Fred James
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July 31, 2019

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

Dear Mr. Wruck:

RE: British Columbia Utilities Commission (BCUC or Commission)
British Columbia Hydro and Power Authority (BC Hydro)
Fiscal 2019 Annual Report to the Commission

BC Hydro writes pursuant to BCUC Letter Nos. L-36-94 and L-14-95, and subsection 45(6) of the *Utilities Commission Act* to provide BC Hydro's Fiscal 2019 Annual Report to the BCUC for the period April 1, 2018 to March 31, 2019.

BC Hydro's Fiscal 2019 Annual Report to the BCUC includes the following information:

- Important Changes During the Year for the year ended March 31, 2019;
- Detailed financial schedules and variance explanations for the year ended March 31, 2019;
- A summary of planned capital extension projects and anticipated regulatory filings;
- A list of internal audit report topics for the year ended March 31, 2019;
- The Waneta Transaction report for the year ended March 31, 2019 in compliance with BCUC Order No. G-130-18;
- A summary report on volumes and pricing of transmission capacity reassignments and simultaneous window submissions for the year ended March 31, 2019 in compliance with BCUC Order No. G-102-09;
- Appendix A – Annual Deferral Accounts Report: In compliance with BCUC Order No. G-96-04 Directive 8, items 17 and 19, and Order No. G-140-17; and
- Appendix B – Debt Management Regulatory Account Annual Status Report: In compliance with BCUC Order No. G-42-16.

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

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Enclosure

BC Hydro
Power smart

BC Hydro Fiscal 2019 Annual Report to the British Columbia Utilities Commission

April 1, 2018 to March 31, 2019

BC Hydro
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List of Appendices

1 Declaration

I, David Wong, of 333 Dunsmuir Street, Vancouver, B.C., do hereby certify:

1. That I am the Executive Vice-President, Finance, Technology, Supply Chain & Chief Financial Officer of BC Hydro located at 333 Dunsmuir Street, Vancouver, B.C.
2. That I have examined the content of this report and the information set out herein is complete and accurate, to the best of my knowledge, information and belief. I have read and understand Section 106 and 109.1 to 109.8 of the *Utilities Commission Act*.

I also confirm BC Hydro's compliance with the Commission's financial directives with regard to the following attachments:

- Section 10.1: Waneta Transaction Annual Report as required by Commission Order No. G-130-18, Directive 4 (e);
- Section 10.2: Summary Report on Volume and Pricing of Transmission Capacity Reassignments and Simultaneous Submission Window as required by Commission Order No. G-102-09;
- Appendix A: Annual Deferral Accounts Report[1] as required by Commission Order No. G-96-04 Directive 8, items 17 and 19; and
- Appendix B: Debt Management Regulatory Account Annual Status Report as required by Commission Order No. G-42-16.

[1] BC Hydro received a Variance to Order G-112-14 on September 14, 2017 requiring BC Hydro to file the Deferral Accounts Report on an annual basis and include it with the BC Hydro Annual Report to the British Columbia Utilities Commission within four months following the end of the fiscal year.

Per:

David Wong

Executive Vice-President, Finance, Technology, Supply Chain & Chief Financial Officer,

British Columbia Hydro and Power Authority

July 31, 2019

2 Directors and Officers

Report below the name, title and business address of each director and officer, as at March 31, 2019.

Name	Business Address	Office Held
Board of Directors		
Ken Peterson	333 Dunsmuir St Vancouver, BC V6B 5R3	Executive Chair
Lenard F. Boggio	333 Dunsmuir St Vancouver, BC V6B 5R3	Director
Daryl Fields[1]	333 Dunsmuir St Vancouver, BC V6B 5R3	Director
Bob Gallagher	333 Dunsmuir St Vancouver, BC V6B 5R3	Director
James Hatton	333 Dunsmuir St Vancouver, BC V6B 5R3	Director
Irene Lanzinger[1]	333 Dunsmuir St Vancouver, BC V6B 5R3	Director
Valerie Lambert	333 Dunsmuir St Vancouver, BC V6B 5R3	Director
John Nunn	333 Dunsmuir St Vancouver, BC V6B 5R3	Director
Catherine Roome[1]	333 Dunsmuir St Vancouver, BC V6B 5R3	Director
Chris Sanderson	333 Dunsmuir St Vancouver, BC V6B 5R3	Director

1 Daryl Fields, Irene Lanzinger and Catherine Roome were appointed Directors on December 10, 2018.

Name	Business Address	Office Held
Officer (Executive Team)		
Chris O'Riley	333 Dunsmuir St Vancouver, BC V6B 5R3	President and Chief Operating Officer
Janet Fraser	333 Dunsmuir St Vancouver, BC V6B 5R3	Executive Vice-President, People, Customer, Corporate Affairs
Maureen Daschuk	333 Dunsmuir St Vancouver, BC V6B 5R3	Senior Vice-President, Integrated Planning
David Lebeter	333 Dunsmuir St Vancouver, BC V6B 5R3	Senior Vice-President, Safety
Al Leonard	333 Dunsmuir St Vancouver, BC V6B 5R3	Senior Vice-President, Capital Infrastructure Project Delivery
Mark Poweska[2]	333 Dunsmuir St Vancouver, BC V6B 5R3	Executive Vice-President, Operations
Ken McKenzie	333 Dunsmuir St Vancouver, BC V6B 5R3	Executive Vice-President, Site C
David Wong[3]	333 Dunsmuir St Vancouver, BC V6B 5R3	Executive Vice-President, Finance, Technology, Supply Chain & Chief Financial Officer

2 Mark Poweska resigned from his position on April 27, 2019. Matt Wilson is currently the acting Executive Vice-President of Operations.

3 David Wong was appointed as Executive Vice-President, Finance, Technology, Supply Chain & Chief Financial Officer on August 3, 2018.

3 Control Over Utility

If any corporation, business trust, or similar organization or combination of such organizations jointly held control over the utility at end of year, state name of controlling corporation or organization, manner in which control was held and extent of control. If control was in a holding company organization, show the chain of ownership or control to the main parent company or organization. If control was held by a trustee(s), state name of trustee(s), name of beneficiary or beneficiaries for whom trust was maintained, and purpose of the trust.

Government of B.C., sole Shareholder.

4 Corporations Controlled by BC Hydro

1. Report below the names of all corporations, business trusts and similar organizations, controlled directly or indirectly by BC Hydro at any time during the year. If control ceased prior to end of year, give particulars in a footnote.
2. If control was by other means than a direct holding of voting rights, state in a footnote the manner in which control was held, naming any intermediaries involved.
3. If control was held jointly with one or more other interests, state the fact in a footnote and name other interests.

The following table lists BC Hydro's fully operational or fully active operating subsidiary companies as of March 31, 2019.

Name of Company Controlled	Kind of Business	Percent Voting Stock Owned	Footnote Reference
Powerex Corp.	Marketer of wholesale energy products and services in Western Canada and the Western United States.	100	Direct Control
Powertech Labs Inc.	Research and technology provider; services include: testing, problem solving and consulting services.	100	Direct Control
BCHPA Captive Insurance Company Ltd	To assist BC Hydro in the management of its insurance program.	100	Direct Control
Columbia Hydro Constructors Ltd	Administers the projects and supplies the labour force for projects primarily on the Columbia River.	100	Direct Control
Tongass Power and Light Company	Company acquired by BC Hydro in 1964 as a "border accommodation" due to Hyder's remoteness from Alaska-based electrical suppliers. Tongass is connected to the BC Hydro system by a distribution line and a transfer pricing agreement formalizes the services provided.	100	Direct Control

Definitions

1. Direct control is that which is exercised without interposition of an intermediary.
2. Indirect control is that which is exercised by the interposition of an intermediary which exercises direct control.
3. Joint control is that in which neither interest can effectively control or direct action without the consent of the other, as where the voting control is equally divided between two holders, or each party holds a veto power over the other.

5 Important Changes During the Year – Fiscal 2019

Furnish particulars, including effective dates, concerning the matters indicated below:

1. Changes or additions to franchise rights.
2. Acquisition or disposal of ownership in other companies; consolidation, merger or reorganization with other companies.
3. Acquisition or disposal of an operating unit or system.
4. Important leaseholds.
5. Important extension or reduction in generation, transmission or distribution systems.
6. Estimated annual effect and nature of important wage scale changes during the year.
7. Important legal proceedings pending, in progress, or concluded during the year.

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1. None.
2. BC Hydro dissolved 1148573 BC Ltd.
3. None.
4. Important leasehold information can be found in BC Hydro's Consolidated Financial Statements of the 2018/19 BC Hydro Annual Service Plan Report as follows:
   - *Leased Assets* section within Note 11: *Property, Plant and Equipment,* page 66;
   - *Finance Lease Liabilities* section within Note 21: *Other Non-Current Liabilities,* page 94;

- *Lease and Service Agreements* section within Note 22: *Commitments and Contingencies,* page 95; and
- Significant accounting policies for important leaseholds are disclosed in the *Leases* section within Note 3: *Significant Accounting Policies,* page 59.

A link to this report is provided: http://www.bchydro.com/about/accountability_reports/financial_reports/annual_reports.html.

5. In fiscal 2019 BC Hydro expanded three substations in Delta, Campbell River, and Burnaby, added one new substation in Kamloops, and completed an area reinforcement project in south Surrey. BC Hydro also completed dam safety upgrades at the WAC Bennett Dam and at the Bridge River facility and purchased the remaining two-thirds of the Waneta facility.

Expansion of the Arnott substation in Delta from 100 MVA 230/25 kV to 200 MVA 230/25 kV was completed in August 2018. The project included two new 150 MVA 230/25 kV transformers and eight new 25 kV feeder positions as well as a new control building and replacement of obsolete protection and control systems. The scope required to increase capacity at Arnott was completed and placed into service before fiscal 2019, with remaining feeder testing and commissioning completed in fiscal 2019. The capacity increase at Arnott was required to meet area loads, including those from the Tsawwassen Mills development.

The Campbell River substation was upgraded from 100 MVA 138/25 kV to 184 MVA 138/25 kV in October 2018 with the addition of a new 75 MVA 138/25 kV transformer, control building, and distribution feeders. The capacity increase was required to address aging assets and to meet anticipated load growth in the City of Campbell River and the surrounding area.

The Horne Payne substation in Burnaby was expanded by installing two 150 MVA 230/25 kV transformers, three 50 MVA/25 kV feeder sections, and a new control building. This project was driven by aging assets and voltage conversion as well as load growth largely related to development of the Brentwood Mall area of North Burnaby. The capacity at Horne Payne was increased from 190 MVA at 12 kV to 340 MVA, with 190 MVA remaining at 12 kV, and the remaining 150 MVA at 25 kV. The expansion came into service in January 2019.

A new 100 MVA 138/25 kV Kamloops substation was completed in November 2018. The property can accommodate expansion to 200 MVA capacity. The substation includes two 75 MVA 138/25 kV transformers and an initial four 25 kV feeders, as well as associated protection and control equipment. The substation is required to serve anticipated load growth in the Kamloops area.

The South Surrey Area Reinforcement Project was completed in October 2018, and included the addition of a 75 MVA 69/25 kV transformer and 69 kV ring bus at the Nicomekl substation, a 69 kV circuit breaker at the White Rock substation, and thermal upgrades to 5 km of the 69 kV transmission circuit between the McLellan and Nicomekl substations. The area reinforcement improves supply in south Surrey from 160 MVA to 200 MVA, which is required to meet anticipated load growth in the area.

The GMS WAC Bennett Dam Riprap Upgrade Project went into service in April 2018. The project repaired the Dam and prevented further damage by designing and installing a more weather-resistant limestone robust riprap protection system for the areas most vulnerable to erosion and by eliminating the over-steepened sections of the Dam. The project will extend the estimated effective life of the riprap by approximately 75 to 100 years, with regular maintenance.

The Bridge River 2 Strip and Recoat Penstock 1 Interior Project went into service in November 2018. The project stripped and recoated the penstock interior to prevent further corrosion, and extended the structural life of the penstock. The new coating is expected to last at least 25 to 30 years.

BC Hydro purchased the remaining two-thirds interest in the 490 MW Waneta Facility (**Waneta**) on the Pend d'Oreille River in July 2018. The previous owner, Teck Metals Ltd., continues to act as the operator of the facility during a 20-year lease term and will continue to receive two-thirds of the Waneta output to serve its smelter load; during the lease BC Hydro continues to receive one-third of the Waneta output. Once the lease ends, BC Hydro will be the sole unencumbered owner of Waneta and will also purchase the related transmission assets which connect Waneta directly to the BC Hydro system.

6. Union wage scales increased 0.5 per cent effective April 1, 2018, and 1.75 per cent effective February 1, 2019. Manager and exempt professional (**M&P**) salary scales were not increased in fiscal 2019.

7. Important legal proceedings pending, in progress, or concluded during the year can be found in BC Hydro's Consolidated Financial Statements of the 2018/19 BC Hydro Annual Service Plan Report as follows:

   - *Contingencies and Guarantees* section within Note 22: *Commitments and Contingencies*, page 95.

   A link to this report is provided: http://www.bchydro.com/about/accountability_reports/financial_reports/annual_reports.html.

6 Fiscal 2019 Financial Schedules and Variance Explanations

BC Hydro has provided, in Attachment 1 to this section, a detailed comparison between the fiscal 2019 RRA Plan and fiscal 2019 actual financial results, including variance explanations. Included in Attachment 2 to this section are financial schedules which provide additional comparison details to the fiscal 2019 RRA Plan and fiscal 2019 actual financial results and which support the fiscal 2019 information and tables provided in Attachment 1.[1]

[1] Please note the amounts presented in the tables in Attachment 1 may not add due to rounding.

BC Hydro Fiscal 2019 Annual Report to the British Columbia Utilities Commission

Attachment 1 to Section 6

Fiscal 2019 Financial Schedules and Variance Explanations

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List of Tables

In sections 1 through 7, variance explanations are provided for actual gross amounts in fiscal 2019 compared to the fiscal 2019 RRA Plan. In general, explanations are provided where variances between actual and planned amounts are greater than 10 per cent, with a minimum variance threshold of $5 million.

1 Cost of Energy Variance Explanations (Schedule 4.0)

Table 1 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 and reservoir storage levels which constrained hydro generation;
- Line 13 - Lower revenues from surplus sales primarily due to lower water inflows and reservoir storage levels which constrained hydro generation; and
- Line 14 - Higher net purchases from Powerex due to limited opportunities to export energy because of low water levels.

2 Operating Costs and Provisions Variance Explanations (Schedule 5.0)

Table 2 Fiscal 2019 Operating Costs and Provisions Variances

	($ million)	Schedule Reference	F2019 RRA	F2019 Actual	F2019 Diff	F2019 % 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 2 above) was related to higher net provisions, $30.0 million (line 21 in Table 2 above) was related to higher regulatory account additions for provisions. These amounts were partially offset by $12.2 million (Line 9 in Table 2 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 2 above) include reallocation of costs related to a reorganization which had a net zero impact to BC Hydro (Line 9 in Table 2 above).

3 Taxes Variance Explanations (Schedule 6.0)

Table 3 Fiscal 2019 Taxes Variances

	($ million)	Schedule Reference	F2019 RRA	Actual	Diff	% Diff
			1	2	3=2-1	4=3/1
1	Grants in Lieu	6.0 L16	102.6	105.2	2.6	3%
2	School Taxes	6.0 L17	133.6	134.9	1.3	1%
3	IPP Capital Leases	6.0 L18	2.5	2.5	-	0%
4	Waneta 2/3 Property Taxes	6.0 L19	-	0.1	0.1	N/A
5	**Subtotal Before Regulatory Accounts**	6.0 L19	**238.7**	**242.7**	4.1	2%
6	Deferred Account Additions	6.0 L21	-	0.0	0.0	N/A
7	**Total Gross Taxes**	1.0 L3	**238.7**	**242.7**	4.1	2%

Fiscal 2019 actual gross Taxes of $242.7 million were comparable to the fiscal 2019 RRA Plan amount of $238.7 million.

4 Amortization Variance Explanations (Schedule 7.0)

Table 4 Fiscal 2019 Amortization Variances

	($ million)	Schedule Reference	F2019 RRA	Actual	Diff	% Diff
			1	2	3=2-1	4=3/1
1	Amortization of Capital Assets	7.0 L5	828.0	848.5	20.5	2%
2	Dismantling Costs	7.0 L10	-	-	-	N/A
3	IPP Capital Leases	7.0 L12	22.8	22.8	(0.0)	0%
4	**Subtotal Before Regulatory Accounts**		**850.9**	**871.3**	20.5	2%
5	Deferred Account Additions	7.0 L15	-	-	-	N/A
6	**Total Gross Amortization**	1.0 L4	**850.9**	**871.3**	20.5	2%

Fiscal 2019 actual gross Amortization was $20.5 million or 2 per cent higher than the fiscal 2019 RRA Plan due to higher amortization of capital assets, primarily due to the purchase of the remaining two-thirds interest in the Waneta Dam and Generating Facility, which increased capital assets in service.

5 Finance Charges Variance Explanations (Schedule 8.0)

Table 5 Fiscal 2019 Finance Charges Variances

	($ million)	Schedule Reference	F2019 RRA	F2019 Actual	F2019 Diff	F2019 % Diff
			1	2	3=2-1	4=3/1
1	Sinking Fund Income	8.0 L10	(5.6)	(8.7)	(3.1)	56%
2	Long-Term Debt Costs	8.0 L11	825.8	814.9	(10.9)	-1%
3	Short-Term Debt Costs	8.0 L12	52.0	39.5	(12.5)	-24%
4	Interest Capitalized	8.0 L13	(152.1)	(130.0)	22.2	-15%
5	Other (Income) / Loss	8.0 L14	4.6	28.5	23.9	519%
6	IPP Capital Leases	8.0 L15	42.4	42.4	0.0	0%
7	Accretion - Non-Deferrable	8.0 L16	1.1	1.2	0.1	6%
8	Non-Current PEB	8.0 L17	(10.9)	55.9	66.8	-613%
9	NTL Supplemental Interest Income	8.0 L18	(1.2)	-	1.2	-100%
10	Other Leases	8.0 L19	-	0.0	0.0	N/A
11	**Subtotal Before Regulatory Accounts**	8.0 L20	**756.1**	**843.9**	87.8	12%
12	Regulatory Account Additions	8.0 L8	17.7	348.4	330.7	1865%
13	**Total Gross Finance Charges**	1.0 L5	**773.8**	**1,192.3**	418.5	54%

Fiscal 2019 actual gross Finance Charges were $418.5 million or 54 per cent higher than the fiscal 2019 RRA Plan. This was primarily due to:

- Line 4 - Lower interest capitalized of $22.2 million due to lower work in progress balances eligible for capitalization;
- Line 5 - Higher other loss of $23.9 million primarily due to $12.9 million in higher interest charges related to the Skagit River Agreement as a result of an increase in the applicable interest rate on adoption of IFRS 15, *Revenue from Contacts with Customers* which provides specific guidance on interest rates for financing included in a contract and lower interest income of $14.9 million related to the Mining Customer Payment Plan;
- Line 8 - Higher non-current post-employment benefit costs of $66.8 million due to an actual liability discount rate that was lower than the expected long-term rate of return on pension plan assets; and
- Line 12 - Higher regulatory account additions of $330.7 million primarily due to a decrease in the fair value of future debt hedges as a result of changes in forward interest rates.

Partially offset by:

- Line 3 - Lower short-term debt costs of $12.5 million due to lower interest rates and lower outstanding short-term debt balance.

6 Miscellaneous Revenue Variance Explanations (Schedule 15.0)

Table 6 Fiscal 2019 Non-Tariff Revenue Variances

	($ million)	Schedule Reference	F2019 RRA	F2019 Actual	F2019 Diff	F2019 % Diff
			1	2	3=2-1	4=3/1
1	Amortization of Contributions	15.0 L1+L8+L12	57.1	60.1	3.0	5%
2	External OATT	15.0 L4	14.0	15.4	1.4	10%
3	FortisBC Wheeling Agreement	15.0 L5	5.0	5.2	0.2	4%
4	Secondary Revenue (MMBU, Secondary Use, Other)	15.0 L6+L11+L28	24.2	33.4	9.3	38%
5	Interconnections	15.0 L7	1.9	4.9	3.0	160%
6	Meter/Trans Rents & Power	15.0 L14	13.4	14.7	1.3	10%
7	Smart Metering & Infrastructure	15.0 L15	3.0	3.3	0.3	10%
8	Diversion Net Recoveries	15.0 L16	0.1	0.2	0.1	70%
9	Other Operating Recoveries	15.0 L17	4.8	4.0	(0.8)	-17%
10	Customer Crisis Fund Rider Revenue	15.0 L18	-	4.1	4.1	N/A
11	Waneta 2/3	15.0 L24	-	6.3	6.3	N/A
12	Corporate General Rents	15.0 L26	3.2	4.1	0.8	26%
13	Late Payment Charges	15.0 L27	7.2	8.0	0.8	12%
14	NTL Supplemental Charge	15.0 L9	2.0	2.3	0.2	12%
15	Other (Income) / Loss	15.0 L2+L19+L29	4.7	6.6	1.9	40%
16	**Subtotal Before Regulatory Accounts**	15.0 L31	**140.6**	**172.5**	31.9	23%
17	Deferral Account Additions	15.0 L34	-	51.9	51.9	N/A
18	**Total Gross Miscellaneous Revenue**	1.0 L7	**140.6**	**224.4**	83.8	60%

Fiscal 2019 actual gross miscellaneous revenue was $83.8 million or 60 per cent higher than the fiscal 2019 RRA Plan. This was primarily due to:

- Line 4 – Higher secondary revenues of $9.3 million primarily due to a one-time settlement for third party attachments to transmission poles, higher than planned transmission third party projects for shared assets, and higher than planned house moves and temporary connections;
- Line 11 – Higher revenues of $6.3 million due to BC Hydro’s purchase of the remaining two-thirds interest of the Waneta Dam and Generating Facility, approved by BCUC Order No. G-130-18. The two-thirds interest is leased back to Teck who is responsible paying its share of the operating costs, water rentals

and property taxes in relation to its leased interest. The operating costs are offset in miscellaneous revenues; and

- Line 17 – Higher deferral account additions of $51.9 million due to BC Hydro's purchase of the remaining two-thirds interest of the Waneta Dam and Generating Facility. Fiscal 2019 lease revenues arising from the Waneta 2017 Transaction and the revenues associated with capital expenditures made by Teck, with respect to BC Hydro's purchase of Teck's two-thirds interest in Waneta during the lease term, are deferred to the Non-Heritage Deferral Account in accordance with BCUC Order No. G-130-18.

7 Summary of Inter-Segment Revenue Variance Explanations (Schedule 3.0)

Table 7 Fiscal 2019 Inter-Segment Revenue Variances

	($ million)	Schedule Reference	F2019 RRA	F2019 Actual	F2019 Diff	F2019 % Diff
			1	2	3=2-1	4=3/1
1	Powerex - Business Support Allocation	3.0 L1	(2.9)	(2.9)	-	0%
2	Mark to Market Losses (Gains)	3.0 L2	-	1.0	1.0	N/A
3	Powerex PTP Charges	3.0 L3	(16.6)	(26.4)	(9.8)	59%
4	BC Hydro PTP Charges	3.0 L4	(45.9)	(34.3)	11.6	-25%
5	**Total Inter-Segment Revenue**	1.0 L8	**(65.3)**	**(62.5)**	2.8	-4%

Fiscal 2019 actual Inter-Segment revenues were $2.8 million or 4 per cent lower than the fiscal 2019 RRA Plan due to lower net Point-to-Point charges because there were fewer reservations than expected.

8 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.

8.1 Overall Capital Expenditures and Additions Variance Explanations

Table 8 and Table 9 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 8 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 9 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%**

8.2 Generation Capital Expenditures and Additions Variance Explanations

Generation capital expenditures and capital additions in fiscal 2019 are presented in Table 10 and Table 11 below. Results exclude amounts for the Site C Project and the Waneta 2/3 Interest Acquisition, which are presented separately in sections 8.6 and 8.7 below.

Table 10 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 11 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.

8.3 Transmission Capital Expenditures and Additions Variance Explanations

Transmission fiscal 2019 capital expenditures and capital additions are provided in Table 12 and Table 13, below.

Table 12 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 13 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 60kV 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 revaluated 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 only 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.

8.4 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 14 and Table 15, below.

Table 14 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 15 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 capital expenditures were $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.

8.5 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 16 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 17 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 18 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 19 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 20 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 21 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 22 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 23 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.

8.6 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 24 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 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 25 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.

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

Table 26 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 27 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.

BC Hydro Fiscal 2019 Annual Report to the British Columbia Utilities Commission

Attachment 2 to Section 6

Financial Schedules

1 Financial Schedules[1]

1 These consolidated financial statements have been prepared in accordance with International Financial Reporting Standards (**IFRS**) as issued by the International Accounting Standards Board (**IASB**).

Revenue Requirements Summary
($ million)

Line		Column / Reference	F2019 RRA	F2019 Actual	F2019 Diff
			1	2	3 = 2 - 1
1	**Cost of Energy**	4.0 L17	1,762.9	1,518.7	(244.2)
2	**Operating Costs**	5.0 L54	1,221.0	1,277.0	56.0
3	**Taxes**	6.0 L22	238.7	242.7	4.1
4	**Amortization**	7.0 L16	850.9	871.3	20.5
5	**Finance Charges**	8.0 L1	773.8	1,192.3	418.5
6	**Return on Equity**	9.0 L12	712.0	(428.2)	(1,140.2)
7	**Miscellaneous Revenue**	15.0 L38	(140.6)	(224.4)	(83.8)
8	**Inter-Segment Revenue**	3.0 L5	(65.3)	(62.5)	2.8
	Deferral Accounts				
9	Deferral Account Additions	2.1 L24	0.0	586.0	586.0
10	Interest on Deferral Accounts	2.1 L25	(26.6)	8.2	34.7
11	Deferral Account Recoveries	2.1 L26	241.8	240.6	(1.3)
12	Total		215.3	834.7	619.4
	Other Regulatory Accounts				
13	Regulatory Account Additions	2.2 L204	(201.6)	(636.5)	(434.8)
14	Interest on Regulatory Accounts	2.2 L205	(33.5)	(35.7)	(2.2)
15	Regulatory Account Recoveries	2.2 L206	(111.6)	956.9	1,068.5
16	Total		(346.8)	284.8	631.5
	Subsidiary Net Income				
17	Powerex Net Income		(115.1)	(435.7)	(320.5)
18	Powertech Net Income		(5.1)	(3.5)	1.6
19	Total		(120.2)	(439.1)	(318.9)
20	**Less Other Utilities Revenue**	14.0 L8	(12.1)	(29.6)	(17.5)
21	**Less Liquefied Natural Gas Revenue**	14.0 L9	(10.9)	(1.8)	9.1
22	**Less Deferral Rider**	14.0 L11	(241.8)	(240.6)	1.2
23	**Total Rate Revenue Requirement**		4,836.8	4,795.2	(41.6)

Deferral Accounts
($ million)

Line		Column	Reference	F2019 RRA	F2019 Actual	F2019 Diff
				1	2	3 = 2 - 1
	Heritage Deferral Account					
1	Beginning of Year			(16.0)	(103.7)	(87.7)
2	Adjustment to Opening Balance			0.0	(318.9)	(318.9)
3	Additions		Line 30	0.0	(95.2)	(95.2)
4	Interest			(0.6)	(18.5)	(18.0)
5	Recovery			5.1	51.2	46.2
6	End of Year			(11.5)	(485.1)	(473.6)
	Non-Heritage Deferral Account					
7	Beginning of Year			612.8	463.3	(149.5)
8	Adjustment to Opening Balance			0.0	(0.6)	(0.6)
9	Additions		Line 31	0.0	(118.4)	(118.4)
10	Additions - Waneta 2/3		15.0 L37		(51.9)	(51.9)
11	Interest			21.3	12.7	(8.6)
12	Recovery			(194.0)	(229.1)	(35.1)
13	End of Year			440.1	76.1	(364.0)
	Trade Income Deferral Account					
14	Beginning of Year			167.1	126.8	(40.3)
15	Adjustment to Opening Balance			0.0	0.0	0.0
16	Additions		Line 32	0.0	(320.5)	(320.5)
17	Interest			5.8	(2.4)	(8.2)
18	Recovery			(52.9)	(62.7)	(9.8)
19	End of Year			120.0	(258.8)	(378.8)
	End of Year Balances					
20	Heritage		Line 6	(11.5)	(485.1)	(473.6)
21	Non-Heritage		Line 13	440.1	76.1	(364.0)
22	Trade Income		Line 19	120.0	(258.8)	(378.8)
23	Total			548.6	(667.7)	(1,216.4)
	Summary					
24	Deferral Account Additions			0.0	(586.0)	(586.0)
25	Interest on Deferral Accounts			26.6	(8.2)	(34.7)
26	Deferral Account Recoveries			(241.8)	(240.6)	1.3
27	Adjustment to Opening Balance		L2+L8+L15	0.0	(319.5)	(319.5)
28	Deferral Account Net Transfers			(215.3)	(1,154.2)	(939.0)
29	**Interest Rate**		8.0 L26	4.13%	3.99%	(0.14%)
	Summary of Items Subject to Deferral					
30	Cost of Heritage Energy		4.0 L28	317.1	221.9	(95.2)
31	Cost of Non-Heritage Energy		4.0 L41	1,482.9	1,364.5	(118.4)
32	Trade Income		1.0 L17	(115.1)	(435.7)	(320.5)

Other Regulatory Accounts
($ million)

Line		Reference Column	F2019 RRA	F2019 Actual	F2019 Diff
			1	2	3 = 2 - 1
	Demand-Side Management				
1	Beginning of Year		954.6	902.5	(52.1)
2	Adjustment to Opening Balance		0.0	0.0	0.0
3	Additions	5.0 L19	127.9	111.3	(16.6)
4	Amortization on Existing		(102.8)	(99.3)	3.6
5	Amortization on Additions		0.0	0.0	0.0
6	End of Year		979.7	914.5	(65.2)
	First Nations Costs				
7	Beginning of Year		120.3	104.3	(16.0)
8	Adjustment to Opening Balance		0.0	0.0	0.0
9	Additions	5.0 L20	2.8	2.3	(0.5)
10	Transfer from Provision	Line 18	12.4	13.7	1.3
11	Interest		4.5	4.0	(0.4)
12	Recovery		(39.0)	(39.3)	(0.3)
13	End of Year		101.0	85.0	(16.0)
	First Nations Settlement Provisions				
14	Beginning of Year		395.7	414.2	18.5
15	Adjustment to Opening Balance		0.0	0.0	0.0
16	Additions - Operating	5.0 L46	0.0	2.4	2.4
17	Additions - Accretion	8.0 L4	17.4	17.5	0.0
18	Transfer to Negotiation Costs		(12.4)	(13.7)	(1.3)
19	End of Year		400.7	420.3	19.7
	Site C Project				
20	Beginning of Year		471.5	472.0	0.5
21	Adjustment to Opening Balance		0.0	0.0	0.0
22	Additions	5.0 L21+8.0 L22	0.0	0.3	0.3
23	Interest		19.5	19.0	(0.5)
24	Recovery		0.0	0.0	0.0
25	End of Year		491.0	491.3	0.4
	Future Removal and Site Restoration				
26	Beginning of Year		0.0	(0.0)	(0.0)
27	Adjustment to Opening Balance		0.0	0.0	0.0
28	Additions	5.0 L51			0.0
29	Recovery		0.0	0.0	0.0
30	End of Year		0.0	0.0	0.0
	Foreign Exchange Gains/Losses				
31	Beginning of Year		(32.0)	(31.3)	0.6
32	Adjustment to Opening Balance		0.0	0.0	0.0
33	Additions	8.0 L2	(3.5)	4.0	7.5
34	Recovery		38.6	39.2	0.6
35	End of Year		3.1	11.9	8.7
	Pre-1996 Customer Contributions				
36	Beginning of Year		88.2	88.2	(0.0)
37	Adjustment to Opening Balance		0.0	0.0	0.0
38	Recovery		(4.9)	(4.9)	0.0
39	End of Year		83.3	83.3	(0.0)
	Storm Restoration Costs				
40	Beginning of Year		9.8	46.5	36.6
41	Adjustment to Opening Balance		0.0	0.0	0.0
42	Additions	5.0 L22	0.0	18.9	18.9
43	Interest		0.2	2.6	2.4
44	Recovery		(10.0)	(10.0)	(0.0)
45	End of Year		(0.0)	58.0	58.0
	Capital Project Investigation				
46	Beginning of Year		15.3	15.3	(0.0)
47	Adjustment to Opening Balance		0.0	0.0	0.0
48	Recovery		(4.8)	(4.8)	0.0
49	End of Year		10.5	10.5	(0.0)
	F2010 ROE Adjustment				
50	Beginning of Year		0.0	0.0	0.0
51	Recovery		0.0	0.0	0.0
52	End of Year		0.0	0.0	0.0

Other Regulatory Accounts
($ million)

Line		Reference	F2019 RRA	F2019 Actual	F2019 Diff
	Column		1	2	3 = 2 - 1
	Amortization of Capital Additions				
53	Beginning of Year		(3.2)	(5.2)	(2.0)
54	Adjustment to Opening Balance		0.0	(0.0)	(0.0)
55	Additions		0.0	20.4	20.4
56	Interest		(0.1)	(0.1)	(0.0)
57	Recovery		3.3	3.3	0.0
58	End of Year		0.0	18.4	18.4
	Total Finance Charges				
59	Beginning of Year		(101.8)	(139.4)	(37.6)
60	Adjustment to Opening Balance		0.0	5.0	5.0
61	Additions	8.0 L21	0.0	52.8	52.8
62	Recovery		101.8	101.8	0.0
63	End of Year		0.0	20.3	20.2
	Smart Metering & Infrastructure				
64	Beginning of Year		239.1	239.2	0.1
65	Adjustment to Opening Balance		0.0	0.0	0.0
66	Additions - Deferred Operating	5.0 L23	0.0	0.0	0.0
67	Additions - DSMD Write-Off	5.0 L49	0.0	0.0	0.0
68	Additions - Miscellaneous Revenue		0.0	0.0	0.0
69	Interest		9.2	9.2	(0.1)
70	Recovery		(31.0)	(31.1)	(0.1)
71	End of Year		217.3	217.2	(0.1)
	Home Purchase Option Plan				
72	Beginning of Year		0.0	0.0	(0.0)
73	Adjustment to Opening Balance		0.0	0.0	0.0
74	Interest		0.0	0.0	(0.0)
75	Recovery		0.0	0.0	0.0
76	End of Year		0.0	0.0	(0.0)
	Non-Current Pension Cost				
77	Beginning of Year		557.6	303.4	(254.2)
78	Adjustment to Opening Balance		0.0	0.0	0.0
79	OCI Deferral		0.0	173.1	173.1
80	Additions	5.0 L25	0.0	0.0	0.0
81	Recovery - Operating		(57.9)	(57.9)	0.0
82	Recovery - Finance Charges		0.0	66.8	66.8
83	Transfer to PEB Current Pension-Addition		0.0	0.0	0.0
84	Transfer to PEB Current Pension-Recovery		0.0	0.0	0.0
85	End of Year		499.7	485.5	(14.3)
	Waneta				
86	Beginning of Year		0.0	0.0	0.0
87	Recovery		0.0	0.0	0.0
88	End of Year		0.0	0.0	0.0
	Environmental Provisions				
89	Beginning of Year		301.5	309.6	8.0
90	Adjustment to Opening Balance		0.0	0.0	0.0
91	Additions - Deferred Operating	5.0 L47	0.0	(7.1)	(7.1)
92	Additions - Accretion	8.0 L5	3.7	5.9	2.2
93	Transfer to Rock Bay		(9.3)	(0.3)	9.0
94	Transfer to Remediation (Asbestos)		(13.6)	(11.0)	2.6
95	Transfer to Remediation (PCB)		(15.3)	(18.6)	(3.3)
96	Recovery				0.0
97	End of Year		267.0	278.5	11.5
	Rock Bay Remediation				
98	Beginning of Year		(9.1)	(20.0)	(10.9)
99	Adjustment to Opening Balance		0.0	0.0	0.0
100	Transfer from Environmental	Line 93	9.3	0.3	(9.0)
101	Interest		(0.2)	(0.8)	(0.6)
102	Recovery		(0.0)	(0.0)	(0.0)
103	End of Year		0.0	(20.5)	(20.6)
	IFRS PP&E				
104	Beginning of Year		1,025.4	1,025.4	(0.0)
105	Adjustment to Opening Balance		0.0	0.0	0.0
106	Additions - Deferred Operating	5.0 L24	67.2	67.2	(0.0)
107	Recovery		(28.2)	(28.2)	(0.0)
108	End of Year		1,064.4	1,064.4	(0.0)

Other Regulatory Accounts
($ million)

Line		Reference Column	F2019 RRA	F2019 Actual	F2019 Diff
			1	2	3 = 2 - 1
	IFRS Pension				
109	Beginning of Year		535.4	535.4	(0.0)
110	Adjustment to Opening Balance		0.0	0.0	0.0
111	Recovery		(38.2)	(38.2)	0.0
112	End of Year		497.1	497.1	(0.0)
	Arrow Water Divestiture Costs				
113	Beginning of Year		0.0	0.0	(0.0)
114	Adjustment to Opening Balance		0.0	0.0	0.0
115	Transfer from Provision	Line 123	0.3	3.0	2.7
116	Interest		0.0	0.0	(0.0)
117	Recovery		(0.3)	(3.0)	(2.7)
118	End of Year		0.0	0.0	(0.0)
	Arrow Water Provision				
119	Beginning of Year		2.8	2.9	0.0
120	Adjustment to Opening Balance		0.0	0.0	0.0
121	Additions	5.0 L48	0.0	0.0	0.0
122	Additions - Accretion	8.0 L6	0.2	0.2	0.0
123	Transfer to Arrow Water Costs		(0.3)	(3.0)	(2.7)
124	Recovery		0.0	0.0	0.0
125	End of Year		2.7	0.0	(2.7)
	Remediation				
126	Beginning of Year		1.7	(28.6)	(30.3)
127	Adjustment to Opening Balance		0.0	0.0	0.0
128	Transfer from Env. Prov. (Asbestos)	Line 94	13.6	11.0	(2.6)
129	Transfer from Env. Prov. (PCB)	Line 95	15.3	18.6	3.3
130	Interest		0.0	(1.2)	(1.3)
131	Recovery		(30.6)	(30.6)	0.0
132	End of Year		0.0	(30.8)	(30.8)
	Rate Smoothing				
133	Beginning of Year		814.9	814.9	(0.0)
134	Adjustment to Opening Balance		0.0	0.0	0.0
135	Additions		0.0	0.0	0.0
136	Recovery		321.4	(814.9)	(1,136.3)
137	End of Year		1,136.3	0.0	(1,136.3)
	Real Property Sales				
138	Beginning of Year		15.9	37.7	21.9
139	Adjustment to Opening Balance		0.0	0.0	0.0
140	Additions	5.0 L27+L50	(14.0)	10.0	24.0
141	Interest		0.4	1.4	1.1
142	Recovery		0.0	0.0	0.0
143	End of Year		2.2	49.2	46.9
	Minimum Reconnection Charge				
144	Beginning of Year		(0.0)	(0.0)	0.0
145	Adjustment to Opening Balance		0.0	0.0	0.0
146	Additions		0.0	0.0	0.0
147	Interest		(0.0)	0.0	0.0
148	Recovery		0.0	0.0	0.0
149	End of Year		(0.0)	0.0	0.0
	Debt Management				
150	Beginning of Year		0.0	(157.8)	(157.8)
151	Adjustment to Opening Balance		0.0	(0.0)	(0.0)
152	Additions	8.0 L7	0.0	321.0	321.0
153	Recovery		0.0	0.0	0.0
154	End of Year		0.0	163.2	163.2
	Dismantling Cost				
155	Beginning of Year		0.0	35.4	35.4
156	Adjustment to Opening Balance		0.0	(0.0)	(0.0)
157	Additions	5.0 L51	0.0	11.3	11.3
158	Interest		0.0	1.6	1.6
159	Recovery		0.0	0.0	0.0
160	End of Year		0.0	48.3	48.3

Other Regulatory Accounts
($ million)

Line	Column	Reference	F2019 RRA	F2019 Actual	F2019 Diff
			1	2	3 = 2 - 1
	PEB Current Pension Costs				
161	Beginning of Year		5.7	3.3	(2.5)
162	Adjustment to Opening Balance		0.0	0.0	0.0
163	OCI Deferral		0.0	0.0	0.0
164	Additions	5.0 L25+L26	0.0	0.7	0.7
165	Recovery - Operating		(5.7)	(5.7)	(0.0)
166	Transfer from NC Current Pension-Addition	Line 83	0.0	0.0	0.0
167	Transfer from NC Current Pension-Recovery	Line 84	0.0	0.0	0.0
168	End of Year		(0.0)	(1.7)	(1.7)
	Customer Crisis Fund				
169	Beginning of Year		0.0	0.1	0.1
170	Additions	5.0 L28	0.0	(2.7)	(2.7)
171	Recovery		0.0	0.0	0.0
172	End of Year		0.0	(2.6)	(2.6)
	End of Year Balances				
173	Demand-Side Management	Line 6	979.7	914.5	(65.2)
174	First Nations Costs	Line 13	101.0	85.0	(16.0)
175	First Nations Settlement Provisions	Line 19	400.7	420.3	19.7
176	Site C Project	Line 25	491.0	491.3	0.4
177	Future Removal and Site Restoration	Line 30	0.0	0.0	0.0
178	Foreign Exchange Gains/Losses	Line 35	3.1	11.9	8.7
179	Pre-1996 Customer Contributions	Line 39	83.3	83.3	(0.0)
180	Storm Restoration Costs	Line 45	(0.0)	58.0	58.0
181	Capital Project Investigation	Line 49	10.5	10.5	(0.0)
182	F2010 ROE Adjustment	Line 52	0.0	0.0	0.0
183	Amortization of Capital Additions	Line 58	0.0	18.4	18.4
184	Total Finance Charges	Line 63	0.0	20.3	20.2
185	Smart Metering & Infrastructure	Line 71	217.3	217.2	(0.1)
186	Home Purchase Option Plan	Line 76	0.0	0.0	(0.0)
187	Non-Current Pension Cost	Line 85	499.7	485.5	(14.3)
188	Waneta	Line 88	0.0	0.0	0.0
189	Environmental Provisions	Line 97	267.0	278.5	11.5
190	Rock Bay Remediation	Line 103	0.0	(20.5)	(20.6)
191	IFRS PP&E	Line 108	1,064.4	1,064.4	(0.0)
192	IFRS Pension	Line 112	497.1	497.1	(0.0)
193	Arrow Water Divestiture Costs	Line 118	0.0	0.0	(0.0)
194	Arrow Water Provision	Line 125	2.7	0.0	(2.7)
195	Remediation	Line 132	0.0	(30.8)	(30.8)
196	Rate Smoothing	Line 137	1,136.3	0.0	(1,136.3)
197	Real Property Sales	Line 143	2.2	49.2	46.9
198	Minimum Reconnection Charge	Line 149	(0.0)	0.0	0.0
199	Debt Management	Line 154	0.0	163.2	163.2
200	Dismantling Cost	Line 160	0.0	48.3	48.3
201	PEB Current Pension Costs	Line 168	(0.0)	(1.7)	(1.7)
202	Customer Crisis Fund	Line 172	0.0	(2.6)	(2.6)
203	Total		5,756.2	4,861.1	(895.1)
	Summary				
204	Regulatory Account Additions		201.6	636.5	434.8
205	Interest on Regulatory Accounts		33.5	35.7	2.2
206	Regulatory Account Recoveries		111.6	(956.9)	(1,068.5)
207	Adjustments to Opening Balances		0.0	5.0	5.0
208	OCI Deferral (Pension)		0.0	173.1	173.1
209	Regulatory Account Net Transfers		346.8	(106.7)	(453.4)
210	**Interest Rate**	8.0 L26	4.13%	3.99%	(0.14%)

Reconciliation of Current and Gross Views
($ million)

Line		Reference Column	F2019 RRA	F2019 Actual	F2019 Diff
			1	2	3 = 2 - 1
	Inter-Segment Revenue				
1	Powerex - Business Support Allocation		(2.9)	(2.9)	0.0
2	Mark to Market Losses (Gains)		0.0	1.0	1.0
3	Powerex PTP Charges		(16.6)	(26.4)	(9.8)
4	BC Hydro PTP Charges		(45.9)	(34.3)	11.6
5	Total		(65.3)	(62.5)	2.8

Cost of Energy
($ million)

Line		Reference Column	F2019 RRA	F2019 Actual	F2019 Diff
			1	2	3 = 2 - 1
	Cost of Energy ($ million)				
	Heritage Energy				
1	Water Rentals		356.4	363.1	6.7
2	Natural Gas for Thermal Generation		10.7	7.6	(3.1)
3	Domestic Transmission - Other		22.1	22.3	0.2
4	Non-Treaty Storage and Libby Coordination Agreements		(7.2)	(181.9)	(174.7)
5	Remissions and Other		(33.1)	(33.9)	(0.8)
6	Total		349.0	177.2	(171.8)
	Non-Heritage Energy				
7	IPPs and Long-Term Commitments		1,439.3	1,247.2	(192.1)
8	Non-Integrated Area		31.1	28.9	(2.2)
9	Gas & Other Transportation		6.1	9.4	3.3
10	Water Rentals (Waneta 2/3)	15.0 L22	0.0	2.4	2.4
11	Total		1,476.5	1,287.9	(188.6)
	Market Energy				
12	Market Electricity Purchases		35.9	125.0	89.1
13	Surplus Sales		(129.2)	(115.0)	14.2
14	Net Purchases (Sales) from Powerex		0.7	25.0	24.3
15	Domestic Transmission - Export		29.9	18.5	(11.4)
16	Total		(62.6)	53.5	116.1
17	**Total Gross COE**	L6+L11+L16	1,762.9	1,518.7	(244.2)
	Items Subject to HDA				
18	Heritage Energy	Line 6	349.0	177.2	(171.8)
19	Less: F15-F19 Water Rentals (Waneta 1/3)		(6.3)	(6.6)	(0.3)
20	Market Electricity Purchases	Line 12	35.9	125.0	89.1
21	Surplus Sales	Line 13	(129.2)	(115.0)	14.2
22	Domestic Transmission - Export	Line 15	29.9	18.5	(11.4)
23	Costs in Operating/Amortization		12.9	12.2	(0.7)
24	Notional Water Rentals		0.7	4.1	3.5
25	Skagit and Ancillary Revenue	14.0 L8	(12.1)	(29.6)	(17.5)
26	Deferred Operating HDA	5.0 L16	0.0	(0.2)	(0.2)
27	Other		36.2	36.2	(0.0)
28	Total		317.1	221.9	(95.2)
	Items Subject to NHDA				
29	Non-Heritage Cost of Energy	Line 11	1,476.5	1,287.9	(188.6)
30	Add: F15-F19 Water Rentals (Waneta 1/3)	Line 19	6.3	6.6	0.3
31	Less: Water Rentals (Waneta 2/3)	Line 10	0.0	(2.4)	(2.4)
32	Net Purchases (Sales) from Powerex	Line 14	0.7	25.0	24.3
33	Commodity Risk		0.0	1.0	1.0
34	Notional Water Rental	Line 24	(0.7)	(4.1)	(3.5)
35	Revenue Variance		0.0	50.7	50.7
36	Deferred Operating NHDA	5.0 L17	0.0	(0.5)	(0.5)
37	Deferred Amortization NHDA	7.0 L14	0.0	0.0	0.0
38	Deferred Taxes NHDA	6.0 L21	0.0	0.0	0.0
39	Deferred Provision NHDA	5.0 L44	0.0	0.0	0.0
40	Other		0.0	0.3	0.3
41	Total		1,482.9	1,364.5	(118.4)

Operating Costs and Provisions - Total Company
($ million)

Line	Column	Reference	F2019 RRA	F2019 Actual	F2019 Diff
			1	2	3 = 2 - 1
	Operating Costs by Business Group				
1	Integrated Planning		270.1	285.9	15.8
2	Capital Infrastructure Project Delivery		81.9	85.9	4.0
3	Operations		216.2	215.6	(0.6)
4	Safety		54.9	53.6	(1.3)
5	Finance, Technology, Supply Chain		265.0	261.2	(3.8)
6	People, Customer, Corporate Affairs		122.5	105.5	(17.0)
7	Other		(251.6)	(250.5)	1.0
8	F17-F19 RRA Compliance Filing Adjustment		10.4	0.0	(10.4)
9	**Base Operating Costs**		769.5	757.2	(12.2)
10	IFRS Ineligible Capitalized Costs		147.7	147.7	0.0
11	Independent Power Producer Capital Leases		54.3	54.4	0.0
12	Waneta 2/3		0.0	3.7	3.7
13	Customer Crisis Fund		0.0	4.1	4.1
14	**Total Base Operating Costs Adjustment**		202.0	209.8	7.8
15	**Net Operating Costs**	L9+L14	971.5	967.1	(4.4)
	Deferral Account Additions				
16	Transfers to HDA		0.0	(0.2)	(0.2)
17	Transfers to NHDA		0.0	(0.5)	(0.5)
18	Total		0.0	(0.7)	(0.7)
	Regulatory Account Additions				
19	Demand-Side Management		127.9	111.3	(16.6)
20	First Nations Costs		2.8	2.3	(0.5)
21	Site C Project		0.0	0.3	0.3
22	Storm Restoration		0.0	18.9	18.9
23	Smart Metering & Infrastructure		0.0	0.0	0.0
24	IFRS Capitalized Overhead		67.2	67.2	(0.0)
25	PEB Current Pension Costs		0.0	0.7	0.7
26	PEB CPC - F17-F19 RRA Compliance Filing Adjustment		0.0	0.0	0.0
27	Real Property Sales		0.0	0.6	0.6
28	Customer Crisis Fund		0.0	(2.7)	(2.7)
29	Total		197.9	198.7	0.8
30	**Total Gross Operating Costs**	L15+L18+L29	1,169.4	1,165.1	(4.3)
	Net Provisions & Other				
31	Integrated Planning		35.6	50.7	15.1
32	Capital Infrastructure Project Delivery		0.0	3.9	3.9
33	Operations		3.6	3.7	0.1
34	Safety		0.0	0.4	0.4
35	Finance, Technology, Supply Chain		0.0	3.9	3.9
36	People, Customer, Corporate Affairs		0.0	1.5	1.5
37	Other		5.9	11.2	5.3
	Dismantling Expense				
38	Integrated Planning		24.0	24.0	0.0
39	Capital Infrastructure Project Delivery		0.7	0.7	0.0
40	Operations		6.0	6.0	0.0
41	Finance, Technology, Supply Chain		0.0	0.0	0.0
42	Real Property Sales		(10.0)	(10.0)	0.0
43	Total		65.7	95.9	30.2
	Deferral Account Additions - Provisions & Other				
44	Transfers to NHDA		0.0	0.0	0.0
45	Total		0.0	0.0	0.0
	Regulatory Account Additions - Provisions & Other				
46	First Nations Provisions		0.0	2.4	2.4
47	Environmental Provisions		0.0	(7.1)	(7.1)
48	Arrow Water Provision		0.0	0.0	0.0
49	Smart Metering & Infrastructure DSMD Write-Off		0.0	0.0	0.0
50	Real Property Sales		(14.0)	9.4	23.4
51	Dismantling Expense		0.0	11.3	11.3
52	Total		(14.0)	16.0	30.0
53	**Total Gross Provisions & Other**	L43 + L45 + L52	51.7	111.9	60.3
54	**Total Gross Operating and Provisions & Other**	L30 + L53	1,221.0	1,277.0	56.0

Taxes
($ million)

Line		Reference Column	F2019 RRA	F2019 Actual	F2019 Diff
			1	2	3 = 2 - 1
	Generation				
1	Grants in Lieu		25.4	25.6	0.2
2	School Taxes		17.8	16.9	(0.9)
3	Total		43.2	42.5	(0.7)
	Transmission				
4	Grants in Lieu		57.2	60.5	3.3
5	School Taxes		90.0	91.8	1.8
6	Total		147.2	152.3	5.1
	Distribution				
7	Grants in Lieu		8.4	8.2	(0.1)
8	School Taxes		20.3	20.0	(0.2)
9	Total		28.6	28.3	(0.4)
	Customer Care				
10	IPP Capital Leases		2.5	2.5	0.0
	Waneta 2/3				
11	Teck portion of property taxes	15.0 L23	0.0	0.1	0.1
12	Total		2.5	2.6	0.1
	Business Support				
13	Grants in Lieu		11.7	10.9	(0.8)
14	School Taxes		5.6	6.1	0.6
15	Total		17.2	17.0	(0.2)
	Total Before Regulatory Accounts				
16	Grants in Lieu	L1+L4+L7+L13	102.6	105.2	2.6
17	School Taxes	L2+L5+L8+L14	133.6	134.9	1.3
18	IPP Capital Leases	L10	2.5	2.5	0.0
19	Waneta 2/3 Property Taxes	L11	0.0	0.1	0.1
20	Total		238.7	242.7	4.1
	Deferral Account Additions				
21	Transfers to NHDA		0.0	0.0	0.0
22	**Total Gross Taxes**	L20 + L21	238.7	242.7	4.1

Depreciation and Amortization
($ million)

Line		Reference Column	F2019 RRA	F2019 Actual	F2019 Diff
			1	2	3 = 2 - 1
	Amortization of Capital Assets				
1	Generation		226.7	234.5	7.8
2	Transmission		225.6	224.0	(1.6)
3	Distribution		197.8	200.2	2.4
4	Business Support		178.0	189.8	11.8
5	Total		828.0	848.5	20.5
	Dismantling Costs				
6	Generation		0.0	0.0	0.0
7	Transmission		0.0	0.0	0.0
8	Distribution		0.0	0.0	0.0
9	Business Support		0.0	0.0	0.0
10	Total		0.0	0.0	0.0
	IPP Capital Leases				
11	IPP Capital Leases		22.8	22.8	(0.0)
12	Total		22.8	22.8	(0.0)
	Other Leases				
13	Amortization		0.0	0.0	0.0
	Deferral Account Additions				
14	Transfers to NHDA		0.0	0.0	0.0
15	Total		0.0	0.0	0.0
16	**Total Gross Amortization**		850.9	871.3	20.5

Finance Charges
($ million)

Line	Column	Reference	F2019 RRA	F2019 Actual	F2019 Diff
			1	2	3 = 2 - 1
1	**Total Gross Finance Charges**	L8 + L20	773.8	1,192.3	418.5
	Regulatory Account Additions				
2	FX Gains/Losses		(3.5)	4.0	7.5
3	Deferred IPP Capital Leases (Total Finance Charge Reg. Account Additions)		0.0	(0.1)	(0.1)
4	Accretion - First Nations		17.4	17.5	0.0
5	Accretion - Environmental		3.7	5.9	2.2
6	Accretion - Arrow Water		0.2	0.2	0.0
7	Debt Management		0.0	321.0	321.0
8	Total		17.7	348.4	330.7
9	**Adj. for Regulatory Account Additions**		756.1	843.9	87.8
	Total Before Regulatory Accounts				
10	Sinking Fund Income		(5.6)	(8.7)	(3.1)
11	Long-Term Debt Costs		825.8	814.9	(10.9)
12	Short-Term Debt Costs		52.0	39.5	(12.5)
13	Interest Capitalized		(152.1)	(130.0)	22.2
14	Other (Income) / Loss		4.6	28.5	23.9
15	IPP Capital Leases		42.4	42.4	0.0
16	Accretion - Non-Deferrable		1.1	1.2	0.1
17	Non-Current PEB		(10.9)	55.9	66.8
18	NTL Supplemental Interest Income		(1.2)	0.0	1.2
19	Other Leases		0.0	0.0	0.0
20	Total		756.1	843.9	87.8
21	Total Finance Charge Regulatory Acct. Additions		0.0	(52.8)	(52.8)
22	Site C Project (IFRS 14 IDC impact)		0.0	0.0	0.0
	Weighted Average Cost of Debt (WACD) Rate				
23	Total Gross Finance Charges	Line 1	773.8	1,192.3	418.5
24	WACD Adjustment		112.0	(341.8)	(453.8)
25	Finance Charges for WACD		885.8	850.5	(35.3)
26	Weighted Average Cost of Debt (WACD) Rate		4.13%	3.99%	(0.14%)

Return on Equity
($ million)

			F2019		
		Reference	RRA	Actual	Diff
Line	Column		1	2	3 = 2 - 1
	Deemed Equity				
1	Rate Base	10.0 L4	21,665.7	22,565.0	899.3
2	Pre-1996 Customer Contns	2.2 L39	(83.3)	(83.3)	0.0
3	Powerex & Powertech Assets		43.6	63.8	20.3
4	Allowance for Working Capital		250.0	250.0	0.0
5	Total		21,876.0	22,795.5	919.5
6	Deemed Equity Percentage		30.0%	30.0%	0.0%
7	Year-End Deemed Equity		6,562.8	6,838.7	275.9
8	Mid-Year Deemed Equity		6,338.4	6,422.1	83.8
9	Achieved ROE			(6.67%)	
10	Allowed ROE / Derived ROE (F18-F21)		11.23%		
11	Return on Equity		712.0	(428.2)	(1,140.2)
12	Gross Return on Equity		712.0	(428.2)	(1,140.2)

Rate Base
($ million)

Line		Column	Reference	F2019 RRA	F2019 Actual	F2019 Diff
				1	2	3 = 2 - 1
	Total					
1	Net Assets in Service		12.0 L13	22,402.1	23,312.2	910.1
2	Net Contributions		11.0 L13	(1,716.1)	(1,661.8)	54.4
3	Net DSM		2.2 L6	979.7	914.5	(65.2)
4	Total			21,665.7	22,565.0	899.3
5	Mid-Year			20,920.2	21,176.4	256.2

Contributions
($ million)

Line		Reference Column	F2019 RRA	F2019 Actual	F2019 Diff
			1	2	3 = 2 - 1
	Contributions in Aid - Total				
1	Gross Contns - Beginning of Year		2,525.1	2,625.3	100.1
2	IFRS Opening Balance Adjustment		0.0	(256.6)	(256.6)
3	Additions		106.4	185.0	78.6
4	Retirements & Transfers		(6.2)	(14.7)	(8.5)
5	Gross Contns - End of Year		2,625.3	2,539.0	(86.3)
6	Accum Amort - Beginning of Year		863.3	855.8	(7.4)
7	IFRS Opening Balance Adjustment		0.0	(14.8)	(14.8)
8	Amortization		50.9	52.6	1.7
9	Amortization of Pre-96 CIAC		(4.9)	(4.9)	0.0
10	Retirements & Transfers		0.0	(7.2)	(7.2)
11	IFRS amortization reclassification		0.0	(4.2)	(4.2)
12	Accum Amort - End of Year		909.2	877.3	(31.9)
13	Net Contributions - End of Year		1,716.1	1,661.8	(54.4)

Assets - Total (Excluding DSM and IPP Capital Leases)
($ million)

			F2019		
		Reference	RRA	Actual	Diff
Line		Column	1	2	3 = 2 - 1
	Gross Assets in Service				
1	Opening Balance		25,393.9	25,029.3	(364.6)
2	Adjustment to Opening Balance		0.0	(3,509.6)	(3,509.6)
3	Capital Additions	13.0 L21	2,387.8	3,553.1	1,165.3
4	Retirements & Transfers		(39.7)	(116.5)	(76.9)
5	Closing Balance		27,742.1	24,956.3	(2,785.8)
	Accumulated Amortization				
6	Opening Balance		4,512.0	4,374.6	(137.4)
7	Adjustment to Opening Balance		0.0	(3,506.5)	(3,506.5)
8	Amortization on Existing Assets		681.0	681.1	0.1
9	Amortization on Additions	13.0 L35	147.0	167.4	20.4
10	Accelerated Amort on Burrard		0.0	0.0	0.0
11	Retirements & Transfers		0.0	(72.5)	(72.5)
12	Closing Balance		5,340.0	1,644.1	(3,695.9)
13	**Net Assets in Service (Year-End)**		22,402.1	23,312.2	910.1

Capital Expenditures and Additions
($ million)

Line		Reference Column	F2019 RRA	F2019 Actual	F2019 Diff
			1	2	3 = 2 - 1
	Capital Expenditures				
1	Generation Growth		0.7	5.5	4.8
2	Generation - Waneta 2/3		0.0	1,218.8	1,218.8
3	Generation Sustaining		424.3	364.7	(59.6)
4	Transmission Growth		192.7	224.3	31.6
5	Transmission Sustaining		373.9	193.0	(180.9)
6	Distribution Growth		209.5	296.0	86.5
7	Distribution Sustaining		187.6	206.7	19.1
8	Site C Project		829.2	1,116.7	287.5
9	Technology		78.8	84.3	5.5
10	Properties		88.3	48.4	(39.9)
11	Fleet & Other		39.6	58.3	18.7
12	Total		2,424.6	3,816.7	1,392.1
	Total Capital Additions				
13	Generation		1,332.3	1,185.5	(146.7)
14	Generation - Waneta 2/3		0.0	1,220.3	1,220.3
15	Transmission		458.8	529.2	70.5
16	Distribution		413.0	448.4	35.4
17	Site C Project		0.0	0.0	0.0
18	Technology		112.6	64.1	(48.5)
19	Properties		25.5	33.0	7.5
20	Fleet & Other		45.7	72.5	26.8
21	Total		2,387.8	3,553.1	1,165.3
	Unfinished Construction				
22	Beginning of Year		4,249.1	4,306.8	57.8
23	Adjustments		0.0	(17.1)	(17.1)
24	Change in Unfinished		36.8	263.6	226.8
25	End of Year		4,285.8	4,553.3	267.5
26	Mid-Year Balance		4,267.5	4,430.1	162.6
	Amortization on Additions				
27	Generation		43.3	41.0	(2.3)
28	Generation - Waneta 2/3		0.0	19.7	19.7
29	Transmission		30.4	33.3	2.9
30	Distribution		23.5	27.6	4.1
31	Site C Project		0.0	0.0	0.0
32	Technology		36.6	29.8	(6.8)
33	Properties		7.2	6.5	(0.7)
34	Fleet & Other		6.1	9.4	3.4
35	Total		147.0	167.4	20.4

Domestic Energy Sales and Revenue

Line		Reference Column	F2019 RRA	F2019 Actual	F2019 Diff
			1	2	3 = 2 - 1
	Domestic Revenues ($ million)				
1	Residential		2,067.9	2,025.2	(42.7)
2	Light Industrial and Commercial		1,821.9	1,832.3	10.4
3	Large Industrial		830.0	829.6	(0.4)
4	Irrigation		5.0	6.3	1.3
5	Street Lighting		43.2	41.1	(2.1)
6	New Westminster & Tongass		31.4	29.7	(1.7)
7	Fortis		37.4	31.0	(6.4)
8	Seattle City Light		12.1	29.6	17.5
9	Liquefied Natural Gas		10.9	1.8	(9.1)
10	Subtotal		4,859.8	4,826.6	(33.2)
11	Revenue from Deferral Rider		241.8	**240.6**	(1.2)
12	Total		5,101.6	5,067.2	(34.4)
13	**Deferral Account Rate Rider**		**5.0%**	**5.0%**	

Miscellaneous Revenue
($ million)

Line		Reference Column	F2019 RRA	F2019 Actual	F2019 Diff
			1	2	3 = 2 - 1
	Generation				
1	Amortization of Contributions		0.3	0.3	(0.0)
2	Other		1.6	2.0	0.5
3	Total		1.9	2.3	0.5
	Transmission				
4	External OATT		14.0	15.4	1.4
5	FortisBC Wheeling Agreement		5.0	5.2	0.2
6	Secondary Revenue		5.0	8.7	3.6
7	Interconnections		1.9	4.9	3.0
8	Amortization of Contributions		14.4	21.1	6.8
9	NTL Supplemental Charge		2.0	2.3	0.2
10	Total		42.4	57.6	15.3
	Distribution				
11	Secondary Use Revenue & Other		13.8	20.9	7.1
12	Amortization of Contributions		42.4	38.6	(3.8)
13	Total		56.2	59.5	3.3
	Customer Care				
14	Meter/Trans Rents & Power Factor Surcharges		13.4	14.7	1.3
15	Smart Metering & Infrastructure Impact		3.0	3.3	0.3
16	Diversion Net Recoveries		0.1	0.2	0.1
17	Other Operating Recoveries		4.8	4.0	(0.8)
18	Customer Crisis Fund Rider Revenue		0.0	4.1	4.1
19	Other		2.4	3.2	0.8
	Waneta 2/3				
20	Lease revenue from Teck				0.0
21	Teck portion of operating costs		0.0	3.7	3.7
22	Teck portion of water rentals		0.0	2.4	2.4
23	Teck portion of property taxes		0.0	0.1	0.1
24	Subtotal		0.0	6.3	6.3
25	Total		23.6	35.6	12.0
	Business Support				
26	Corporate General Rents		3.2	4.1	0.8
27	Late Payment Charges		7.2	8.0	0.8
28	MMBU Secondary Revenue		5.4	3.9	(1.5)
29	Other		0.8	1.4	0.6
30	Total		16.6	17.4	0.8
31	**Total Before Regulatory Accounts**		140.6	172.5	31.9
	Deferral Account Additions				
32	Waneta 2/3				
32	Lease revenue from Teck		0.0	50.6	50.6
33	Teck portion of capital expenditures		0.0	1.3	1.3
34	Subtotal		0.0	51.9	51.9
	Regulatory Account Additions				
35	Smart Metering & Infrastructure Impact		0.0	0.0	0.0
36	Minimum Reconnection Charge		0.0	0.0	0.0
37	Subtotal		0.0	0.0	0.0
38	**Total Gross Miscellaneous Revenue**		140.6	224.4	83.8

7 Planned Capital Extension Projects and Anticipated Regulatory Filings

In this section, a summary of planned capital extension projects and anticipated regulatory filings is provided. The summary of planned capital extensions includes a list of planned capital extension projects with a total forecast cost of more than $5 million as shown in the Appendix I (**Appendix I**) in the Fiscal 2020 to Fiscal 2021 Revenue Requirements Application (**F2020-F2021 RRA**) filed with the BCUC on February 25, 2019 and capital extensions that were identified from the currency date noted in Appendix I up until March 31, 2019. The information provided identifies projects that may be subject to a future regulatory filing (i.e., Certificate of Public Convenience and Necessity (**CPCN**) or section 44.2).

BC Hydro Fiscal 2019 Annual Report to the British Columbia Utilities Commission

Attachment to Section 7

Summary of Planned Capital Extension Projects and Anticipated Regulatory Filings

List of Tables

This attachment includes two tables. Table 1 lists, by category, the capital extensions with a total forecast cost of more than $5 million that are included in Appendix I in the Fiscal 2020 to Fiscal 2021 Revenue Requirements Application (**F2020-F2021 RRA**) and capital extensions that were identified from the currency date noted in Appendix I up until March 31, 2019. Projects that may be the subject of a future regulatory filing are identified with a reference to Table 2. BC Hydro has redacted certain customer, project and extension names in this filing that are deemed to be commercially sensitive.

In its Capital Project Filing Guidelines[1] BC Hydro committed to provide in this report an indication of the projects that may be the subject of a CPCN or section 44.2 filing. Table 2 reflects BC Hydro's current expectations regarding upcoming filings with the rationale for the filing type.[2]

Table 1 Planned Capital Extension Projects ($ million)

Project Name	Total Forecast Cost[3]	Reference (from F2020-F2021 RRA Appendix I)
Generation Sustaining Capital		
John Hart Generating Station Replacement	1,092.9	Appendix I, Page 1, Line 2, Appendix J, Page 3

1 Filed with the BCUC on July 23, 2010.

2 Projects listed are identified in the "Current or Potential Application" column of Appendix I of the F2020-F2021 RRA.

3 Total Forecast Costs shown in this column are based on the upper value of the Current Pre-Implementation Cost Estimate ranges shown in Appendix I of the F2020-F2021 RRA (Column J) for projects in the Definition or Future development phase. The Current Authorized Amount in Appendix I (Column K) has been used for projects in the Implementation phase or for projects that are in-service.

Project Name	Total Forecast Cost[3]	Reference (from F2020-F2021 RRA Appendix I)
Generation Growth Capital		
Revelstoke Install Unit 6	569.0	Appendix I, Page 1, Line 1, Appendix J, Page 1
Site C Project	10,005.0[4]	Appendix I, Page 10, Line 15, Appendix J, Page 129
Transmission Sustaining Capital		
BR1 T3 & BRT T4A Replacement	TBD	Appendix I, Page 4, Line 29, Appendix J, Page 99
Hundred Mile House T1/T2 EOL Replacement	TBD	Appendix I, Page 4, Line 30
Mainwaring Station Upgrade	TBD	Appendix I, Page 4, Line 33, Appendix J, Page 103
Ah-sin-heek - Substation Replacement	TBD	Appendix I, Page 5, Line 37
Norgate - Substation Upgrade	TBD	Appendix I, Page 5, Line 38, Appendix J, Page 108
Patricia - Substation Upgrade	TBD	Appendix I, Page 5, Line 39
Wood Pole Substation Rep - MTE	6.0	Appendix I, Page 5, Line 44
Wood Pole Substation Rep - PSN	5.8	Appendix I, Page 5, Line 45
Canal Flats - Substation Wood Pole Replacement	TBD	Appendix I, Page 5, Line 51
Project C	TBD	Appendix I, Page 5, Line 55
Circuit Refurbishments - F15 - 2L13/14	N/A	Appendix I, Page 5, Line 65

[4] The total capital forecast cost of $10,005.0 million includes the Project Reserve of $708.0 million, which is held by the Treasury Board. The approved total project cost (including regulatory and certain operating expenditures) is $10.7 billion.

Project Name	Total Forecast Cost[3]	Reference (from F2020-F2021 RRA Appendix I)
Transmission Growth Capital		
Fort St. John and Taylor Electric Supply	53.1	Appendix I, Page 4, Line 1, Appendix J, Page 67
DVES: West End Strategic Property Purchase	80.7	Appendix I, Page 4, Line 2, Appendix J, Page 69
Peace Region Electric Supply (**PRES**)	348.0	Appendix I, Page 4, Line 3, Appendix J, Page 71
Metro North Transmission (**MNT**)[5]	530.0	Appendix I, Page 4, Line 4, Appendix J, Page 73
Bridge River Transmission Project	TBD	Appendix I, Page 4, Line 5, Appendix J, Page 75
West Kelowna Transmission and Westbank Upgrade Projects[6]	TBD	Appendix I, Page 4, Line 6, Appendix J, Page 77
East Vancouver - Substation Construction[7]	TBD	Appendix I, Page 4, Line 7, Appendix J, Page 79
West End - Substation Construction and System Reinforcement[8]	TBD	Appendix I, Page 4, Line 8, Appendix J, Page 80
Peace to Kelly Lake Capacitors[9]	TBD	Appendix I, Page 4, Line 9, Appendix J, Page 82
Lower Mainland - Capacitive and Reactive Power Reinforcement	TBD	Appendix I, Page 4, Line 10, Appendix J, Page 84
Capilano Substation Upgrade	88.0	Appendix I, Page 4, Line 12, Appendix J, Page 87

5 Please refer to Note 7 in Table 2.
6 Please refer to Note 8 in Table 2.
7 Please refer to Note 9 in Table 2.
8 Please refer to Note 10 in Table 2.
9 Please refer to Note 11 in Table 2.

Project Name	Total Forecast Cost[3]	Reference (from F2020-F2021 RRA Appendix I)
Mount Lehman Substation Upgrade	TBD	Appendix I, Page 4, Line 13, Appendix J, Page 89
Clayburn Substation Upgrade	TBD	Appendix I, Page 4, Line 14, Appendix J, Page 91
Project B (Substation)	TBD	Appendix I, Page 4, Line 15, Appendix J, Page 93
Pemberton - Substation Upgrade	TBD	Appendix I, Page 4, Line 16, Appendix J, Page 95
Bremner-Trio Hydro Project	7.9	Appendix I, Page 4, Line 17
UBC Load Increase Stage 2	55.2	Appendix I, Page 4, Line 18
Customer A	5.8	Appendix I, Page 4, Line 19
Customer B	102.0	Appendix I, Page 4, Line 20
Customer C	TBD	Appendix I, Page 4, Line 21
Prince George Terrace Capacitors (**PGTC**)	TBD	N/A
Bear Mountain to Dawson Creek - Transmission Voltage Conversion[10]	TBD	N/A
North Montney Power Supply[11]	TBD	N/A
Distribution Growth Capital		
Customer D	10.0	Appendix I, Page 7, Line 1
Customer E	6.0	Appendix I, Page 7, Line 2
Customer F	9.0	Appendix I, Page 7, Line 3
Customer G	TBD	Appendix I, Page 7, Line 4
Customer H	TBD	Appendix I, Page 7, Line 5

10 Please refer to Note 12 in Table 2.

11 Please refer to Note 13 in Table 2.

Project Name	Total Forecast Cost[3]	Reference (from F2020-F2021 RRA Appendix I)
12F51 & 53 HPN Voltage Conversion (LM-BBY-048)	12.1	Appendix I, Page 7, Line 6
HPN 12F54, 72Q, 73Q, and 324 Voltage Conversion (LM-BBY-051)	14.1	Appendix I, Page 7, Line 7
Bringing additional capacity from ARN to Tilbury (FV-FVW-057)	23.7	Appendix I, Page 7, Line 8
Three new MLE Feeders to offload CBN (LM-FVE-607)	13.0	Appendix I, Page 7, Line 9
HPN 77Q, 323, 326 and 327 Voltage Conversion Preparation (LM-BBY-062)	18.0	Appendix I, Page 7, Line 10
LOH 12F68 Voltage Conversion and Transfer to HPN (LM-BBY-064)	15.0	Appendix I, Page 7, Line 11
Voltage Conversion Prep for RIM Substation (LM-FVW-718)	8.0	Appendix I, Page 7, Line 12
New MUR Circuit to Offload MUR 12F66 and MUR 12F84 (LM-VAN-020)	13.0	Appendix I, Page 7, Line 13
WKA New Substation Bring 4 New Feeders (SI-KAM-001)	18.0	Appendix I, Page 7, Line 14
DUG Extension Along Highway 1 East (SI-KAM-008)	8.0	Appendix I, Page 7, Line 15
CBL New Feeder South Campbell River (VI-NVI-417)	TBD	Appendix I, Page 7, Line 16
Two Fleetwood feeders to offload McLellan (FV-FVW-723)	TBD	Appendix I, Page 7, Line 17
Lower Mainland - George Dickie Feeder Voltage Conversion (LM-VAN-066)	TBD	Appendix I, Page 7, Line 18
George Dickie - Voltage Conversion preparation of 4F54, 4F61, 4F64 and 4F65 and cutover to Sperling 12F64 (LM-VAN-094)	TBD	Appendix I, Page 7, Line 19
Other		
Project B (Property)	TBD	Appendix I, Page 10, Line 11, Appendix J, Page 93

Table 2 Projects with Anticipated Regulatory Filings

Note	Project	Filing Type	Rationale for Filing Type
1	John Hart Dam Seismic Upgrade	Section 44.2	Anticipated to exceed $100 million threshold for Generation projects but is not considered an extension to the BC Hydro system because this project is not designed to serve incremental load and there is no increase in generating capability.
2	Ladore Spillway Seismic Upgrade	Section 44.2	Anticipated to exceed $100 million threshold for Generation projects but is not considered an extension to the BC Hydro system because this project is not designed to serve incremental load and there is no increase in generating capability.
3	Strathcona Upgrade Discharge	Section 44.2	Anticipated to exceed $100 million threshold for Generation projects but is not considered an extension to the BC Hydro system because this project is not designed to serve incremental load and there is no increase in generating capability.

Note	Project	Filing Type	Rationale for Filing Type
4	Bridge River 1 Replace Units 1-4 Generators / Governors	Section 44.2	Anticipated to exceed $100 million threshold for Generation projects but is not considered an extension to the BC Hydro system because this project is not designed to serve incremental load and there is no increase in generating capability.
5	Seven Mile Overhaul Units 1 to 3 Turbines	Section 44.2	Anticipated to exceed $100 million threshold for Generation projects but is not considered an extension to the BC Hydro system because this project is not designed to serve incremental load and there is no increase in generating capability.
6	Revelstoke - U1 - U4 Stator Replacement	Section 44.2	Anticipated to exceed $100 million threshold for Generation projects but is not considered an extension to the BC Hydro system because this project is not designed to serve incremental load and there is no increase in generating capability.
7	Metro North Transmission Project	CPCN	Anticipated to exceed $100 million threshold for Transmission projects and considered an extension to BC Hydro's system.
8	West Kelowna Transmission and Westbank Upgrade Projects	CPCN	BCUC Order No. G-47-18 directed BC Hydro to file a CPCN application for these projects.
9	East Vancouver - Substation Construction	CPCN	Anticipated to exceed $100 million threshold for Transmission projects and considered an extension to BC Hydro's system.
10	West End - Substation Construction and System Reinforcement	CPCN	Anticipated to exceed $100 million threshold for Transmission projects and considered an extension to BC Hydro's system.
11	Peace to Kelly Lake Capacitors	CPCN	Anticipated to exceed $100 million threshold for Transmission projects and considered an extension to BC Hydro's system.
12	Bear Mountain to Dawson Creek - Transmission Voltage Conversion	CPCN	Anticipated to exceed $100 million threshold for Transmission projects and considered an extension to BC Hydro's system.

Note	Project	Filing Type	Rationale for Filing Type
13	North Montney Power Supply	CPCN	Anticipated to exceed $100 million threshold for Transmission projects and considered an extension to BC Hydro's system.

The following projects are expected to exceed the Capital Project Filing Guideline threshold but are not included in Table 2:

- The PRES project is expected to exceed the Capital Project Filing Guideline threshold but is a prescribed undertaking pursuant to section 18 of the *Clean Energy Act* (and the related Greenhouse Gas Reduction Regulation section 4(2));
- The Revelstoke Install Unit 6 project is expected to exceed the Capital Project Filing Guideline threshold but is exempt from the CPCN requirement pursuant to section 7 of the *Clean Energy Act*.
- The PGTC project is expected to exceed the Capital Project Filing Guideline threshold but is exempted under Ministerial Order M73/2013, dated March 25, 2013.

8 Internal Audit Review and/or Report Provided in Fiscal 2019

British Columbia Utilities Commission Letter No. L-36-94, Direction No. 5

A list of topics covered in the internal audit reports together with a brief description of each topic.

The following internal audits were completed in the year ended March 31, 2019.

All audits were conducted in conformance with the International Standards for the Professional Practice of Internal Auditing.

A. Risk Based Audits

Integrated Planning

- Dam Safety
  - ▶ Description: Evaluated whether risks are identified, prioritized, and managed to ensure objectives of BC Hydro's Dam Safety Program are achieved.

Capital Infrastructure Project Delivery

- Cheakamus Units 1 & 2 Generator Replacement Project
  - ▶ Description: Provided assurance that the Cheakamus Units 1 & 2 Generator Replacement Project is appropriately managed and executed to deliver stated objectives.

Finance, Technology, Supply Chain

- Smart Meter Operations Audit
  - ▶ Description: Assessed whether the Smart Meter system is fully operationalized, managed and functioning effectively.

- Cybersecurity Audit
  - Description: Assessed whether BC Hydro has effective governance and appropriate controls related to threat and vulnerability management, incident response and vendor risk management.

Operations

- Energy Studies Process
  - Description: Evaluated whether the monthly Energy Studies process reliably supports operations, financial and strategic planning at BC Hydro.

Safety

- Confined Space Program
  - Description: Assessed whether an effective Confined Space Program is in place and being followed.
- Learning & Development
  - Description: Assessed the effectiveness of learning and development to ensure employees have the right skills at the right time.
- Asbestos Management Program
  - Description: Assessed whether an effective Asbestos Management Program is in place and being followed.

People, Customer, Corporate Affairs

- Customer Billing
  - Description: Assessed whether Customer Service billing processes and controls ensure bills are complete, accurate, timely and in accordance with the electric tariff.

B. Core Financial Process Audits

Powerex

- Trade Processing Controls
  - Description: Confirmed whether controls for trade processing are operating effectively.

C. Policy Compliance

Powerex

- Non-energy Procurement and Disbursements
  - Description: Assessed internal controls within the purchases, payables and disbursements cycle to ensure transactions are valid, authorized, accurate, complete and timely.

D. Project Completion and Evaluation Reviews

Capital Infrastructure Project Delivery

- Big Bend Substation
  - Reviewed the Executive Summary to the Capital Projects Committee of the Board and validate management's representation.
- Surrey Area Fleetwood Substation
  - Reviewed the Executive Summary to the Capital Projects Committee of the Board and validate management's representation.
- W.A.C. Bennett Dam Upgrade
  - Reviewed the Executive Summary to the Capital Projects Committee of the Board and validate management's representation.

E. Audit Follow-ups

Capital Infrastructure Project Delivery

- Engineering Service Provider Contracts
  - ▶ Description: Follow-up to the fiscal 2018 audit that reviewed whether effective processes and controls are in place to ensure Engineering Service Providers are fulfilling their contractual obligations.
- Horne Payne Substation Upgrade Project
  - ▶ Description: Follow-up to the fiscal 2018 audit that provided assurance that the Horne Payne Substation Upgrade Project is being appropriately managed and executed to deliver stated objectives.
- Indigenous Relations Agreement Management
  - ▶ Description: Follow-up to the fiscal 2018 audit that assessed whether BC Hydro is effectively executing agreements in support of its Indigenous Relations Strategy.

Integrated Planning

- Load Forecasting
  - ▶ Description: Follow-up to the fiscal 2018 audit that reviewed the load forecasting process to ensure timely and reliable energy and peak demand forecasts which supports operational, financial and strategic planning at BC Hydro.
- Generation Maintenance
  - ▶ Description: Follow-up to the fiscal 2017 audit that provided assurance there is an effective Generation Maintenance program to ensure assets are well maintained.

Finance, Technology, Supply Chain

- Enterprise Billing Infrastructure Project
  - Description: Follow-up to the fiscal 2018 audit that provided assurance during implementation that the Enterprise Billing Infrastructure Project was being effectively executed to attain project objectives.

Operations

- Construction Services
  - Description: Follow-up to the fiscal 2018 audit that assessed whether Construction Services effectively manages and delivers work to meet client needs.

Policy Compliance

- BC Hydro Business and Travel Expenses
  - Description: Follow-up to the fiscal 2018 audit that assessed compliance with employee business and travel expense policies and procedures.
- Project Portfolio Management
  - Description: Follow-up to the fiscal 2018 audit that assessed whether there is compliance with Project and Portfolio Management requirements and the effectiveness of the quality assurance function.

Powerex

- Business & Travel Expense
  - Description: Follow-up to the fiscal 2018 audit that assessed compliance with employee business and travel expense policies and procedures.

- Regulatory Reporting
  - Description: Follow-up to the fiscal 2018 audit that assessed processes to ensure Powerex is in compliance with regulatory requirements.

9 Management Letter Topics from External Auditor

British Columbia Utilities Commission Letter No. L-36-94, Direction No. 4

A list of topics covered in the management letter.

Not applicable. BC Hydro did not receive a management letter from our external auditor in fiscal 2019.

10 British Columbia Utilities Commission Status Report of Compliance with Financial Directives or Commitments

10.1 The Waneta Transaction Report as prescribed in British Columbia Utilities Commission Order No. G-130-18

The Waneta Transaction Report shall consist of and shall be provided in a format acceptable to the Commission. The reports will be submitted as part of BC Hydro's Regulatory Annual Report and as an appendix in its Revenue Requirements Applications until 2058.

The fiscal 2019 Waneta Transaction Report as prescribed in British Columbia Utilities Commission Order No. G-130-18, Directive 4 (e) is attached.

BC Hydro Fiscal 2019 Annual Report to the British Columbia Utilities Commission

Attachment to Section 10.1

Fiscal 2019 Waneta Transaction Annual Report

Table of Contents

List of Tables

1 Introduction

The Waneta Transaction Annual Report is prepared in compliance with BCUC Order No. G-130-18, Directive 4(e) of the Commission's Decision on the Waneta 2017 Transaction[1], as follows.

4. Pursuant to section 43 of the *Act*, the Commission Panel directs BC Hydro to file with the Commission:

   (e) An annual Waneta 2017 Transaction report (**Report**) which must include the following[2]:

      i. The operations, maintenance and capital expenditures including those major sustaining capital expenditures or operating and maintenance expenditures that BC Hydro was entitled to refer to a third-party referee and the related referee determinations as well as any significant non-sustaining capital expenditures that BC Hydro had the right to veto.

      ii. Annual cash flow comparison of actual expenditures versus estimated expenditures and an explanation for any variance greater than ten percent from the estimated expenditures;

      iii. Organization chart showing the Operator and members of the Operating Committee;

      iv. The monthly energy sale volumes and revenues; and the annual average energy selling price (in $/MWh);

      v. Summary of the Resource Physical Major Risks and mitigation measures employed;

[1] BCUC Decision and Order G130-18, dated July 18, 2018 on British Columbia Hydro and Power Authority's Application for approval of BC Hydro's proposed purchase from Teck Metals Ltd. of its two-third Interest in the Waneta Dam along with Teck's transmission assets (Waneta 2017 Transaction Application).

[2] Order No. G-130-18 included a bulleted list of directives under 4(e) which have been replaced with roman numerals for ease of reference against the sections in this report.

vi. Statement of Delivery of Capacity and Energy to BC Hydro under the Waneta 2017 Transaction; and

vii. Statement of Entitlement Adjustments under the Canal Plant Agreement and amendments to the Canal Plant Agreement.

viii. Once BC Hydro has purchased Teck's Transmission Assets, the annual OATT revenues accrued from Line 71.

(f) The Report will be submitted as part of BC Hydro's annual report and as an appendix in its revenue requirements applications until 2058.

2 Third-party Determinations (Response to Directive 4(e)(i))

No operations, maintenance and capital expenditures were referred to a third-party referee in fiscal 2019. Matters which require the unanimous approval of the Operating Committee, and which are subject to resolution by a third-party referee if Teck's and BC Hydro's representatives on the Operating Committee are unable to reach agreement, are set out in section 6.7(a) of the COPOA.

Non-Sustaining Capital Expenditures that are a "Shared Upgrade" require unanimous approval of the Operating Committee, and if there is no agreement, then the upgrade does not proceed (and there is no referral to a third-party referee) as set out in section 6.8(a) of the COPOA. BC Hydro notes that a Non-Sustaining Capital Expenditure can also be undertaken by BC Hydro at its sole discretion and cost (i.e., a BC Hydro Upgrade). There were no Non-Sustaining Capital Expenditures or BC Hydro Upgrades in fiscal 2019.

3 Operations, Maintenance and Capital Expenditures (Response to Directive 4(e)(ii))

Table 1 below provides the comparison of the actual (accrued) and forecast expenditures for fiscal 2019, with an explanation for variances greater than

10 per cent. BC Hydro's one-third share of costs are for the full fiscal 2019 year whereas Teck's two-third portion of costs are only shown for the part of the fiscal year after the Waneta 2017 Transaction closed.

Table 1 Comparison of Actual[1] and Forecast Expenditures for BC Hydro's 1/3, Fiscal 2019

($ thousand)	F2019 Forecast	F2019 Actual	Variance	Variance (%)	Variance Explanation (if >10 %)
	1	2	3 = 2 - 1	4 = 3/1 x 100	
Operations and Maintenance[2]	2,626	2,610	16	(1)	
Sustaining Capital	1,936	736	(1,200)	(62)	The negative variance in fiscal 2019 was the result of delaying sustaining capital projects into subsequent years while resources at Teck focused on the completion of the Waneta 2017 Transaction. The bulk of the deferred costs relate to the Unit 3 Life Extension project which is expected to transition into the execution phase in the fall of 2019.
Water Fees	6,675	6,632	(43)	(1)	

1 BC Hydro is reporting actual expenditures on an accrual basis.
2 Includes insurance and Teck administration.

Table 2 Comparison of Actual[1] and Forecast Expenditures for Teck's 2/3[3], August 2018 to March 2019

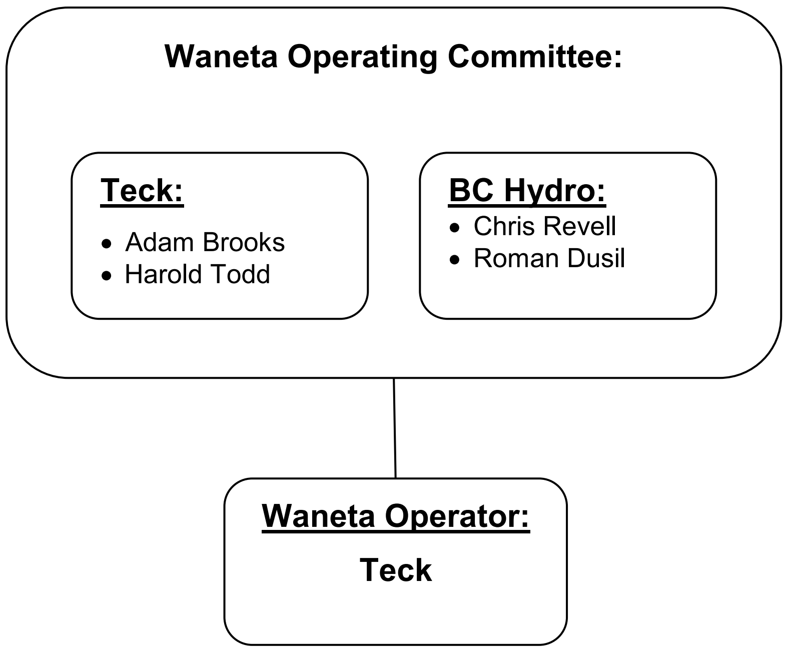
($ thousand)	F2019 Forecast	F2019 Actual	Variance	Variance (%)	Variance Explanation (if >10 %)
	1	2	3 = 2 - 1	4 = 3/1 x 100	
Operations and Maintenance[2]	3,843	3,711	(132)	(3)	
Sustaining Capital	3,871	1,377	(2,494)	(64)	Teck's share of actual expenditures is reported for the partial fiscal year after the Waneta 2017 Transaction completed. The negative variance in fiscal 2019 was the result of deferring sustaining capital projects into subsequent years while resources at Teck focused on the completion of the Waneta 2017 Transaction. The bulk of the deferred costs relate to the Unit 3 Life Extension project which is expected to transition into the execution phase in the fall of 2019.
Water Fees	2,420	2,420	(0)	0	

1. BC Hydro is reporting actual expenditures on an accrual basis.
2 Includes insurance and Teck administration.
3 Upon the completion of the Waneta 2017 Transaction, accounting rules require Teck's portions of costs to be accounted for in BC Hydro's financial statements. These costs have been broken out separately to isolate the effect of the change in accounting treatment from the variance reporting of BC Hydro's share of costs given that the change took place part way through fiscal 2019.

Based on the criteria defined under the Co-Possessors and Operating Agreement, unanimous approval of the Operating Committee was required for the calendar 2018 budgets. This provision was triggered as a result of increases to base cost pressures, non-routine work and planned capital work.

4 Organization Chart (Response to Directive 4(e)(iii))

The following chart shows the members of the Operating Committee and the Operator.



5 Surplus Power Rights Agreement (Response to Directive 4(e)(iv))

Table 3 below provides monthly energy sale volumes and payments pursuant to the Surplus Power Rights Agreement with Teck. BC Hydro purchased a total of 146.6 GWh of surplus energy from Teck during fiscal 2019 under section 5 of the agreement at an average price of C$59.39/MWh.

Table 3 Surplus Power Rights Agreement Purchases

	Apr 2018	May 2018	Jun 2018	Jul 2018	Aug 2018	Sep 2018	Oct 2018	Nov 2018	Dec 2018	Jan 2019	Feb 2019	Mar 2019	Total
Invoice Total ($k)	-	138	-	-	2	-	4,499	503	-	758	1,156	1,652	8,708
Volume (MWh)	-	5,785	-	-	124	-	84,491	9,386	-	11,823	20,000	15,000	146,609

6 Risks and Mitigation Measures (Response to Directive 4(e)(v))

Three dam stability projects are currently planned as part of phase two of the dam stability work which has been reported on previously, including: 1) installation of piezometers, 2) borehole and concrete testing and 3) a buried channel assessment. The piezometers were installed in 2018 to provide additional data collection sites to assess water pressure on the dam. One of the penstocks was intercepted by the drill during the installation of one of the piezometers. Work immediately stopped to facilitate the development of a mitigation plan which has since been implemented and a permanent fix now in place. No further risks are anticipated related to this incident.

The borehole and concrete testing also occurred in 2018 with results to confirm concrete strength expected soon. The buried channel assessment is an ongoing study to assess potential percolation flows and effectiveness of a drainage filter that was installed during the original construction of the Waneta Dam in the 1950s. The assessment will continue into fiscal 2020.

7 Delivery of Capacity and Energy to BC Hydro (Response to Directive 4(e)(vi))

The annual capacity and energy benefit to BC Hydro under the Waneta Transaction is the reduction in the amount of entitlement that BC Hydro is obligated to provide

Teck under the Canal Plant Agreement (**CPA**), with and without the Waneta 2017 Transaction. The reduction in BC Hydro's obligation to provide capacity and energy entitlement to Teck for fiscal 2019, with and without the Waneta 2017 Transaction, is provided below in Table 4. Additional information on this entitlement adjustment is provided in section 8 of this report.

Table 4 Comparison of BC Hydro's Obligation to Provide CPA Entitlement

F2019 (April 1, 2018 to March 31, 2019)	Without Waneta Transaction	With Waneta Transaction	Reduction
	1	2	3 = 1 - 2
Base Capacity Entitlement (MW)	496 (winter peak)	248 (winter peak)	248
Base Energy Entitlement (GWh)	2,746	1,880	866

8 Statement of Entitlement Adjustments under the Canal Plant Agreement (Response to Directive 4(e)(vii))

The last entitlement adjustment resulted from a redetermination when the Waneta Expansion came online in April 2015.

9 Annual OATT Revenues Accrued from Line 71 (Response to Directive 4(e)(viii))

Teck continues to own Line 71 until the end of the Waneta Lease in 2038 (or 2048 if Teck elects to extend the lease). As such, there were no OATT revenues in fiscal 2019.

10.2 Summary Report on Volumes and Pricing of Transmission Capacity Reassignment and Simultaneous Submission Window as Required by British Columbia Utilities Commission Order No. G-102-09

The Commission Panel directs BCTC to prepare a summary report on the volumes and pricing of any reassigned transmission capacities on its system. This report is to be included in BCTC's annual report to the Commission.

The fiscal 2019 summary report on volumes and pricing of transmission capacity reassignments, and simultaneous submission window, as required by Commission Order No. G-102-09 is provided.

10.2.1 Introduction

On November 21, 2008, British Columbia Transmission Corporation (**BCTC**) applied to the Commission to amend its Open Access Transmission Tariff (**OATT**) (**the Application**). The Application consisted of four parts:

- Amendments requested to maintain consistency with the revised pro forma tariff of U.S. Federal Energy Regulatory Commission (**FERC**);
- Miscellaneous "housekeeping amendments" required to address minor issues which had arisen under BCTC's current OATT;
- Amendments to the rate design for Short-Term Point-to-Point transmission service; and
- Amendments to address issues which had arisen on the British Columbia to Alberta path, including a complaint filed by TransCanada Energy Ltd., one of BCTC's customers, on October 9, 2008.

On September 10, 2009, the Commission issued its Decision on all parts of the Application. (The TransCanada Energy Ltd. complaint was addressed in a separate decision issued on the same day.) In its Decision and Order No. G-102-09, among other things, the Commission directed BCTC to include two new reports in its Annual Financial Report to the Commission. The following two reports are provided below:

- Transmission capacity reassignment; and
- Assessment of simultaneous submission window.

Unless otherwise defined, capitalized terms in sections 10.2.2 and 10.2.3 are defined in the North American Energy Standards Board's (**NAESB**) Business Practice Standards (**BPS**) Abbreviations, Acronyms and Definition of Terms document.

10.2.2 Transmission capacity reassignment

BCTC proposed to amend the OATT to accord with FERC Order 890 provisions that lifted the price cap on reassignment of transmission capacity for a trial period ending in October 2010, subject to FERC assessment of the impact of the measure. BCTC proposed to review FERC's assessment and file any necessary changes to the OATT with the Commission.

The Commission approved the Capacity Reassignment provisions as proposed in the Application, and observed that the creation of a secondary market may provide increased access to the transmission system, thereby promoting more efficient utilization of the grid. The Decision noted that the implementation plan described in FERC Order 890 included a requirement for quarterly reporting, and directed BCTC to include a summary report in BCTC's annual report to the Commission on the volumes and pricing of any reassigned transmission capacity on its system.[1]

On December 1, 2010, BC Hydro implemented the Market Operations Development System (**MODS**). MODS provides BC Hydro the ability to facilitate the capacity reassignment provisions contemplated in the Application.

During the fiscal year ended March 31, 2019, BC Hydro observed that 892 Confirmed Resale transactions occurred on five paths:

- Nine Resale transactions occurred on the AESO-BCHA path;
- 21 occurred on the BCHA-AESO path;
- 813 occurred on the BCHA-BPAT path;
- 36 occurred on the BPAT-AESO wheel through path; and
- 13 occurred on the BPAT-BCHA path.

[1] In The Matter Of British Columbia Transmission Corporation and Amendments to The Open Access Transmission Tariff Decision, September 10, 2009, page 7.

Of the total Resale transactions:

- 833 were from Hourly Firm Point-to-Point (**PTP**) Transmission Service to Hourly Firm PTP Transmission Service;
- One was from Daily Firm PTP Transmission Service to Daily Firm PTP Transmission Service;
- 14 were from Monthly Firm PTP Transmission Service to Monthly Firm PTP Transmission Service; and
- 44 were from Yearly Firm PTP Transmission Service to Yearly Firm PTP Transmission Service.

On four of the five paths (AESO-BCHA, BCHA-AESO, BCHA-BPAT, and BPAT-BCHA), the same customer resold transmission service to itself. On the fifth path (BPAT-AESO), transmission service was sold from one customer to a second customer, and the second customer resold the transmission service to a third customer. Each path's Resales were scheduled on the same path, Point of Receipt (**POR**), and Point of Delivery (**POD**) as the Original transmission reservation, but for terms varying from one hour up to five months.

On the AESO-BCHA path, nine Resale transactions ranging from 40 MW to 387 MW were resold during four months of the fiscal year. All of these Resale transmission reservations were the aggregation of two to six reservations from one customer to itself on the same path. The duration of the Resale transmission reservations ranged from one day to one month.

On the BCHA-AESO path, 21 Resale transactions ranging from 7 MW to 380 MW were resold. A total of 380 MW was resold every month in the fiscal year. All of these Resale transmission reservations were the aggregation of two to five transmission reservations from one customer to itself on the same path. In one of these months, an additional 100 MW was resold from one customer to itself on the same path. In eight of these months, an additional 330 MW was resold from one customer to itself on the same path.

On the BCHA-BPAT path, there were a total of 813 hourly Resale transmission reservations. All Resale transmission reservations were the aggregation up to 10 transmission reservations from one customer to itself on the same path and ranged from 1 MW and 1,973 MW. The duration of the Resale transmission reservations ranged from one hour to three days.

On the BPAT-AESO path, 36 Resale transactions ranging from 25 MW to 50 MW were resold on the same path ranging from one hour up to one month. In each month of the fiscal year, two to four transmission reservations were resold from one customer to a second customer. The second customer aggregated the two Resale transmission reservations and resold the capacity to a third customer.

On the BPAT-BCHA path, 13 Resale transactions ranging from 2 MW to 214 MW were resold during two months of the fiscal year. All of these Resale transmission reservations were the aggregation of two to five reservations from one customer to itself on the same path. The duration of the Resale transmission reservations ranged from four hours to two days.

Prices of the Confirmed Resale transmission reservations varied between originating and resold transmission reservations. Prices ranged from $1.00 to $8.75 with $0.00 being the smallest difference in price and $7.05 being the greatest difference in price.

On the AESO-BCHA path, all nine Resale were priced at $8.05 while originating transmission reservation prices ranged from $7.90 to $8.05. Two Resale transmission reservations had a higher price, and seven Resale transmission reservations had the same price as their originating transmission reservations.

On the BCHA-AESO path, 21 Resale transmission reservation prices ranged from $8.02 to $8.05 while originating transmission reservation prices ranged from $1.00 to

$8.75. Fifteen Resale transmission reservations had a lower price, five Resale transmission reservations had a higher price, and one Resale transmission reservation had a price equal to their originating transmission reservations.

On the BCHA-BPAT path, 813 Resale and originating transmission reservation prices ranged from $1.00 to $8.05. Two-hundred and thirty-five Resale transmission reservations had the same price as their originating transmission reservations. Five-hundred and seventy-eight Resale transmission reservations had a higher price.

On the BPAT-AESO path, 36 Resale transmission reservation prices ranged from $7.86 to $8.75 while originating transmission reservation prices ranged from $5.40 to $8.75. 31 Resale transmission reservations had a higher price, and five Resale transmission reservations had a lower price than their originating transmission reservations.

On the BPAT-BCHA path, 13 Resale transmission reservation prices ranged from $8.02 to $8.05. All 13 Resale transmission reservations had the same price as their originating transmission reservations.

A total of four Resale transmission reservations were Annulled. All of these transmission reservations were for Hourly Firm PTP Transmission Service.

10.2.3 Assessment of Simultaneous Submission Window (SSW)

During the fiscal year ended March 31, 2019, BC Hydro experienced 17 instances of SSW, which involved a total of 52 Transmission Service Requests (**TSRs**). In each instance, the SSW opened during the first five minutes of the earliest request time for Hourly Firm and Non-Firm Transmission Service, which ranged from one to five working days prior to the start of service (subject to extended windows, if applicable).

There were no instances of SSW during the months of April, May and June 2018.

During the month of July 2018, there were five instances of SSW. Fifteen Original TSRs for Hourly Firm Transmission Service and 10 Original TSRs for Hourly Non-Firm Transmission Service ranging from 17 MW to 1,420 MW were submitted on OASIS within the five-minute SSW between 00:00:00 PPT to 00:05:00 PPT. Twenty TSRs were Confirmed and granted the requested capacity shortly after the SSW closed, three of which were subsequently Displaced by competing TSRs. Three TSRs were Refused for insufficient Available Transfer Capability (**ATC**). Two TSRs were Invalid for being submitted too early and were not included in the SSW.

During the month of August 2018, there was one instance of SSW. One Original TSR for Hourly Firm Transmission Service for 100 MW was submitted on OASIS within the five minute SSW between 00:00:00 PPT to 00:05:00 PPT. The TSR was Confirmed and granted the requested capacity shortly after the SSW closed, and was subsequently Displaced by a competing request.

There were no instances of SSW during the month of September 2018.

During the month of October 2018, there were three instances of SSW. Eight Redirect TSRs for Hourly Firm Transmission Service ranging from 7 MW to 380 MW were submitted on OASIS within the five-minute SSW between 00:00:00 PPT to 00:05:00 PPT. Seven TSRs were Confirmed and granted the requested capacity shortly after the SSW closed. One TSR was Retracted due to expiry of Counteroffer.

During the month of November 2018, there were six instances of SSW. Fifteen Redirect and one Original TSRs for Hourly Firm Transmission Service ranging from 16 MW to 380 MW were submitted on OASIS within the five minute SSW between 00:00:00 PPT to 00:05:00 PPT. Eight TSRs were Confirmed and granted the requested capacity shortly after the SSW closed. Five TSRs were Refused for insufficient ATC and one TSR was Withdrawn by the customer in response to a Counteroffer. Two TSRs were Invalid and were not included in the SSW; one for being submitted too early and one due to insufficient capacity to redirect.

During the month of December 2018, there was one instance of SSW. One Original TSR for Hourly Firm Transmission Service for 50 MW was submitted on OASIS within the five minute SSW between 00:00:00 PPT to 00:05:00 PPT. The TSR was Refused for insufficient ATC.

There were no instances of SSW during the months of January and February 2019.

During the month of March 2019, there was one instance of SSW. One Original TSR for Hourly Non-Firm Transmission Service for 400 MW was submitted on OASIS within the five minute SSW between 00:00:00 PPT to 00:05:00 PPT. The TSR was Confirmed and granted the requested capacity shortly after the SSW closed.

Given the limited number of SSW instances, including one instance in which there were multiple parties competing for the same capacity, and the fact that each Confirmed TSR was granted its requested capacity, BC Hydro is of the view that no gaming has transpired since the implementation of SSW.

BC Hydro Fiscal 2019 Annual Report to the British Columbia Utilities Commission

Appendix A

Annual Deferral Accounts Report

April 1, 2018 to March 31, 2019

Table of Contents

British Columbia Hydro and Power Authority
Summary of Deferral Accounts
For the Twelve Months Ended March 31, 2019
($ million)

Line No.	Particulars (Note 1)	Opening Balance at April 1, 2018 (Note 2)	Changes (Schedule B)		Amortization (Note 6)	Interest (Note 7)	Net Change (Appendix 1 Lines 29 - 31)	Ending Balance at March 31, 2019
	(1)	(2)	(3)		(4)	(5)	(6) = (3)+(4)+(5)	(7)=(2)+(6)
1	Heritage Deferral Account (HDA)	(422.6)	(95.2)	Note 3	51.2	(18.5)	(62.4)	(485.1)
2	Non-Heritage Deferral Account (NHDA)	462.8	(170.3)	Note 4	(229.1)	12.7	(386.7)	76.1
3	Trade Income Deferral Account (TIDA)	126.8	(320.5)	Note 5	(62.7)	(2.4)	(385.6)	(258.8)
4	Total	167.0	(586.0)		(240.6)	(8.2)	(834.7)	(667.7)

Due to minor rounding some totals may not add.

Note 1: In the October 29, 2004 Commission Decision (Order No. G-96-04), the Commission approved the creation of four deferral accounts (Heritage Deferral Account, Non-Heritage Deferral Account, Trade Income Deferral Account and BCTC Deferral Account) to capture the differences between forecasts used in setting rates and actual costs. By Order No. G-16-11, the Commission approved the termination of the BCTC Deferral Account.

Note 2: On April 1, 2018, BC Hydro adopted a new IFRS revenue standard. The application of IFRS 15, Revenue from Contracts with Customers, impacted the recognition of revenues under the Skagit River Agreement and the Northwest Transmission Line TS No. 37. The adoption of IFRS 15 resulted in a retroactive decrease in unearned revenues and a corresponding adjustment of ($318.9) million and ($0.6) million to the opening balance in the Heritage Deferral Account and the Non-Heritage Deferral Account, respectively.

Note 3: The transfers of ($95.2) million, which increased the credit balance in the HDA, are primarily due to lower than approved Non-treaty storage and Libby Coordination agreements costs, higher than approved Skagit Valley Treaty and Ancillary Revenues, and lower than approved domestic transmission costs. This is partially offset by higher than approved market electricity purchases, higher than approved water rental costs and lower than approved surplus sales. Non-treaty storage and Libby Coordination agreements costs are lower than approved due to more releases from storage to take advantage of higher market prices. Skagit Valley Treaty and Ancillary Revenues are higher than approved mainly due to the adoption of IFRS 15 revenue recognition assessment for Skagit revenues. The increase in Skagit Valley Treaty revenues is offset by an increase in finance charges that was deferred to the Total Finance Charges Regulatory Account. Domestic transmission costs are lower than approved mainly due to fewer domestic exports. The lower water inflows and reservoir storage levels resulted in fewer export opportunities and placed constraints on hydro generation resulting in higher than approved market electricity purchases and lower than approved surplus sales. Water rental costs are higher than approved as water rental payments in fiscal 2019 were based on the prior year's generation volume, which was higher than the approved, at current year's rates.

Please see Schedule B and C for details.

Note 4: The transfers of ($170.3) million, which decreased the debit balance in the NHDA, are primarily due to lower than approved Independent Power Producers (**IPPs**) and long-term purchase commitments costs, and the deferral of the lease revenues associated with BC Hydro's purchase of Teck's two-third interest in Waneta. This is partially offset by lower than approved domestic revenues and higher than approved net imports to the Trade Account. IPPs and long-term commitments costs are lower than approved primarily due to lower deliveries from hydro projects due to low water inflows, delayed commercial operations date for several projects, suspension of the Standing Offer Program, lower deliveries from wind projects, and termination of several Electricity Purchase Agreements. Fiscal 2019 lease revenues arising from the Waneta 2017 Transaction are deferred in NHDA pursuant to Commission Order No. G-130-18 dated July 18, 2018. Domestic revenues are lower than approved due to lower residential revenues, lower large industrial revenues and lower other energy sales, partially offset by higher light industrial and commercial revenues. Trade Account costs are higher than approved due to higher net imports to the Trade Account. The Trade Account is eliminated upon consolidation and does not impact net income.

Please see Schedule B and C for details.

Note 5: The transfers of ($320.5) million, which decreased the debit balance in the TIDA, are primarily due to higher than approved Powerex net income. Please see Schedule B, line 24.

Note 6: Revenues collected via the Deferral Account Rate Rider (**DARR**) are used to amortize (reduce) the deferral account balances in accordance with Section 10(3) in Direction No. 7 of the Fiscal 2015-Fiscal 2016 Revenue Requirements Application (**Fiscal 2015-Fiscal 2016 RRA**). The reduction is allocated to each deferral account based on the proportion of the ending fiscal 2018 deferral account balances. In Phase One of the Comprehensive Review, the Government of B.C. repealed Direction No. 7. In the Fiscal 2020-Fiscal 2021 Revenue Requirements Application (**Fiscal 2020-Fiscal 2021 RRA**), BC Hydro is requesting BCUC approval to reduce the DARR from 5 percent to 0 per cent on April 1, 2019 and to refund the forecast fiscal 2019 net closing balance and the forecast fiscal 2020 and fiscal 2021 net additions and net interest applied to the Cost of Energy Variance Accounts, over the fiscal 2020 to fiscal 2021 test period.

Note 7: Interest is calculated on the monthly balance in each deferral account. The interest rate used is BC Hydro's weighted average cost of debt for its current fiscal year per Directive 1 (xxv) of the Fiscal 2012 to Fiscal 2014 Revenue Requirements Application.

British Columbia Hydro and Power Authority
Summary of Deferral Accounts Changes
For the Twelve Months Ended March 31, 2019
($ million)

Line No.	Particulars	Approved	Actual	Variance	Ref.
	(1)	(2)	(3)	(4) = (3) - (2)	(5)
1	**Items Subject to Heritage Deferral Account**				
2	Heritage Deferral Account Transactions	285.6	205.8	(79.9)	See Schedule C, Line 25
3	Notional Water Rental (Displaced Hydro)	0.7	4.1	3.5	Note 1
4	Skagit Valley Treaty & Ancillary Revenue	(12.1)	(29.6)	(17.5)	Note 2
5	Costs in Operating / Amortization	12.9	12.2	(0.7)	Note 3
6	Deferred Operating Costs in HDA	-	(0.2)	(0.2)	Note 4
7	Less: Water Rentals (Waneta 1/3)	(6.3)	(6.6)	(0.3)	Note 5
8	Other	36.2	36.2	(0.0)	Note 6
9	Total	317.1	221.9	(95.2)	Schedule A Line 1
10					
11	**Items Subject to Non-Heritage Deferral Account**				
12	Non-Heritage Deferral Account Transactions	1,477.3	1,312.9	(164.4)	See Schedule C, Line 26
13	Commodity Risk	-	1.0	1.0	Note 7
14	Notional Water Rental (Displaced Hydro)	(0.7)	(4.1)	(3.5)	Note 1
15	Domestic Revenue Variance	-	50.7	50.7	Note 8
16	Deferred Operating Costs in NHDA	-	(0.5)	(0.5)	Note 9
17	Add: Water Rentals (Waneta 1/3)	6.3	6.6	0.3	Note 5
18	Less: Water rentals (Waneta - 2/3)	-	(2.4)	(2.4)	Note 10
19	Lease Revenues (Waneta - 2/3)	-	(51.9)	(51.9)	Note 11
20	Other	-	0.3	0.3	Note 12
21	Total	1,482.9	1,312.6	(170.3)	Schedule A Line 2
22					
23	**Trade Income Deferral Account**				
24	Trade Income	(115.1)	(435.7)	(320.5)	Note 13, Schedule A Line 3

Due to minor rounding some totals may not add.

Note 1: Notional Water Rentals (Displaced Hydro) relates to water rentals associated with trade income. The Notional Water Rental mechanism is described in BC Hydro's response to BCUC IR 1.2.36 dated January 23, 2004. The transactions relating to the Notional Water Rental are eliminated on consolidation and there is no net impact on the combined HDA and NHDA as the transactions are mirrored within each account.

Note 2: Skagit revenues recognized for fiscal 2019 are higher due to the adoption of IFRS 15, Revenues from Contracts with Customers.

Note 3: Costs associated with compensation and mitigation efforts to fund fish and wildlife programs, Water Use Plan amortization, and Water Use Plan licence costs are reclassified from cost of energy to other line items on the financial statements under International Financial Reporting Standards. Since the nature of these costs has not changed, they continue to be treated as Heritage cost of energy for deferral accounting purposes.

Note 4: Deferred Operating Costs in the HDA mainly relates to the costs associated with maintaining water use plan licenses.

Note 5: Heritage Deferral Account Transactions (Line 2 above) includes the water rental fees relating to the Waneta one-third interest that were included in the Non-Heritage Cost of Energy in previous Applications. In the Fiscal 2020-Fiscal 2021 RRA, BC Hydro has reported the water rental fees relating to the Waneta one-third interest in the Heritage Cost of Energy.

Note 6: Other amounts deferred in the HDA include amortization of First Nations settlement and prior negotiation costs of $36.2 million and variable costs relating to thermal generation, of which was nil in fiscal 2019.

Note 7: Commodity Risk of $1.0 million consists of gains/losses on intercompany transactions that are offset by corresponding transactions in the TIDA. There is no net impact on the combined NHDA and TIDA balances due to these transactions.

Note 8:

Domestic Revenue Variance ($ million)	Approved	Actual	Variance
Residential	2,067.9	2,025.2	42.7
Light industrial and commercial	1,821.9	1,832.3	(10.4)
Large industrial (includes LNG revenues)	840.9	831.4	9.5
Other energy sales	117.0	108.1	8.9
Domestic Revenue Variance deferred in NHDA (Line 15)	4,847.7	4,797.0	50.7

Load Variance: as per Directive 5 of the Fiscal 2015-Fiscal 2016 RRA Decision per Commission Order No. G-48-14, BC Hydro is allowed to continue to defer in the NHDA the variances between the actual and forecast cost of energy arising from differences between forecast and actual domestic customer load. The net cost of energy variance due to domestic customer load is calculated by adding the domestic revenue variance (Line 15) to the gross cost of energy variance (Line 2 + Line 12) as shown below.

Gross Cost of Energy Variance ((79.9) + (164.4))	(244.2)
Domestic Revenue Variance	50.7
Net Cost of Energy deferred	(193.5)

Note 9: Deferred Operating Costs in the NHDA includes ($0.5) million favorable variance relating to lower than approved IPP capital lease expenses.

Note 10: Pursuant to Commission Order No. G-130-18, BC Hydro may exclude the variances between forecast and actual water rental costs in a given year arising from the Waneta 2017 Transaction from the water rental variances that are deferred to the Non-Heritage Deferral Account.

Note 11: Lease revenues of ($51.9) million deferred in the NHDA relates to BC Hydro's purchase of Teck's two-third interest in Waneta. Per Commission Order No. G-130-18, fiscal 2019 lease revenues arising from the Waneta 2017 Transaction and the revenues associated with capital expenditures made by Teck with respect to BC Hydro's purchase of Teck's two-third interest in Waneta during the Lease Term may be deferred to the Non-Heritage Deferral Account.

Note 12: Other amounts deferred in the NHDA include a variance of ($1.4) million on External OATT revenues (via Miscellaneous Revenues), ($0.2) million on the Northwest Transmission Line TS No. 37 revenue offset by $1.8 million on point-to-point wheeling charges to Powerex (via Intersegment Revenues).

Note 13: Powerex net income reported for regulatory purposes is net of $2.9 million corporate overhead allocation from BC Hydro to Powerex in accordance with Directive 9 of the Fiscal 2009-Fiscal 2010 Revenue Requirements Application Decision.

British Columbia Hydro and Power Authority
Domestic Cost of Energy
For the Twelve Months Ended March 31, 2019
($ million)

Line No.	Particulars		Approved	Actual	Variance	Ref.
	(1)		(2)	(3)	(4) = (3) - (2)	(5)
1	**Cost of Energy - Heritage Energy:**					
2	Water rentals		356.4	363.1	6.7	
3	Natural gas for thermal generation		10.7	7.6	(3.1)	
4	Domestic Transmission - Other		22.1	22.3	0.2	
5	Non-Treaty Storage and Libby Coordination Agreements		(7.2)	(181.9)	(174.7)	
6	Remissions and Other		(33.1)	(33.9)	(0.8)	
7			349.0	177.2	(171.8)	
8						
9	**Cost of Energy - Non-Heritage Energy:**					
10	IPPs and long-term purchase commitments		1,439.3	1,247.2	(192.1)	
11	Non-Integrated Areas		31.1	28.9	(2.2)	
12	Gas and Other Transportation		6.1	9.4	3.3	
13	Water rentals (Waneta - 2/3)		0.0	2.4	2.4	
14			1,476.5	1,287.9	(188.6)	
15						
16	**Cost of Energy - Market Energy:**					
17	Market electricity purchases		35.9	125.0	89.1	
18	Surplus Sales		(129.2)	(115.0)	14.2	
19	Net purchases / (sales) from / to Powerex (Trade Account)		0.7	25.0	24.3	Note 1
20	Domestic Transmission - Export		29.9	18.5	(11.4)	
21			(62.6)	53.5	116.1	
22						
23	**Total Domestic Cost of Energy**		**1,762.9**	**1,518.7**	**(244.2)**	
24						
25	**Heritage Deferral Account Transactions**	[Line 7+17+18+20]	**285.6**	**205.8**	**(79.9)**	Schedule B Line 2
26	**Non-Heritage Deferral Account Transactions**	[Line 14+19]	**1,477.3**	**1,312.9**	**(164.4)**	Schedule B Line 12
27	**Total Domestic Cost of Energy**	[Line 25+26]	**1,762.9**	**1,518.7**	**(244.2)**	
28						
29	**Cost of Energy - Heritage Energy (GWh):**					
30	Water rentals		46,368	42,341	(4,027)	
31	Natural gas for thermal generation		234	191	(43)	
32	Exchange net		(354)	(155)	200	
33			46,248	42,377	(3,871)	
34						
35	**Cost of Energy - Non-Heritage Energy (GWh):**					
36	IPPs and long-term purchase commitments		15,199	14,248	(951)	
37	Non-Integrated Areas:		120	103	(17)	
38			15,320	14,351	(968)	
39						
40	**Cost of Energy Market Energy (GWh):**					
41	Market electricity purchases		934	2,035	1,101	
42	Surplus Sales		(4,517)	(2,230)	2,287	
43	Net purchases from Powerex (Displaced Hydro)		105	647	542	
44			(3,478)	452	3,930	
45						
46	Total sources of supply		58,089	57,181	(908)	
47	Less : Line loss and system use		(5,425)	(4,768)	657	
48						
49	**Total Domestic Sales Volumes**		52,664	52,413	(251)	

Due to minor rounding some totals may not add.

Note 1: These sales / purchases relate to allocations of energy between BC Hydro and Powerex. These sales / purchases are eliminated against trade cost of energy on consolidation. Intercompany transactions between BC Hydro and Powerex have no net impact on the combined NHDA and the TIDA balances.

British Columbia Hydro and Power Authority
Consolidated Statement of Operations
For the Twelve Months Ended March 31, 2019
($ million)

Line No.	Particulars	Approved	Actual	Variance	Ref.
	(1)	(2)	(3)	(4) = (3) - (2)	(5)
1	**REVENUES**				
2	Domestic				
3	Residential	2,067.9	2,025.2	(42.7)	
4	Light industrial and commercial	1,821.9	1,832.3	10.4	
5	Large industrial (includes LNG revenues)	840.9	831.4	(9.5)	
6	Other energy sales	117.0	108.1	(8.9)	
7	Seattle City Light	12.1	29.6	17.5	
8	Revenue from Deferral Rider	241.8	240.6	(1.2)	
9	Miscellaneous	140.6	224.4	83.8	
10		5,242.2	5,291.6	49.4	
11	Intersegment revenues	65.3	62.5	(2.8)	
12		5,307.6	5,354.2	46.6	
13	**EXPENSES**				
14	Domestic energy costs	1,762.9	1,518.7	(244.2)	Schedule C Line 23
15	Operating costs	1,221.0	1,277.0	56.0	
16	Depreciation and amortization	850.9	871.3	20.5	
17	Taxes	238.7	242.7	4.1	
18	Finance charges	773.8	1,192.3	418.5	
19		4,847.3	5,102.0	254.7	
20	**DOMESTIC INCOME (LOSS) BEFORE TRANSFER**				
21	**(TO)/FROM DEFERRAL ACCTS**	**460.3**	**252.2**	**(208.1)**	
22					
23	**POWEREX NET INCOME (LOSS)**	**115.1**	**435.7**	**320.5**	Schedule B Lines 23-24
24	**POWERTECH NET INCOME (LOSS)**	**5.1**	**3.5**	**(1.6)**	
25					
26	**TOTAL INCOME BEFORE TRANSFER (TO)/FROM**				
27	**DEFERRAL ACCOUNTS**	**580.5**	**691.3**	**110.8**	
28					
29	Heritage Deferral Account	4.5	(62.4)	(66.9)	
30	Non-Heritage Deferral Account	(172.7)	(386.7)	(214.0)	
31	Trade Income Deferral Account	(47.1)	(385.6)	(338.5)	
32	Dismantling Costs Regulatory Account	-	12.9	12.9	Note 1
33	First Nation Costs & Provisions Regulatory Account	(14.3)	(13.1)	1.2	
34	Demand-Side Management Regulatory Account	25.1	12.0	(13.1)	
35	Site C Regulatory Account	19.5	19.3	(0.1)	
36	Non-Current Pension Costs Regulatory Account	(57.9)	9.0	66.8	Note 2
37	PEB Current Pension Regulatory Account	(5.7)	(5.0)	0.7	
38	Foreign Exchange Gains/Losses Regulatory Account	35.1	43.2	8.1	
39	Total Finance Charge Regulatory Account	101.8	154.6	52.8	
40	Environmental Provisions Regulatory Account	(34.5)	(31.1)	3.5	
41	Smart Metering and Infrastructure Regulatory Account	(21.7)	(22.0)	(0.2)	
42	IFRS Property Plant & Equipment Regulatory Account	39.0	39.0	(0.0)	
43	IFRS Pension Regulatory Account	(38.2)	(38.2)	0.0	
44	Rate Smoothing Regulatory Account	321.4	(814.9)	(1,136.3)	Note 3
45	Debt Management Regulatory Account	-	321.0	321.0	
46	Other Regulatory Accounts	(22.7)	28.5	51.2	Note 4
47	**TOTAL NET INCOME**	**712.0**	**(428.2)**	**(1,140.2)**	

Due to minor rounding some totals may not add.

Note 1: Pursuant to Fiscal 2017-Fiscal 2019 Revenue Requirements Application Decision, March 1, 2018, Commission Order No. G-47-18, Directive 11, the Commission directed the establishment of the Dismantling Costs Regulatory Account and approved the deferral of variances between forecast and actual dismantling costs over the fiscal 2017 to fiscal 2019 test period. In the Fiscal 2020-Fiscal 2021 RRA, BC Hydro has proposed to continue the Dismantling Cost Regulatory Account.

Note 2: Net Income includes a regulatory transfer of $9.0 million in the Non-Current Pension Costs Regulatory Account, which consist of $66.8 million variance on non-current pension cost in fiscal 2019 and ($57.9) million in amortization of fiscal 2011 to fiscal 2016 balances. In addition, deferred in the Non-Current Pension Costs Regulatory Account, but not reflected in the table above, is $173.1 million related to actuarial (gains)/losses of non-current pension costs that flow through Other Comprehensive Income instead of the Net Income.

Note 3: As a result of Phase One of the Comprehensive Review, BC Hydro ceased using the Rate Smoothing Regulatory Account and wrote off the balance in the account at the end of the third quarter of fiscal 2019 (December 2018). In the Fiscal 2020-Fiscal 2021 RRA, BC Hydro has requested BCUC approval to close the Rate Smoothing Regulatory Account as this account has a zero balance.

Note 4: Included in Other Regulatory Accounts are the following regulatory assets and liabilities: Pre-1996 Contributions in Aid of Construction, Storm Restoration Costs, Capital Project Investigation Costs, Amortization of Capital Additions, Rock Bay Remediation, Arrow Water Systems & Provision, Remediation, Real Property Sales and Customer Crisis Fund.

British Columbia Hydro and Power Authority
Intersegment Revenues
For the Twelve Months Ended March 31, 2019
($ million)

Line No.	Particulars	Approved	Actual	Variance	Reference
	(1)	(2)	(3)	(4) = (3) - (2)	(5)
1	Point-to-Point wheeling charge to Powerex	16.6	26.4	9.8	Note 1
2					
3	Point-to-Point wheeling charge to BCH	45.9	34.3	(11.6)	Note 2
4					
5	Allocation of BCH Corporate costs to Powerex	2.9	2.9	0.0	Note 3
6					
7	Mark to Market Gains	0.0	(1.0)	(1.0)	Schedule B Line 13
8					
9	Total	65.3	62.5	(2.8)	Appendix 1 Line 11

Due to minor rounding some totals may not add.

Note 1: These transmission revenues relate to an allocation of BC Hydro's cost of purchases of point-to-point transmission within B.C. for export and some import transactions. These revenues are eliminated against trade cost of energy on consolidation. The variance is deferred in the NHDA - please refer to Schedule B, Line 20 and Note 12.

Note 2: These transmission revenues relate to an allocation of BC Hydro's cost of purchases of point-to-point transmission relating to BC Hydro's Skagit Valley Treaty commitment, Canadian Entitlement Agreement (OATT Schedule 01), Domestic Exports, Scheduling, and System Control and Dispatch Services (OATT Schedule 03). These revenues are eliminated against domestic cost of energy on consolidation. The variance is deferred in the NHDA - please refer to Schedule B, Line 20 and Note 12.

Note 3: These revenues relate to an allocation of corporate overhead costs to Powerex and are eliminated against Trade Income.

Deferral Accounts Rules

The following “rules” are used by BC Hydro to determine transfers to the Deferral Accounts. These rules are derived from BC Hydro’s interpretation of the evidence and testimony provided during the Fiscal 2005 to Fiscal 2006 Revenue Requirement Application (**RRA**) proceeding and from Directive No. 19 of the BCUC’s October 29, 2004 Decision on the Fiscal 2005 to Fiscal 2006 RRA (BCUC Order No. G-96-04). These rules have been updated for the:

- Fiscal 2007 to Fiscal 2008 RRA Negotiated Settlement Agreement (**NSA**) (BCUC Order No. G-143-06);
- Directives included in the BCUC’s Decision on the Fiscal 2009 to Fiscal 2010 RRA (BCUC Order No. G-16-09);
- Fiscal 2011 RRA NSA (BCUC Order No. G-180-10);
- Directives included in the BCUC’s Decision on the Fiscal 2012 to Fiscal 2014 RRA (BCUC Order No. G-77-12A);
- Directives included in the BCUC’s Decision on the Fiscal 2015 to Fiscal 2016 RRA (BCUC Order No. G-48-14); and
- Directives included in the BCUC’s Decision on the Fiscal 2017 to Fiscal 2019 RRA (BCUC Order No. G-47-18).

In Phase One of the Comprehensive Review, the Government of B.C. repealed Directions 3, 6 and 7 to the BCUC. Direction No. 7 to the BCUC included the Heritage Contract. The repeal of the Heritage Contract has no impact on BC Hydro or ratepayers; however, it provides BC Hydro with the flexibility to re-categorize its Cost of Energy into Heritage Energy, Non-Heritage Energy and Market Energy as shown in Schedule C. Some of the Orders referred to above reference terms that were included in the Heritage Contract, such as the Heritage Payment Obligation. BC Hydro has revised the Deferral Account Rules to update these references.

Where a component of the Deferral Account Rules below is followed by a footnote, the language is from the noted BCUC decision or ongoing regulatory proceeding. Where a footnote is not shown, the language represents BC Hydro’s interpretation of the evidence and testimony noted above.

Heritage Deferral Account (HDA)

Items Subject to Heritage Deferral Account (HDA)

Commission Decision, October 29, 2004, Page 41:

Commission Findings

The Commission Panel approves the HDA as proposed by BC Hydro

Variances between the forecast and the actual cost for the following will flow through the HDA:

1. Cost of energy[1]

   This includes the cost of Heritage Energy,[2] all Market Electricity Purchases, Surplus Sales[1] and Domestic Transmission – Export costs. This item is explained in greater detail below to provide clarification on the methodology used to determine variances:

   - Gains/losses on energy derivatives and financial instruments used to minimize energy costs are included as part of total energy costs;
   - Variances resulting from changes to compensation and mitigation costs, water rental remissions, or Skagit energy transportation contracts are eligible for deferral. These are price variances as they do not vary with volume; and
   - Variances between forecast and actual load curtailment costs are to be included in the HDA.[3]

2. Variable costs related to thermal generation.[1]

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[1] Per Fiscal 2005 to Fiscal 2006 RRA Decision, Directive 11 (BCUC Order No. G-96-04), amended by the Fiscal 2009 to Fiscal 2010 RRA Decision, Directive 31 (BCUC Order No. G-16-09), as continued by the Fiscal 2015 to Fiscal 2016 RRA Decision, Directive 5 (BCUC Order No. G-48-14) .

[2] As shown in Schedule C of the Annual Deferral Accounts Report.

[3] Per Fiscal 2009 to Fiscal 2010 RRA Decision, Directive 30 (BCUC Order No.G-16-09).

3. Significant unplanned major maintenance costs greater than $1 million related to single event equipment or infrastructure failure or caused by weather related events.[1]
4. Significant unplanned major capital expenditures having an incremental annual impact on the Income Statement greater than $1 million related to single event equipment or infrastructure failure or caused by weather related events.[1]
5. Amortization of unplanned deferred capital costs pursuant to BCUC Order No. G-53-02.[1, 4]
6. Skagit Valley Treaty revenues and ancillary services revenues.[1]
7. An interest charge/credit[5] is to be applied to the monthly balance in each deferral account at BC Hydro's weighted average cost of debt for its current fiscal year.[6]

[4] Per Fiscal 2017 to Fiscal 2019 RRA Decision, Directive 7, annual negotiation costs related to First Nations are excluded from amounts deferred to the Heritage Deferral Account, effective March 31, 2017 (BCUC Order No. G-47-18).

[5] Per Fiscal 2005 to Fiscal 2006 RRA Decision, Directive 18, amended by the Fiscal 2007 to Fiscal 2008 RRA Negotiated Settlement Agreement (BCUC Order No. G-143-06).

[6] Per Fiscal 2012 to Fiscal 2014 RRA Decision, Directive 1 (xxv) (BCUC Order No. G-77-12A).

Non-Heritage Deferral Account (NHDA)

Items Subject to Non Heritage Deferral Account (NHDA)

Commission Decision, October 29, 2004, Page 41:

Commission Findings

The Commission Panel approves all elements of the NHDA, except the distribution emergency restoration costs elements, item 4, because it can be forecast with some confidence, unlike unplanned major capital expenditures and unplanned major maintenance expenditures, and because of risk/reward considerations. Given the denial of item 4 of the NHDA, item 3 of the NHDA is to be as set forth in Final Argument.

Variances between the forecast and the actual cost for the following components will flow through the NHDA:

1. Cost of energy[7] - all energy costs variances not deferred to the HDA. This item is explained in greater detail below to provide clarification on the methodology used to determine variances:

   - Any variances relating to fixed price gas and other transportation contracts would flow through the deferral accounts as they do not vary with volume;

   - Future Trade: when Powerex purchases energy for future trade the cost of the purchase from the external party and the sale to BC Hydro of this energy is recorded in Powerex and is included as part of Trade Income. The BC Hydro side of the entry is shown as part of domestic energy costs (on consolidation, the Powerex revenue from BC Hydro and the BC Hydro energy costs from Powerex are eliminated). The difference between Actual and Plan on the BC Hydro side relating to energy for future trade flows

[7] Per Fiscal 2005 to Fiscal 2006 RRA Decision, Directive 12 (BCUC Order No. G-96-04), amended by Fiscal 2009 to Fiscal 2010 RRA Decision, Directive 31 (BCUC Order No. G-16-09), as continued by the Fiscal 2015 to Fiscal 2016 RRA Decision, Directive 5 (BCUC Order No. G-48-14).

through the Non-Heritage Deferral Account. The Powerex side of the transaction, which is part of Trade Income, flows through the Trade Income Deferral Account. Similar treatment is made when the energy is returned to Powerex;

- Future Trade: when Powerex purchases energy for future trade, Heritage Energy is charged with a notional water rental charge for the use of this energy. The other side of this entry is shown as part of Non-Heritage energy. These entries are eliminated on consolidation. The difference between the Actual and Plan notional water rentals that is part of Heritage Energy flows through the Heritage Deferral Account. The opposite variance relating to the Non-Heritage side of the notional water rental transaction flows through the Non-Heritage Deferral Account; and
- Gains/losses on energy derivatives and financial instruments used to minimize energy costs are included as part of total energy costs.

2. Significant unplanned major maintenance costs greater than $1 million related to single event equipment or infrastructure failure.[7]
3. Significant unplanned major capital expenditures having an incremental annual impact on the Income Statement greater than $1 million related to single event equipment or infrastructure failure or caused by weather related events.[7]
4. Founding Partner Benefits and CIS Credits under the ABS Contract.[7, 8]
5. Impact of load variance:[9]
   - The Net Cost of Energy deferral amount is calculated by subtracting the Gross Load Variance and adding the Net Load Variance to the Gross Cost of Energy deferral amount. In practice, because Net Load Variance equals

[8] The ABS Contract expired on April 30, 2018 and all services previously performed by Accenture have been repatriated by BC Hydro.

[9] Per Fiscal 2009 to Fiscal 2010 RRA Decision, Directive 31 (BCUC Order No. G-16-09) and Fiscal 2012 to Fiscal 2014 RRA Decision, Directive 1 (ix) (BCUC Order No. G-77-12A), as continued by the Fiscal 2015 to Fiscal 2016 RRA Decision, Directive 5 (BCUC Order G-48-14).

Gross Load Variance less Domestic Revenue Variance, the Net Cost of Energy Deferral simplifies to the Gross Cost of Energy Deferral minus the Domestic Revenue Variance.

6. Costs incurred by BC Hydro in fiscal 2014 or a later fiscal year arising from the decommissioning of the Burrard Thermal Plant that are not required for transmission support services, including employee retention costs, penalties or damages that arise as a result of the decommissioning, and the net increase in amortization expense in fiscal 2015 and fiscal 2016.[10]

7. Variances related to the Northwest Transmission Line (**NTL**) Supplemental Charge revenues in conjunction with Tariff Supplement No. 37 amendments.[11]

8. Variances related to Electricity Purchase Agreements (**EPAs**) classified as finance leases in the Fiscal 2017 to Fiscal 2019 RRA. BC Hydro has deferred cost variances attributable to EPAs classified as finance leases that would not be transferred to existing regulatory accounts pursuant to existing orders in fiscal 2017 and fiscal 2018, which benefitted ratepayers.

   In the Fiscal 2020 to Fiscal 2021 Revenue Requirements Application, BC Hydro is seeking BCUC approval to:

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

   - Defer any variances related to the accounting for Electricity Purchase Agreements determined to be leases under IFRS 16, which are not eligible for deferral treatment under existing orders, to the Non-Heritage Deferral Account;

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10 Per Fiscal 2015 to Fiscal 2016 RRA Decision, Directive 6 (BCUC Order No. G-48-14).

11 Per Tariff Supplement No. 37 Amendments Application Decision, Directive 3 (BCUC Order No. G-68-17).

9. Fiscal 2019 incremental lease revenues arising from the Waneta 2017 Transaction and the revenue BC Hydro will be required to recognize from time to time in consequence of Teck's capital expenditures at Waneta until the end of the Lease Period.[12]

10. Variances between forecast and actual transmission service revenue[13] including External OATT revenues and point-to-point charges to Powerex.

11. An interest charge/credit[14] is applied to the monthly balance in each deferral account at BC Hydro's weighted average cost of debt for its current fiscal year.[15]

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12 Per Waneta 2017 Transaction Application Decision, Directive 3 (BCUC Order No. G-130-18).

13 Per Disposition and Termination of BCTC Regulatory Accounts and BC Hydro's BCTC Deferral Account Application Decision, Directive 4 (BCUC Order No. G-16-11).

14 Per Fiscal 2005 to Fiscal 2006 RRA Decision, Directive 18, amended by the Fiscal 2007 to Fiscal 2008 RRA Negotiated Settlement Agreement (BCUC Order No. G-143-06).

15 Per Fiscal 2012 to Fiscal 2014 RRA Decision, Directive 1 (xxv) (BCUC Order No. G-77-12A).

Trade Income Deferral Account (TIDA)

Commission Decision, October 29, 2004, Page 42, Section 4.6:

Commission Findings

The Commission Panel approves the TIDA as proposed by BC Hydro

- Any variance between the forecast Trade Income and the actual Trade Income will flow through the TIDA, except where Annual Trade Income is below zero[16];
- Actual Trade Income is determined by excluding the impact on BC Hydro's consolidated net income due to foreign currency translation gains and losses on intercompany balances between BC Hydro and Powerex Corp; and
- An interest charge/credit[17] is to be applied to the monthly balance in each deferral account at BC Hydro's weighted average cost of debt for its current fiscal year.[18]

16 Per Fiscal 2020 to Fiscal 2021 Revenue Requirements Application, although Direction No. 7 has been repealed, BC Hydro continues to include the net income of its subsidiaries in its revenue requirements and continues to define Trade Income on the same basis as previously defined in Direction No. 7. The effect of this approach is that Trade Income will not be less than zero.

17 Per Fiscal 2005 to Fiscal 2006 RRA Decision, Directive 18, amended by the Fiscal 2007 to Fiscal 2008 RRA Negotiated Settlement Agreement (BCUC Order No. G-143-06).

18 Per Fiscal 2012 to Fiscal 2014 RRA Decision, Directive 1 (xxv) (BCUC Order No. G-77-12A).

BC Hydro
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BC Hydro Fiscal 2019 Annual Report to the British Columbia Utilities Commission

Appendix B

Debt Management Regulatory Account
Annual Status Report
April 1, 2018 to March 31, 2019

Background

On March 30, 2016, the BCUC issued Order No. G-42-16 which authorized BC Hydro to establish a Debt Management Regulatory Account (**DMRA**) to capture mark-to-market gains and losses on financial contracts that hedge future long-term debt to mitigate interest rate risk on future long-term debt that BC Hydro intends to issue.

BC Hydro agreed to provide the BCUC with annual reporting on the DMRA in its Annual Report to the BCUC.

Report as at March 31, 2019

During fiscal 2019, BC Hydro hedged the interest rate risk on an additional $3.3 billion of forecast total borrowing requirements to fiscal 2025. BC Hydro executed 21 future debt hedges (**FDHs**), of which none had settled as at March 31, 2019. The hedges consisted of 10-year and 30-year interest rate swaps and 30-year Government of Canada bond locks, with contract maturity dates ranging from approximately six months to 5.5 years and forecast yields ranging from 3.13 per cent to 3.62 per cent. The addition of these $3.3 billion of FDHs in fiscal 2019 brought the total FDHs placed in fiscal 2017 to fiscal 2019 to $10.0 billion, of which $6.1 billion remain outstanding. Based on BC Hydro's 2019/20 – 2021/22 Service Plan, at March 31, 2019, BC Hydro has hedged 75 per cent of forecast total borrowing requirements from fiscal 2020 to fiscal 2025. The details of all FDHs are included in Appendix 1.

At March 31, 2019, the DRMA had a negative balance of $163 million, which included net unrealized losses of $285 million and realized net gains of $122 million on the $3.9 billion of settled FDHs. This was a net decrease of $321 million from the balance at March 31, 2018 and was mainly due to a decrease in long-term yields on

$1.0 billion of hedges placed in the last quarter of fiscal 2018 and the additional $3.3 billion in hedges placed in the second half of fiscal 2019.

The unrealized loss of $285 million relating to the $6.1 billion in outstanding FDHs remains sensitive to changes in long-term yields and will continue to change until the hedges are settled on maturity. A 100 basis point change in long-term yields would result in a change of approximately $800 million to $1 billion in the value of the $6.1 billion in outstanding FDHs.

Any realized gains and losses will be amortized over the remaining term of the issued debt starting at the beginning of the test period following the test period during which the long-term debt associated with a particular hedge is issued. As a result, the effective interest rate on hedged debt is a combination of the gain or loss on the settled FDH and the yield of the underlying debt issuance.

Appendix 1 – Future Debt Hedges Report

As of March 31, 2019
(in millions of Canadian dollars)

Name	Execution Date	Transaction Type	Forecast Debt Issuance & Contract Maturity Year	Contract Settlement Date	Hedge Term	Notional Amount	Forecast Borrowing Yield	Actual Yield	Fair Market Value[2]	Settlement Value[2]	Total DMRA Balance Before Amortization[2]	Amortization	DMRA Balance[2]
Hedges Placed F2017													
FDH1 [1]	2016-05-16	Bond Lock	F2017	16-Nov	10 years	200	2.24%	3.01%		2.7	2.7	0.0	2.7
FDH2A	2016-05-11	Bond Lock	F2017	16-Sep	30 years	200	2.97%	3.00%		(11.3)	(11.3)	0.0	(11.3)
FDH2B	2016-05-12	Bond Lock	F2017	16-Sep	30 years	100	3.01%	3.00%		(6.7)	(6.7)	0.0	(6.7)
FDH3	2016-05-18	Bond Lock	F2018	17-Mar	10 years	300	2.36%	2.35%		8.0	8.0	0.0	8.0
FDH4	2016-05-24	Bond Lock	F2018	17-Oct	10 years	200	2.38%	2.37%		7.4	7.4	0.0	7.4
FDH5	2016-05-31	Bond Lock	F2018	17-Jun	30 years	200	3.04%	2.87%		0.1	0.1	0.0	0.1
FDH6	2016-09-23	Swap	F2018	17-Oct	10 years	200	2.09%	1.83%		17.0	17.0	0.0	17.0
FDH7	2016-09-23	Swap	F2018	17-Oct	10 years	200	2.08%	1.82%		17.2	17.2	0.0	17.2
FDH8	2016-09-26	Swap	F2018	17-Sep	30 years	200	2.64%	2.27%		40.9	40.9	0.0	40.9
FDH9	2016-09-29	Swap	F2019	18-May	10 years	200	2.09%	1.84%		22.7	22.7	0.0	22.7
FDH10	2016-10-06	Swap	F2019	18-Apr	30 years	200	2.76%	2.14%		38.7	38.7	0.0	38.7
FDH11	2016-06-08	Swap	F2019	18-Sep	10 years	300	2.53%	2.16%		22.4	22.4	0.0	22.4
FDH12	2016-06-08	Swap	F2019	18-Sep	10 years	200	2.54%	2.17%		14.7	14.7	0.0	14.7
FDH13	2016-06-14	Swap	F2020		10 years	300	2.54%		5.3		5.3		5.3
FDH14	2016-06-22	Swap	F2020		10 years	200	2.74%		0.3		0.3		0.3
FDH15	2016-10-12	Swap	F2020		10 years	200	2.57%		3.7		3.7		3.7
FDH16	2016-10-13	Swap	F2021		10 years	300	2.60%		5.2		5.2		5.2
FDH17	2016-10-13	Swap	F2021		10 years	200	2.60%		3.4		3.4		3.4
FDH18	2016-10-20	Swap	F2021		10 years	300	2.69%		4.2		4.2		4.2
FDH19	2016-10-20	Swap	F2021		10 years	200	2.69%		2.7		2.7		2.7
Subtotal						**$4,400**			**$24.8**	**$173.8**	**$198.6**		**$198.6**
Hedges Placed F2018													
FDH20	2017-09-29	Bond Lock	F2019	18-Jul	10 years	200	2.96%	2.88%		(1.6)	(1.6)	0.0	(1.6)
FDH21	2017-10-03	Bond Lock	F2019	18-Jul	10 years	200	3.00%	2.92%		(2.2)	(2.2)	0.0	(2.2)
FDH22	2017-09-29	Bond Lock	F2019	18-Jul	30 years	200	3.35%	3.36%		(17.3)	(17.3)	0.0	(17.3)
FDH23A	2017-10-04	Bond Lock	F2019	18-Jun	10 years	100	3.01%	2.84%		(0.4)	(0.4)	0.0	(0.4)
FDH23B	2017-10-04	Bond Lock	F2019	18-Jun	10 years	100	3.01%	2.87%		(0.4)	(0.4)	0.0	(0.4)
FDH24A	2017-10-02	Bond Lock	F2019	18-Aug	30 years	100	3.36%	3.35%		(6.4)	(6.4)	0.0	(6.4)
FDH24B	2017-10-03	Bond Lock	F2019	18-Aug	30 years	100	3.38%	3.37%		(6.8)	(6.8)	0.0	(6.8)
FDH25	2017-09-28	Bond Lock	F2019	18-Aug	30 years	250	3.37%	3.36%		(16.7)	(16.7)	0.0	(16.7)
FDH26/27	2018-01-29	Swap	F2020		30 years	50	3.44%		(4.8)		(4.8)		(4.8)
FDH28	2018-02-05	Swap	F2021		30 years	75	3.64%		(10.2)		(10.2)		(10.2)
FDH29	2018-02-05	Swap	F2021		30 years	75	3.64%		(10.1)		(10.1)		(10.1)
FDH30/31	2018-02-08	Swap	F2022		30 years	175	3.67%		(23.2)		(23.2)		(23.2)
FDH32	2018-02-06	Swap	F2022		30 years	100	3.60%		(11.7)		(11.7)		(11.7)
FDH33	2018-02-07	Swap	F2022		30 years	100	3.58%		(11.4)		(11.4)		(11.4)
FDH34/35	2018-02-01	Swap	F2023		30 years	250	3.52%		(23.9)		(23.9)		(23.9)
FDH36/37	2018-01-24	Swap	F2023		30 years	200	3.40%		(14.7)		(14.7)		(14.7)
Subtotal						**$2,275**			**($110.0)**	**($51.7)**	**($161.6)**		**($161.6)**
Hedges Placed F2019													
FDH38	2018-12-07	Swap	F2022		10 years	125	3.33%		(6.0)		(6.0)		(6.0)
FDH39	2018-12-06	Swap	F2023		10 years	100	3.40%		(4.6)		(4.6)		(4.6)
FDH40	2018-12-07	Swap	F2023		10 years	125	3.41%		(5.6)		(5.6)		(5.6)
FDH41	2018-12-07	Swap	F2024		10 years	175	3.46%		(7.5)		(7.5)		(7.5)
FDH42	2018-12-06	Swap	F2024		30 years	175	3.62%		(18.6)		(18.6)		(18.6)
FDH43	2019-01-15	Bond Lock	F2020		30 years	150	3.13%		(11.0)		(11.0)		(11.0)
FDH44	2019-01-16	Bond Lock	F2020		30 years	125	3.17%		(10.3)		(10.3)		(10.3)
FDH45A	2019-01-17	Bond Lock	F2021		30 years	200	3.20%		(16.6)		(16.6)		(16.6)
FDH45B	2019-01-17	Bond Lock	F2021		30 years	125	3.20%		(10.4)		(10.4)		(10.4)
FDH46A	2019-01-15	Swap	F2021		30 years	100	3.43%		(8.7)		(8.7)		(8.7)
FDH46B	2019-01-16	Swap	F2021		30 years	225	3.49%		(22.6)		(22.6)		(22.6)
FDH47	2019-01-08	Swap	F2022		10 years	275	3.15%		(9.1)		(9.1)		(9.1)
FDH48	2019-01-09	Swap	F2022		30 years	100	3.41%		(7.8)		(7.8)		(7.8)
FDH49	2019-01-09	Swap	F2022		10 years	300	3.22%		(11.0)		(11.0)		(11.0)
FDH50	2019-01-10	Swap	F2022		30 years	175	3.41%		(13.2)		(13.2)		(13.2)
FDH51	2019-01-14	Swap	F2023		10 years	250	3.26%		(8.6)		(8.6)		(8.6)
FDH52	2019-01-10	Swap	F2023		10 years	125	3.27%		(4.2)		(4.2)		(4.2)
FDH53	2019-01-11	Swap	F2023		30 years	100	3.42%		(7.4)		(7.4)		(7.4)
FDH54	2019-01-09	Swap	F2024		10 years	175	3.33%		(5.7)		(5.7)		(5.7)
FDH55	2019-01-08	Swap	F2024		30 years	125	3.44%		(9.1)		(9.1)		(9.1)
FDH56	2019-01-15	Swap	F2025		10 years	75	3.39%		(2.3)		(2.3)		(2.3)
Subtotal						**$3,325**			**($200.2)**	**$0.0**	**($200.2)**		**($200.2)**
Total						**$10,000**			**($285.3)**	**$122.1**	**($163.2)**		**($163.2)**

[1] Actual debt was a 30 year issue.

[2] Gain / (loss)

1 # Appendix 2 – Glossary for Appendix 1

Name	BC Hydro reference for each individual FDH
Execution Date	Date the FDH was entered into.
Transaction Type	Type of Future Debt Hedge **Bond Locks** – contracts with financial institutions that are based on the performance of Government of Canada Treasury Bonds. Under a Bond Lock, BC Hydro will effectively sell a particular Government of Canada Bond at the current interest rate and effectively repurchase it at a pre-defined future date at the then-prevailing market interest rate **Forward Swaps** – contracts with financial institutions whereby BC Hydro will pay the current interest rate on the Interest Rate Swap[1] and agree to receive the prevailing interest rate on the Interest Rate Swap at a pre-defined future date.
Forecast Debt Issuance and Contract Maturity Year	Fiscal year the FDH derivative contract is forecast to be unwound and cash settled (set at the inception of the hedge) and the related future debt is expected to be issued.
Contract Settlement Date	Date the FDH derivative was actually unwound and cash settled.
Hedge Term	The term of the future debt issue that is being hedged (i.e., either a 10-year debt issue or a 30-year debt issue).
Notional Amount	The dollar value of the FDH derivative. The notional amount of the derivative will be equal to the principal amount of the related future debt issue.
Forecast Borrowing Yield	The anticipated yield on a particular future debt issue on the day the FDH was executed. The forecast borrowing yield is subject to change based on the difference between the change in the yield on Province of BC Bonds vs. the change in the yield on the underlying FDHs (Bond lock or Forward Swap) since the inception of the hedges. The actual yield will only be known upon the cash settlement of the FDH and the issuance of the related future debt.
Actual Yield	The effective yield on the future debt issuance taking into account the gain or loss on the related FDH.
Fair Market Value	The mark to market value of the FDHs that are not yet cash settled.
Settlement Value	The amount of cash paid out by BC Hydro or received by BC Hydro upon the unwinding and cash settlement of the FDH. A loss on the FDH would involve a cash payment by BC Hydro and a gain on the FDH would involve a receipt of cash by BC Hydro.
Total DMRA Balance Before Amortization	The amount of gain or loss on FDHs recorded in the DMRA since inception. Comprised of mark to market gains and losses and settlement gains and losses.

1 A Canadian Interest Rate Swap is an agreement between two counterparties that agree to exchange an interest payment based on the CDOR Canadian Dollar Offer Rate index.

Amortization	The amount removed from the DMRA and included in Net Income. The gains or losses in the DMRA will be amortized over the remaining term of the associated long-term debt issuances, commencing at the beginning of the test period subsequent to the test period in which the long-term debt to which the Future Debt Hedge is associated is issued. The combination of the amortization of the DMRA and the interest charges on the underlying debt result in the effective yield on the debt at its hedged rate.
DMRA Balance	The balance in the DMRA at the report date.