing suitable land for the new office; and
- The Fleet Services Facility Project was deferred to fiscal 2025.

Fiscal 2019 capital additions were comparable with the fiscal 2019 RRA Plan.

Fleet/Other Fiscal 2019 Capital Expenditures and Additions Variances

Table G-19 Fiscal 2019 Fleet/Other Capital Expenditures Variances

($ million)	F2019			
	RRA	**Actual**	**Diff**	**% Diff**
	1	2	3=2-1	4=3/1
Fleet	29.6	35.9	6.3	21%
Other	10.0	22.4	12.4	124%
Total	**39.6**	**58.2**	**18.6**	**47%**

Table G-20 Fiscal 2019 Fleet/Other Capital Additions Variances

($ million)	F2019			
	RRA	**Actual**	**Diff**	**% Diff**
	1	2	3=2-1	4=3/1
Fleet	30.2	35.7	5.5	18%
Other	15.5	36.8	21.3	137%
Total	**45.7**	**72.5**	**26.8**	**59%**

Fleet 2019 capital expenditures and additions were comparable with the fiscal 2019 RRA Plan.

Fiscal 2019 capital expenditures for ‘Other’ were $12.4 million or 124 per cent above the fiscal 2019 RRA Plan primarily due to unplanned work related to the Smart Metering Infrastructure Field Area sustainment project. In addition, there was an unplanned project to replace storage racks at 24 locations to comply with new WorkSafeBC regulations.

Fiscal 2019 capital additions for ‘Other’ were $21.3 million or 137 per cent above the fiscal 2019 RRA Plan primarily due to the unplanned work described in the preceding paragraph and communication equipment planned as part of transmission projects but are classified as general assets for accounting purposes, instead of Technology assets where the additions were planned.

5.6 Site C Project Capital Expenditures and Additions Variance Explanations

Site C Project fiscal 2019 capital expenditures and capital additions are presented in the tables below.

Table G-21 Fiscal 2019 Site C Project Capital Expenditures Variances

($ million)	F2019			
	RRA	Actual	Diff	% Diff
	1	2	3=2-1	4=3/1
Total Site C	**829.2**	**1,116.7**	**287.5**	**35%**

In December 2014, the project was approved for the total Expected Amount of $8.3 billion. On February 9, 2018 BC Hydro’s Board of Directors approved a revised budget of $10.7 billion, including project reserve.

Fiscal 2019 capital expenditures were $287.5 million or 35 per cent above the fiscal 2019 RRA Plan, established prior to the revision of the project’s budget, primarily due to:

- Main civil works expenditures for unplanned investment in equipment, settlement of claims and incentive payments;
- The transmission line contract being awarded for higher than the planned amount;
- Higher than planned south bank substation costs for major equipment and electric materials;
- Additional infrastructure costs related to the stilling basin;
- Higher than planned construction management and engineering costs due to an increase in required resources and a higher reliance on contractors; and
- Reservoir clearing work incurred in fiscal 2019 that was planned in prior fiscal years.

The increases described above were partially offset by highways work and property purchases being shifted to future fiscal years.

Table G-22 Fiscal 2019 Site C Project Capital Additions Variances

($ million)	F2019			
	RRA	Actual	Diff	% Diff
	1	2	3=2-1	4=3/1
Total Site C	-	-	-	-

There were no planned or actual capital additions for fiscal 2019.

5.7 Waneta 2/3 Interest Acquisition Capital Expenditures and Additions Variance Explanations

Table G-23 Fiscal 2019 Waneta 2/3 Interest Acquisition Capital Expenditures Variances

($ million)	F2019			
	RRA	Actual	Diff	% Diff
	1	2	3=2-1	4=3/1
Waneta 2/3 Interest Acquisition	**-**	**1,218.8**	**1,218.8**	**-**

Table G-24 Fiscal 2019 Waneta 2/3 Interest Acquisition Capital Additions Variances

($ million)	F2019			
	RRA	Actual	Diff	% Diff
	1	2	3=2-1	4=3/1
Waneta 2/3 Interest Acquisition	**-**	**1,220.3**	**1,220.3**	**-**

BC Hydro purchased Teck Resources Ltd.'s two-third interest in the Waneta Dam and Generating Facility in July 2018. This purchase was not included in the fiscal 2019 RRA Plan as it was not contemplated at the time of filing. This acquisition was reviewed by the BCUC and by Order No. G-130-18, the BCUC approved the acquisition on July 18, 2018.