Chris Sandve
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August 31, 2023

Patrick Wruck
Commission Secretary and Manager
Regulatory Services
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 2023 Annual Report to the Commission

BC Hydro writes pursuant to BCUC Letter Nos. L-36-94, L-14-95, L-45-15, and subsection 45(6) of the *Utilities Commission Act* to provide BC Hydro's Fiscal 2023 Annual Report to the Commission for the period April 1, 2022, to March 31, 2023.

BC Hydro's Fiscal 2023 Annual Report to the Commission includes BC Hydro's progress on its UNDRIP implementation plan in accordance with Directive 84 of BCUC Order No. G-91-23.

In accordance with the BCUC's letter on Safety Matters, dated July 5, 2023, BC Hydro will enclose its listing of all material safety matters commencing with the Fiscal 2024 Annual Report.

For further information, please contact Joe Maloney at 604-623-4348 or by email at bchydroregulatorygroup@bchydro.com.

Yours sincerely,

Chris Sandve
Chief Regulatory Officer

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Enclosure

BC Hydro Fiscal 2023 Annual Report to the British Columbia Utilities Commission

April 1, 2022 to March 31, 2023

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List of Appendices

1 Declaration

I, Ryan Layton, 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.; and
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*.

BC Hydro has also complied with the Commission's financial directives with regard to the following:[1]

- Section 6, Attachment 2: A breakdown between storm restoration costs and evacuation relief costs in the Storm Restoration Costs Regulatory Account as required by Item 5 of BCUC Order No. G-215-20 (Schedule 2.2, Line 39);
- Section 6, Attachment 1: Financial Schedules and Variance Explanations in accordance with BCUC Order No. G-187-21 (section 3, Cost of Energy Variance Explanations);
- Section 6, Attachment 1: Financial Schedules and Variance Explanations in accordance with BCUC Order No. G-313-19 (section 3.3.1);
- Section 6, Attachment 1, section 12: Financial Schedules and Variance Explanations in accordance with BCUC Letter No. L-65-20;

[1] Directive 62 of the BCUC's Decision on the Fiscal 2020 to Fiscal 2021 Revenue Requirements Application directed BC Hydro to file annually as part of its annual report to the BCUC, in confidence, if necessary, a summary of Powertech's net income in sufficient detail to enable the BCUC to determine whether the inclusion of Powertech's net income is appropriate. On March 22, 2021, the Government of B.C. deposited Order in Council No. 172, which amended Direction No. 8 to the BCUC. In accordance with the amendments to Direction No.8, BC Hydro requested that Directive 62 be rescinded. The BCUC considered BC Hydro's request and on June 28, 2021, issued Order No. G-197-21 which rescinded this directive.

- Section 6, Attachment 1, section 1: Financial Schedules and Variance Explanations – Domestic Energy Sales Variance Explanation in accordance with Directive 4 of BCUC Order No. G-246-20;
- Section 7, Attachment: Summary of Planned Capital Extension Projects and Anticipated Regulatory Filings as required by Directive 2 of BCUC Order No. G-313-19 (section 3.1.3);
- Section 10: Waneta Transaction Annual Report as required by Directive 4(e) of BCUC Order No. G-130-18;
- Section 11: UNDRIP Plan Progress in Fiscal 2023 as required by BCUC Order No. G-91-23;
- Section 12: Annual Report Summary Information in accordance with BCUC Letter No. L-8-22;
- Appendix A: Annual Deferral Accounts Report[2] as required by Directive 8 of BCUC Order No. G-96-04;
- Appendix B: Debt Management Regulatory Account Annual Status Report as required by Directive 4 of BCUC Order No. G-42-16;
- Appendix C – Residential Service Customers Charging Zero Emission Vehicles at their Dwelling Annual Report as required by Directive 2 of BCUC Order No. G-92-19; and,
- Appendix D – Performance of Rate Schedule 1894 and 1895 as required by BCUC Order No. G-38-21.

[2] BC Hydro received a Variance to Order No. 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: ______________________

Ryan Layton

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

British Columbia Hydro and Power Authority

August 31, 2023

2 Directors and Officers

Report below the name, title and business address of each director and officer, as at March 31, 2023.

Name	Business Address	Office Held
Board of Directors		
Doug Allen[1]	333 Dunsmuir St Vancouver, BC V6B 5R3	Chair
Lynette DuJohn	333 Dunsmuir St Vancouver, BC V6B 5R3	Director
Daryl Fields	333 Dunsmuir St Vancouver, BC V6B 5R3	Director
Amanda Hobson[2]	333 Dunsmuir St Vancouver, BC V6B 5R3	Director
Irene Lanzinger	333 Dunsmuir St Vancouver, BC V6B 5R3	Director
Clarence Louie	333 Dunsmuir St Vancouver, BC V6B 5R3	Director
Victoria McMillan	333 Dunsmuir St Vancouver, BC V6B 5R3	Director
Nalaine Morin	333 Dunsmuir St Vancouver, BC V6B 5R3	Director
Vasee Navaratnam	333 Dunsmuir St Vancouver, BC V6B 5R3	Director
John Nunn	333 Dunsmuir St Vancouver, BC V6B 5R3	Director
Catherine Roome	333 Dunsmuir St Vancouver, BC V6B 5R3	Director
Lori Wanamaker[3]	333 Dunsmuir St Vancouver, BC V6B 5R3	Vice Chair
Officer (Executive Team)		
Chris O’Riley	333 Dunsmuir St Vancouver, BC V6B 5R3	President and Chief Executive Officer

[1] Doug Allen’s appointment term expired on May 31, 2023, and Lori Wanamker was appointed Chair on June 1, 2023.

[2] Amanda Hobson was appointed as Director May 6, 2022.

[3] Lori Wanamaker was appointed as Director January 1, 2023, Vice Chair on January 18, 2023, and Chair on June 1, 2023. A new Vice Chair has not been appointed.

Name	Business Address	Office Held
Maureen Daschuk	333 Dunsmuir St Vancouver, BC V6B 5R3	Executive Vice-President, Integrated Planning
Ken Duke	333 Dunsmuir St Vancouver, BC V6B 5R3	Senior Vice-President & General Counsel
Al Leonard	333 Dunsmuir St Vancouver, BC V6B 5R3	Executive Vice-President, Capital Infrastructure Project Delivery
Darren Kahl	333 Dunsmuir St Vancouver, BC V6B 5R3	Executive Vice-President, Site C
Charlotte Mitha	333 Dunsmuir St Vancouver, BC V6B 5R3	Executive Vice-President, Operations
Kirsten Peck	333 Dunsmuir St Vancouver, BC V6B 5R3	Senior Vice-President, Safety & Chief Compliance Officer
Diana Stephenson	333 Dunsmuir St Vancouver, BC V6B 5R3	Senior Vice-President, Customer & Corporate Affairs
Carolynn Ryan	333 Dunsmuir St Vancouver, BC V6B 5R3	Senior Vice-President People & Chief Human Resources Officer
David Wong[4]	333 Dunsmuir St Vancouver, BC V6B 5R3	Executive Vice-President, Finance, Technology, Supply Chain & Chief Financial Officer

[4] David Wong resigned, and his last day of employment was May 12, 2023. Ryan Layton, Chief Accounting Officer, is now the Executive Vice-President, Finance, Technology, Supply Chain & Chief Financial Officer.

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, 2023.[1]

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
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

[1] BC Hydro has not included Columbia Hydro Constructors Ltd. (**CHC**) in this list. BC Hydro considers CHC to be active but not "fully operational or fully active", in that it was not used for construction work during the year.

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; and
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 2023

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. None;
3. None;
4. Important leasehold information can be found in BC Hydro’s Consolidated Financial Statements of the 2022/23 BC Hydro Annual Service Plan Report as follows:
   - Leasehold information within Note 12: Right-Of-Use Assets and Long-term energy purchase agreements, property leases and other leases sections within Note 19: Lease Liabilities;
   - Energy Commitments and Lease and Service Agreements sections within Note 25: Commitments and Contingencies; and

- Significant accounting policies for important leaseholds are disclosed in the Leases section within Note 3: Significant Accounting Policies.

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

5. In fiscal 2023, BC Hydro placed into service the Mica Replace Units 1 to 4 Generator Transformers project, the Mount Lehman Substation Upgrade project, and the Waneta U3 Life Extension project.

   The Mica Replace Units 1 to 4 Generator Transformers project was put into service in December 2022. The project replaced twelve single phase transformers, which had been in service for over 40 years, with modern, reliable explosion-resistant transformers to improve system reliability and reduce safety risks for workers and equipment in an underground power station.

   The Mount Lehman Substation Upgrade project was put into service in February 2023. The project was to address load growth in the Abbotsford area by increasing the firm capacity of Mount Lehman Substation. The project has increased the firm transformer capacity of the Substation from 100 MVA to 200 MVA and the 25 kV feeder capacity from 100 MVA to 150 MVA. By completing this project, BC Hydro is able to address safety issues at Sumas Way Substation and Clayburn Substation.

   The Waneta U3 Life extension project was put into service in December 2022. The project addressed risks with a deteriorating stator and chronic cavitation damage to the runner by installing a new stator and runner;

6. Union wage scales increased 3.24% plus 25 cents an hour effective April 1, 2022. Manager and exempt professional (**M&P**) salary scales increased 2.0% effective July 1, 2022; and

7. Important legal proceedings pending, in progress, or concluded during the year can be found in BC Hydro's Consolidated Financial Statements of the 2022/23 BC Hydro Annual Service Plan Report as follows:

- Contingencies and Guarantees section within Note 25: Commitments and Contingencies.

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

6 Fiscal 2023 Financial Schedules and Variance Explanations

BC Hydro has provided, in Attachment 1 to this section, a detailed comparison between the fiscal 2023 Decision and fiscal 2023 actual financial results, including variance explanations. Included in Attachment 2 to this section are financial schedules which provide additional comparison details between the fiscal 2023 Decision and fiscal 2023 actual financial results.

Power smart

BC Hydro Fiscal 2023 Annual Report to the British Columbia Utilities Commission

Attachment 1 to Section 6

Fiscal 2023 Financial Schedules and Variance Explanations

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List of Tables

In sections 1 through 9, variance explanations are provided for actual gross amounts in fiscal 2023 compared to the fiscal 2023 RRA decision (**Decision**) amounts. Apart from domestic energy sales and domestic revenue variances, explanations are provided where variances between actual and Decision amounts are greater than 10%, with a minimum variance threshold of $5 million. Domestic energy sales variance explanations are provided for each customer sector.

1 Domestic Energy Sales Variance Explanations (Schedule 14.0)

This section compares fiscal 2023 actual domestic energy sales amounts in GWh with the fiscal 2023 Decision.

Table 1 Fiscal 2023 Domestic Energy Sales Variances

		Schedule	F2023			
	(GWh)	Reference	Decision	Actual	Diff	% Diff
			1	2	3=2-1	4=3/1
1	Residential	14.0 L1	19,657	19,547	(109)	-1%
2	Light Industrial and Commercial	14.0 L2	18,760	19,247	487	3%
3	Large Industrial	14.0 L3	13,163	13,437	275	2%
4	Other	14.0 L4:L10	1,733	2,028	295	17%
5	Electrification Plan	14.0 L15	207	-	(207)	-100%
6	**Total Domestic Energy Sales**	14.0 L16	**53,519**	**54,260**	**740**	1%

The fiscal 2023 Decision domestic sales forecast was based on the December 2020 Load Forecast adjusted for the Decision. Overall, fiscal 2023 actual domestic energy sales were 740 GWh (or 1%) higher than the fiscal 2023 Decision. This was primarily due to:

- Line 1 - Actual Residential sales were 109 GWh (or 1%) lower than the fiscal 2023 Decision. Variances in Residential sales are driven by three main factors: temperature, electricity sales per account (use per account), and number of accounts. In fiscal 2023, the Residential sales variance was primarily due to lower use per account which accounted for a reduction of 789 GWh. While the exact drivers are not known, the likely primary driver is the faster recovery from the COVID-19 pandemic compared to the assumptions used in the load forecast underlying the Decision. Residential customers were originally projected to still spend more time working or studying from home resulting in higher consumption. The unfavourable variance is partially offset by temperature, which accounted for an increase of 548 GWh. There were colder than normal temperatures in April, May, November, and December, which was partially offset by warmer temperatures in September and October. The number of accounts was also favourable. The total number of accounts was 15,240 (or 0.8%) higher than the Decision, which accounted for an increase of 151 GWh;

- Line 2 - Actual Light Industrial and Commercial sales were 487 GWh (or 3%) higher than the fiscal 2023 Decision. The Commercial sector is comprised of a diverse group of business classes and higher energy consumption can generally be attributed to many different factors. The principal driver was the rebound from the COVID-19 pandemic. Our December 2020 Load Forecast assumed some continued downward adjustment for the Commercial sector load associated with the COVID-19 pandemic. Light Industrial and Commercial sales were favourably impacted by the weather resulting in an increase of 142 GWh, similar to Residential sales as explained above. The number of accounts was also favourable. The total number of accounts was 1,894 (or 0.8%) higher than Decision;
- Line 3 - Actual large Industrial sales were 275 GWh (or 2%) higher than the fiscal 2023 Decision or 14 GWh (or 0.1%) higher if the Electrification Plan

related loads are included. The favourable variance can primarily be attributed to higher actual load than forecasted in the Crypto and Pulp & Paper sectors, which was partially offset by unfavorable variances in the Wood Manufacturing, Oil & Gas & LNG, Chemical, Metal Mining, and Coal Mining sectors;

- Line 4 – Actual Other sales were 295 GWh (or 17%) higher than the fiscal 2023 Decision. The favourable variance was primarily driven by higher sales to FortisBC; and
- Line 5 – The Electrification Plan contributed to increased actual sales of 586 GWh compared to increased sales of 207 GWh, relative to the December 2020 Load Forecast that was included in the Decision. This represents a positive variance of 379 GWh (or 183%). In BC Hydro's operational and financial reporting, actual sales related to the Electrification Plan are embedded in the actual sales for the Residential, Commercial, and Light Industrial, and Large Industrial sectors. To avoid restating each sector by removing both actuals and plan amounts, the Electrification Plan is shown as zero in actuals in Table 1.

2 Domestic Revenue Variance Explanations (Schedule 14.0)

This section compares fiscal 2023 actual domestic revenue amounts with the fiscal 2023 Decision.

Table 2 Fiscal 2023 Domestic Revenue Variances

	($ million)	Schedule Reference	F2023 Decision	Actual	Diff	% Diff
			1	2	3=2-1	4=3/1
1	Residential	14.0 L17	2,371.4	2,193.1	(178.3)	-8%
2	Light Industrial and Commercial	14.0 L18	1,974.2	1,880.2	(94.1)	-5%
3	Large Industrial	14.0 L19	836.8	865.7	28.9	3%
4	Other	14.0 L20:L26	158.8	148.2	(10.7)	-7%
5	Subtotal	14.0 L27	5,341.2	5,087.2	(254.1)	-5%
6	Electrification Plan	14.0 L31	13.8	-	(13.8)	-100%
7	Less: EV Fast Charging Revenues	14.0 L32	(1.0)	(1.6)	(0.6)	64%
8	Revenue from Deferral Rider	14.0 L33	(106.5)	(107.8)	(1.3)	1%
9	**Total Domestic Revenues**	14.0 L34	**5,247.5**	**4,977.7**	(269.7)	-5%

The fiscal 2023 actual domestic revenues were $269.7 million (or 5%) lower than the fiscal 2023 Decision. This was primarily due to:

- Line 1 - Residential revenue was $178.3 million (or 8%) lower, mostly driven by the issuance of cost-of-living credits of $171.3 million, as well as lower sales, as described in section 1 above;
- Line 2 - Light Industrial and Commercial revenue was $94.1 million (or 5%) lower, primarily due to the issuance of cost-of-living credits of $114.2 million. This was partially offset by higher sales as described in section 1 above;
- Line 3 - Large Industrial customer revenue was $28.9 million (or 3%) higher due to higher overall sales, as described in section 1 above;
- Line 4 - Other revenue was $10.7 million (or 7%) lower, primarily due to the issuance of cost-of-living credits of $29.0 million. It was partially offset by higher sales to FortisBC as described in section 1; and
- Line 6 – Actual revenues for the Electrification Plan are included in lines 1 to 3.

3 Cost of Energy Variance Explanations (Schedule 4.0)

This section compares fiscal 2023 actual sources of energy supply and cost of energy amounts with the fiscal 2023 Decision.

Table 3 Fiscal 2023 Sources of Supply Variances

		Schedule	F2023			
	(GWh)	Reference	Decision	Actual	Diff	% Diff
			1	2	3=2-1	4=3/1
1	Water Rentals	4.0 L1	46,134	46,138	4	0%
2	IPPs and Long-Term Commitments	4.0 L7	15,959	15,409	(551)	-3%
3	Natural Gas for Thermal Generation	4.0 L2	187	175	(12)	-6%
4	System Imports	4.0 L10	2,617	3,992	1,375	53%
5	System Exports	4.0 L11	(5,878)	(5,621)	257	-4%
6	Non-Integrated Area	4.0 L8	110	117	7	6%
7	Exchange Net	4.0 L3	(363)	(826)	(463)	127%
8	Electrification Plan - Heritage Energy	4.0 L5	(360)	-	360	-100%
9	Electrification Plan - Market Energy	4.0 L13	596	-	(596)	-100%
10	**Total Sources of Supply**	4.0 L15	**59,001**	**59,383**	381	1%

Fiscal 2023 actual sources of supply were 381 GWh (or 1%) higher than the fiscal 2023 Decision. This was primarily due to:

- Lines 4, 5 – Higher net market imports of 1,632 GWh (or 50%) driven by drier conditions and below average inflows in the year.

Partially offset by:

- Line 2 - Lower IPPs and Long-term Commitments of 551 GWh (or 3%) primarily due to more outages, lower inflows, and expired and terminated Electricity Purchase Agreements, partially offset by one IPP that increased the amount of energy available for sale to BC Hydro;

- Line 7 - Lower Net Exchange of 463 GWh (or 127%) due to lower generation from the Canal Plant and Keenleyside Entitlement agreement plants; and
- Line 8, 9 – Actual sources of supply from the Electrificiation Plan are included in lines 1 to 7.

Table 4 Fiscal 2023 Cost of Energy Variances

		Schedule	F2023			
	($ million)	Reference	Decision	Actual	Diff	% Diff
			1	2	3=2-1	4=3/1
	Heritage Energy					
1	Water Rentals	4.0 L16	389.0	398.0	8.9	2%
2	Natural Gas for Thermal Generation	4.0 L17	9.7	10.5	0.9	9%
3	Domestic Transmission - Other	4.0 L18	25.1	26.4	1.3	5%
4	Non-Treaty Storage and Libby Coordination Agreements	4.0 L19	(26.3)	(169.8)	(143.5)	546%
5	Remissions and Other	4.0 L20	(44.0)	(43.2)	0.8	-2%
6	Electrification Plan - Heritage Energy	4.0 L22	(0.4)	0.0	0.4	-100%
7	Electrification Plan - NTSA	4.0 L23	2.9	0.0	(2.9)	-100%
8	**Subtotal**	4.0 L24	**356.0**	**222.0**	(134.1)	-38%
	Non-Heritage Energy					
9	IPPs and Long-Term Commitments	4.0 L25	1,470.0	1,420.9	(49.1)	-3%
10	Non-Integrated Area	4.0 L26	28.4	44.1	15.7	55%
11	Gas & Other Transportation	4.0 L27	4.4	4.6	0.2	4%
12	Water Rentals (Waneta 2/3)	4.0 L28	3.5	3.5	0.0	0%
13	**Subtotal**	4.0 L29	**1,506.3**	**1,473.1**	(33.2)	-2%
	Market Energy					
14	System Imports	4.0 L30	125.6	644.5	518.9	413%
15	System Exports	4.0 L31	(225.8)	(728.5)	(502.7)	223%
16	Domestic Transmission - Export	4.0 L32	14.1	24.9	10.8	77%
17	Electrification Plan - Market Energy	4.0 L34	(3.0)	0.0	3.0	-100%
18	**Subtotal**	4.0 L35	(89.2)	(59.1)	30.1	-34%
19	**Total Gross Cost of Energy**	1.0 L1	**1,773.2**	**1,636.0**	(137.2)	-8%

Fiscal 2023 actual gross Cost of Energy was $137.2 million (or 8%) lower than the fiscal 2023 Decision. This was primarily due to:

- Line 4 – Higher recovery associated with Non-Treaty Storage and Libby Coordination agreements of $143.5 million (or 546%) due to higher net releases of water at higher prices.

Partially offset by:

- Line 10 – Higher Non-Integrated Areas costs of $15.7 million (or 55%) largely due to higher diesel fuel costs for the diesel generating stations;
- Lines 14 to 15 – Lower net Market Energy exports of $16.2 million (or 16%) due to fewer net system exports driven by dry conditions and below average inflows for the year; and,
- Lines 16 – Higher Domestic Transmission Export of $10.8 million (or 77%) due to higher point-to-point charges due to more imports required across the fall and winter as a result of the low inflows.

4 Operating Costs and Provisions Variance Explanations (Schedule 5.0)

This section compares fiscal 2023 actual gross operating costs and provisions amounts with the fiscal 2023 Decision.

Table 5 Fiscal 2023 Operating Costs and Provisions Variances

	($ million)	Schedule Reference	F2023 Decision	Actual	Diff	% Diff
			1	2	3=2-1	4=3/1
1	Integrated Planning	5.0 L1	354.6	370.2	15.6	4%
2	Capital Infrastructure Project Delivery	5.0 L2	84.8	96.1	11.2	13%
3	Operations	5.0 L3	266.5	273.4	7.0	3%
4	Safety	5.0 L4	65.6	66.3	0.7	1%
5	Finance, Technology, Supply Chain	5.0 L5	308.4	313.2	4.9	2%
6	People, Customer, Corporate Affairs	5.0 L6	95.3	96.7	1.4	1%
7	Other	5.0 L7	(253.2)	(243.7)	9.5	-4%
8	**Base Operating Costs**	5.0 L8	**921.9**	**972.2**	50.3	5%
9	IFRS Ineligible Capitalized Costs	5.0 L9	214.9	214.9	-	0%
10	Waneta 2/3	5.0 L10	5.9	6.0	0.1	2%
11	**Subtotal**	5.0 L11	**220.8**	**220.9**	0.1	0%
12	Deferred Account Additions	5.0 L15	-	3.9	3.9	0%
13	Regulatory Account Additions	5.0 L30	148.5	111.6	(36.9)	-25%
14	**Subtotal**		**148.5**	**115.5**	(33.0)	-22%
15	**Total Gross Operating Costs**	1.0 L2	**1,291.3**	**1,308.7**	17.4	1%
16	Net Provisions & Other	5.01 L8	104.9	109.2	4.3	4%
17	Regulatory Account Additions - Provisions & Other	5.01 L19	-	26.2	26.2	0%
18	**Total Gross Provisions & Other**	1.0 L3	**104.9**	**135.3**	30.5	29%
19	**Total Gross Operating Costs and Provisions**		**1,396.1**	**1,444.0**	47.9	3%

Fiscal 2023 actual gross Operating Costs and Provisions were $47.9 million (or 3%) higher than the fiscal 2023 Decision. Apart from base operating costs that are managed on a company-wide basis, explanations are provided for line items with variances greater than 10% with a minimum variance threshold of $5 million, and are as follows:

- Line 8 – Higher base operating costs of $50.3 million (5%) primarily due to higher expenditures in maintenance programs for generation corrective work, transmission stations work, distribution line work including routine trouble, spend related to First Nations initiatives, and higher spend for building and facility maintenance; and

- Line 18 – Higher regulatory account additons for provisions and other of $26.2 million (100%) primarily due to higher First Nations provision amounts relating to a true up of CPI escalation factors as defined in agreements with First Nations.

Partially offset by:

- Line 14 – Lower regulatory account additions for operating costs of $36.9 million (or 25%) due to lower than planned increase in the Demand Side Management **(DSM)** Regulatory Account, including Low Carbon Electrification **(LCE)**, which was primarily due to a recovery of prior year incentives in the Thermo-Mechanical Pulping DSM program and customer project completions shifting to future fiscal years in the LCE – Industry program. The lower additions was also driven by a decrease in the Post-Employment Benefit (**PEB**) Current Pension Costs Regulatory Account attributed to the increase in the discount rate from 3.40% in the fiscal 2023 Decision versus 4.38% in the fiscal 2023 actuals.

5 Taxes Variance Explanations (Schedule 6.0)

This section compares fiscal 2023 actual taxes amounts with the fiscal 2023 Decision.

Table 6 Fiscal 2023 Taxes Variances

	($ million)	Schedule Reference	F2023 Decision	Actual	Diff	% Diff
			1	2	3=2-1	4=3/1
1	Grants in Lieu	6.0 L15	126.8	124.6	(2.2)	-2%
2	School Taxes	6.0 L16	155.9	151.1	(4.9)	-3%
3	Waneta 2/3 Property Taxes	6.0 L17	0.8	0.7	(0.1)	-12%
4	**Subtotal Before Regulatory Accounts**	6.0 L18	**283.5**	**276.4**	(7.2)	-3%
5	Deferred Account Additions	6.0 L19	-	-	-	N/A
6	**Total Gross Taxes**	1.0 L4	**283.5**	**276.4**	(7.2)	-3%

Fiscal 2023 actual gross Taxes of $276.4 million is comparable to the fiscal 2023 Decision of $283.5 million.

6 Amortization Variance Explanations (Schedule 7.0)

This section compares fiscal 2023 actual amortization amounts with the fiscal 2023 Decision.

Table 7 Fiscal 2023 Amortization Variances

	($ million)	Schedule Reference	F2023 Decision	F2023 Actual	F2023 Diff	F2023 % Diff
			1	2	3=2-1	4=3/1
1	Amortization of Capital Assets	7.0 L9	951.4	961.9	10.4	1%
2	IPP Capital Leases	7.0 L10	77.1	78.4	1.3	2%
3	Other Leases	7.0 L12	2.0	0.9	(1.1)	-54%
4	**Subtotal Before Regulatory Accounts**		**1,030.5**	**1,041.1**	10.7	1%
5	Deferred Account Additions	7.0 L14	-	1.3	1.3	0%
6	**Total Gross Amortization**	1.0 L5	**1,030.5**	**1,042.4**	12.0	1%

Fiscal 2023 actual gross Amortization of $1,042.4 million is comparable to the fiscal 2023 Decision of $1,030.5 million.

7 Finance Charges Variance Explanations (Schedule 8.0)

This section compares fiscal 2023 actual finance charges amounts with the fiscal 2023 Decision.

Table 8 Fiscal 2023 Finance Charge Variances

	($ million)	Schedule Reference	F2023 Decision	Actual	Diff	% Diff
			1	2	3=2-1	4=3/1
1	Sinking Fund Income	8.0 L11	(4.0)	(9.5)	(5.5)	136%
2	Long-Term Debt Costs	8.0 L12	828.9	813.8	(15.1)	-2%
3	Short-Term Debt Costs	8.0 L13	12.2	60.4	48.3	398%
4	Interest Capitalized	8.0 L14	(317.5)	(349.5)	(32.1)	10%
5	Other (Income) / Loss	8.0 L15	47.4	35.1	(12.3)	-26%
6	IPP Capital Leases	8.0 L16	43.4	43.4	-	0%
7	Accretion - Non-Deferrable	8.0 L17	1.6	2.2	0.6	38%
8	Non-Current PEB	8.0 L18	(53.3)	43.4	96.7	-181%
9	Other Leases	8.0 L19	1.0	1.2	0.2	17%
10	**Subtotal Before Regulatory Accounts**	8.0 L20	**559.6**	**640.5**	80.9	14%
11	Regulatory Account Additions	8.0 L9	23.5	(169.2)	(192.7)	-819%
12	**Total Gross Finance Charges**	1.0 L6	**583.2**	**471.3**	(111.8)	-19%

Fiscal 2023 actual gross Finance Charges were $111.8 million (or 19%) lower than the fiscal 2023 Decision. This was primarily due to:

- Line 1 – Higher sinking fund income of $5.5 million (or 136%) due to higher interest rates;
- Line 4 - Higher interest capitalized of $32.1 million (or 10%) due to higher work in progress balances eligible for interest during construction;
- Line 5 – Lower other loss of $12.3 million (or 26%) due to higher interest income, higher investment income, and foreign exchange gains on U.S. temporary investments; and
- Line 11 - Lower regulatory account additions of $192.7 million (or 819%) primarily due to an increase in the fair value of future debt hedges as a result of increases in forward interest rates.

Partially offset by:

- Line 3 - Higher short-term debt costs of $48.3 million (or 398%) due to higher interest rates; and

- Line 8 - Higher non-current PEB costs of $96.7 million (or 181%) primarily due to a lower liability discount rate for estimating pension plan income in actuals versus the expected long-term rate of return on pension plan assets used for the fiscal 2023 Decision.

8 Miscellaneous Revenue Variance Explanations (Schedule 15.0)

This section compares fiscal 2023 actual miscellaneous revenue amounts with the fiscal 2023 Decision.

Table 9 Fiscal 2023 Miscellaneous Revenue Variances

		Schedule	F2023			
	($ million)	Reference	Decision	Actual	Diff	% Diff
			1	2	3=2-1	4=3/1
1	Amortization of Contributions	15.0 L1+L8+L12	67.7	69.1	1.5	2%
2	External OATT	15.0 L4	12.3	30.4	18.1	147%
3	FortisBC Wheeling Agreement	15.0 L5	5.7	6.0	0.3	5%
4	Secondary Revenue (MMBU, Secondary Use, Other)	15.0 L6+L11+L28	29.1	36.0	6.8	23%
5	Interconnections	15.0 L7+L13	7.0	12.9	6.0	86%
6	Meter/Trans Rents & Power	15.0 L15	16.6	15.9	(0.7)	-4%
7	Smart Metering & Infrastructure	15.0 L16	1.5	1.5	(0.0)	-1%
8	Diversion Net Recoveries	15.0 L17	0.1	0.1	(0.0)	-47%
9	Other Operating Recoveries	15.0 L18	4.2	4.1	(0.1)	-2%
10	Waneta 2/3	15.0 L24	90.1	90.1	0.0	0%
11	Corporate General Rents	15.0 L26	3.6	3.6	(0.0)	-1%
12	Late Payment Charges	15.0 L27	7.9	7.6	(0.3)	-4%
13	Low Carbon Fuel Credits	15.0 L29	31.4	56.9	25.5	81%
14	NTL Supplemental Charge	15.0 L9	2.4	2.4	-	0%
15	Other (Income) / Loss	15.0 L2+L19+L30	5.7	8.3	2.5	45%
16	**Subtotal Before Regulatory Accounts**	15.0 L32	**285.2**	**344.7**	59.5	21%
17	Deferral Account Additions	15.0 L34	2.8	6.8	4.0	146%
18	**Total Gross Miscellaneous Revenue**	1.0 L8	**287.9**	**351.5**	63.6	22%

Fiscal 2023 actual gross Miscellaneous Revenue was $63.6 million (or 22%) higher than the fiscal 2023 Decision. This was primarily due to:

- Line 2 – Higher External OATT revenue of $18.1 million (or 149%), primarily due to higher than planned revenues from Loss Compensation Service (i.e., transmission customers who elected Loss Compensation Service paid more to BC Hydro to cover for their additional line losses if they scheduled more energy than planned), and higher than planned volume and rates for point-to-point transmission services;
- Line 4 - Higher secondary revenue of $6.8 million (or 23%), primarily due to a number of factors including higher than planned volume of scrap sales, higher house moves and temporary connections, higher than planned third party projects for shared assets, and higher than planned collection from damage to plant. These favourable variances are partially offset by lower than planned collections from NIA secondary revenue;
- Line 5 - Higher interconnections revenue of $6.0 million (or 86%), primarily due to higher than planned project revenues from feasibility, system and facilities studies; and
- Line 14 - Higher low carbon fuel credits revenue of $25.5 million (or 81%), primarily due to higher than planned average market prices of Low Carbon Fuel Credits sales to Powerex. This favourable variance is deferred to the Low Carbon Fuel Credits Variance regulatory account.

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

This section compares fiscal 2023 actual inter-segment revenue amounts with the fiscal 2023 Decision.

Table 10 Fiscal 2023 Inter-Segment Revenue Variances

	($ million)	Schedule Reference	F2023 Decision	Actual	Diff	% Diff
			1	2	3=2-1	4=3/1
1	Powerex - Business Support Allocation	3.0 L1	(0.3)	(0.3)	-	0%
2	Mark to Market Losses (Gains)	3.0 L2	-	69.0	69.0	0%
3	Powerex PTP Charges	3.0 L3	(39.0)	(58.7)	(19.7)	51%
4	BC Hydro PTP Charges	3.0 L4	(32.5)	(44.1)	(11.5)	35%
5	**Total Inter-Segment Revenue**	1.0 L9	**(71.8)**	**(34.1)**	37.8	-53%

Fiscal 2023 actual Inter-Segment revenues were $37.8 million (or 53%) lower than the fiscal 2023 Decision due to higher market losses of $69.0 million related to the transactions under the Energy Transfer Pricing Agreement between BC Hydro and Powerex, partially offset by higher point-to-point transmission charges of $31.2 million (or 44%) (line 3 and 4 in Table 10 above) as more imports were required across the fall and winter due to the low inflows. The mark to market losses are fully offset in Powerex's net income and have no impact on BC Hydro's consolidated net income or ratepayers.

10 Capital Expenditures and Capital Additions Variance Explanations

The following tables and discussion provide information on the variances between fiscal 2023 actual capital expenditures and capital additions compared to the fiscal 2023 Decision amounts in the Fiscal 2023 to Fiscal 2025 Revenue Requirements Application, which had a currency date of January 1, 2021.

On an annual basis, BC Hydro manages over 900 projects and programs in various 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 due to as-found equipment conditions or other factors 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 the plan in a particular year may be offset by project expenditures and additions in a subsequent year. The variances provided are against planned annual capital expenditures and additions, and are not necessarily reflective of the total project cost. 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 through BC Hydro's Service Plan Budget to Actual Cost performance metric. BC Hydro achieved this metric in fiscal 2023. Specifically, over the last five years, BC Hydro successfully delivered 217 capital projects at a total cost of $3.46 billion, which is 2.64% under the aggregated budget of $3.55 billion and within the target of +/- 5% of budget.

Variances are provided for each main asset category in the tables below. The amounts presented in the tables in this section may not perfectly add up due to rounding. The actual capital additions information is presented using the same classification as the planned capital additions in Chapter 6 of BC Hydro's Fiscal 2023 to Fiscal 2025 Revenue Requirements Application.

In general, explanations are provided where variances between actual and planned amounts are greater than 10%, with a minimum variance threshold of $10 million.

10.1 Overall Capital Expenditures and Additions Variance Explanations

Table 11 and Table 12 below provide BC Hydro's fiscal 2023 capital expenditures and capital additions by main asset category.

Table 11 Fiscal 2023 Capital Expenditure Variances

($ million)	F2023			
	Decision	**Actual**	**Diff**	**% Diff**
	1	2	3=2-1	4=3/1
Generation	300.9	332.1	31.2	10%
Site C Project	2,708.3	2,186.6	(521.7)	-19%
Transmission & Distribution	995.4	1,132.5	137.0	14%
Business Support				
Technology	109.4	105.9	(3.5)	-3%
Properties	83.4	58.7	(24.7)	-30%
Fleet	42.0	40.0	(2.0)	-5%
Business Support - Other and Other Technology	38.1	39.0	0.9	2%
Total Gross	**4,277.5**	**3,894.7**	**(382.8)**	**-9%**
Less: Contribution in Aid	(188.1)	(255.2)	(67.1)	36%
Total	**4,089.5**	**3,639.5**	**(450.0)**	**-11%**
Electrification				
Transmission Load Interconnection - Growth	14.6	7.2	(7.4)	-50%
Transmission Regional System Reinforcement - Growth	8.0	-	(8.0)	-100%
Total Transmission Electrification	22.6	7.2	(15.4)	**-68%**
Distribution System Expansion and Improvement - Growth	4.0	3.4	(0.6)	-15%
Distribution Electric Vehicle Charging Infrastructure - Sustain	2.0	-	(2.0)	-100%
Total Distribution Electrification	6.0	3.4	(2.6)	**-43%**
Total Electrification	**28.7**	**10.7**	**(18.0)**	**-63%**
Total	**4,118.1**	**3,650.2**	**(468.0)**	**-11%**

Fiscal 2023 gross capital expenditures, before Electrification, were $382.8 million (or 9%) below the fiscal 2023 Decision, excluding contribution in aid, primarily because:

- The Site C Project was $521.7 million below plan mainly due to the Main Civil Works, Generating Station and Spillways, and Right Bank Foundation Enhancements construction areas being underspent compared to plan information available at the time of developing the Revenue Requirement Application Plan, as discussed in section 10.7; and

- Properties was $24.7 million below plan mainly due to the schedule changes for various projects, as discussed in section 10.6; and

The decrease in capital expenditures above was partially offset by the following:

- Generation was $31.2 million above plan primarily due to schedule changes for various projects as discussed in section 10.2;
- Transmission capital expenditures of $28.1 million above plan primarily due to the schedule changes for various projects, as discussed in section 10.3; and
- Distribution was $108.9 million above plan primarily due to increased activities for various programs as discussed in section 10.4.

Fiscal 2023 capital expenditures and capital additions results for the Electrification Plan are presented separately in section 10.5 below.

Table 12 Fiscal 2023 Capital Additions Variances

($ million)	F2023			
	Decision	**Actual**	**Diff**	**% Diff**
	1	2	3=2-1	4=3/1
Generation	443.2	292.1	(151.1)	-34%
Site C Project	-	5.2	5.2	100%
Transmission & Distribution	800.2	892.1	91.9	11%
Business Support				
Technology	130.6	73.1	(57.5)	-44%
Properties	32.7	34.1	1.4	4%
Fleet	42.0	26.5	(15.5)	-37%
Business Support - Other and Other Technology	28.3	27.3	(1.0)	-3%
Total Gross	**1,477.0**	**1,350.5**	**(126.6)**	**-9%**
Less: Contribution in Aid	(170.1)	(178.0)	(7.9)	5%
Total	**1,306.9**	**1,172.5**	**(134.5)**	**-10%**
Electrification				
Transmission Load Interconnection - Growth	9.4	-	(9.4)	-100%
Transmission Regional System Reinforcement - Growth	5.2	-	(5.2)	-100%
Total Transmission Electrification	14.6	-	(14.6)	**-100%**
Distribution System Expansion and Improvement - Growth	1.6	0.7	(0.9)	-57%
Distribution Electric Vehicle Charging Infrastructure - Sustain	1.6	-	(1.6)	-100%
Total Distribution Electrification	3.2	0.7	(2.5)	**-78%**
Total Electrification	**17.8**	**0.7**	**(17.1)**	**-96%**
Total	**1,324.8**	**1,173.1**	**(151.6)**	**-11%**

Fiscal 2023 gross capital additions, before Electrification, were $126.6 million (or 9%) below the fiscal 2023 Decision, excluding contribution in aid, primarily because:

- Generation capital additions were below plan by $151.1 million, primarily due to schedule changes for various projects and delays that shifted the timing of placing certain assets in-service, as discussed in section 10.2;
- Technology capital additions were below plan by $57.5 million, primarily due to project schedule delays that shifted the timing of placing certain assets in-service, as discussed in section 10.6; and

- Fleet capital addtions were below plan by $15.5 million, primarily due to delays in the procurement of vehicles as a result of global supply chain issues, which delayed the completion of the quality control checks before vehicles are put into service, as discussed in section 10.6.

The decrease in capital additions above was partially offset by the following:

- Transmission capital additions were above plan by $44.4 million, primarily due to schedule changes for various projects that shifted the timing of placing certain assets in-service, as discussed in section 10.3; and
- Distribution capital additions were above plan by $47.5 million, primarily due to higher distribution customer driven extension activities and schedule changes for various programs that shifted the timing of placing certain assets in-service, as discussed in section 10.4.

Fiscal 2023 capital expenditures and capital additions results for the Electrification Plan are presented separately in section 10.5 below.

10.2 Generation Capital Expenditures and Additions Variance Explanations

Generation capital expenditures and capital additions in fiscal 2023 are presented in Table 13 and Table 14 below. Results exclude amounts for the Site C Project, which are presented separately in section 10.7 below.

1 2 3 **Table 13 Fiscal 2023 Generation Capital Expenditures Variances (Excluding Site C Project)**

($ million)	F2023			
	Decision	**Actual**	**Diff**	**% Diff**
	1	2	3=2-1	4=3/1
Hydroelectric Generation				
Growth	-	0.5	0.5	100%
Redevelopment / Rehabilitation	0.3	0.2	0.0	2%
Dam Safety	118.4	158.7	40.3	34%
Sustaining - Other	174.6	165.4	(9.2)	-5%
Total Hydroelectric Generation	293.3	324.8	31.5	11%
Total Non-Integrated Areas	10.2	4.8	(5.4)	-53%
Total Thermal Generation	1.3	2.5	1.2	90%
Less: Portfolio Risk Adjustment	(3.9)	-	3.9	-100%
Total Gross	**300.9**	**332.1**	**31.2**	**10%**
Less: Contribution in Aid	-	-	-	-
Total	**300.9**	**332.1**	**31.2**	**10%**

4 5 **Table 14 Fiscal 2023 Generation Capital Additions Variances (Excluding Site C Project)**

($ million)	F2023			
	Decision	**Actual**	**Diff**	**% Diff**
	1	2	3=2-1	4=3/1
Hydroelectric Generation				
Growth	-	0.3	0.3	100%
Redevelopment / Rehabilitation	0.3	0.2	0.0	2%
Dam Safety	103.6	72.2	(31.4)	-30%
Sustaining - Other	335.3	215.8	(119.5)	-36%
Total Hydroelectric Generation	439.2	288.5	(150.7)	-34%
Total Non-Integrated Areas	4.5	3.3	(1.2)	-27%
Total Thermal Generation	0.6	0.3	(0.3)	-45%
Less: Portfolio Risk Adjustment	(1.1)	-	1.1	-100%
Total Gross	**443.2**	**292.1**	**(151.1)**	**-34%**
Less: Contribution in Aid	-	-	-	-
Total	**443.2**	**292.1**	**(151.1)**	**-34%**

6 *Growth Capital*

7 Fiscal 2023 capital expenditures and capital additions were comparable to the
8 fiscal 2023 Decision.

Redevelopment/ Rehabilitation

Fiscal 2023 capital expenditures and capital additions were comparable to the fiscal 2023 Decision.

Dam Safety

Fiscal 2023 capital expenditures were $40.3 million (or 34%) above the fiscal 2023 Decision. This was primarily because:

- The Bridge River 1 – Penstock Concrete Foundation Refurbishment project was $13.3 million above plan because additional slope stabilization work was required along the four penstocks on a steep slope due to poor rock quality found following removal of the debris that had accumulated around the penstocks;
- The John Hart Dam Seismic Upgrade project was $9.5 million above plan because selected site preparation activities were advanced to mitigate project schedule risks;
- The W.A.C. Bennett Dam – Spillway Concrete Upgrades project was $9.3 million above plan because part of the construction work planned for fiscal 2022 was completed in fiscal 2023, due to reduced spillway availability in fiscal 2022 and high strength of the existing concrete which slowed down the progress of concrete removal; and
- The Lake Buntzen 1 Coquitlam Tunnel Gates Refurbishment project was $6.1 million above plan because of delays in construction from fiscal 2022 to fiscal 2023 due to the discovery of safety hazards related to geotechnical conditions at the site.

The remaining above plan variance of $2.1 million was due to smaller variances on many offsetting projects.

Fiscal 2023 capital additions were $31.4 million (or 30%) below plan. This was primarily because:

- The Cheakamus Recoat Units 1 and 2 Penstocks (Interior and Exterior) project was $29.2 million below plan due to additional scope for rock scaling, meshing, and debris removal around the penstocks resulting in a delay to the project in-service date;
- The Lake Buntzen 1 Coquitlam Tunnel Gates Refurbishment project was $17.5 million below plan due to the discovery of above and below ground geotechnical safety hazards resulting in delays to construction and the project in-service date; and
- The Revelstoke Replace Downie Slide Instrumentation project was $14.4 million below plan because the project was completed in fiscal 2022, ahead of the planned in-service date of fiscal 2023.

The below plan variances were partially offset by:

- The W.A.C. Bennett Dam – Spillway Concrete Upgrades project was $12.3 million above plan because the project in-service date planned for fiscal 2022 was delayed to fiscal 2023, due to reduced spillway availability in fiscal 2022 and high strength of the existing concrete which slowed down the progress of concrete removal;
- The Various Sites – Reservoir Booms Replacement – F2020 project was $7.9 million above plan because the project was put in-service in fiscal 2023, earlier than the planned fiscal 2024 in-service date; and

- The Bridge River 1 – Mitigate Surge Spill Hazard project was $7.7 million above plan due to resource constraints resulting in construction schedule delay, as well as additional excavation and rock fall protection work due to project site conditions resulting in a delay to the project in-service date from fiscal 2022 to fiscal 2023.

The remaining above plan variance of $1.8 million was due to smaller variances on many offsetting projects.

Sustaining – Other

Fiscal 2023 capital expenditures were comparable to the fiscal 2023 Decision.

Fiscal 2023 capital additions were $119.5 million (or 36%) below the fiscal 2023 Decision. This was primarily because:

- The Wahleach Refurbish Generator project was $48.5 million below plan because the project construction and in-service date was delayed by two years due to COVID-19 related supply chain disruptions in 2020, a severe weather incident in 2021, and additional scope requirements from as-found conditions;
- The G.M. Shrum G1 to 10 Control System Upgrade project was $32.5 million below plan because the project in-service date was delayed due to schedule delays resulting from internal resourcing challenges;
- The Mica Upgrade HVAC System project was $29.4 million below plan because the project in-service date was delayed due to additional time required for the contractor to finalize the design;
- The Mica – Reactor Replacement project was $14.9 million below plan due to a delay in confirming Mandatory Reliability Standards compliance during final acceptance of the installed equipment that was expected in fiscal 2023. The

work has been confirmed compliant but the delay shifted the project in-service date to fiscal 2024;

- The Jordan – Upgrade Governor & PRV Controls project was $11.9 million below plan because of schedule delays in fiscal 2023 due to additional time required to consider alternative procurement strategies to support the work, as well as generation system operating constraints in fiscal 2024, which have delayed construction to fiscal 2025;
- The Puntledge Recoat Interior and Exterior of Steel Penstock project was $10.1 million below plan because the project was put into service in fiscal 2022, ahead of the planned fiscal 2023 in-service date;
- The Various – Water License Renewal project was $8.6 million below plan because the project has been extended for two years to allow for additional consultation with Indigenous groups and stakeholders; and
- The Seven Mile Upgrade Powerhouse Crane Controls project was $8.3 million below plan because the project went into service in fiscal 2022, ahead of the planned fiscal 2023 in-service date.

The decrease in capital additions outlined above was partially offset by:

- The Mica Replace Units 1 to 4 Generator Transformers project was $29.6 million above plan because the project construction and in-service date was moved from fiscal 2022 to fiscal 2023 due to additional testing required for the Unit 3 transformer;
- The Strathcona – G1 Generator Rewind project was $10.4 million above plan due to resource constraints resulting in delays to construction and the movement of the in-service date from fiscal 2022 to fiscal 2023; and

- The Bridge River 2 – Transformer 7 Replacement project was $9.3 million above plan, due to supply chain delays and outage availability constraints resulting in delay to the transformer replacement in fiscal 2022. The project in-service date was shifted from fiscal 2022 to fiscal 2023.

The remaining below plan variance of $4.6 million was due to smaller variances on many offsetting projects.

Non-Integrated Areas and Thermal Generation

Fiscal 2023 capital expenditures and additions for Non-Integrated Areas were comparable to the fiscal 2023 Decision.

Fiscal 2023 capital expenditures and additions for Thermal Generation were comparable to the fiscal 2023 Decision.

Portfolio Risk Adjustment

The Portfolio Risk Adjustment accounts for the uncertainty in the schedule and cost of projects when establishing the Capital Plan. 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.

The Fiscal 2023 Decision Portfolio Risk Adjustment amount was $3.9 million for capital expenditures and $1.1 million for capital additions.

10.3 Transmission Capital Expenditures and Additions Variance Explanations

Transmission fiscal 2023 capital expenditures and capital additions are provided in Table 15 and Table 16 below.

Table 15 Fiscal 2023 Transmission Capital Expenditures Variances

($ million)	F2023			
	Decision	**Actual**	**Diff**	**% Diff**
	1	2	3=2-1	4=3/1
Transmission Growth				
Regional System Reinforcement	25.6	16.7	(8.8)	-35%
Bulk System Reinforcement	4.0	3.4	(0.6)	-14%
Station Expansion & Modification	42.7	49.5	6.8	16%
Feeder Positions / Section Additions	0.0	0.0	0.0	0%
Generator Interconnections	1.0	2.3	1.3	137%
Transmission Load Interconnection	59.7	41.8	(17.9)	-30%
Total Growth	132.9	113.8	(19.2)	-14%
Transmission Sustain - Stations				
Circuit Breakers	39.1	38.1	(1.0)	-3%
Other Power Equipment	121.4	108.1	(13.3)	-11%
Protection and Control	35.9	31.9	(3.9)	-11%
Stations Auxiliary Equipment	42.6	44.3	1.6	4%
Stations Risk Mitigation	13.2	4.9	(8.3)	-63%
Telecommunications	22.0	20.7	(1.2)	-6%
Total Sustain - Stations	274.2	248.1	(26.1)	-10%
Transmission Sustain - Lines				
Cable Sustainment	5.6	(0.7)	(6.3)	-113%
O/H Lines Life Extension	70.1	109.8	39.7	57%
O/H Lines Performance Improvement	-	1.0	1.0	100%
O/H Lines Risk Mitigation	9.1	14.2	5.2	57%
ROW Sustainment	9.8	4.4	(5.4)	-56%
Third Party Requested Transmission Line Relocations	13.1	12.7	(0.5)	-4%
Total Sustain - Lines	107.7	141.3	33.6	31%
Less: Portfolio Risk Adjustment	(39.8)	-	39.8	-100%
Total Gross	**475.1**	**503.2**	**28.1**	**6%**
Less: Contribution in Aid	(29.7)	(54.8)	(25.1)	85%
Total	**445.4**	**448.5**	**3.1**	**1%**

Table 16 Fiscal 2023 Transmission Capital Additions Variances

($ million)	F2023			
	Decision	**Actual**	**Diff**	**% Diff**
	1	2	3=2-1	4=3/1
Transmission Growth				
Regional System Reinforcement	0.9	6.4	5.6	643%
Bulk System Reinforcement	-	-	-	-
Station Expansion & Modification	0.0	54.1	54.1	100%
Feeder Positions / Section Additions	0.0	0.0	0.0	0%
Generator Interconnections	3.6	2.3	(1.3)	-36%
Transmission Load Interconnection	5.1	1.2	(3.8)	-76%
Total Growth	9.6	64.1	54.5	570%
Transmission Sustain - Stations				
Circuit Breakers	12.6	22.4	9.7	77%
Other Power Equipment	155.6	80.4	(75.1)	-48%
Protection and Control	10.8	2.3	(8.5)	-79%
Stations Auxiliary Equipment	25.8	37.7	11.9	46%
Stations Risk Mitigation	10.4	2.5	(7.9)	-76%
Telecommunications	12.4	9.6	(2.8)	-22%
Total Sustain - Stations	227.6	154.9	(72.6)	-32%
Transmission Sustain - Lines				
Cable Sustainment	3.9	(1.9)	(5.8)	-148%
O/H Lines Life Extension	58.8	54.7	(4.1)	-7%
O/H Lines Performance Improvement	-	-	-	-
O/H Lines Risk Mitigation	10.5	8.3	(2.2)	-21%
ROW Sustainment	10.4	18.2	7.8	75%
Third Party Requested Transmission Line Relocations	18.5	3.8	(14.7)	-79%
Total Sustain - Lines	102.1	83.1	(19.0)	-19%
Less: Portfolio Risk Adjustment	(81.6)	-	81.6	-100%
Total Gross	**257.7**	**302.1**	**44.4**	**17%**
Less: Contribution in Aid	(12.9)	(8.6)	4.3	-33%
Total	**244.8**	**293.5**	**48.7**	**20%**

Transmission Growth - Regional System Reinforcement

Fiscal 2023 capital expenditures and additions were comparable to the fiscal 2023 Decision.

Transmission Growth – Bulk System Reinforcement

Fiscal 2023 capital expenditures and capital additions were comparable to the fiscal 2023 Decision.

Transmission Growth – Station Expansion & Modification

Fiscal 2023 capital expenditures were comparable to the fiscal 2023 Decision.

Fiscal 2023 capital additions were $54.1 million (or 100%) above plan because:

- The Mount Lehman Substation Upgrade project was $52.8 million above plan because the project was put into service in fiscal 2023, ahead of the planned fiscal 2024 in-service date.

The remaining above plan variance of $1.3 million was due to smaller variances on many offsetting projects.

Transmission Growth – Feeder Positions / Section Additions

Fiscal 2023 capital expenditures and additions were comparable to the fiscal 2023 Decision.

Transmission Growth – Generator Interconnections

Fiscal 2023 capital expenditures and additions were comparable to the fiscal 2023 Decision.

Transmission Growth – Transmission Load Interconnection

Fiscal 2023 capital expenditures were $17.9 million (or 30%) below the fiscal 2023 Decision. These capital expenditures are third-party driven and, as a result, the timing and scope of these projects is highly uncertain.

Fiscal 2023 capital additions were comparable to the fiscal 2023 Decision.

Transmission Sustain-Stations

Circuit Breakers

Fiscal 2023 capital expenditures and capital additions were comparable to the fiscal 2023 Decision.

Other Power Equipment

Fiscal 2023 capital expenditures were $13.3 million (or 11%) below the fiscal 2023 Decision primarily because:

- The Bridge River – T4 Transformer Replacement project was $8.2 million below plan because of the challenges of getting outages for completing the work in fiscal 2023, resulting in a delay to fiscal 2024; and
- The Peace to Kelly Lake Stations Sustainment project was $6.9 million below plan due to cost savings on design, as well as the timing of procurement payments shifting from fiscal 2023 to fiscal 2024.

The decrease in capital expenditures outlined above was partially offset by:

- The Natal – 60-138 kV Switchyard Upgrade project was $7.7 million above plan because of increased costs for materials, equipment, and contract work.

The remaining below plan variance of $5.9 million was due to smaller variances on various projects and work programs.

Fiscal 2023 capital additions were $75.1 million (or 48%) below the fiscal 2023 Decision. This was primarily due to the following:

- The Jordan River – Switchyard Upgrade project was $30.1 million below plan due to outage availability constraints resulting in delays to construction shifting the project in-service date to fiscal 2024;

- The Bridge River – T4 Transformer Replacement project was $26.6 million below plan because the project in-service date was delayed to fiscal 2024 due to the challenges of getting outages for completing the work;
- The Sandspit Substation Replacement project was $12.7 million below plan because the project in-service date was delayed due to construction delays resulting from supply chain delays, concrete rework, and resource constraints; and
- The Ah-sin-heek - Substation Replacement project was $9.9 million below plan due to geotechnical issues requiring additional design resulting in delays to the project in-service date to fiscal 2025.

The below plan variances above are partially offset by the $4.2 million above plan variances on various projects.

Protection and Control

Fiscal 2023 capital expenditures and additions were comparable to the fiscal 2023 Decision.

Stations Auxiliary Equipment

Fiscal 2023 capital expenditures were comparable to the fiscal 2023 Decision.

Fiscal 2023 capital additions were $11.9 million (or 46%) above the fiscal 2023 Decision primarily because:

- The Substation Safety and Minor Capital program was $7.7 million above plan because the program had delays in construction due to resource constraints, material delivery delay as a result of supply chain issues, and re-planning of outages. The program close-out and in-service date shifted from fiscal 2022 to fiscal 2023.

The remaining variance of $4.2 million was due to smaller above plan variances on various projects and programs.

Stations Risk Mitigation

Fiscal 2023 capital expenditures and capital additions were comparable to the fiscal 2023 Decision.

Telecommunications

Fiscal 2023 capital expenditures and capital additions were comparable to the fiscal 2023 Decision.

Transmission Sustain-Lines

Cable Sustainment

Fiscal 2023 capital expenditures and capital additions were comparable to the fiscal 2023 Decision.

O/H Lines Life Extension

Fiscal 2023 capital expenditures were $39.7 million (or 57%) above the fiscal 2023 Decision. This was primarily because:

- The Transmission Wood Structure and Framing Replacements program was $14.7 million above plan because the program completed more units than planned as a result of newly identified scope in fiscal 2023 as well as scope deferred from fiscal 2022.

The remaining variance of $25.0 million was due to higher spare transmission and distribution poles, transformers, and wires expenditures.

Fiscal 2023 capital additions were comparable to the fiscal 2023 Decision.

O/H Lines Performance Improvement

Fiscal 2023 capital expenditures and capital additions were comparable to the fiscal 2023 Decision.

O/H Lines Risk Mitigation

Fiscal 2023 capital expenditures and capital additions were comparable to the fiscal 2023 Decision.

ROW Sustainment

Fiscal 2023 capital expenditures and capital additions were comparable to the fiscal 2023 Decision.

Third Party Requested Transmission Line Relocations

Fiscal 2023 capital expenditures were comparable to the fiscal 2023 Decision.

Fiscal 2023 capital additions were $14.7 million below the fiscal 2023 Decision. These capital additions are third-party driven and, as a result, the timing and scope of these projects is highly uncertain.

Portfolio Risk Adjustment

The Portfolio Risk Adjustment accounts for the uncertainty in the schedule and cost of projects when establishing the Capital Plan. 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.

The Fiscal 2023 RRA Portfolio Risk Adjustment amount was $(39.8) million in capital expenditures and $(81.6) million in capital additions.

Contribution in Aid

Fiscal 2023 Transmission Contribution in Aid expenditures were $25.1 million (or 85%) above the fiscal 2023 Decision due to timing of the contributions received from the transmission load interconnection customers.

Fiscal 2023 Transmission Contribution in Aid additions were comparable to the fiscal 2023 Decision.

10.4 Distribution Capital Expenditures and Additions Variance Explanations

Distribution fiscal 2023 capital expenditures and capital additions are provided in Table 17 and Table 18 below.

The System Expansion and Improvement portfolio is generally comprised of smaller, shorter duration projects.

Table 17 Fiscal 2023 Distribution Capital Expenditures Variances

($ million)	F2023			
	Decision	**Actual**	**Diff**	**% Diff**
	1	2	3=2-1	4=3/1
Distribution Growth				
Customer Driven	255.4	310.4	55.0	22%
System Expansion and Improvement	70.8	85.5	14.7	21%
Uneconomic Extension Assistance	0.4	0.3	(0.1)	-15%
Total Growth	326.6	396.2	69.7	21%
Distributon Sustain				
System Expansion and Improvement	37.8	47.9	10.1	27%
Asset Replacement				
Poles	51.5	56.8	5.3	10%
Overhead Equipment	35.6	48.6	13.0	36%
Underground Equipment	39.1	45.7	6.7	17%
Trouble	21.2	24.3	3.0	14%
Asset Replacement sub-total	147.4	175.5	28.0	19%
Beautification	4.8	0.7	(4.1)	-86%
Electric Vehicle Charging Infrastructure[1]	3.7	9.0	5.3	143%
Total Sustain	193.8	233.0	39.2	20%
Total Gross	**520.3**	**629.2**	**108.9**	**21%**
Less: Contribution in Aid	(158.4)	(200.4)	(42.1)	27%
Total	**362.0**	**428.8**	**66.8**	**18%**

[1] Actuals include the installation of EV Charging Stations to support the Electrification Plan.

Table 18 Fiscal 2023 Distribution Capital Additions Variances

($ million)	F2023			
	Decision	**Actual**	**Diff**	**% Diff**
	1	2	3=2-1	4=3/1
Distribution Growth				
Customer Driven	253.2	324.1	70.9	28%
System Expansion and Improvement	53.7	56.4	2.7	5%
Uneconomic Extension Assistance	0.4	0.3	(0.1)	-17%
Total Growth	307.3	380.8	73.5	24%
Distributon Sustain				
System Expansion and Improvement	76.9	36.8	(40.1)	-52%
Asset Replacement				
Poles	50.6	43.5	(7.1)	-14%
Overhead Equipment	39.1	48.8	9.7	25%
Underground Equipment	39.5	44.1	4.6	12%
Trouble	21.1	32.6	11.5	54%
Asset Replacement sub-total	150.3	169.0	18.7	12%
Beautification	4.4	2.1	(2.3)	-52%
Electric Vehicle Charging Infrastructure[1]	3.6	1.3	(2.3)	-64%
Total Sustain	235.2	209.2	(26.0)	-11%
Total Gross	**542.6**	**590.0**	**47.5**	**9%**
Less: Contribution in Aid	(157.2)	(169.4)	(12.2)	8%
Total	**385.4**	**420.6**	**35.3**	**9%**

[1] Actuals include the installation of EV Charging Stations to support the Electrification Plan.

Distribution Growth – Customer Driven

Fiscal 2023 capital expenditures were $55.0 million (or 22%) above the fiscal 2023 Decision due to an increase in distribution customer driven extension activities, meter purchases for secondary connections, Ministry of Transportation and Infrastructure relocation activities, and the required design effort to support these increases. This work is difficult to plan as it is dependent on customer requests and related timing.

Fiscal 2023 capital additions were $70.9 million (or 28%) above the fiscal 2023 Decision primarily due to the increase in capital expenditures as well as the timing of a few major customer projects going in-service in fiscal 2023.

Distribution Growth - System Expansion and Improvement

Fiscal 2023 capital expenditures were $14.7 million (or 21%) above the fiscal 2023 Decision. Growth-driven system expansion and improvement expenditures address existing capacity constraints to meet anticipated customer load growth.

The priority of growth-driven system upgrades is influenced by new customer load connections and general load growth from 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.

Fiscal 2023 capital additions were comparable to the fiscal 2023 Decision.

Distribution Growth - Uneconomic Extension Assistance

Fiscal 2023 capital expenditures and capital additions were comparable to the fiscal 2023 Decision.

Distribution Sustain - System Expansion and Improvement

Fiscal 2023 capital expenditures were $10.1 million (or 27%) above the fiscal 2023 Decision.

System expansion and improvement sustaining expenditures maintain and improve distribution system performance including addressing customer reliability, safety risks, and meeting regulatory, legal, or environmental requirements.

The above plan variance was primarily due to:

- The Downtown Vancouver – Underground Murrin Feeders to Eliminate H-Frames in Gastown program was $8.9 million above plan because the program construction schedule was delayed to fiscal 2023 due to unforeseen construction challenges mainly with customer vaults.

The remaining $1.2 million variance was due to smaller above plan variances on various projects.

Fiscal 2023 capital additions were $40.1 million (or 52%) below the fiscal 2023 Decision because:

- The H-Frame Elimination - Chinatown program was $18.7 million below plan due to the completion of work and placement of assets in-service throughout fiscal 2022 ahead of the planned fiscal 2023 in-service date; and
- The Downtown Vancouver – Underground Murrin Feeders to Eliminate H-Frames in Gastown program was $16.3 million below plan because the program construction schedule was delayed due to unforeseen construction challenges mainly relating to customer vaults.

The remaining variance of $5.1 million was due to smaller below plan variances on various projects.

Distribution Sustain - Asset Replacement

Distribution Asset replacements are planned and adjusted as an entire program based on inspections and changes in the prioritization of different assets.

Fiscal 2023 capital expenditures were $28.0 million (or 19%) above the fiscal 2023 Decision primarily due to significant unit cost increases across the Distribution Asset Replacement Programs. The overhead equipment replacement was further impacted by increased volumes to address phaseout of overhead transformers with high polychlorinated biphenol (**PCB**) content and units vulnerable to failure due to excessive loading.

Fiscal 2023 capital additions were $18.7 million (or 12%) above the fiscal 2023 Decision primarily due to the timing of completing the fiscal 2022 fall and winter power restoration work orders shifting the placement of assets in service to fiscal 2023.

Distribution Sustain - Beautification

Fiscal 2023 capital expenditures and capital additions were comparable to the fiscal 2023 Decision.

Distribution Sustain - Electric Vehicle Charging Infrastructure

Fiscal 2023 capital expenditures and capital additions included additional installation of EV Charging Stations to support the Electrification Plan. They were comparable to the fiscal 2023 Decision.

Contribution in Aid

Fiscal 2023 Distribution Contribution in Aid expenditures were $42.1 million (or 27%) above the fiscal 2023 Decision primarily because of the higher than planned distribution customer driven extension activities.

Fiscal 2023 Distribution Contribution in Aid additions were $12.2 million (or 8%) above the fiscal 2023 Decision primarily due to timing differences on the completion of customer work.

10.5 Electrification Capital Expenditures and Additions Variance Explanations

Table 19 Fiscal 2023 Electrification Capital Expenditures Variances

($ million)	F2023			
	Decision	**Actual**	**Diff**	**% Diff**
Transmission Growth	1	2	3=2-1	4=3/1
Transmission Load Interconnection - Growth	14.6	7.2	(7.4)	-50%
Transmission Regional System Reinforcement - Growth	8.0	-	(8.0)	-100%
Total Transmission Electrification	22.6	7.2	(15.4)	-68%
Distribution Growth				
Distribution System Expansion and Improvement - Growth	4.0	3.4	(0.6)	-15%
Distribution Sustain				
Distribution Electric Vehicle Charging Infrastructure - Sustain[1]	2.0	-	(2.0)	-100%
Total Distribution Electrification	6.0	3.4	(2.6)	-43%
Total Electrification	**28.7**	**10.7**	**(18.0)**	**-63%**

[1] Actuals of the installation of EV Charging Stations are included in Distribution - Table 17

Table 20 Fiscal 2023 Electrification Capital Additions Variances

($ million)	F2023			
	Decision	**Actual**	**Diff**	**% Diff**
Transmission Growth	1	2	3=2-1	4=3/1
Transmission Load Interconnection - Growth	9.4	-	(9.4)	-100%
Transmission Regional System Reinforcement - Growth	5.2	-	(5.2)	-100%
Total Transmission Electrification	14.6	-	(14.6)	-100%
Distribution Growth				
Distribution System Expansion and Improvement - Growth	1.6	0.7	(0.9)	-57%
Distribution Sustain				
Distribution Electric Vehicle Charging Infrastructure - Sustain[1]	1.6	-	(1.6)	-100%
Total Distribution Electrification	3.2	0.7	(2.5)	-78%
Total Electrification	**17.8**	**0.7**	**(17.1)**	**-96%**

[1] Actuals of the installation of EV Charging Stations are included in Distribution - Table 18

BC Hydro has developed a planning allowance for the incremental capital expenditures and additions required to support the increased loads associated with the Electrification Plan in the fiscal 2023 to fiscal 2025 Revenue Requirements

Application. The planning allowance is based on the forecast demand under the Electrification Plan multiplied by a unit cost informed by BC Hydro's non-bulk transmission and distribution reference prices.

The planned incremental investments to implement the Electrification Plan include three categories:

- Transmission Interconnection of new customer loads;
- System reinforcements on the Transmission and Distribution system; and
- Additional installation of EV Charging Stations.

Transmission Load Interconnection

Fiscal 2023 capital expenditures were $7.4 million (or 50%) below the fiscal 2023 Decision.

Fiscal 2023 capital additions were $9.4 million (or 100%) below the fiscal 2023 Decision.

These capital additions are third-party driven and, as a result, the number of projects, timing, location, and scope of these projects is highly uncertain due to customer business decisions and economic conditions. This uncertainty impacts the likelihood of actuals matching the planning allowance.

Transmission Regional System Reinforcement

Fiscal 2023 capital expenditures and capital additions were $8.0 million and $5.2 million below the fiscal 2023 Decision, respectively. BC Hydro continues significant planning efforts to identify and understand system constraints that may require system reinforcement and, as of fiscal 2023, none of the identified investments have progressed to the capital phase of the project lifecycle.

Distribution System Expansion and Improvement

Fiscal 2023 capital expenditures and capital additions of the system reinforcements on the Distribution system were comparable to the fiscal 2023 Decision.

Additional Installation of EV Charging Stations

The fiscal 2023 capital expenditures and capital additions of the additional EV charging stations were captured in section 10.4, Table 17, and Table 18, under Sustain, Electric Vehicle Charging Infrastructure.

10.6 Business Support Capital Expenditures and Additions Variance Explanations

Business Support includes capital expenditures and additions for Technology, Properties, Fleet, and Other categories. Business Support Fiscal 2023 capital expenditures and capital additions are presented by category in the tables below.

Table 21 Fiscal 2023 Business Support Capital Expenditures Variances

($ million)	F2023			
	Decision	**Actual**	**Diff**	**% Diff**
	1	2	3=2-1	4=3/1
Business Support				
Technology and Other Technology (Tables 23 and 29)	109.4	105.9	(3.5)	-3%
Properties	83.4	58.7	(24.7)	-30%
Fleet	42.0	40.0	(2.0)	-5%
Business Support - Other	38.1	39.0	0.9	2%
Total	**272.9**	**243.5**	**(29.4)**	**-11%**

Table 22 Fiscal 2023 Business Support Capital Additions Variances

($ million)	F2023			
	Decision	Actual	Diff	% Diff
	1	2	3=2-1	4=3/1
Business Support				
Technology and Other Technology (Tables 24 and 30)	130.6	73.1	(57.5)	-44%
Properties	32.7	34.1	1.4	4%
Fleet	42.0	26.5	(15.5)	-37%
Business Support - Other	28.3	27.3	(1.0)	-3%
Total	**233.6**	**161.0**	**(72.5)**	**-31%**

Technology

Table 23 Fiscal 2023 Technology Capital Expenditures Variances

($ million)	F2023			
	Decision	Actual	Diff	% Diff
	1	2	3=2-1	4=3/1
Technology	109.2	102.1	(7.0)	-6%
Total	**109.2**	**102.1**	**(7.0)**	**-6%**

Table 24 Fiscal 2023 Technology Capital Additions Variances

($ million)	F2023			
	Decision	Actual	Diff	% Diff
	1	2	3=2-1	4=3/1
Technology	119.0	73.1	(45.9)	-39%
Total	**119.0**	**73.1**	**(45.9)**	**-39%**

Fiscal 2023 capital expenditures were comparable to the fiscal 2023 Decision.

Fiscal 2023 capital additions were $45.9 million (or 39%) below the fiscal 2023 Decision because:

- The Energy Management System (EMS) 3.3 Upgrade project was $12.4 million below plan because the project in-service date was delayed due to schedule changes related to scope increases to include additional detail design and development, and delayed infrastructure delivery due to global supply chain issues;

- The Advanced Distribution Management System project was $11.0 million below plan because the project in-service date was delayed due to ongoing discussions with the product vendor and ongoing review of the product market;
- The KIDC Network Refresh to ACI project was $8.0 million below plan because the project's estimated in-service date was delayed to fiscal 2026 primarily to allow for a change in the staffing model due to project complexity and difficulty finding required resources;
- The SAP Business Warehouse on HANA Migration project was $4.5 million below plan because the estimated in-service date was changed to fiscal 2024 once the project was initiated and more detailed project planning information became available; and
- The Time Based Rates project was $4.4 million below plan because the project in-service date was delayed due to an extension in the Definition phase schedule to incorporate rate changes;

The remaining variance of $5.6 million was due to other variances on various projects.

Properties

Table 25 Fiscal 2023 Properties Capital Expenditures Variances

($ million)	F2023			
	Decision	**Actual**	**Diff**	**% Diff**
	1	2	3=2-1	4=3/1
Building Development	55.3	8.5	(46.8)	-85%
Building Improvements and Others	28.2	50.3	22.1	78%
Total	**83.4**	**58.7**	**(24.7)**	**-30%**

Table 26 Fiscal 2023 Properties Capital Additions Variances

($ million)	F2023			
	Decision	**Actual**	**Diff**	**% Diff**
	1	2	3=2-1	4=3/1
Building Development	6.6	0.0	(6.6)	-100%
Building Improvements and Others	26.1	34.1	8.0	31%
Total	**32.7**	**34.1**	**1.4**	**4%**

BC Hydro's approach is to manage the Properties' Building Improvements projects and Building Development projects as a combined Building Projects portfolio to meet the annual plan. As some projects are delayed others are advanced, based on changing priorities that may include asset condition or operational requirements.

Fiscal 2023 capital expenditures for Properties' Building Development projects were $46.8 million or (85%) below the fiscal 2023 Decision. This was primarily because:

- The Materials Classification Facility Building Redevelopment project was $20.3 million below plan as planned construction activities did not occur due to delays in municipal permitting;
- The Chilliwack Field Building Redevelopment project was $9.1 million below plan as the project has not progressed into construction due to a prolonged search for a suitable development site and some components of the facility design taking longer than anticipated;
- The North Vancouver Building Redevelopment project was $8.4 million below plan as the project has not progressed into construction due to a much longer than anticipated municipal permitting process and some components of the facility design taking longer than anticipated; and

- The Duncan Building Redevelopment project was $5.6 million below plan because the project start was delayed from fiscal 2022 due to the advancement of other projects as well as delays due to additional design work.

The remaining below plan variance of $3.4 million was due to variances on various smaller projects.

Fiscal 2023 capital additions for Properties' Building Development projects were comparable to the fiscal 2023 Decision.

As Properties manages the project portfolios on an overall basis to meet the annual plan, the impact of these delays was partially offset by the advancement of Building Improvements and Others.

Fiscal 2023 capital expenditures for Properties' Building Improvements and Others projects were $22.1 million or (78%) above the fiscal 2023 Decision due to a greater number of small projects being advanced as described above.

Fiscal 2023 capital additions for Properties' Building Improvements and Others projects were comparable to the fiscal 2023 Decision.

Fleet

Table 27 Fiscal 2023 Fleet Capital Expenditures Variances

($ million)	F2023			
	Decision	**Actual**	**Diff**	**% Diff**
	1	2	3=2-1	4=3/1
Fleet	42.0	40.0	(2.0)	-5%
Total	**42.0**	**40.0**	**(2.0)**	**-5%**

Table 28 Fiscal 2023 Fleet Capital Additions Variances

($ million)	F2023			
	Decision	**Actual**	**Diff**	**% Diff**
	1	2	3=2-1	4=3/1
Fleet	42.0	26.5	(15.5)	-37%
Total	**42.0**	**26.5**	**(15.5)**	**-37%**

Fiscal 2023 capital expenditures for Fleet were comparable to the fiscal 2023 Decision.

Fiscal 2023 capital additions for Fleet were $15.5 million (or 37%) below the fiscal 2023 Decision because of delays in the procurement of vehicles as a result of global supply chain issues, which delayed the completion of the quality control checks before vehicles are put into service.

Business Support - Other and Other Technology

Table 29 Fiscal 2023 Business Support –Other and Other Technology Capital Expenditures Variances

($ million)	F2023			
	Decision	**Actual**	**Diff**	**% Diff**
	1	2	3=2-1	4=3/1
Business Support - Other	38.1	39.0	0.9	2%
Other Technology	0.2	3.8	3.6	100%
Total	**38.3**	**42.7**	**4.4**	**12%**

Table 30 Fiscal 2023 Business Support –Other and Other Technology Capital Additions Variances

($ million)	F2023			
	Decision	**Actual**	**Diff**	**% Diff**
	1	2	3=2-1	4=3/1
Business Support - Other	28.3	27.3	(1.0)	-3%
Other Technology	11.6	-	(11.6)	-100%
Total	**39.9**	**27.3**	**(12.6)**	**-31%**

Business Support - Other

Business Support – Other is comprised of capital expenditures such as security equipment, field tools, and minor equipment.

Fiscal 2023 capital expenditures and capital additions for Business Support - Other were comparable to the fiscal 2023 Decision.

Other Technology

Other Technology is comprised of the Mobile Radio Optimization - LM project, which was not classified as part of the main asset Technology category as the project was for Field Operations tools and equipment. Fiscal 2023 capital expenditures were comparable to the fiscal 2023 Decision.

Fiscal 2023 capital additions were $11.6 million (or 100%) below the fiscal 2023 Decision due to the Mobile Radio Optimization – LM project in-service date being delayed to fiscal 2025 as a result of design changes, resource constraints, issues with securing permits and supply chain delays.

10.7 Site C Project Capital Expenditures and Additions Variance Explanations

Site C Project fiscal 2023 capital expenditures and capital additions are presented in the tables below.

Table 31 Fiscal 2023 Site C Project Capital Expenditures Variances

($ million)	F2023			
	Decision	**Actual**	**Diff**	**% Diff**
	1	2	3=2-1	4=3/1
Total Site C	**2,708.3**	**2,186.6**	**(521.7)**	**-19%**

Table 32 Fiscal 2023 Site C Project Capital Additions Variances

($ million)	F2023			
	Decision	**Actual**	**Diff**	**% Diff**
	1	2	3=2-1	4=3/1
Total Site C	**-**	**5.2**	**5.2**	**100%**

Fiscal 2023 capital expenditures were $521.7 million (or 19%) below the fiscal 2023 Decision due to the Main Civil Works, Generating Station and Spillways, and Right Bank Foundation Enhancements construction areas being underspent compared to plan information available at the time of developing the Revenue Requirement Application Plan. The Site C Project forecast remains at the $16 billion estimate with full in-service in calendar 2025 as announced in June 2021.

Fiscal 2023 capital additions were comparable to the fiscal 2023 Decision.

11 Capital Projects and Programs: First Full Funding Amount vs Estimate at Completion

In compliance with BCUC Order No. G-313-19,[1] Table 33 below provides a comparison of the First Full Funding (**FFF**) amount and estimate at completion (**EAC**) for all projects and programs of projects that meet the following criteria:

- Achieved final in-service date between April 1, 2022 and March 31, 2023; or final in-service date achieved prior to this fiscal year and where the remaining capital expenditures have increased 25% or more and a minimum amount of $0.5 million compared to the estimated remaining capital expenditures when previously reported;

[1] BCUC Order G-313-19 from the Review of the Regulatory Oversight of Capital Expenditures and Projects proceedings, page 27, “The final, actual cost for completed capital projects and programs above a materiality threshold.”

- Met a materiality threshold of total capital expenditures of at least $20 million for Power System and Building projects and programs, and $10 million for Technology projects and programs. These align with the thresholds for inclusion in Appendix J in future revenue requirements applications; and
- Were not recurring projects and programs that were financially authorized at a group, program or other aggregated level. This ensures consistency with the information provided in the Attachment to section 7.

[Table 33](#) includes the variance between the EAC[2] and the FFF[3] amounts and provides a brief explanation for any variance greater than or equal to 10%.

Table 33 Projects and Programs with Final In-Service Dates between April 1, 2022 to March 31, 2023 and Meet the Criteria Stated Above

($ million)

A	B			C	D	E	F		G	H	I	J	K	
Planning ID	Name of Project	BCUC Application Reference -if applicable (Note 1)	F23-25 RRA Appendix J Reference	Actual In-Service Date (Note 2)	Financially Closed (Note 3)	First Full Funding Amount (Note 4)	F23-25 RRA Appendix I Authorized Amount (Note 5)	BCUC Application Approved Amount (Note 1)	LTD Costs (Note 6)	Estimate At Completion (Note 7)	Variance [H-E]	Diff (%) [I/E]	Variance Explanation (>=10 percent)	BCUC Application Progress Reports Reference (Note 1)
92840	Circuit Refurbishments - F15 - 2L13/14	N/A	N/A	F2023	N	20.1	N/A	N/A	21.8	22.3	2.3	11%	**Note A**	N/A
92907	Mount Lehman Substation Upgrade	N/A	Page 128	F2023	N	54.5	59.1	N/A	53.2	55.0	0.5	1%		N/A
93646	COK Distribution Egress Reinforcement (LM-COQ-694)	N/A	N/A	F2023	N	13.3	N/A	N/A	20.7	20.7	7.4	56%	**Note B**	N/A
900575	Barnard 50/60 Feeder Section Replacement	N/A	Page 100	F2022	N	43.0	47.9	N/A	46.3	47.1	4.0	9%		N/A
G000241	Puntledge Recoat Interior and Exterior of Steel Penstock	N/A	Page 67	F2022	N	31.4	35.7	N/A	35.3	35.7	4.2	13%	**Note C**	N/A
G000489	Bridge River 2 - Strip and Recoat Penstock 2 Interior	N/A	Page 11	F2023	N	29.7	35.3	N/A	27.8	29.6	(0.0)	0%		N/A
G001047	Waneta U3 Life Extension	N/A	Page 93	F2023	N	37.5	37.5	N/A	37.3	37.1	(0.4)	-1%		N/A
G003207	Mica Replace Units 1 to 4 Generator Transformers	N/A	Page 59	F2023	N	74.7	79.8	N/A	74.7	89.0	14.3	19%	**Note D**	N/A

Note 1 BCUC Application refers to CPCN or Section 44.2 Applications

Note 2 Actual in-service date refers to the final project in-service date achieved

Note 3 Financally closed is when the project has completed all project closing procedures, no additional incremental costs are expected, and project has been closed in the financial system

Note 4 First Full Funding refers to the total capital cost of the project (excluding project reserve) when it was first approved for full Implementation Phase by BC Hydro

Note 5 Authorized Amount refers to the total capital cost of the project, including project reserve, included in the F23 to F25 RRA Appendix I

Note 6 LTD costs refer to the life-to-date capital costs as of March 31, 2023

Note 7 Estimate at Completion refers to the forecasted capital cost when the project is expected to be financially closed

[2] The estimate at completion (**EAC**) is the forecast of capital expenditures for the project or program at financial close. It includes the actual capital cost of the project or program at the in-service date plus any estimated trailing costs to address deficiencies or to otherwise complete the project or program and achieve financial close.

[3] The First Full Funding (**FFF**) amount includes actual capital expenditures incurred during the Identification and Definition phases plus the estimate of capital expenditures for the Implementation phase approved before the Implementation phase. Approval of First Full Funding is required to start the Implementation phase.

Note A: The Circuit Refurbishments - F15 - 2L13/14 project was $2.3 million (or 11%) above the First Full Funding amount because two complex structures, in very poor condition, were added to the project scope. The higher Estimate At Completion costs were also due to increased helicopter costs, and more complex civil work as well as postponement of the Fall 2021 outage work to the Fall 2022.

Note B: The COK Distribution Egress Reinforcement (LM-COQ-694) project was $7.4 million (or 56%) above the First Full Funding amount primarily due to additional requirements in the new Water Sustainability Act permit and construction complexities in completing the western duct bank across Scott Creek.

Note C: The Puntledge Recoat Interior and Exterior of Steel Penstock project was $4.2 million (or 13%) above the First Full Funding amount due to design changes related to the type of coatings and the methodology for preparing the penstock surfaces and applying the coatings. The longer than expected project duration also contributed to the cost increase.

Note D: The Mica Replace Units 1 to 4 Generator Transformers project went into service in December 2022. The project was $14.3 million (or 19%) above the First Full Funding amount because one of the transformers developed issues and was exchanged with a spare transformer. The higher Estimate At Completion costs were due to the purchase and constructing infrastructure to store an additional spare transformer.

BC Hydro Fiscal 2023 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**).

BC Hydro
F23 Actual

Schedule cso
Page 1

Consolidated Statement of Operations
($ million)

Line		Column Reference	F2023 Decision	F2023 Actual	F2023 Diff
			1	2	3 = 2 - 1
	REVENUES				
	Domestic				
1	Residential	14.0 L17+L28	2,368.8	2,193.1	(175.7)
2	Light industrial and commercial	14.0 L18+L29	1,974.0	1,880.2	(93.9)
3	Large industrial (includes LNG revenues)	14.0 L19+L30	853.3	865.7	12.4
4	Other energy sales	14.0 L20:L23 +L26+L32	127.8	116.5	(11.4)
5	Seattle City Light	14.0 L24	30.0	30.0	0.0
6	Revenue from Deferral Rider	14.0 L33	(106.5)	(107.8)	(1.3)
7	Miscellaneous	15.0 L35	287.9	351.5	63.6
8	Subtotal		5,535.4	5,329.3	(206.1)
9	Intersegment revenues	3.0 L5	71.8	34.1	(37.8)
10	**TOTAL REVENUES**	L8+L9	**5,607.3**	**5,363.4**	**(243.9)**
	EXPENSES				
11	Domestic energy costs	1.0 L1	1,773.2	1,636.0	(137.2)
12	Operating costs	1.0 L2+L3	1,396.1	1,444.0	47.9
13	Depreciation and amortization	1.0 L5	1,030.5	1,042.4	12.0
14	Taxes	1.0 L4	283.5	276.4	(7.2)
15	Finance charges	1.0 L6	583.2	471.3	(111.8)
16	Subtotal	L11:L15	5,066.4	4,870.2	(196.3)
17	**TRANSFER (TO)/FROM DEFERRAL ACCOUNTS**	L10-L17	**540.8**	**493.2**	**(47.6)**
18	**POWEREX NET INCOME**	1.0 L18	**224.2**	**1,051.4**	**827.2**
19	**POWERTECH NET INCOME (LOSS)**	1.0 L19	**3.0**	**5.4**	**2.4**
20	**CAPTIVE INSURANCE NET INCOME**	1.0 L20	**0.0**	**0.3**	**0.3**
21	**COLUMBIA HYDRO CONTRACTORS NET INCOME**	1.0 L21	**-**	**(0.2)**	**(0.2)**
22	**TO/(FROM) DEFERRAL ACCOUNTS**	L17:L21	**768.0**	**1,550.1**	**782.0**

BC Hydro
F23 Actual

Schedule cso
Page 2

Line	Column	Reference	F2023 Decision	F2023 Actual	F2023 Diff
			1	2	3 = 2 - 1
23	Heritage Deferral Account	2.1 L3:L5	(42.2)	(137.6)	(95.4)
24	Non-Heritage Deferral Account	2.1 L9:L13	86.5	74.3	(12.2)
25	Trade Income Deferral Account	2.1 L17:L23	109.4	(686.7)	(796.2)
26	Load Variance	2.1 L28:L30	(64.7)	(65.7)	(1.0)
27	Biomass Energy Program Variance	2.1 L34:L37	9.7	(34.1)	(43.8)
28	Low Carbon Fuel Credits Variance	2.1 L41:L44	0.0	(18.0)	(18.0)
29	Demand-Side Management Reg. Account	2.2 L3:L6	23.2	(10.2)	(33.4)
30	First Nation Costs Regulatory Account	2.2 L10:L13	(17.1)	(17.3)	(0.2)
31	First Nation Settlement Provisions Reg. Acct.	2.2 L17:L19	4.0	32.9	28.9
32	Site C Regulatory Account	2.2 L23:L25	26.9	24.1	(2.8)
33	Foreign Exchange Gains/Losses Reg. Account	2.2 L29:L30	(0.1)	5.4	5.4
34	Pre-1996 Customer Contributions Reg. Acct.	2.2 L30:L31	(5.1)	(5.1)	(0.0)
35	Storm Restoration Regulatory Account	2.2 L33:L34	3.5	(4.7)	(8.2)
36	Capital Project Investigation Costs Reg. Acct.	2.2 L45	-	-	-
37	Amortization of Capital Additions Reg. Acct.	2.2 L45:L47	(0.8)	2.1	2.9
38	Total Finance Charges Regulatory Account	2.2 L51:L53	(12.9)	6.4	19.3
39	Smart Metering and Infrastructure Reg. Acct.	2.2 L57:L61	(21.6)	(21.4)	0.3
40	Non-Current Pension Costs Reg. Account	2.2 L66:L70	(29.7)	67.1	96.7
41	Environmental Provisions Regulatory Account	2.2 L74:L77	(39.5)	(34.6)	5.0
42	Rock Bay Remediation Regulatory Account	2.2 L81:L84	-	-	-
43	IFRS Property Plant & Equipment Reg. Account	2.2 L81:L82	(31.6)	(31.6)	(0.0)
44	IFRS Pension Regulatory Account	2.2 L86	(38.2)	(38.2)	0.0
45	Remediation Regulatory Account	2.2 L90:L93	11.3	16.9	5.6
46	Real Property Sales Regulatory Account	2.2 L97:L99	1.4	(2.6)	(4.1)
47	Debt Management Regulatory Account	2.2 L103:L104	(18.1)	(219.2)	(201.0)
48	Dismantling Costs Regulatory Account	2.2 L108:L110	1.5	(10.0)	(11.4)
49	PEB Current Pension Regulatory Account	2.2 L114:L118	8.3	(14.1)	(22.4)
50	Customer Crisis Fund Regulatory Account	2.2 L122:L127	(13.8)	(17.7)	(4.0)
51	Mining Customer Payment Plan	2.2 L131:L134	(2.5)	(2.3)	0.1
52	Project Write-off Costs	2.2 L138:L140	(2.3)	0.9	3.2
53	Electric Vehicle Fast Charging	2.2 L144:L151	4.5	0.6	(3.9)
54	Mandatory Reliability Standard Costs	2.2 L155:L157	(5.4)	0.7	6.0
55	Load Attraction Costs	2.2 L161:L163	8.7	0.8	(7.8)
56	Depreciation Study	2.2 L167:L169	(9.8)	(5.6)	4.2
57	Electrification Customer Connection Costs	2.2 L173:L175	0.5	0.5	(0.0)
58	Cloud Costs	2.2 L179:L181	-	11.4	11.4
59	Inflationary Pressures	2.2 L185:L188	-	(57.8)	(57.8)
60	**TOTAL TRANSFER TO/(FROM) DEFERRAL ACCOUNTS**	1.0 L13+L17	**(56.02)**	**(1,190.48)**	**(1,134.5)**
61	**TOTAL NET INCOME**	L22+L60	**712.0**	**359.7**	**(352.4)**

BC Hydro
F23 Actual
Revenue Requirements Summary
($ million)

Schedule 1.0
Page 3

Line		Reference	F2023 Decision	F2023 Actual	F2023 Diff
	Column		9	10	11 = 10 - 9
1	**Cost of Energy**	4.0 L36	1,773.2	1,636.0	(137.2)
2	**Operating Costs**	5.0 L34	1,291.3	1,308.7	17.5
3	**Provisions & Other**	5.01 L20	104.9	135.3	30.5
4	**Taxes**	6.0 L20	283.5	276.4	(7.2)
5	**Amortization**	7.0 L16	1,030.5	1,042.4	12.0
6	**Finance Charges**	8.0 L1	583.2	471.3	(111.8)
7	**Return on Equity**	9.0 L12	712.0	359.7	(352.3)
8	**Miscellaneous Revenue**	15.0 L35	(287.9)	(351.5)	(63.6)
9	**Inter-Segment Revenue**	3.0 L5	(71.8)	(34.1)	37.8
	Deferral Accounts				
10	Deferral Account Additions	2.1 L60	2.8	938.7	935.9
11	Interest on Deferral Accounts	2.1 L61	5.0	37.0	31.9
12	Deferral Account Recoveries	2.1 L62	(106.5)	(107.8)	(1.3)
13	Total		(98.7)	867.9	966.5
	Other Regulatory Accounts				
14	Regulatory Account Additions	2.2 L215	(184.0)	86.2	270.2
15	Interest on Regulatory Accounts	2.2 L217	(24.4)	(25.6)	(1.2)
16	Regulatory Account Recoveries	2.2 L218	363.1	262.0	(101.1)
17	Total		154.7	322.6	168.0
	Subsidiary Net Income				
18	Powerex Trade Income		(224.2)	**(1,051.4)**	(827.2)
19	Powertech Net Income		(3.0)	**(5.4)**	(2.4)
20	Captive Insurance Net Income		(0.0)	**(0.3)**	(0.3)
21	Columbia Hydro Contractors Net Income		0.0	**0.2**	0.2
22	Total		(227.2)	(1,056.9)	(829.7)
23	**Less Other Utilities Revenue**	14.0 L24	(30.0)	**(30.0)**	(0.0)
24	**Less Liquefied Natural Gas Revenue**	14.0 L25	0.0	**0.0**	0.0
25	**Less Deferral Account Rate Rider**	14.0 L32	106.5	**107.8**	1.3
26	**Total Rate Revenue Requirement**		5,324.0	5,055.5	(268.5)

BC Hydro — Schedule 2.1
F23 Actual — Page 4
Deferral Accounts
($ million)

Line		Column	Reference	F2023 Decision	F2023 Actual	F2023 Diff
				9	10	11 = 10 - 9
	Heritage Deferral Account					
1	Beginning of Year			90.1	105.4	15.3
2	Adjustment to Opening Balance			0.0	0.0	0.0
3	Additions		Line 66	0.0	(121.2)	(121.2)
4	Interest			2.1	1.9	(0.2)
5	Recovery			(44.3)	(18.3)	26.0
6	End of Year			47.9	(32.2)	(80.1)
	Non-Heritage Deferral Account					
7	Beginning of Year			(190.7)	(185.6)	5.1
8	Adjustment to Opening Balance			0.0	0.0	0.0
9	Transfer to Load Variance			0.0	0.0	0.0
10	Additions		Line 67	0.0	58.2	58.2
11	Additions - Waneta 2/3		15.0 L34	(2.8)	(6.8)	(4.0)
12	Interest			(4.4)	(8.3)	(3.9)
13	Recovery			93.6	32.2	(61.5)
14	End of Year			(104.2)	(110.2)	(6.1)
	Trade Income Deferral Account					
15	Beginning of Year			(233.6)	(503.6)	(270.0)
16	Adjustment to Opening Balance			0.0	0.0	0.0
17	Transfer to Inflationary Pressures			0.0	74.0	74.0
18	Transfer to Customer Crises Fund			0.0	6.0	6.0
19	Transfer to Customer Credits			0.0	320.0	320.0
20	Additions		Line 68	0.0	(827.2)	(827.2)
21	Interest			(5.3)	(26.8)	(21.5)
22	Transfer from Customer Credits		Line 50	0.0	(320.0)	(320.0)
23	Recovery			114.7	87.3	(27.4)
24	End of Year			(124.2)	(1,190.3)	(1,066.1)
	Load Variance					
25	Beginning of Year			136.9	32.9	(104.0)
26	Adjustment to Opening Balance			1.1	0.0	(1.1)
27	Transfer from NHDA			0.0	0.0	0.0
28	Additions			0.0	(59.5)	(59.5)
29	Interest			3.1	(0.5)	(3.5)
30	Recovery			(67.8)	(5.7)	62.1
31	End of Year			73.3	(32.8)	(106.1)

BC Hydro | **Schedule 2.1**
F23 Actual | **Page 5**
Deferral Accounts
($ million)

Line		Column	Reference	F2023 Decision	F2023 Actual	F2023 Diff
				9	10	11 = 10 - 9
	Biomass Energy Program Variance					
32	Beginning of Year			(20.6)	(40.4)	(19.8)
33	Adjustment to Opening Balance			0.0	(0.0)	(0.0)
34	Additions - Cost of Energy		Line 70	0.0	(48.5)	(48.5)
35	Additions - Revenue		Line 71	0.0	9.0	9.0
36	Interest			(0.5)	(1.6)	(1.1)
37	Recovery			10.1	7.0	(3.1)
38	End of Year			(11.0)	(74.6)	(63.6)
	Low Carbon Fuel Credits Variance					
39	Beginning of Year			0.0	(30.2)	(30.2)
40	Adjustment to Opening Balance			0.0	0.0	0.0
41	Transfer to EV Fast Charging			0.0	3.9	3.9
42	Additions		Line 72	0.0	(25.5)	(25.5)
43	Interest			0.0	(1.7)	(1.7)
44	Recovery			0.0	5.2	5.2
45	End of Year			0.0	(48.3)	(48.3)
	Customer Credits Regulatory Account					
46	Beginning of Year			0.0	0.0	0.0
47	Adjustment to Opening Balance			0.0	0.0	0.0
48	Transfer from TIDA		Line 19	0.0	320.0	320.0
49	Interest			0.0	0.0	0.0
50	Transfer to TIDA			0.0	(320.0)	(320.0)
51	End of Year			0.0	0.0	0.0
	End of Year Balances					
52	Heritage		Line 6	47.9	(32.2)	(80.1)
53	Non-Heritage		Line 14	(104.2)	(110.2)	(6.1)
54	Trade Income		Line 24	(124.2)	(1,190.3)	(1,066.1)
55	Load Variance		Line 31	73.3	(32.8)	(106.1)
56	Biomass Energy Program Cost		Line 38	(11.0)	(74.6)	(63.6)
57	Low Carbon Fuel Credits Variance		Line 45	0.0	(48.3)	(48.3)
58	Customer Credits Regulatory Account		Line 51	0.0	0.0	0.0
59	Total			(118.1)	(1,488.4)	(1,370.3)
	Summary					
60	Deferral Account Additions			(2.8)	(938.7)	(935.9)
61	Interest on Deferral Accounts			(5.0)	(37.0)	(31.9)
62	Deferral Account Recoveries			106.5	107.8	1.3
63	Adjustment to Opening Balance			1.1	(0.0)	(1.2)
64	Net Transfers			99.8	(867.9)	(967.7)
65	**Interest Rate**		8.0 L27	3.02%	3.37%	0.34%

BC Hydro **Schedule 2.1**
F23 Actual **Page 6**
Deferral Accounts
($ million)

Line		Column	Reference	F2023 Decision	F2023 Actual	F2023 Diff
				9	10	11 = 10 - 9
	Summary of Items Subject to Deferral					
66	Cost of Heritage Energy		4.0 L45	385.0	263.8	(121.2)
67	Cost of Non-Heritage Energy		4.0 L58	1,286.1	1,344.3	58.2
68	Trade Income		1.0 L18	(224.2)	(1,051.4)	(827.2)
69	Load Variance		14.0 L40	(5,302.2)	(5,358.2)	(55.9)
70	Biomass Energy Program Variance - COE		4.0 L59	113.3	64.8	(48.5)
71	Biomass Energy Program Variance - Revenue		14.0 L41	(21.7)	(12.7)	9.0
72	Low Carbon Fuel Credits Variance		15.0 L29	(31.4)	(56.9)	(25.5)

BC Hydro | **Schedule 2.2**
F23 Actual | **Page 7**
Other Regulatory Accounts
($ million)

Line		Column	Reference	F2023 Decision	F2023 Actual	F2023 Diff
				9	10	11 = 10 - 9
	Demand-Side Management					
1	Beginning of Year			872.0	867.6	(4.4)
2	Adjustment to Opening Balance			0.0	0.0	0.0
3	Additions - DSM		5.0 L16	89.5	76.5	(13.0)
4	Additions - Low Carbon Electrification		5.0 L17	45.1	24.7	(20.4)
5	Amortization on Existing			(111.4)	(111.4)	0.0
6	Amortization on Additions			0.0	0.0	0.0
7	End of Year			895.2	857.4	(37.8)
	First Nations Costs					
8	Beginning of Year			37.0	36.4	(0.6)
9	Adjustment to Opening Balance			0.0	0.0	0.0
10	Additions		5.0 L18	1.8	1.4	(0.4)
11	Transfer from FN Settlement Provisions		Line 19	14.4	13.9	(0.5)
12	Interest			0.8	1.1	0.3
13	Recovery			(34.1)	(33.7)	0.4
14	End of Year			19.9	19.1	(0.9)
	First Nations Settlement Provisions					
15	Beginning of Year			431.6	432.4	0.9
16	Adjustment to Opening Balance			0.0	0.0	0.0
17	Additions - Operating		5.01 L12	0.0	28.4	28.4
18	Additions - Accretion		8.0 L6	18.4	18.4	(0.0)
19	Transfer to First Nations Costs			(14.4)	(13.9)	0.5
20	End of Year			435.6	465.3	29.8
	Site C Project					
21	Beginning of Year			542.1	541.9	(0.2)
22	Adjustment to Opening Balance			0.0	0.0	0.0
23	Additions		5.0 L19-8.0 L22	10.5	6.1	(4.4)
24	Interest			16.5	18.0	1.5
25	Recovery			0.0	0.0	0.0
26	End of Year			569.0	565.9	(3.0)
	Foreign Exchange Gains/Losses					
27	Beginning of Year			7.0	6.2	(0.8)
28	Adjustment to Opening Balance			0.0	0.0	0.0
29	Additions		8.0 L4	0.6	5.9	5.4
30	Recovery			(0.6)	(0.6)	0.1
31	End of Year			6.9	11.5	4.6
	Pre-1996 Customer Contributions					
32	Beginning of Year			67.9	67.9	0.0
33	Adjustment to Opening Balance			0.0	0.0	0.0
34	Recovery			(5.1)	(5.1)	(0.0)
35	End of Year			62.8	62.8	(0.0)

BC Hydro | **Schedule 2.2**
F23 Actual | **Page 8**
Other Regulatory Accounts
($ million)

Line		Column	Reference	F2023 Decision	F2023 Actual	F2023 Diff
				9	10	11 = 10 - 9
	Storm Restoration Costs					
36	Beginning of Year			(10.5)	(16.3)	(5.7)
37	Adjustment to Opening Balance			0.0	0.0	0.0
38	Additions – Storm Restoration Costs		5.0 L20	0.0	(8.7)	(8.7)
39	Additions - Evacuation Relief			0.0	0.9	0.9
40	Interest			(0.3)	(0.6)	(0.4)
41	Recovery			3.8	3.8	(0.0)
42	End of Year			(7.0)	(20.9)	(13.9)
	Amortization of Capital Additions					
43	Beginning of Year			2.5	5.5	3.1
44	Adjustment to Opening Balance			0.0	0.0	0.0
45	Additions		7.0 L18	0.0	2.9	2.9
46	Interest			0.1	0.1	0.0
47	Recovery			(0.9)	(0.9)	0.0
48	End of Year			1.7	7.7	6.0
	Total Finance Charges					
49	Beginning of Year			38.6	38.7	0.1
50	Adjustment to Opening Balance			0.0	(0.0)	(0.0)
51	Transfer from Rock Bay			0.0	0.0	0.0
52	Additions		8.0 L21	0.0	19.3	19.3
53	Recovery			(12.9)	(12.9)	0.0
54	End of Year			25.8	45.1	19.4
	Smart Metering & Infrastructure					
55	Beginning of Year			151.3	151.2	(0.1)
56	Adjustment to Opening Balance			0.0	0.0	0.0
57	Additions - Deferred Operating			0.0	0.0	0.0
58	Additions - DSMD Write-Off			0.0	0.0	0.0
59	Additions - Miscellaneous Revenue			0.0	0.0	0.0
60	Interest			4.2	4.7	0.5
61	Recovery			(25.8)	(26.0)	(0.3)
62	End of Year			129.7	129.8	0.1
	Non-Current Pension Cost					
63	Beginning of Year			1.7	(669.0)	(670.8)
64	Adjustment to Opening Balance			0.0	0.0	0.0
65	OCI Deferral			0.0	(251.5)	(251.5)
66	Additions			0.0	0.0	0.0
67	Recovery - Operating			(29.7)	(29.7)	(0.0)
68	Recovery - Finance Charges			0.0	96.7	96.7
69	Transfer to PEB Current Pension-Addition			0.0	0.0	0.0
70	Transfer to PEB Current Pension-Recovery			0.0	0.0	0.0
71	End of Year			(27.9)	(853.4)	(825.5)

BC Hydro
F23 Actual
Other Regulatory Accounts
($ million)

Schedule 2.2
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Line		Reference	F2023 Decision	F2023 Actual	F2023 Diff
	Column		9	10	11 = 10 - 9
	Environmental Provisions				
72	Beginning of Year		273.8	275.3	1.5
73	Adjustment to Opening Balance		0.0	(0.0)	(0.0)
74	Additions - Deferred Operating	5.01 L13	0.0	8.7	8.7
75	Additions - Accretion	8.0 L7	4.6	6.7	2.1
76	Transfer to Remediation (Asbestos)		(10.4)	(40.0)	(29.6)
77	Transfer to Remediation (PCB)		(33.7)	(9.9)	23.8
78	End of Year		234.2	240.7	6.4
	IFRS PP&E				
79	Beginning of Year		1,039.0	1,039.0	0.0
80	Adjustment to Opening Balance		0.0	0.0	0.0
81	Additions - Deferred Operating		0.0	0.0	0.0
82	Recovery		(31.6)	(31.6)	(0.0)
83	End of Year		1,007.5	1,007.5	(0.0)
	IFRS Pension				
84	Beginning of Year		382.4	382.4	0.0
85	Adjustment to Opening Balance		0.0	0.0	0.0
86	Recovery		(38.2)	(38.2)	0.0
87	End of Year		344.2	344.2	0.0
	Remediation				
88	Beginning of Year		(33.9)	(41.0)	(7.1)
89	Adjustment to Opening Balance		0.0	(0.0)	(0.0)
90	Transfer from Env. Prov. (Asbestos)	Line 76	10.4	40.0	29.6
91	Transfer from Env. Prov. (PCB)	Line 77	33.7	9.9	(23.8)
92	Interest		(0.8)	(1.0)	(0.2)
93	Recovery		(32.0)	(32.0)	0.0
94	End of Year		(22.6)	(24.2)	(1.6)
	Real Property Sales				
95	Beginning of Year		48.1	32.3	(15.8)
96	Adjustment to Opening Balance		0.0	0.0	0.0
97	Additions	5.0 L22+5.01 L15	0.0	(3.4)	(3.4)
98	Interest		1.4	0.7	(0.7)
99	Recovery		0.0	0.0	0.0
100	End of Year		49.5	29.7	(19.9)
	Debt Management				
101	Beginning of Year		462.1	286.1	(176.0)
102	Adjustment to Opening Balance		0.0	0.0	0.0
103	Additions	8.0 L8	0.0	(201.0)	(201.0)
104	Recovery		(18.1)	(18.1)	0.0
105	End of Year		444.0	67.0	(377.0)

BC Hydro — **Schedule 2.2**
F23 Actual — **Page 10**
Other Regulatory Accounts
($ million)

Line		Reference	F2023 Decision	F2023 Actual	F2023 Diff
	Column		9	10	11 = 10 - 9
	Dismantling Cost				
106	Beginning of Year		(4.5)	(11.0)	(6.6)
107	Adjustment to Opening Balance		0.0	0.0	0.0
108	Additions	5.01 L16	0.0	(11.0)	(11.0)
109	Interest		(0.1)	(0.6)	(0.5)
110	Recovery		1.6	1.6	0.0
111	End of Year		(3.0)	(21.0)	(18.0)
	PEB Current Pension Costs				
112	Beginning of Year		(24.8)	(24.0)	0.8
113	Adjustment to Opening Balance		0.0	0.0	0.0
114	OCI Deferral		0.0	0.0	0.0
115	Additions	5.0 L21	0.0	(22.4)	(22.4)
116	Recovery - Operating		8.3	8.3	(0.0)
117	Transfer from Non-Current Pension-Addition	Line 69	0.0	0.0	0.0
118	Transfer from Non-Current Pension-Recovery	Line 70	0.0	0.0	0.0
119	End of Year		(16.5)	(38.1)	(21.5)
	Customer Crisis Fund				
120	Beginning of Year		34.9	35.4	0.5
121	Adjustment to Opening Balance		0.0	0.0	0.0
122	Additions - CCF	5.0 L23 - Line123	0.0	1.9	1.9
123	Additions - COVID-19 Relief operating costs		0.0	0.0	0.0
124	Additions - COVID-19 Residential Grants		0.0	0.0	0.0
125	Transfer from TIDA	2.1 L18	0.0	(6.0)	(6.0)
126	Interest		0.8	0.9	0.1
127	Recovery		(14.6)	(14.6)	0.0
128	End of Year		21.1	17.7	(3.5)
	Mining Customer Payment Plan				
129	Beginning of Year		7.5	7.4	(0.1)
130	Adjustment to Opening Balance		0.0	0.0	0.0
131	Additions	5.0 L25	0.0	0.0	0.0
132	Additions - COVID-19 SGS Waivers		0.0	0.0	0.0
133	Interest		0.2	0.3	0.1
134	Recovery		(2.6)	(2.6)	0.0
135	End of Year		5.0	5.0	0.0
	Project Write-off Costs				
136	Beginning of Year		7.8	35.4	27.6
137	Adjustment to Opening Balance		0.0	0.0	0.0
138	Additions	5.01 L17	0.0	2.2	2.2
139	Interest		0.2	1.2	1.0
140	Recovery		(2.5)	(2.5)	(0.0)
141	End of Year		5.5	36.3	30.8

BC Hydro | **Schedule 2.2**
F23 Actual | **Page 11**
Other Regulatory Accounts
($ million)

Line		Column	Reference	F2023 Decision	F2023 Actual	F2023 Diff
				9	10	11 = 10 - 9
	Electric Vehicle Fast Charging					
142	Beginning of Year			7.4	7.2	(0.2)
143	Adjustment to Opening Balance			(1.1)	(1.1)	0.0
144	Additions - Operating Costs		5.0 L24	2.5	3.2	0.7
145	Additions - Cost of Energy			0.1	0.2	0.0
146	Additions - Depreciation		7.0 L19:L20	1.3	0.4	(0.9)
147	Additions - LCFC Revenue		2.1 L41	(0.0)	(3.9)	(3.9)
148	Additions - Public Charging Revenue		14.0 L37	(1.0)	(1.6)	(0.6)
149	Additions - Finance Charge		8.0 L23	0.3	0.5	0.2
150	Interest			0.2	0.2	0.0
151	Recovery			(0.0)	0.0	0.0
152	End of Year			9.8	5.0	(4.7)
	Mandatory Reliability Standard Costs					
153	Beginning of Year			16.1	14.6	(1.6)
154	Adjustment to Opening Balance			0.0	0.0	0.0
155	Additions		5.0 L25	0.0	5.9	5.9
156	Interest			0.4	0.6	0.2
157	Recovery			(5.8)	(5.8)	(0.0)
158	End of Year			10.8	15.2	4.5
	Load Attraction Costs					
159	Beginning of Year			0.0	0.0	0.0
160	Adjustment to Opening Balance			0.0	0.0	0.0
161	Additions		5.0 L26	8.7	0.9	(7.7)
162	Interest			0.1	0.0	(0.1)
163	Recovery			(0.1)	(0.1)	(0.0)
164	End of Year			8.7	0.8	(7.8)
	Depreciation Study					
165	Beginning of Year			29.5	29.5	(0.0)
166	Adjustment to Opening Balance			0.0	0.0	0.0
167	Additions		7.0 L21	0.0	0.0	0.0
168	Interest			0.7	0.8	0.1
169	Recovery			(10.6)	(6.5)	4.1
170	End of Year			19.7	23.9	4.2
	Electrification Customer Connection Costs					
171	Beginning of Year			0.0	0.0	0.0
172	Adjustment to Opening Balance			0.0	0.0	0.0
173	Additions		5.0 L29	0.5	0.5	(0.0)
174	Interest			0.0	0.0	0.0
175	Recovery			0.0	0.0	0.0
176	End of Year			0.5	0.5	(0.0)

BC Hydro | **Schedule 2.2**
F23 Actual | **Page 12**
Other Regulatory Accounts
($ million)

Line		Column	Reference	F2023 Decision	F2023 Actual	F2023 Diff
				9	10	11 = 10 - 9
	Cloud Costs					
177	Beginning of Year			0.0	0.0	0.0
178	Adjustment to Opening Balance			0.0	0.0	0.0
179	Additions		5.0 L28	0.0	11.4	11.4
180	Interest			0.0	0.0	0.0
181	Recovery			0.0	0.0	0.0
182	End of Year			0.0	11.4	11.4
	Inflationary Pressures					
183	Beginning of Year			0.0	0.0	0.0
184	Adjustment to Opening Balance			0.0	0.0	0.0
185	Additions - Op costs		5.0 L27	0.0	16.9	16.9
186	Transfer from TIDA		2.1 L17	0.0	(74.0)	(74.0)
187	Interest			0.0	(0.7)	(0.7)
188	Recovery			0.0	0.0	0.0
189	End of Year			0.0	(57.8)	(57.8)

BC Hydro | **Schedule 2.2**
F23 Actual | **Page 13**
Other Regulatory Accounts
($ million)

Line		Column	Reference	F2023 Decision	F2023 Actual	F2023 Diff
				9	10	11 = 10 - 9
	End of Year Balances					
183	Demand-Side Management		Line 7	895.2	857.4	(37.8)
184	First Nations Costs		Line 14	19.9	19.1	(0.9)
185	First Nations Settlement Provisions		Line 20	435.6	465.3	29.8
186	Site C Project		Line 26	569.0	565.9	(3.0)
187	Foreign Exchange Gains/Losses		Line 31	6.9	11.5	4.6
188	Pre-1996 Customer Contributions		Line 35	62.8	62.8	(0.0)
189	Storm Restoration Costs		Line 42	(7.0)	(20.9)	(13.9)
190	Capital Project Investigation		Line 46	0.0	0.0	0.0
191	Amortization of Capital Additions		Line 48	1.7	7.7	6.0
192	Total Finance Charges		Line 54	25.8	45.1	19.4
193	Smart Metering & Infrastructure		Line 62	129.7	129.8	0.1
194	Non-Current Pension Cost		Line 71	(27.9)	(853.4)	(825.5)
195	Environmental Provisions		Line 78	234.2	240.7	6.4
196	Rock Bay Remediation		Line 85	0.0	0.0	0.0
197	IFRS PP&E		Line 83	1,007.5	1,007.5	(0.0)
198	IFRS Pension		Line 87	344.2	344.2	0.0
199	Remediation		Line 94	(22.6)	(24.2)	(1.6)
200	Real Property Sales		Line 100	49.5	29.7	(19.9)
201	Debt Management		Line 105	444.0	67.0	(377.0)
202	Dismantling Cost		Line 111	(3.0)	(21.0)	(18.0)
203	PEB Current Pension Costs		Line 119	(16.5)	(38.1)	(21.5)
204	Customer Crisis Fund		Line 128	21.1	17.7	(3.5)
205	Mining Customer Payment Plan		Line 135	5.0	5.0	0.0
206	Project Write-off Costs		Line 141	5.5	36.3	30.8
207	Electric Vehicle Fast Charging		Line 152	9.8	5.0	(4.7)
208	Mandatory Reliability Standard Costs		Line 158	10.8	15.2	4.5
209	Load Attraction Costs		Line 164	8.7	0.8	(7.8)
210	Depreciation Study		Line 170	19.7	23.9	4.2
211	Electrification Customer Connection Costs		Line 176	0.5	0.5	(0.0)
212	Cloud Costs		Line 182	0.0	11.4	11.4
213	Inflationary Pressures		Line 189	0.0	(57.8)	(57.8)
214	Total			4,229.9	2,954.1	(1,275.8)
	Summary					
215	Regulatory Account Additions			184.0	(86.2)	(270.2)
216	Regulatory Account Addition (EV Charging Revenues)			(1.0)	(1.6)	(0.6)
217	Interest on Regulatory Accounts			24.4	25.6	1.2
218	Regulatory Account Recoveries			(363.1)	(262.0)	101.1
219	Adjustments to Opening Balances			(1.1)	(1.2)	(0.1)
220	OCI Deferral (Pension)			0.0	(251.5)	(251.5)
221	Regulatory Account Net Transfers			(156.8)	(576.9)	(420.1)
222	**Interest Rate**		8.0 L27	3.02%	3.37%	0.34%

BC Hydro | **Schedule 3.0**
F23 Actual | **Page 14**

Reconciliation of Current and Gross Views
($ million)

Line		Column	Reference	F2023 Decision	F2023 Actual	F2023 Diff
				9	10	11 = 10 - 9
	Inter-Segment Revenue					
1	Powerex - Business Support Allocation			(0.3)	(0.3)	0.0
2	2020 TPA Revaluation (Mark-to-Market (gains)/losses)			0.0	69.0	69.0
3	Powerex PTP Charges			(39.0)	(58.7)	(19.7)
4	BC Hydro PTP Charges			(32.5)	(44.1)	(11.5)
5	Total			(71.8)	(34.1)	37.8

Note 1: These revenues relate to an allocation of corporate costs to Powerex and are eliminated against Trade Income.

Note 2: 2020 TPA Revaluation (Mark-to-Market (gains)/losses) of $69 million consists of mark-to-market 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 3: These transmission revenues relate to an allocation to Powerex of BC Hydro's cost of purchases of point-to-point transmission within B.C. for export and import transactions. These revenues are eliminated against trade cost of energy on consolidation. The variance is deferred to the NHDA and is offset by corresponding variances deferred to the TIDA. There is no net impact on the combined NHDA and TIDA balances due to these transactions.

Note 4: 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 import transactions and point-to-point transmission relating to BC Hydro's Skagit Valley Treaty commitment. These revenues are eliminated against domestic cost of energy on consolidation. The variance is in the NHDA and is offset by corresponding variances deferred to the HDA. There is no net impact on the combined NHDA and HDA balances due to these transactions.

BC Hydro — **Schedule 4.0**
F23 Actual — **Page 15**
Cost of Energy

Line		Column	Reference	F2023 Decision	F2023 Actual	F2023 Diff
				9	10	11 = 10 - 9
	Sources of Supply (GWh)					
	Heritage Energy					
1	Hydro Generation (Water Rentals)			46,134	46,138	4
2	Natural Gas for Thermal Generation			187	175	(12)
3	Exchange Net			(363)	(826)	(463)
4	Subtotal			45,957	45,487	(471)
5	Electrification Plan - Heritage Energy			(360)		360
6	Total			45,598	45,487	(111)
	Non-Heritage Energy					
7	IPPs and Long-Term Commitments			15,959	15,409	(551)
8	Non-Integrated Area			110	117	7
9	Total			16,069	15,525	(544)
	Market Energy					
10	System Imports			2,617	3,992	1,375
11	System Exports			(5,878)	(5,621)	257
12	Subtotal			(3,261)	(1,629)	1,632
13	Electrification Plan - Market Energy			596		(596)
14	Total			(2,665)	(1,629)	1,036
15	**Total Sources of Supply**		L6+L9+L14	59,001	59,383	381
	Cost of Energy ($ million)					
	Heritage Energy					
16	Water Rentals			389.0	398.0	8.9
17	Natural Gas for Thermal Generation			9.7	10.5	0.9
18	Domestic Transmission - Other			25.1	26.4	1.3
19	Non-Treaty Storage and Libby Coordination Agreements			(26.3)	(169.8)	(143.5)
20	Remissions and Other			(44.0)	(43.2)	0.8
21	Subtotal			353.5	222.0	(131.6)
22	Electrification Plan - Heritage Energy			(0.4)	0.0	0.4
23	Electrification Plan - NTSA			2.9		(2.9)
24	Total			356.0	222.0	(134.1)
	Non-Heritage Energy					
25	IPPs and Long-Term Commitments			1,470.0	1,420.9	(49.1)
26	Non-Integrated Area			28.4	44.1	15.7
27	Gas & Other Transportation			4.4	4.6	0.2
28	Water Rentals (Waneta 2/3)		15.0 L22	3.5	3.5	0.0
29	Total			1,506.3	1,473.1	(33.2)

BC Hydro
F23 Actual
Cost of Energy

Schedule 4.0
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Line		Reference	F2023 Decision	F2023 Actual	F2023 Diff
	Column		9	10	11 = 10 - 9
	Market Energy				
30	System Imports		125.6	644.5	518.9
31	System Exports		(225.8)	(728.5)	(502.7)
32	Domestic Transmission - Export		14.1	24.9	10.8
33	Subtotal		(86.2)	(59.1)	27.1
34	Electrification Plan - Market Energy		(3.0)	0.0	3.0
35	Total		(89.2)	(59.1)	30.1
36	**Total Gross COE**	L24+L29+L35	1,773.2	1,636.0	(137.2)
	Items Subject to HDA				
37	Heritage Energy	Line 24	356.0	222.0	(134.1)
38	Electric Vehicle Fast Charging Additions		0.0	0.0	0.0
39	Domestic Transmission - Export	Line 32	14.1	24.9	10.8
40	Costs in Operating/Amortization		12.6	12.6	0.0
42	Skagit and Ancillary Revenue	14.0 L39	(30.0)	(30.0)	(0.0)
43	Deferred Operating HDA	5.0 L13	0.0	2.1	2.1
44	Other		32.3	32.3	(0.0)
45	Total		385.0	263.8	(121.2)
46	**Total System Inflow (% of Average)**		100%	92%	(8%)
	Items Subject to NHDA				
47	Non-Heritage Cost of Energy	Line 29	1,506.3	1,473.1	(33.2)
48	Less: Water Rentals (Waneta 2/3)	Line 28	(3.5)	(3.5)	(0.0)
49	System Imports	Line 30	125.6	644.5	518.9
50	System Exports	Line 31	(225.8)	(728.5)	(502.7)
51	Electrification Plan	Line 34	(3.0)	0.0	3.0
52	Commodity Risk		0.0	69.0	69.0
53	Electric Vehicle Fast Charging Additions		(0.1)	(0.2)	(0.0)
54	Deferred Operating NHDA	5.0 L14	0.0	1.8	1.8
55	Deferred Amortization NHDA	7.0 L13	0.0	1.3	1.3
56	Other		0.0	(48.5)	(48.5)
57	Less: IPP subject to Biomass Energy Program Variance		(113.3)	(64.8)	48.5
58	Total		1,286.1	1,344.3	58.2
59	**Biomass Energy Program Cost Def. Acct.**		113.3	64.8	(48.5)

BC Hydro
F23 Actual
Operating Costs - Total Company
($ million)

Schedule 5.0
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Line		Column	Reference	F2023 Decision	F2023 Actual	F2023 Diff
				9	10	11 = 10 - 9
	Operating Costs by Business Group					
1	Integrated Planning			354.6	370.2	15.6
2	Capital Infrastructure Project Delivery			84.8	96.1	11.2
3	Operations			266.5	273.4	7.0
4	Safety & Compliance			65.6	66.3	0.7
5	Finance, Technology, Supply Chain			308.4	313.2	4.9
6	Customer and Corporate Affairs			95.3	96.7	1.4
7	Other			(253.2)	(243.7)	9.5
8	**Base Operating Costs**			921.9	972.2	50.3
9	IFRS Ineligible Capitalized Costs			214.9	214.9	0.0
10	Waneta 2/3			5.9	6.0	0.1
11	**Subtotal**			220.8	220.9	0.1
12	**Net Operating Costs**		L8+L11	1,142.7	1,193.2	50.4
	Deferral Account Additions					
13	Transfers to HDA			0.0	2.1	2.1
14	Transfers to NHDA			0.0	1.8	1.8
15	Total			0.0	3.9	3.9
	Regulatory Account Additions					
16	Demand-Side Management			89.5	76.5	(13.0)
17	Low Carbon Electrification			45.1	24.7	(20.4)
18	First Nations Costs			1.8	1.4	(0.4)
19	Site C Project			0.3	0.3	0.0
20	Storm Restoration			0.0	(8.7)	(8.7)
21	PEB Current Pension Costs			0.0	(22.4)	(22.4)
22	Real Property Sales			0.0	(1.2)	(1.2)
23	Customer Crisis Fund			0.0	1.9	1.9
24	Electric Vehicle Fast Charging			2.5	3.2	0.7
25	Mandatory Reliability Standard Costs			0.0	5.9	5.9
26	Load Attraction Costs			8.7	0.9	(7.7)
27	Inflationary Pressures			0.0	16.9	16.9
28	Cloud Computing			0.0	11.4	11.4
29	Electrification Customer Connection Costs			0.5	0.5	(0.0)
30	Total			148.5	111.6	(36.9)
31	**Total Gross Operating Costs**		L12+L15+L30	1,291.3	1,308.7	17.5

BC Hydro Schedule 5.01
F23 Actual Page 18
Provisions & Other - Total Company
($ million)

Line		Column	Reference	F2023 Decision	F2023 Actual	F2023 Diff
				9	10	11 = 10 - 9
	Provisions & Other - By Business Groups					
1	Integrated Planning			78.1	77.5	(0.6)
2	Capital Infrastructure Project Delivery			0.6	3.0	2.5
3	Operations			14.4	12.3	(2.1)
4	Safety & Compliance			0.0	1.3	1.3
5	Finance, Technology, Supply Chain			0.5	8.3	7.8
6	Customer and Corporate Affairs			0.0	0.6	0.6
7	Other			11.3	6.0	(5.3)
8	Total			104.9	109.2	4.3
	Deferral Account Additions					
9	Transfer to HDA			0.0	0.0	0.0
10	Transfers to NHDA			0.0	0.0	0.0
11	Total			0.0	0.0	0.0
	Regulatory Account Additions					
12	First Nations Provisions			0.0	28.4	28.4
13	Environmental Provisions			0.0	8.7	8.7
14	Smart Metering & Infrastructure DSMD Write-Off			0.0	0.0	0.0
15	Real Property Sales			0.0	(2.2)	(2.2)
16	Dismantling Expenses			0.0	(11.0)	(11.0)
17	Project Write-Off Costs			0.0	2.2	2.2
18	Depreciation Study			0.0	0.0	0.0
19	Total			0.0	26.2	26.2
20	**Total Gross Provisions & Other**		L17 + L11 + L19	104.9	135.3	30.5

BC Hydro
F23 Actual
Taxes
($ million)

Schedule 6.0
Page 19

Line		Column	Reference	F2023 Decision	F2023 Actual	F2023 Diff
				9	10	11 = 10 - 9
	Generation					
1	Grants in Lieu			28.9	29.5	0.6
2	School Taxes			18.4	18.4	(0.1)
3	Total			47.3	47.9	0.6
	Transmission					
4	Grants in Lieu			74.7	72.9	(1.8)
5	School Taxes			104.8	103.6	(1.1)
6	Total			179.5	176.6	(2.9)
	Distribution					
7	Grants in Lieu			8.6	8.7	0.1
8	School Taxes			25.4	21.0	(4.4)
9	Total			34.0	29.7	(4.3)
	Customer Care					
	Waneta 2/3					
10	Teck portion of property taxes		15.0 L23	0.8	0.7	(0.1)
11	Total			0.8	0.7	(0.1)
	Business Support					
12	Grants in Lieu			14.5	13.4	(1.1)
13	School Taxes			7.4	8.1	0.7
14	Total			21.9	21.5	(0.4)
	Total Before Regulatory Accounts					
15	Grants in Lieu		L1+L4+L7+L12	126.8	124.6	(2.2)
16	School Taxes		L2+L5+L8+L13	155.9	151.1	(4.9)
17	Waneta 2/3 Property Taxes		L10	0.8	0.7	(0.1)
18	Total			283.5	276.4	(7.2)
	Deferral Account Additions					
19	Transfers to NHDA			0.0	0.0	0.0
20	**Total Gross Taxes**		L18 + L19	283.5	276.4	(7.2)

BC Hydro | **Schedule 7.0**
F23 Actual | **Page 20**
Depreciation and Amortization
($ million)

Line		Column	Reference	F2023 Decision	F2023 Actual	F2023 Diff
				9	10	11 = 10 - 9
	Amortization of Capital Assets					
1	Generation			270.5	272.2	1.7
2	Transmission			243.2	247.4	4.2
3	Distribution			237.3	245.1	7.7
4	Business Support			200.3	197.2	(3.0)
5	Subtotal			951.2	961.9	10.6
	Electrification Plan					
6	Transmission			0.1	0.0	(0.1)
7	Distribution			0.0	0.0	(0.0)
8	Subtotal			0.2	0.0	(0.2)
9	Total			951.4	961.9	10.4
	IPP Capital Leases					
10	IPP Capital Leases			77.1	78.4	1.3
11	Total			77.1	78.4	1.3
	Other Leases					
12	Amortization			2.0	0.9	(1.1)
	Deferral Account Additions					
13	Transfers to NHDA			0.0	1.3	1.3
14	Total			0.0	1.3	1.3
15	Less: Electric Vehicle Costs - Ineligible stations			0.0	0.0	0.0
16	**Total Gross Amortization**			1,030.5	1,042.4	12.0
	Deferral Account Additions					
17	Transfers to NHDA			0.0	(1.3)	(1.3)
	Transfer to Regulatory Account					
18	Amortization on Additions Variance		13.0 L45	0.0	(2.9)	(2.9)
19	Electric Vehicle Costs Additions - New Assets			(1.1)	(0.1)	1.0
20	Electric Vehicle Costs Additions - Existing Assets			(0.3)	(0.3)	(0.1)
21	Depreciation Study			0.0	0.0	0.0
22	Transfer to Regulatory Account			(1.3)	(3.4)	(2.0)

BC Hydro **Schedule 8.0**
F23 Actual **Page 21**
Finance Charges
($ million)

Line		Column	Reference	F2023 Decision	F2023 Actual	F2023 Diff
				9	10	11 = 10 - 9
1	**Before Electrification Plan**			582.3	471.3	(111.0)
2	**Electrification Plan**			0.9		(0.9)
3	**Total Gross Finance Charges**		L9 + L20	583.2	471.3	(111.8)
	Regulatory Account Additions					
4	FX Gains/Losses			0.6	5.9	5.4
5	Deferred IPP Capital Leases (Total Finance Charge Reg. Account Additions)			0.0	0.9	0.9
6	Accretion - First Nations			18.4	18.4	(0.0)
7	Accretion - Environmental			4.6	6.7	2.1
8	Debt Management			0.0	(201.0)	(201.0)
9	Total			23.5	(169.2)	(192.7)
10	**Adj. for Regulatory Account Additions**			559.6	640.5	80.9
	Total Before Regulatory Accounts					
11	Sinking Fund Income			(4.0)	(9.5)	(5.5)
12	Long-Term Debt Costs			828.9	813.8	(15.1)
13	Short-Term Debt Costs			12.2	60.4	48.3
14	Interest Capitalized			(317.5)	(349.5)	(32.1)
15	Other (Income) / Loss			47.4	35.1	(12.3)
16	IPP Capital Leases			43.4	43.4	0.0
17	Accretion - Non-Deferrable			1.6	2.2	0.6
18	Non-Current PEB			(53.3)	43.4	96.7
19	Other Leases			1.0	1.2	0.2
20	Total			559.6	640.5	80.9
21	Total Finance Charge Regulatory Acct. Additions			0.0	(19.3)	(19.3)
22	Site C Project (IFRS 14 IDC impact)			(10.1)	(5.7)	4.4
23	Electric Vehicle Fast Charging			(0.3)	(0.5)	(0.2)
	Weighted Average Cost of Debt (WACD) Rate					
24	Total Gross Finance Charges		Line 1	583.2	471.3	(111.8)
25	WACD Adjustment			320.4	465.8	145.4
26	Finance Charges for WACD			903.5	937.1	33.6
27	Weighted Average Cost of Debt (WACD) Rate			3.02%	3.37%	0.34%

BC Hydro | **Schedule 9.0**
F23 Actual | **Page 22**

Return on Equity
($ million)

Line		Column	Reference	F2023 Decision	F2023 Actual	F2023 Diff
				9	10	11 = 10 - 9
	Deemed Equity					
1	Rate Base		10.0 L4	24,058.4	23,435.9	(622.5)
2	Pre-1996 Customer Contns		2.2 L35	(62.8)	(62.8)	0.0
3	Powerex & Powertech Assets			**96.5**	**41.7**	(54.8)
4	Allowance for Working Capital			**250.0**	**250.0**	0.0
5	Total			24,342.2	23,664.9	(677.3)
6	Deemed Equity Percentage			**30.0%**	**30.0%**	0.0%
7	Year-End Deemed Equity			7,302.7	7,099.5	(203.2)
8	Mid-Year Deemed Equity			7,239.7	7,087.9	(151.7)
9	Achieved ROE					
10	Allowed ROE / Derived ROE (F18-F21)			9.83%	5.07%	
11	Return on Equity			**712.0**	359.7	(352.3)
12	Gross Return on Equity			712.0	359.7	(352.3)

BC Hydro
F23 Actual
Rate Base
($ million)

Schedule 10.0
Page 23

Line		Column / Reference	F2023 Decision	F2023 Actual	F2023 Diff
			9	10	11 = 10 - 9
	Total				
1	Net Assets in Service	12.0 L12	25,314.3	24,846.6	(467.7)
2	Net Contributions	11.0 L10	(2,151.1)	(2,268.1)	(117.0)
3	Net DSM	2.2 L7	895.2	857.4	(37.8)
4	Total		24,058.4	23,435.9	(622.5)
5	Mid-Year		23,860.4	23,371.4	(489.0)

BC Hydro
F23 Actual
Contributions
($ million)

Schedule 11.0
Page 24

Line		Column	Reference	F2023 Decision	F2023 Actual	F2023 Diff
				9	10	11 = 10 - 9
	Contributions in Aid - Total					
1	Gross Contns - Beginning of Year			3,035.6	3,075.3	39.8
2	Additions			188.1	255.2	67.1
3	Retirements & Transfers			(4.9)	(16.0)	(11.1)
4	Gross Contns - End of Year			3,218.7	3,314.5	95.8
5	Accum Amort - Beginning of Year			1,010.0	998.4	(11.6)
6	Amortization			62.8	63.1	0.3
7	Amortization of Pre-96 CIAC			(5.1)	(5.1)	(0.0)
8	Retirements & Transfers			0.0	(10.0)	(10.0)
9	Accum Amort - End of Year			1,067.6	1,046.4	(21.2)
10	Net Contributions - End of Year		L4 - L9	2,151.1	2,268.1	117.0

BC Hydro **Schedule 12.0**
F23 Actual **Page 25**
Assets - Total (Excluding DSM and IPP Capital Leases)
($ million)

				F2023		
			Reference	Decision	Actual	Diff
Line		Column		9	10	11 = 10 - 9
	Gross Assets in Service					
1	Opening Balance			29,150.1	28,795.4	(354.7)
2	Capital Additions		13.0 L28	1,494.8	1,351.1	(143.7)
3	Retirements & Transfers			(45.1)	(144.1)	(99.0)
4	Closing Balance			30,599.9	30,002.5	(597.4)
	Accumulated Amortization					
5	Opening Balance			4,334.1	4,278.1	(56.0)
6	Adjustment to Opening Balance			0.0	0.3	0.3
7	Amortization on Existing Assets			921.6	929.2	7.5
8	Amortization on Additions		13.0 L41	29.6	32.7	3.1
9	Amortization on Electrification		13.0 L44	0.2	0.0	(0.2)
10	Retirements & Transfers			0.0	(84.5)	(84.5)
11	Closing Balance			5,285.5	5,155.9	(129.7)
12	**Net Assets in Service (Year-End)**		L4 - L11	25,314.3	24,846.6	(467.7)

BC Hydro | **Schedule 13.0**
F23 Actual | **Page 26**

Capital Expenditures and Additions
($ million)

Line		Reference Column	F2023 Decision	F2023 Actual	F2023 Diff
			9	10	11 = 10 - 9
	Capital Expenditures				
1	Generation Growth		0.0	0.5	0.5
2	Generation Sustaining		300.9	331.6	30.7
3	Transmission Growth		125.2	113.8	(11.4)
4	Transmission Sustaining		349.9	389.5	39.6
5	Distribution Growth		326.6	396.2	69.7
6	Distribution Sustaining		193.8	233.0	39.2
7	Site C Project		2,708.3	2,186.6	(521.7)
8	Technology		109.4	105.9	(3.5)
9	Properties		83.4	58.7	(24.7)
10	Fleet & Other		80.1	78.9	(1.2)
11	Subtotal		4,277.5	3,894.7	(382.8)
	Electrification Plan				
12	Transmission Growth		22.6	7.2	(15.4)
13	Distribution Growth		4.0	3.4	(0.6)
14	Distribution Sustaining		2.0	0.0	(2.0)
15	Subtotal		28.7	10.7	(18.0)
16	Total		4,306.2	3,905.4	(400.8)
	Total Capital Additions				
17	Generation		443.2	292.1	(151.1)
18	Transmission		257.7	302.1	44.4
19	Distribution		542.6	590.0	47.5
20	Site C Project		0.0	5.2	5.2
21	Technology		130.6	73.1	(57.5)
22	Properties		32.7	34.1	1.4
23	Fleet & Other		70.3	53.8	(16.5)
24	Subtotal		1,477.0	1,350.5	(126.6)
	Electrification Plan				
25	Transmission		14.6	0.0	(14.6)
26	Distribution		3.2	0.7	(2.5)
27	Subtotal		17.8	0.7	(17.1)
28	Total		1,494.8	1,351.1	(143.7)
	Unfinished Construction				
29	Beginning of Year		10,797.0	10,113.4	(683.6)
30	Adjustments		0.0	(1.0)	(1.0)
31	Change in Unfinished		2,811.3	2,554.2	(257.1)
32	End of Year		13,608.4	12,666.6	(941.8)
33	Mid-Year Balance		12,202.7	11,390.0	(812.7)

BC Hydro Schedule 13.0
F23 Actual Page 27
Capital Expenditures and Additions
($ million)

Line		Reference Column	F2023 Decision	F2023 Actual	F2023 Diff
			9	10	11 = 10 - 9
	Amortization on Additions				
34	Generation		5.0	**4.0**	(1.0)
35	Transmission		3.1	**4.5**	1.3
36	Distribution		6.7	**13.2**	6.6
37	Site C Project		0.0	**0.0**	0.0
38	Technology		11.8	**8.0**	(3.8)
39	Properties		0.5	**0.7**	0.1
40	Fleet & Other		2.5	**2.4**	(0.2)
41	Subtotal		29.6	32.7	3.1
	Electrification Plan				
42	Transmission		0.1		(0.1)
43	Distribution		0.0		(0.0)
44	Subtotal		0.2		(0.2)
45	Total		29.8	32.7	2.9

BC Hydro | **Schedule 14.0**
F23 Actual | **Page 28**
Domestic Energy Sales and Revenue

Line		Reference Column	F2023 Decision	F2023 Actual	F2023 Diff
			9	10	11 = 10 - 9
	Domestic Energy Sales (GWh)				
1	Residential		19,657	19,547	(109)
2	Light Industrial and Commercial		18,760	19,247	487
3	Large Industrial		13,163	13,437	275
4	Irrigation		80	71	(9)
5	Street Lighting		215	195	(20)
6	New Westminster & Tongass		506	489	(17)
7	Fortis		618	954	336
8	Seattle City Light		310	313	3
9	Liquefied Natural Gas		0	0	0
10	Other		3	6	3
11	Subtotal		53,312	54,260	947
	Electrification Plan				
12	Residential		(22)		22
13	Light Industrial and Commercial		(31)		31
14	Large Industrial		261		(261)
15	Subtotal		207		(207)
16	Total		53,519	54,260	740
	Domestic Revenues ($ million)				
17	Residential		2,371.4	2,193.1	(178.3)
18	Light Industrial and Commercial		1,974.2	1,880.2	(94.1)
19	Large Industrial		836.8	865.7	28.9
20	Irrigation		7.3	5.7	(1.6)
21	Street Lighting		42.9	40.4	(2.5)
22	New Westminster & Tongass		35.1	28.9	(6.2)
23	Fortis		42.5	41.4	(1.1)
24	Seattle City Light		30.0	30.0	0.0
25	Liquefied Natural Gas		0.0	0.0	0.0
26	Other		1.0	1.7	0.7
27	Subtotal		5,341.2	5,087.2	(254.1)
	Electrification Plan				
28	Residential		(2.5)		2.5
29	Light Industrial and Commercial		(0.2)		0.2
30	Large Industrial		16.5		(16.5)
31	Subtotal		13.8		(13.8)
32	Less: EV Fast Charging Revenues		(1.0)	(1.6)	(0.6)
33	Revenue from Deferral Account Rate Rider		(106.5)	(107.8)	(1.3)
34	Total		5,247.5	4,977.7	(269.7)
35	**Deferral Account Rate Rider**		-2.0%	-2.0%	

BC Hydro **Schedule 14.0**
F23 Actual **Page 29**
Domestic Energy Sales and Revenue

Line		Column	Reference	F2023 Decision	F2023 Actual	F2023 Diff
				9	10	11 = 10 - 9
	Baseline					
36	Evacuation Relief to Storm Restoration			0.0	(0.9)	(0.9)
37	EV Fast Charging Revenue Variance			1.0	1.6	0.6
38	Customer Credits Variance			0.0	(314.6)	(314.6)
39	Skagit and Ancillary Revenue to HDA			30.0	30.0	0.0
40	Load Variance			5,302.2	5,358.2	55.9
41	Biomass Energy Program Variance			21.7	12.7	(9.0)
42	Total			5,355.0	5,087.2	(267.8)

BC Hydro | **Schedule 15.0**
F23 Actual | **Page 30**
Miscellaneous Revenue
($ million)

Line		Reference	F2023 Decision	F2023 Actual	F2023 Diff
	Column		9	10	11 = 10 - 9
	Generation				
1	Amortization of Contributions		0.2	0.2	0.0
2	Other		1.9	2.2	0.4
3	Total		2.1	2.5	0.4
	Transmission				
4	External OATT		12.3	30.4	18.1
5	FortisBC Wheeling Agreement		5.7	6.0	0.3
6	Secondary Revenue		6.8	7.0	0.2
7	Interconnections		6.1	9.8	3.7
8	Amortization of Contributions		11.9	10.8	(1.1)
9	NTL Supplemental Charge		2.4	2.4	0.0
10	Total		45.1	66.3	21.2
	Distribution				
11	Secondary Use Revenue & Other		19.0	22.8	3.7
12	Amortization of Contributions		55.6	58.1	2.6
13	Interconnections		0.9	3.1	2.3
14	Total		75.4	84.0	8.5
	Customer Care				
15	Meter/Trans Rents & Power Factor Surcharges		16.6	15.9	(0.7)
16	Smart Metering & Infrastructure Impact		1.5	1.5	(0.0)
17	Diversion Net Recoveries		0.1	0.1	(0.0)
18	Other Operating Recoveries		4.2	4.1	(0.1)
19	Other		3.0	5.2	2.2
	Waneta 2/3				
20	Lease revenue from Teck		79.8	79.8	0.0
21	Teck portion of operating costs		5.9	6.0	0.1
22	Teck portion of water rentals		3.5	3.5	0.0
23	Teck portion of property taxes		0.8	0.7	(0.1)
24	Subtotal		90.1	90.1	0.0
25	Total		115.5	116.9	1.4
	Business Support				
26	Corporate General Rents		3.6	3.6	(0.0)
27	Late Payment Charges		7.9	7.6	(0.3)
28	MMBU Secondary Revenue		3.3	6.3	3.0
29	Low Carbon Fuel Credits		31.4	56.9	25.5
30	Other		0.8	0.8	(0.0)
31	Total		47.1	75.2	28.1
32	**Total Before Regulatory Accounts**	L3 + L10 + L14 + L25 + L31	285.2	344.7	59.5

BC Hydro
F23 Actual
Miscellaneous Revenue
($ million)

Schedule 15.0
Page 31

Line		Column	Reference	F2023 Decision	F2023 Actual	F2023 Diff
				9	10	11 = 10 - 9
	Deferral Account Additions					
	Waneta 2/3					
33	Teck portion of capital expenditures			2.8	6.8	4.0
34	Subtotal			2.8	6.8	4.0
35	**Total Gross Miscellaneous Revenue**		L32 + L34	287.9	351.5	63.6

7 Planned Capital Extension Projects and Anticipated Regulatory Filings

The attachment to this section summarizes planned capital extension projects and anticipated regulatory filings. The attachment includes the following four tables as well as the criteria used in identifying the projects reported:

- Table 1: Capital Extension Projects;
- Table 2: Projects with Anticipated CPCN or section 44.2 Filings;
- Table 3: Extension Capital Expenditures Approved at the Group, Program or Aggregated Level; and,
- Table 4: Capital Expenditures net of Contributions in Aid.

BC Hydro Fiscal 2023 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 four tables consistent with the information provided in previous annual reports. In the tables, BC Hydro has redacted commercially sensitive customer information.

Table 1 lists, by category: (i) the capital extension[1] projects with a total forecast or planned cost of more than $5 million that were included in Appendix I in the Fiscal 2023 to Fiscal 2025 Revenue Requirements Application; and, (ii) new capital extension projects that were identified from the currency date noted in Appendix I up until March 31, 2023.

BC Hydro's current expectation regarding projects that may be subject to a future CPCN or section 44.2 regulatory filing is provided in Table 2. This includes projects identified in Appendix I in the Fiscal 2023 to Fiscal 2025 Revenue Requirements Application, as well as any that were identified from the currency date noted in Appendix I up until March 31, 2023.

BC Hydro filed an Application with the BCUC on March 17, 2023, outlining a proposal for Amending the Major Capital Projects Filing Guidelines, which includes escalating the expenditure thresholds for major project filings. The proceeding is ongoing. In the interim, the information provided in Table 2 continues to follow the 2018 Capital Project Filing Guideline expenditure thresholds for CPCN and section 44.2 filings, namely $100 million for Power System projects, $50 million for Buildings projects, and $20 million for Information Technology projects approved by the BCUC.

In compliance with Directive 2 of BCUC Order No. G-313-19, Table 3 provides a listing and the forecast capital cost, where available, of all capital expenditures with

[1] An extension is a project initiated with the intent to expand the service area or capacity of a utility plant or system, in accordance with paragraph 13 of BC Hydro's 2018 Capital Filing Guidelines filed with the BCUC on January 17, 2020.

a total forecast or planned capital cost of $50 million or greater that meet the following two criteria:

- Financial approval of the capital expenditure is authorized or expected to be authorized at a group, program, or other aggregated level; and,
- Any subset of capital expenditures within the group, program or other aggregated level is an extension as defined in BC Hydro's 2018 Capital Filing Guidelines (**2018 Guidelines**).[2]

In compliance with BCUC Letter No. L-65-20, Table 4 provides a summary of Capital Expenditures categorized by CPCN, System Extensions which do not meet the threshold for a CPCN filing, and Other Capital Expenditures for the current fiscal reporting year and the following two fiscal years.

Table 1 Capital Extension Projects ($ million)

Planning ID	Project Name	Total Forecast Cost[3]	Reference (from F2023 - F2025 RRA)
Generation Growth Capital			
115778	Site C Project	16,000.0[4]	Appendix I, Site C, Line 1 Appendix J, F2023-F2025 RRA

2 Filed with the BCUC on January 17, 2020.

3 For projects included in Table 1, the Total Forecast Cost shown is:

- The Authorized Amount for projects in the Implementation phase and projects that are in-service;
- The Pre-Implementation Cost Estimate for projects in the Definition phase where an engineering estimate is available; and,
- For projects in Future or Identification phase, to be determined (**TBD**) is provided for the Pre-Implementation Cost Estimate. For Future phase projects, a problem or opportunity has been identified, but the required response has not yet been determined. In Identification phase, a number of identified alternative responses are being investigated, and each alternative can result in very different project scope, schedule, and cost.

4 Approved in June 2021, the Site C project estimate is $16 billion with a project in-service date of calendar year 2025. The updated Project estimate includes the present value of the future operating payments and costs deferred to the Site C Regulatory Account.

Planning ID	Project Name	Total Forecast Cost[3]	Reference (from F2023 - F2025 RRA)
Generation Sustain Capital			
G003207	Mica Replace Units 1 to 4 Generator Transformers	89	Appendix I, Generation, Line 47, Appendix J, F2023-F2025 RRA
G000334	Wahleach Refurbish Generator	64	Appendix I, Generation, Line 57, Appendix J, F2023-F2025 RRA
G001047	Waneta U3 Life Extension	38	Appendix I, Generation, Line 58, Appendix J, F2023-F2025 RRA
G000776	Bridge River 1 Replace Units 1-4 Generators / Governors	326 - 257	Appendix I, Generation, Line 59, Appendix J, F2023-F2025 RRA
TX902612	Various Sites - Grid Scale Storage & Renewable Enablement Template Project	14	N/A
G000183	Mica - U1 - U2 Turbine Overhaul	TBD	N/A
G000252	Revelstoke - U1 - U4 Stator Replacement	TBD	N/A
G003058	Kootenay Canal - U1 - U4 Generators Refurbishment	TBD	N/A
G004155	Seven Mile - U1 - U3 Turbine Upgrade	TBD	N/A
Transmission Growth Capital			
92423	Bridge River Transmission Project	112 - 67	Appendix I, Transmission, Line 1, Appendix J, F2023-F2025 RRA
901572	North Montney Region - Electrification	TBD	Appendix I, Transmission, Line 2, Appendix J, F2023-F2025 RRA
94034	West Kelowna Transmission and Westbank Upgrade Projects	TBD	Appendix I, Transmission, Line 3, Appendix J, F2023-F2025 RRA
900598	West End - Substation Construction and System Reinforcement	TBD	Appendix I, Transmission, Line 4, Appendix J, F2023-F2025 RRA
900266	East Vancouver - Substation Construction	TBD	Appendix I, Transmission, Line 6, Appendix J, F2023-F2025 RRA
900992	Lower Mainland - Capacitive and Reactive Power Reinforcement	166 - 95	Appendix I, Transmission, Line 9, Appendix J, F2023-F2025 RRA

Planning ID	Project Name	Total Forecast Cost[3]	Reference (from F2023 - F2025 RRA)
901574	Prince George to Terrace Capacitors Project	583 - 331	Appendix I, Transmission, Line 10, Appendix J, F2023-F2025 RRA
93788	Capilano Substation Upgrade	87	Appendix I, Transmission, Line 11, Appendix J, F2023-F2025 RRA
92910	Clayburn Substation Upgrade	36	Appendix I, Transmission, Line 12, Appendix J, F2023-F2025 RRA
92907	Mount Lehman Substation Upgrade	58	Appendix I, Transmission, Line 13, Appendix J, F2023-F2025 RRA
900268	Horne Payne - Feeder Section Addition	TBD	Appendix I, Transmission, Line 14, Appendix J, F2023-F2025 RRA
901580	Customer IPID - 901580	16 - 12	Appendix I, Transmission, Line 15,
901573	Customer IPID - 901573	58 - 19	Appendix I, Transmission, Line 16,
901851	Customer IPID - 901851	15	Appendix I, Transmission, Line 17,
901581	Customer IPID - 901581	61 - 47	Appendix I, Transmission, Line 18,
901940	Customer IPID - 901940	21 - 7	Appendix I, Transmission, Line 19,
902121	Customer IPID - 902121	24 - 8	Appendix I, Transmission, Line 20,
901943	Customer IPID - 901943	178 - 58	Appendix I, Transmission, Line 21,
901938	Customer IPID - 901938	6	Appendix I, Transmission, Line 22,
901569	Customer IPID - 901569	10	N/A
901853	Customer IPID - 901853	6	N/A
93500	Customer IPID - 93500	TBD	N/A
901930	Customer IPID - 901930	71 - 57	N/A
902343	Customer IPID - 902343	72 - 23	N/A
TX902780	Westbank - 75MVA Transformer Addition	20 - 15	N/A
94016	McLellan - Substation Upgrade	TBD	N/A
TX902471	Clayburn - Substation Upgrade (2nd Phase)	TBD	N/A

Planning ID	Project Name	Total Forecast Cost[3]	Reference (from F2023 - F2025 RRA)
TX902566	Customer IPID - TX902566	TBD	N/A
Transmission Sustain Capital			
900243	SPG Metalclad Switchgear Replacement	76	Appendix I, Transmission, Line 23, Appendix J, F2023-F2025 RRA
901612	Pemberton - Substation Rebuild	37 - 13	Appendix I, Transmission, Line 25,
901613	Maple Ridge - Feeder Section 60 Series Refurbishment	TBD	Appendix I, Transmission, Line 26, Appendix J, F2023-F2025 RRA
900564	Hundred Mile House T1/T2 EOL Replacement	20	Appendix I, Transmission, Line 29,
900152	Natal Sub - NTL 60-138 kV Rebuild	84	Appendix I, Transmission, Line 32, Appendix J, F2023-F2025 RRA
94079	Sandspit Substation Replacement	17	Appendix I, Transmission, Line 33,
94081	Ah-Sin-Heek - Substation Replacement	TBD	Appendix I, Transmission, Line 34,
92478	Mainwaring Station Upgrade	154	Appendix I, Transmission, Line 41, Appendix J, F2023-F2025 RRA
92479	Newell Substation Upgrade	TBD	Appendix I, Transmission, Line 42, Appendix J, F2023-F2025 RRA
901045	Canal Flats - Substation Wood Pole Replacement	19 - 6	Appendix I, Transmission, Line 55,
901049	Skookumchuck - Substation Wood Pole Replacement	25 - 8	Appendix I, Transmission, Line 56,
900766	Project IPID - 900766	TBD	Appendix I, Transmission, Line 64,
901002	2L146 - Cable Replacement	TBD	Appendix I, Transmission, Line 72, Appendix J, F2023-F2025 RRA
94057	Gulf Islands - Transmission Reinforcement	TBD	Appendix I, Transmission, Line 74, Appendix J, F2023-F2025 RRA
TX902716	2L143 - Cable Replacement	TBD	N/A
Distribution Growth Capital			
DY-1545	Customer IPID DY-1545	34	Appendix I, Distribution, Line 1
901955	Customer IPID 901955	15 - 5	Appendix I, Distribution, Line 3

Planning ID	Project Name	Total Forecast Cost[3]	Reference (from F2023 - F2025 RRA)
902127	Customer IPID 902127	TBD	Appendix I, Distribution, Line 4
902128	Customer IPID 902128	TBD	Appendix I, Distribution, Line 5
900316	LOH 12F56, 12F62 Voltage Conversion Preparation (LM-BBY-082)	10	Appendix I, Distribution, Line 6
901518	Mount Lehman New Feeder to Offload Balfour, Mount Lehman and Gloucester Feeders (FV-ABT-042)	5	Appendix I, Distribution, Line 7
93650	Two New CBN Feeders to Offload SMW (LM-FVE-606)	17 - 10	Appendix I, Distribution, Line 8
92802	Glenmore Voltage Conversion (LM-NSC-088)	23	Appendix I, Distribution, Line 9
901355	Norgate - Offload NOR Loads to NVR Feeders (LM-NSH-074)	22 - 12	Appendix I, Distribution, Line 10
901356	North Vancouver - Offload NVR Loads to LYN New Feeders (LM-NSH-075)	20	Appendix I, Distribution, Line 11
900431	Oldfield (OFD) Voltage Conversion 12 to 25kV (NI-NEW-273)	14	Appendix I, Distribution, Line 12
901132	Three Fleetwood Feeders to Offload McLellan (FV-FVW-723)	41	Appendix I, Distribution, Line 13
93669	Three New MLE Feeders to Offload CBN (LM-FVE-607)	13	Appendix I, Distribution, Line 14
901890	Fleetwood - Distribution Feeder Ductbank and Feeder Installation (FV-FVW-023)	50 - 28	Appendix I, Distribution, Line 16
901949	Fleetwood - Distribution Feeder Ductbank and Feeder Installation (FV-FVW-805)	14 - 5	Appendix I, Distribution, Line 17
901820	Tofino - New LBH 25F54 Feeder Installation to Offload LBH 25F52 (VI-PAL-010)	13	Appendix I, Distribution, Line 19
900541	Vancouver Island - Saltspring 25F61 Cable Extension to North Pender Island (VI-GUL-005)	TBD	Appendix I, Distribution, Line 20 Appendix J, F2023-F2025 RRA
902374	Puntledge - Offload Puntledge to Buckley Bay via Feeder Load Transfers (VI-CTY-002)	14 – 7	N/A

Planning ID	Project Name	Total Forecast Cost[3]	Reference (from F2023 - F2025 RRA)
902375	Abbotsford - Offload Mount Lehman 25F53, 25F61 and 25F33 (FV-ABT-056)	15 – 5	N/A
901557	Customer IPID - 901557	33 - 26	N/A
902353	Customer IPID - 902353	TBD	N/A
901353	Richmond - Offload Richmond feeders and Lansdowne Mall Voltage Conversion (FV-FVW-719)	9	N/A
93390	Capilano – 12F54 Voltage Conversion (LM-NSC-111)	7	N/A
900364	CAP distribution voltage conversion for 57, and 59 (LM-NSH-040)	7	N/A
901931	Gulf Islands - SAL 2561 Reinforcement on Salt Spring Island and North Pender Island (VI-GUL-014)	8 - 6	N/A
D902553	Customer IPID - D902553	11 - 4	N/A
902380	Coquitlam - Duct Bank from Como Lake (LM-COQ-869)	TBD	N/A
D902632	Customer IPID - D902632	TBD	N/A
901655	Customer IPID – 901655	TBD	N/A
D902490	Customer IPID – D902490	TBD	N/A
D902603	Customer IPID – D902603	TBD	N/A
Distribution Sustain Capital			
901822	Mission - Feeder 25F51 Tie (FV-ABT-039)	41 - 33	Appendix I, Distribution, Line 23

Table 2 Projects with Anticipated CPCN or Section 44.2 Filings

Planning ID	Project	Filing Type	Rationale for Filing Type
Generation Sustain Capital			
G000668	Ladore Spillway Seismic Upgrade[5]	Section 44.2	The project is estimated to exceed the $100 million threshold for Power System projects and is not considered an extension to the BC Hydro system.
G000525	Strathcona Upgrade Discharge[5]	Section 44.2	The project is estimated to exceed the $100 million threshold for Power System projects and is not considered an extension to the BC Hydro system.
G000459	La Joie - Dam Improvements	Section 44.2	The project will exceed the $100 million threshold for Power System projects and is not considered an extension to the BC Hydro system.
G003365	Mica - Discharge Facilities Seismic and Reliability Upgrades	Section 44.2	The project may exceed the $100 million threshold for Power System projects and is not considered an extension to the BC Hydro system.
G000052	Cheakamus - Dam Improvements	Section 44.2	The project may exceed the $100 million threshold for Power System projects and is not considered an extension to the BC Hydro system.
G003026	Seton - Bypass Installation[6]	Section 44.2	The project is estimated to exceed the $100 million threshold for Power System projects and is not considered an extension to BC Hydro's system.

5 A section 44.2 Application for the Ladore Spillway Seismic Upgrade Project and Strathcona Upgrade Project were filed jointly on June 14, 2023.

6 This project was formerly referred to as 'Seton - Upgrade Unit'. BC Hydro has made the decision to defer the unit replacement work, and to pursue only the bypass installation at this time. The 'Seton - Bypass Installation' project does not include an extension component.

Planning ID	Project	Filing Type	Rationale for Filing Type
G003058	Kootenay Canal - U1 - U4 Generators Refurbishment	Potential CPCN or Section 44.2	The project may exceed the $100 million threshold for Power System projects. Multiple alternatives are under investigation and a determination on whether the project may be considered an extension to the BC Hydro system will depend on the selected alternative.
G000252	Revelstoke - U1 - U4 Stator Replacement	Potential CPCN or Section 44.2	The project may exceed the $100 million threshold for Power System projects. Multiple alternatives are under investigation and a determination on whether the project may be considered an extension to the BC Hydro system will depend on the selected alternative.
G000183	Mica - U1 - U2 Turbine Overhaul	Potential CPCN or Section 44.2	The project may exceed $100 million threshold for Power System projects. Multiple alternatives are under investigation and a determination on whether the project may be considered an extension to the BC Hydro system will depend on the selected alternative.
G004155	Seven Mile - U1 - U3 Turbine Upgrade	Potential CPCN or Section 44.2	The project may exceed the $100 million threshold for Power System projects. Multiple alternatives are under investigation and a determination on whether the project may be considered an extension to the BC Hydro system will depend on the selected alternative.
G000181	Mica Replace U1 - U4 Circuit Breakers	Section 44.2	The project is estimated to exceed the $100 million threshold for Power System projects and is not considered an extension to BC Hydro’s system.
G004173	Wilsey Dam Fish Passage	Section 44.2	The project may exceed the $100 million threshold for Power System projects and is not considered an extension to the BC Hydro system.

Planning ID	Project	Filing Type	Rationale for Filing Type
Transmission Growth Capital			
901572	North Montney Region - Electrification	CPCN	The project may exceed the $100 million threshold for Power System projects and is considered an extension to BC Hydro's system.
94034	West Kelowna Transmission Project	CPCN	BCUC Order No. G-47-18 directed BC Hydro to file a CPCN application for this project. BC Hydro will be seeking relief from Directive 3 of BCUC Order No. G-47-18 regarding the Westbank Substation Upgrade Project.
900598	West End - Substation Construction and System Reinforcement	CPCN	The project will exceed the $100 million threshold for Power System projects and is considered an extension to BC Hydro's system.
900266	East Vancouver - Substation Construction	CPCN	The project will exceed the $100 million threshold for Power System projects and is considered an extension to BC Hydro's system.
901943	Customer IPID - 901943[7]	CPCN	The project is estimated to exceed the $100 million threshold for Power System projects and is considered an extension to the BC Hydro system.
Transmission Sustain Capital			
900019	System Wide – Bulk Electric System Telecom Equipment Replacement	Section 44.2	The project is estimated to exceed the $100 million threshold for Power System projects and is not considered an extension to the BC Hydro system.
92479	Newell - Substation Upgrade	CPCN	The project may exceed the $100 million threshold for Power System projects and is considered an extension to BC Hydro's system.

7 Note that in its Application to Amend Major Capital Projects Filing Guidelines, BC Hydro requested that the BCUC confirm that a CPCN Application is not required for the Customer IPID – 901943 project.

Planning ID	Project	Filing Type	Rationale for Filing Type
901002	2L146 - Cable Replacement	CPCN	The project may exceed the $100 million threshold for Power System projects and is considered an extension to BC Hydro's system.
Properties Sustain Capital			
P201901	Kamloops Field Building Redevelopment	Section 44.2	The project is estimated to exceed the $50 million threshold for Building projects and is not considered an extension to the BC Hydro system.
P201902	North Vancouver Field Facility Redevelopment[8]	Section 44.2	The project is estimated to exceed the $50 million threshold for Building projects and is not considered an extension to the BC Hydro system.
P202001	Campbell River II Field Facility Redevelopment[9]	Section 44.2	The project is estimated to exceed the $50 million threshold for Building projects and is not considered an extension to the BC Hydro system.
P201703	Chilliwack Field Facility Redevelopment[10]	Section 44.2	The project is estimated to exceed the $50 million threshold for Building projects and is not considered an extension to the BC Hydro system.
P202102	Mica Townsite Apartment Accommodations	Section 44.2	The project is estimated to exceed the $50 million threshold for Building projects and is not considered an extension to the BC Hydro system.
Technology Sustain Capital			

[8] Note that in its Application to Amend Major Capital Projects Filing Guidelines, BC Hydro proposed revised thresholds that, if approved, would result in BC Hydro not filing section 44.2 application for the North Vancouver Field Facility Redevelopment Project.

[9] Note that in its Application to Amend Major Capital Projects Filing Guidelines, BC Hydro proposed revised thresholds that, if approved, would result in BC Hydro not filing section 44.2 application for the Campbell River II Field Facility Redevelopment Project.

[10] Note that in its Application to Amend Major Capital Projects Filing Guidelines, BC Hydro proposed revised thresholds that, if approved, would result in BC Hydro not filing section 44.2 application for the Chilliwack Field Facility Redevelopment Project.

Planning ID	Project	Filing Type	Rationale for Filing Type
T002122	Stations Work Management	Section 44.2	The project is estimated to exceed the $20 million threshold for IT projects and is not considered an extension to the BC Hydro system.
T002549	Distribution Design Modernization	Section 44.2	The project is estimated to exceed the $20 million threshold for IT projects and is not considered an extension to the BC Hydro system.
T001379	SAP Upgrade to S/4HANA	Section 44.2	The project is estimated to exceed the $20 million threshold for IT projects and is not considered an extension to the BC Hydro system.

The following project is expected to exceed the Capital Project Filing Guideline threshold for Power System projects but is not included in Table 2:

- The Prince George to Terrace Capacitors project is exempt from Part 3 of the *Utilities Commission Act* pursuant to the Transmission Upgrade Exemption Regulation, as amended by B.C. Reg. 160/2018.

Table 3 Extension Capital Expenditures Approved at the Group, Program or Aggregated Level ($ million)

Planning ID	Program Name	Total Forecast Cost[11]	Reference (from F2023 - F2025 RRA)
	Not applicable		

At this time, there are no groups, programs or other aggregated level of capital expenditures that meet the criteria for inclusion in Table 3.

[11] For programs, the Total Forecast Cost is based on the forecast project cost at the earliest phase in the program. For projects that were included in Appendix I of the Fiscal 2023 to Fiscal 2025 Revenue Requirements Application, the Total Forecast Cost used for the project is:

- The Authorized Amount (Column K) shown in Appendix I of the Fiscal 2023 to Fiscal 2025 Revenue Requirements Application for projects in the Implementation phase and projects that are in-service, and,
- The Pre-Implementation Cost Estimate (Column J) shown in Appendix I of the Fiscal 2023 to Fiscal 2025 Revenue Requirements Application with the upper value of the range shown for projects for which a range was given in Appendix I.

Table 4 Capital Expenditures Net of Contributions in Aid ($ million)

	F2023 Decision	F2023 Actual	F2023 Variance	F2024 Decision	F2025 Decision
	(a)	(b)	(a)-(b)=(c)	(d)	(e)
CPCN	69	25	44	119	221
System Extensions[12]	323	301	22	312	301
Other Capital:					
Section 44.2	104	53	51	179	330
Exempt	1	15	(14)	0	-
Other Capital Investments	913	1,069	(156)	875	789
Site C	2,708	2,187	521	1,755	1,043
Total	4,118	3,650	468	3,240	2,685

[12] System Extensions includes capital expenditures to expand the service area or capacity of a utility plant or system and are not anticipated to exceed the $100 million CPCN filing threshold for Power System projects.

8 Internal Audit Reviews and/or Reports Provided in Fiscal 2023

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, 2023.

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

A. Risk Based Audits

Operations

- Market Operations Development System Controls
  - ▶ Description: Assessed the effectiveness of the Market Operations Development System controls and related business processes to meet Tariff requirements.

Capital Infrastructure Project Delivery

- Property Tax Management
  - ▶ Description: Reviewed the effectiveness of property tax management processes and controls.

Finance, Technology & Supply Chain

- Information Technology Asset Management
  - Description: Assessed whether effective information technology hardware asset management processes and controls are in place.
- Contact Centre Technology Foundation Project Review
  - Description: Reviewed the Project during the system development life cycle to assess if the Project is being executed to meet its objectives and benefits. The engagement will continue into F2024.

Human Resources

- Employee Benefits Administration
  - Description: Assessed whether employee benefits are effectively administered in accordance with policies and plans.

Site C

- Quality Management
  - Description: Reviewed whether Site C quality management plans were being followed to ensure quality objectives are met. This audit focused on the design, manufacture, and construction quality aspects.

Powerex

- Trade Processing Controls
  - Description: Assessed whether controls for trade processing are operating effectively.
- Cybersecurity Audit
  - Description: Assessed the maturity of the cybersecurity program.

Powertech

- Cybersecurity Audit
  - Description: Assessed the maturity of the cybersecurity program.

B. Project Completion and Evaluation Reviews

Capital Infrastructure Project Delivery

- Peace Region Electricity Supply Project
  - Description: Reviewed the Project Completion and Evaluation Report (**PCER**) and Board of Directors Summary Report for the Peace Region Electricity Supply Project. The review provided independent confirmation of Management's submission to the Audit, Finance & Capital Committee of the Board.

C. Audit Follow-Ups

Integrated Planning

- Capital Estimating Process
  - Description: Follow-up to the fiscal 2022 audit that assessed the effectiveness of the estimating process in providing reliable cost estimates for capital projects to support management decisions.

Capital Infrastructure Project Delivery

- Indigenous Relationship Agreements
  - Description: Follow-up to the fiscal 2022 audit that assessed whether the relationship agreements are effectively managed to ensure commitments are tracked and fulfilled.

Safety & Compliance

- Disaster Preparedness
  - ▶ Description: Follow-up to the fiscal 2022 audit that assessed BC Hydro's plans and ability to respond and recover from a catastrophic disruption of business operations.

Customer & Corporate Affairs

- Contact Centre Operations
  - ▶ Description: Follow-up to the fiscal 2022 audit that assessed whether Contact Centre Operations are effective and properly managed to provide quality customer experience.
- Ethics Program
  - ▶ Description: Follow-up to the fiscal 2022 audit that assessed the effectiveness of the Ethics Program and identified program improvement opportunities.

Site C

- Site C Payment Verification
  - ▶ Description: Follow-up to the fiscal 2022 audit that reviewed the invoice verification and approval process to ensure BC Hydro is appropriately billed for work completed in accordance with the agreements.

Powerex

- Market Risk Management
  - ▶ Description: Follow-up to the fiscal 2022 audit that assessed whether market risk management processes at Powerex are operating effectively.

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.

The following topics are covered in the management letter issued to British Columbia Hydro and Power Authority by the external auditor for the year ended March 31, 2023:

1. Government Direction Impact on BC Hydro's Rate-Regulated Accounting; and
2. Improve Audit Logging and Monitoring of Privileged User Activities.

The management letter included an update on the status of the prior year's recommendation related to Security Controls in SAP. The external auditor acknowledged that management had resolved the recommendation.

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 2023 Waneta Transaction Annual Report, as required by Directive 4(e) of BCUC Order No. G-130-18, is attached.

BC Hydro Fiscal 2023 Annual Report to the British Columbia Utilities Commission

Attachment to Section 10.1

Fiscal 2023 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 No. G-130-18, 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;

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

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 2023. 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 Co-Possessors and Operating Agreement (**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 2023.

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

Table 1 below provides the comparison of the fiscal 2023 Decision and actual expenditures for fiscal 2023 for BC Hydro's 1/3 ownership. Table 2 provides the comparison fiscal 2023 Decision and actual expenditures for fiscal 2023 for BC Hydro's 2/3's ownership, managed by Teck. Explanations are provided for variances greater than 10%.

Table 1 Comparison of Actual and Forecast Expenditures for BC Hydro's 1/3, April 1, 2022 to March 31, 2023

($ thousand)	F2023 Decision	F2023 Actual	Variance	Variance (%)	Variance Explanation (if >10 %)
	1	2	3 = 2 - 1	4 = 3/1 x 100	
Operations and Maintenance[1]	2,607	2,836	229	8.8	
Sustaining Capital	1,389	3,182	1,793	129.1	Primarily due to deferral of Waneta Unit 3 Life Extension Project from F22 to F23
Water Fees	6,587	5,937	-651	-9.9	The result of lower actual generation due to drier inflow conditions.

[1] Includes insurance and Teck administration.

Table 2 Comparison of Actual and Forecast Expenditures for Teck's 2/3, April 1, 2022 to March 31, 2023

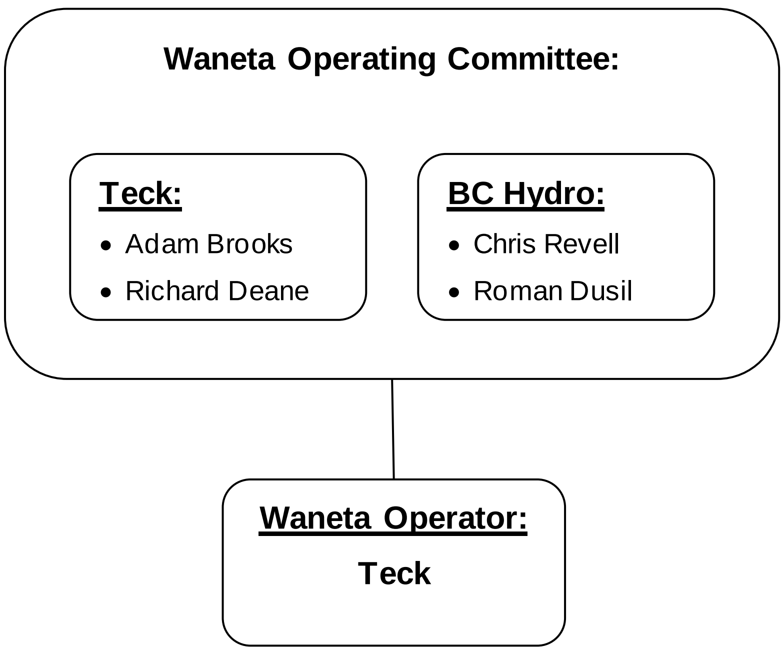
($ thousand)	F2023 Decision	F2023 Actual	Variance	Variance (%)	Variance Explanation (if >10 %)
	1	2	3 = 2 - 1	4 = 3/1 x 100	
Operations and Maintenance[1]	5,934	6,043	109	1.8	
Sustaining Capital	2,778	5,520	2,741	98.7	Primarily due to deferral of Waneta Unit 3 Life Extension Project from F22 to F23
Water Fees	3,543	3,543	0	0	

[1] Includes insurance and Teck administration.

Based on the criteria defined under the COPOA, unanimous approval of the Operating Committee was required for the calendar 2022 sustaining capital budget. This provision was triggered due to increases to planned capital work compared to prior years.

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 393 GWh of surplus energy from Teck during fiscal 2023 under section 5 of the agreement at an average price of C$127.26/MWh. The total volume of energy that was purchased in fiscal 2023 is higher than prior years as a function of the Unit 3 Life Extension (**U3LE**) project that requires Teck to replace its share of lost generation subject to the outage adjustment requirements of the Canal Plant Agreement. These purchases result in an accumulation of surplus energy that BC Hydro purchased under section 5 of the Surplus Power Rights Agreement, most of which is at a discount to the Mid-C index price. The total value, and consequently the average price of the transactions, was higher than in recent years as a function of extraordinarily high market prices that persisted across much of fiscal 2023.

Table 3 Surplus Power Rights Agreement Purchases

	Apr 2022	May 2022	Jun 2022	Jul 2022	Aug 2022	Sep 2022	Oct 2022	Nov 2022	Dec 2022	Jan 2023	Feb 2023	Mar 2023	Total
Invoice Total ($k)	4,582	1,026	233	0	2,607	10,269	4,452	4,678	16,915	2,821	801	1,667	50,051
Volume (MWh)	67,461	15,000	8,131	0	24,649	65,260	63,168	49,623	63,000	15,000	7,000	15,000	393,292

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

A geotechnical assessment of the buried channel was completed in 2021. The assessment looked at three potential failure modes: seepage, liquefaction, and slope stability. The assessment indicated the three potential failure modes are possible with a low likelihood of occurrence. The report recommended several mitigation measures, such as monitoring, inspections, and further study. The monitoring and inspection recommendations are being incorporated in the 2023 revision to the Operating, Maintenance, and Surveillance (**OMS**) manual. A review of the dam safety risks for Waneta is currently underway and further study work will be considered.

A new Waneta Dam 3D stability analysis was initiated using present day best practices and a modelling contractor was selected in 2021. Development of the 3D model is ongoing and is expected to be completed in 2023. The 3D model will inform future Dam Safety related investments.

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 2022, 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

F2023 (April 1, 2022 to March 31, 2023)	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 2023.

11 UNDRIP Plan Progress in Fiscal 2023

The UNDRIP Plan Progress Report is prepared in compliance with BCUC Order No. G-91-23.[1]

BC Hydro began engaging First Nations on the development of a United Nation Declaration on the Rights of Indigenous Peoples (**UNDRIP**) Implementation Plan in spring 2021. Our goal was to develop the UNDRIP Implementation Plan (the **Plan**) in collaboration with First Nations and Indigenous peoples. Our engagement approach was designed to make the Plan accessible to Nations across the Province and support our focus on the Nations most impacted by our presence in their territories.

Engagement was broadly divided into two phases. The first phase involved discussion of the development of the Plan at a high level, including Plan themes and potential actions. During this phase we introduced our intent to develop an UNDRIP Plan and Plan themes during our engagement on the Integrated Resource Plan, in which all B.C. First Nations were invited to participate. We also met individually with Nations that have Relationship Agreements with BC Hydro. The second phase of engagement involved publishing and engaging on the draft Plan itself. During fiscal 2023, we did this in the following ways:

- We sent the draft UNDRIP Implementation Plan to all 200+ B.C. First Nations for review and comment;
- We circulated a survey on the draft Plan to all B.C. First Nations that gave respondents multiple avenues for providing feedback (e.g., through the survey, through a dedicated UNDRIP Implementation Plan email address, and through

[1] Per Page 308 of Decision and Order G-91-3 of the F23-F25 RRA: "…we acknowledge that we are not prescribing the framework of that report, which may be crafted as BC Hydro sees fit, nor directing it to undertake specific activities in pursuit of its UNDRIP implementation. We view such matters are properly within the purview of BC Hydro's management rather than that of the BCUC."

a meeting with BC Hydro). We received survey responses from 26 different Nations, the majority of which agreed that actions in the Plan would advance reconciliation. We received an additional 19 emailed written responses to the draft Plan;

- For those First Nations with Relationship Agreements, our regularly scheduled joint working group meetings provided an opportunity to seek input on the Plan with the Nations' leaders. For many, follow-up workshops were scheduled at a working level which allowed us to focus on Nation-specific issues and interests; and,
- We engaged the First Nations Energy and Mining Council to provide detailed written commentary on the draft Plan.

Overall, we received over 250 comments on the draft Plan, with suggestions on everything from revisions, to Plan language, to new actions that could be included in the Plan. During the latter part of fiscal 2023, BC Hydro focussed on revising the draft UNDRIP Implementation Plan based on this feedback. Because the Plan will be a living document that is revisited over time, there remains room to incorporate feedback from Nations as we continue discussions with First Nations on how BC Hydro can advance reconciliation.

A revised Plan will be published in fiscal 2024. While the Plan contemplates annual reporting on progress, the first annual report has not yet been developed. BC Hydro will engage Nations on the form of reporting, and we expect next year's Plan filing will reflect that engagement.

BC Hydro's UNDRIP Implementation Plan will formalize the work we have already been doing to advance reconciliation for some time. During fiscal 2023, some examples of our progress include:

- Action 1.1 – 2,487 BC Hydro employees have completed our Indigenous 101 and Indigenous 201 courses, introductory and advanced level training programs that build greater awareness of Indigenous peoples' history in Canada, knowledge of UNDRIP, and the context of BC Hydro's work with, and impact on, Indigenous peoples and Nations. In total, 4,969 employees (64% of BC Hydro's work force) have taken one or both of these courses to date;
- Action 1.3 – Created and displayed territorial acknowledgements in the lobbies of our Edmonds and Dunsmuir offices;
- Action 2.2 – Collaborated with four First Nations on the usage of Indigenous languages by developing bilingual signage in the Dane-zaa language for five river crossings along Highway 29, in connection with the Site C project;
- Action 4.3 – Approved funding for ten applications by First Nations to plant culturally significant vegetation in their communities as part of BC Hydro's Community ReGreening Program. In addition, approved $10.2 million for 89 fish and wildlife projects to be implemented in 2023 and 2024 through the Fish & Wildlife Compensation Program, which compensates for fish and wildlife in watersheds impacted by BC Hydro dams;
- Action 4.4. – Engaged over 30 First Nations across seven Water Use Plan Order Reviews, with the goal of seeking consent and consensus through these processes. These reviews are still in progress, with anticipated filings with the Comptroller of Water Rights between 2023 and 2026;
- Action 4.5 – Issued an invitation to Indigenous designated business to qualify to provide BC Hydro with environmental services;
- Action 5.1 – Awarded $227 million in directed procurement contracts to Indigenous designated business;

- Action 5.3 – Hired 29 Indigenous employees; Indigenous employees represented 4% of our workforce (or 302 employees) in fiscal 2023. This percentage exceeds the available Indigenous workforce in B.C.;
- Action 5.4 – Seven Indigenous people participated in BC Hydro's Indigenous Professionals in Development program;
- Action 5.5 – Started to explore with First Nations the potential for Indigenous co-ownership of new transmission lines located in the north coast region of B.C. as a new economic opportunity for First Nations related to our business; and,
- Action 5.7 – Over 120 First Nations participated in our energy management programs resulting in energy efficiency upgrades in over 1,175 homes. In addition, BC Hydro continued to invest in partnerships and initiatives that enable Indigenous leadership in the clean energy transition. Examples include:
  - Our partnership with the Coastal First Nations – Great Bear Initiative to support the Indigenous-Climate Action Network, which enables First Nations in BC Hydro's Non-Integrated Area to hire Climate Action Coordinators that plan and implement initiatives to reduce reliance on diesel-generated electricity in their communities; and,
  - Our partnerships with Indigenous organizations such as the First Nations Energy and Mining Council and the Aboriginal Housing Management Association to enable energy efficient upgrades in Indigenous homes and facilitate access to our programs.

Incorporating the principles of UNDRIP into our business will be a long-term effort. Our UNDRIP Implementation Plan has changed in important ways as a result of thoughtful, wide-ranging feedback from First Nations. Going forward, we will continue to advance the actions outlined above, as well as other actions in the revised Plan; including supporting Indigenous economic participation and ownership in the renewable energy sector as part of future calls for power. By publishing, implementing, and reporting on our UNDRIP Implementation Plan, we will demonstrate how we are adopting UNDRIP as a framework for reconciliation within our mandate as a public utility and advancing true and meaningful reconciliation with Indigenous peoples.

BC Hydro Fiscal 2023 Annual Report to the British Columbia Utilities Commission

Section 12

Annual Report Summary Information

Public Utilities - Annual Report to the BCUC

Instructions

Template Instructions

This template is a supplement to the instructions for completing the annual report for the British Columbia Utilities Commission (BCUC). This template should be completed annually, by all Public Utilities and as directed by the BCUC.

Within the template, enter information into light blue cells only. If there is not enough room to enter the information in the template, please attach additional information.

Please submit the template to the BCUC in both hard copy and electronic, workable excel format. Instructions for completing the worksheet are contained within each worksheet. The entire workbook must be completed.

Annual Report Summary Information Page- L-8-22 Attachment

Public Utility Reporting Template Instructions: Please complete this document and submit with your annual report (in electronic format). Where possible, please include a copy of a high level map of the province with approximate locations marked where you provide regulated service. Please contact Commission Secretary if you have questions or require assistance.

Complete the following information for the Utility:

Entity Name:	BC Hydro
Reporting/Fiscal Period End Date	March 31, 2023 (Fiscal 2023)
Entity Website	bchydro.com
Type of Energy Provided (Electricity, Natural Gas, Propane, etc)	Electricity
Sales Revenue ($)	$8,027 million
Fixed Assests/Rate Base ($) (Total Utility Assets-public)	$23,436 million
Total Capital Additions	$3,839 million
Total Expenses	$2,763 million
Repairs and Maintenance Expenses	$302 million
Net Utility Income (loss)	$360 million
Net Utility Equity (Deficit)	$7,356 million
Return on Equity	5.00%
Cost of Capital	6%
System Average Interruption Frequency Index (SAIFI)	1.50
System Average Interruption Duration Index (SAIDI)	3.14
Number of Pipeline Outages caused by Third Party	N/A
Mileage in km - Pipeline distrbution	N/A
Mileage in km - Pipeline transmission	N/A
Mileage in km- Electrical system distribution	60,289 kms
Energy Delivered (GJ/MWh)	54,259 GWh
Number of Customers	2,188,693
Number of New Customer Connections	15,762
Major Customer Types (Residential, Commercial, Industrial)	Residential, Light Industrial & Commercial, Large Industrial

BC Hydro service area map

BC Hydro
Power smart

CS-1008

BC Hydro Fiscal 2023 Annual Report to the British Columbia Utilities Commission

Appendix A

Annual Deferral Accounts Report

April 1, 2022 to March 31, 2023

List of Schedules

Appendices

Schedule A — British Columbia Hydro and Power Authority Summary of Deferral Accounts For the Year Ended March 31, 2023 ($ million)

Line No.	Particulars (Note 1)	Opening Balance at April 1, 2022	Changes (Note 2)	Amortization (Note 3)	Interest (Note 4)	Net Change	Ending Balance at March 31, 2023
	(1)	(2)	(3)	(4)	(5)	(6) = (3)+(4)+(5)	(7)=(2)+(6)
1	Heritage Deferral Account (HDA)	105.4	(121.2)	(18.3)	1.9	(137.6)	(32.2)
2	Non-Heritage Deferral Account (NHDA)	(185.6)	51.4	32.2	(8.3)	75.3	(110.2)
3	Trade Income Deferral Account (TIDA)	(503.6)	(747.2)	87.3	(26.8)	(686.7)	(1,190.3)
4	Load Variance	32.9	(59.5)	(5.7)	(0.5)	(65.7)	(32.8)
5	Biomass Energy Program Variance	(40.4)	(39.6)	7.0	(1.6)	(34.1)	(74.6)
6	Low Carbon Fuel Credits Variance	(30.2)	(21.6)	5.2	(1.7)	(18.0)	(48.3)
7	Customer Credits Regulatory Account	-	-	-	-	-	-
8	Total	(621.5)	(937.7)	107.8	(37.0)	(866.9)	(1,488.4)

Due to minor rounding some totals may not add.

Note 1: In the BCUC's Decision on the Fiscal 2005 to Fiscal 2006 Revenue Requirements Application dated October 29, 2004 (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.

In the BCUC's Decision on the Fiscal 2020 to Fiscal 2021 Revenue Requirements Application dated October 2, 2020 (Order No. G-246-20), the Commission approved the creation of two additional cost of energy variance accounts. The Load Forecast Variance account captures the variance between planned and actual domestic customer load. The Biomass Energy Program account captures the variance between planned and actual amounts related to the Biomass Energy Program.

In the BCUC's Decision on BC Hydro's Application to Establish the Low Carbon Fuel Credits Variance Regulatory Account dated August 19, 2021 (Order No. G-248-21), the Commission approved the Low Carbon Fuel Credits Variance Regulatory Account to capture the difference between planned and actual revenue from low carbon fuel credits.

Note 2: Please refer to Schedule B for details of the changes.

Note 3: Revenues collected via the Deferral Account Rate Rider (DARR) are used to amortize the deferral account balances in accordance with Section 10(3) in Direction No. 7 of the Fiscal 2015 to Fiscal 2016 Revenue Requirements Application. The DARR revenue is allocated to each deferral account based on the proportion of the deferral account balances at the end of the prior fiscal year. In Phase One of the Comprehensive Review, the Government of B.C. repealed Direction No. 7. In the Decision on the Fiscal 2023 to Fiscal 2025 Revenue Requirements Application, the BCUC approved the requested DARR refund of 2.0 per cent for fiscal 2023 effective April 1, 2022. Commencing in Fiscal 2025, the Trade Income Deferral Account balance will be recovered over a three-year period, through the Trade Income Rate Rider (TIRR). The Commission directed BC Hydro to file for approval of the TIRR annually in a filing separate from the Revenue Requirements Application.

Note 4: Interest is calculated on the monthly balance in each deferral account. The interest rate used is BC Hydro's actual weighted average cost of debt for its current fiscal year per Directive 1 (XXV) of the Fiscal 2012 to Fiscal 2014 Revenue Requirements Application.

Schedule B British Columbia Hydro and Power Authority Summary of Deferral Accounts Changes For the Year Ended March 31, 2023 ($ million)

Line No.	Particulars	Decision	Actual	Variance	Ref.
	(1)	(2)	(3)	(4) = (3) - (2)	(5)
1	**Summary of Deferral Accounts Changes**				
2					
3	**Items Subject to Heritage Deferral Account:**				
4	Heritage Deferral Account Transactions	370.1	246.9	(123.2)	Note 1
5	Skagit Valley Treaty & Ancillary Revenue	(30.0)	(30.0)	(0.0)	
6	Costs in Operating / Amortization	12.6	14.7	2.1	Note 2
7	Other	32.3	32.3	(0.0)	
8	Total	385.0	263.8	(121.2)	Schedule A Line 1
9					
10	**Items Subject to Non-Heritage Deferral Account:**				
11	Non-Heritage Deferral Account Transactions	1,399.4	1,385.5	(14.0)	Note 3
12	Commodity Risk	-	69.0	69.0	Note 4
13	Waneta - 2/3 - Teck Portion of Capital Expenditures	-	(6.8)	(6.8)	Note 5
14	Less: IPP subject to Biomass Energy Program Variance	(113.3)	(64.8)	48.5	Note 6
15	Other	-	(45.3)	(45.3)	Note 7
16	Total	1,286.1	1,337.5	51.4	Schedule A Line 2
17					
18	**Trade Income Deferral Account**				
19	Trade Income	(224.2)	(1,051.4)	(827.2)	
20	Transfers to Inflationary Pressures Regulatory Account	-	74.0	74.0	Note 8
21	Transfers to Customer Crisis Fund	-	6.0	6.0	Note 9
22	Total	(224.2)	(971.4)	(747.2)	Note 10, Schedule A Line 3
23					
24	**Load Variance Deferral Account**				
25	Load Variance	5,302.2	5,358.2	(59.5)	Note 11, Schedule A Line 4
26					
27	**Biomass Energy Program Variance Deferral Account**				
28	Cost of Energy	113.3	64.8	(48.5)	Note 6
29	Revenue	(21.7)	(12.7)	9.0	Note 12
30	Biomass Energy Program Variance	91.6	52.1	(39.5)	Schedule A Line 5
31					
32	**Low Carbon Fuel Credits Variance Deferral Account**				
33	Low Carbon Fuel Credits Variance	0.0	(21.6)	(21.6)	
34	Total	0.0	(21.6)	(21.6)	Note 13, Schedule A Line 6
35					
36	**Customer Credits Regulatory Account**				
37	Customer Credits Variance	-	-	-	Note 14
38					
39	**Total**			(937.7)	Schedule A Line 8 Column 3

Due to minor rounding some totals may not add.

The following Schedule B explanations are provided for variances over +/- $2 million.

Note 1: Actual Heritage Deferral Account Transactions were $123.2 million lower than in the Fiscal 2023 to Fiscal 2025 Revenue Requirements Application Decision (**F23-F25 Decision**), mainly driven by lower costs associated with the Non-Treaty Storage and Libby Coordination agreements of $143.5 million, partially offset by higher water rental costs of $8.9 million, higher Domestic Transmission – Export costs of $10.8 million and higher other costs of $0.6 million. For additional details, please refer to the BC Hydro Annual Report to the Commission, Attachment 1 to section 6 Financial Schedules, Table 4 - Fiscal 2023 Cost of Energy Variances, Lines 13+16+17+19.

Note 2: Costs in Operating/Amortization were $2.1 million higher than in the F23-F25 Decision, primarily due to the deferral of $2.3 million of repair costs for the G2 Air Cooled Condenser at the Fort Nelson plant.

Note 3: Actual Non-Heritage Deferral Account Transactions were $14.0 million lower than in the F23-F25 Decision, mainly driven by lower Independent Power Producer (**IPP**) costs of $49.1 million, partially offset by higher Market Energy costs of $19.2 million, higher Non-Integrated Area costs of $15.7 million and higher Gas and Other Transportation costs of $0.2 million. For additional details, please refer to the BC Hydro Annual Report to the Commission, Attachment 1 to section 6 Financial Schedules, Table 4 – Fiscal 2023 Cost of Energy Variances, Lines 8+18.

Note 4: Commodity Risk variance of $69.0 million consists of mark-to-market losses related to transactions under the energy Transfer Pricing Agreement between BC Hydro and Powerex. These mark-to-market losses are fully offset in Powerex's net income and have no net impact to ratepayers.

Note 5: Revenues of $6.8 million deferred in the NHDA are associated with capital expenditures made by Teck Resources with respect to BC Hydro's purchase of Teck's two-third interest in Waneta. During the lease term these revenues may be deferred to the NHDA, per BCUC Order No. G-130-18.

Note 6: Variances between approved and actual IPP costs incurred under the Biomass Energy Program were excluded from the NHDA and deferred into the Biomass Energy Program account, as approved per BCUC Order No. G-246-20 (Directive 38). Actual IPP costs incurred under the Biomass Energy Program were $48.5 million lower than the F23-F25 Decision, largely due to one energy purchase agreement which was not renewed and IPP outages.

Note 7 Other variances of ($45.3) million deferred into the NHDA include higher intersegment revenues of $31.2 million with Powerex and higher external OATT revenues totaling $18.1 million. This is partially offset by the deferral of $1.8 million of submarine cable repair costs damaged during the 2021 heat dome and $1.3 million of higher than approved IPP capital lease expenses. Intersegment revenues are fully offset in Powerex’s net income with their variances deferred into the Trade Income Deferral Account and have no impact to ratepayers.

Note 8: Pursuant to Order in Council 571, issued November 18, 2022, and BCUC Order No. G-341-22, the Commission authorized BC Hydro to establish an Inflationary Pressures Regulatory Account, transfer $74 million from the Trade Income Deferral Account to this account, and may defer to this account specified costs for the period from April 1, 2022, to March 31, 2025.

Note 9: Pursuant to, Order in Council 571, issued November 18, 2022, and BCUC Order No. G-341-22, the Commission authorized BC Hydro to transfer $6 million from the Trade Income Deferral Account to the Customer Crisis Fund Regulatory Account.

Note 10: The Trade Income variance of ($747.2) million is due to higher than planned Trade Income. The Trade Income Plan is based on a 5-year average of actual Trade Income.

Note 11: The load variance of ($59.5) million is primarily due to higher sales to Light Industrial and Commercial customers due to the rebound from the COVID pandemic, higher sales to Fortis BC as well as favorable variances from Large Industrial customers. For more information, please refer to sections 1 and 2 of Attachment 1 to section 6 of the BC Hydro Fiscal 2023 Annual Report to the British Columbia Utilities Commission. BC Hydro notes that the fiscal 2023 additions to the Load Variance Deferral Account is not equal to the variance between the Decision and the Actual amounts, as the F23-F25 Decision was issued after BC Hydro’s fiscal 2023 financial statements were approved.

Note 12: Actual Biomass Energy Program revenues were $9.0 million lower than in the F23-25 Decision, mainly driven by lower volumes.

Note 13: The fiscal 2023 plan amount was based on a five-year average value of low carbon fuel credits transferred from BC Hydro to Powerex from fiscal 2017 to fiscal 2021. Both the volume of credits that BC Hydro receives each year, and the market price of credits are highly uncertain. The variance reflects higher volume and higher market prices of low carbon fuel credits received in fiscal 2023.

Note 14: Pursuant to Order In Council 571, issued November 18, 2022, and BCUC Order No. G-341-22, the Commission authorized BC Hydro to establish a Customer Credits Regulatory Account and transfer $320 million from the Trade Income Deferral Account to this account. Pursuant to the F23-F25 Decision dated June 19, 2023 (Order No. G-154-23), the Commission approved the reinstatement of the $320 million regulatory liability in the Trade Income Deferral Account, offsetting the above transfer.

BC Hydro Fiscal 2023 Annual Report to the British Columbia Utilities Commission

Appendix A

Appendix 1

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 Requirements 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 following orders and directives:

- 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);
- Directives included in the BCUC's Decision on the Fiscal 2017 to Fiscal 2019 RRA (BCUC Order No. G-47-18);
- Directives included in the BCUC's Decision on the Fiscal 2020 to Fiscal 2021 RRA (BCUC Order No. G-246-20);
- Directives included in the BCUC's Decision on the 2020 Transfer Pricing Agreement (BCUC Order No. G-127-21);
- Directives included in the BCUC's Decision on the application to establish the Low Carbon Fuel Credits Variance Regulatory Account in the compliance filing or Order G-187-21 (BCUC Order No. G-248-21);

- Directives included in the BCUC's Decision on the Direction to the BCUC Respecting Residential and Commercial Customer Account Credits (BCUC Order No. G-341-22);
- Directives included the BCUC's Decision on the Fiscal 2023 to Fiscal 2025 RRA (BCUC Order No. G-91-23); and
- Directives included the BCUC's Decision on the Fiscal 2023 to Fiscal 2025 RRA (BCUC Order No. G-154-23).

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 the BC Hydro Annual Report to the Commission, Attachment 2 to section 6, Financial Schedules, Schedule 4.0 Cost of Energy. 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. These Deferral Account Rules are also updated for the establishment of the Low Carbon Fuel Credits Variance Regulatory Account to capture, on an ongoing basis, the difference between forecast and actual miscellaneous revenue from low carbon fuel credits.

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)

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] and Domestic Transmission – Export costs, as well as all Market Electricity Purchases and Surplus Sales[1] up to March 31, 2020, under the 2003 Transfer Pricing Agreement. The 2003 Transfer Pricing Agreement has been replaced by the 2020 Transfer Pricing Agreement (**2020 TPA**)[3] effective April 1, 2020. BCUC Order No. G-127-21 approved the 2020 TPA as filed by BC Hydro. The adoption of the 2020 TPA resulted in a change in the presentation of transactions relative to the terms used in BCUC Order G-96-04. The terms from Order G-96-04, "Market Electricity Purchases", "Surplus Sales", or and "Net Purchases (**Sales**) From Powerex" were replaced by "System Exports" and "System Imports" under the 2020 TPA and variances in these items are deferred to the Non-Heritage Deferral Account.

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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 the BC Hydro Annual Report to the Commission, Attachment 2 to section 6, Financial Schedules, Schedule 4.0 Cost of Energy.

[3] Per Decision on BC Hydro's 2020 Transfer Pricing Agreement with Powerex, as approved via BCUC Order No. G-127-21.

The following is a list of other variances that also flow through the HDA:

- 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.[4]

2. Variable costs related to thermal generation;[1]
3. Significant unplanned major maintenance costs greater than $1 million related to single event equipment or infrastructure failure or caused by weather related events;[1]
4. Significant unplanned major capital expenditures having an incremental annual impact on the Income Statement greater than $1 million related to single event equipment or infrastructure failure or caused by weather related events;[1]
5. Amortization of unplanned deferred capital costs pursuant to BCUC Order No. G-53-02;[1, 5] and
6. Skagit Valley Treaty revenues and ancillary services revenues;[1]

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

[5] 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).

7. An interest charge/credit[6] is applied to the monthly balance in each deferral account at BC Hydro's weighted average cost of debt for its current fiscal year.[7]

[6] Per Fiscal 2005 to Fiscal 2006 RRA Decision, Directive 18 (BCUC Order No. G-96-04), amended by the Fiscal 2007 to Fiscal 2008 RRA Negotiated Settlement Agreement (BCUC Order No. G-143-06).

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

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[8] - all energy costs variances not deferred to the HDA and the Biomass Energy Program Variance Regulatory account, including all System Imports and System Exports variances under the 2020 TPA with Powerex[3] effective April 1, 2020. These items are 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: For transactions applicable under the 2003 Transfer Pricing Agreement up to March 31, 2020 (replaced with the 2020 TPA[3] with Powerex as of April 1,2020), 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

[8] 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).

Trade Income. The BC Hydro side of the entry is shown as part of domestic energy costs (on consolidation, the Powerex revenue from BC Hydro and the BC Hydro energy costs from Powerex are eliminated). The difference between Actual and Plan on the BC Hydro side relating to energy for future trade flows through the NHDA. The Powerex side of the transaction, which is part of Trade Income, flows through the TIDA. Similar treatment is applied when the energy is returned to Powerex;

- Future Trade: For transactions under the 2003 TPA prior to March 31, 2020 (and replaced by the 2020 TPA[3] with Powerex as of April 1, 2020), when Powerex purchased energy for future trade, Heritage Energy was charged with a notional water rental charge for the use of this energy. The other side of this entry was shown as part of Non-Heritage energy. These entries were eliminated on consolidation. The difference between the Actual and Plan notional water rentals that was part of Heritage Energy flowed through the HDA. The opposite variance relating to the Non-Heritage side of the notional water rental transaction flowed through the NHDA. Notional water rentals are no longer applicable under the 2020 TPA[3] as exports and imports of energy are no longer classified as trade and domestic;
- System Imports: represents purchases of electricity by BC Hydro from Powerex and thermal generation run for Powerex under the 2020 TPA;[3]
- System Exports: represents sales of electricity to Powerex by BC Hydro under the 2020 TPA;[3] 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;[8]

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;[8]

4. Founding Partner Benefits and CIS Credits under the ABS Contract;[8, 9]

5. 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]

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

7. 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;

8. Variances related to the accounting for EPAs determined to be leases under IFRS 16, which are not eligible for deferral treatment under existing orders, to the NHDA, as approved in BCUC's Decision on BC Hydro's fiscal 2020 to fiscal 2021 Revenue Requirements Application;

9. Fiscal 2019 incremental lease revenues arising from the Waneta 2017 Transaction and the revenue BC Hydro is required to recognize from time to

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

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).

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 Open Access Transmission Tariff (**OATT**) revenues and point-to-point charges to Powerex;

11. An interest charge/credit[6] is applied to the monthly balance in each deferral account at BC Hydro's weighted average cost of debt for its current fiscal year;[7] and

12. Commencing in fiscal 2023, and until directed otherwise by the BCUC, defer the actual [energy] costs related to BC Hydro's electric vehicles (**EV**) fast charging service to the EV Fast Charging Regulatory Account.[14]

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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 2023 to Fiscal 2025 RRA Decision, Directive 63 (BCUC Order No. G-91-23)

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;[15]
- Actual Trade Income is determined as the greater of:
    - BC Hydro's consolidated net income adjusted as follows:
        - Subtracting BC Hydro's non-consolidated net income;
        - Subtracting the net income of subsidiaries excluding Powerex;
        - Subtracting any foreign currency translation gains in the fiscal year on intercompany balances between BC Hydro and Powerex;
        - Adding any foreign currency translation losses in the fiscal year on intercompany balances between BC Hydro and Powerex.
    - Zero;
- An interest charge/credit[6] is applied to the monthly balance in each deferral account at BC Hydro's weighted average cost of debt for its current fiscal year;[7]
- BC Hydro is authorized to:

[15] Per OIC 172 Direction No. 8 amendment, BC Hydro includes the net income of Powerex and Powertech in its revenue requirements and defers to the trade income deferral account the variances between actual and forecast trade income. The OIC provides the definition of Trade Income.

- ▶ Transfer $6 million from the TIDA to the Customer Crisis Fund Regulatory Account;[16]
- ▶ Establish an inflationary pressures regulatory account, transfer $74 million from the TIDA to this account;[16] and
- ▶ Establish a customer credit regulatory account and transfer $320 million from the TIDA to this account.[16] However, the Panel later approved the reinstatement of a $320 million regulatory liability in the TIDA as requested by BC Hydro.[17]

- Effective for Fiscal 2024, BC Hydro will no longer classify the TIDA as a Cost of Energy Variance Account based on the findings of the Commission in its decision on April 21, 2023. [18]

16 Per BCUC Order No. G-91-23.
17 Per Fiscal 2023 to Fiscal 2025 RRA Decision, section 3 (BCUC Order No. G-154-23).
18 Per BCUC Order No. G-91-23, page 281, section 4.11.1.2, the BCUC agreed with interveners that the "Trade Income deferral account should not be treated as a cost of energy account."

Biomass Energy Program Variance Regulatory Account

Commission Decision, October 2, 2020, Page 121, Section 4.5.1:

Commission Findings:

> ***"The Commission Panel directs that this account be categorized as one of BC Hydro's cost of energy variance accounts and to apply the same mechanisms for interest charges and recovery that are applicable to the Non-Heritage Deferral Account."[19]***

- All variances between forecast and actual amounts related to the Biomass Energy Program are deferred, including variances in:
  - ▶ Independent Power Producer costs incurred under the Biomass Energy Program;
  - ▶ Domestic Revenues earned under the Biomass Energy Program; and
  - ▶ Any other costs not classified as cost of energy for accounting purposes and incurred under the Biomass Energy Program.
- The same mechanism for recovery that is applicable to the Non-Heritage Deferral Account is applied to the Biomass Energy Program Variance Regulatory Account; and
- An interest charge/credit[6] is applied to the monthly balance at BC Hydro's weighted average cost of debt for its current fiscal year.[7]

[19] Per Fiscal 2020 to Fiscal 2021 RRA Decision, Directive 38 (BCUC Order No. G-246-20).

Load Variance Regulatory Account (LVRA)

Commission Decision, October 2, 2020, Page 43, Section 4.2.4:

Commission Findings:

> ***"The Commission Panel directs the establishment of a load forecast variance account and directs BC Hydro to move all balances related to load forecast variance from the Non Heritage Deferral Account to the load forecast variance account. BC Hydro is directed to use the load forecast variance account to capture the variances between planned and actual domestic customer load. The Panel directs that the load forecast variance account be categorized as one of BC Hydro's cost of energy variance accounts and that BC Hydro apply the same mechanisms for interest charges and recovery that are applicable to the Non-Heritage Deferral Account."***[20]

- All revenue variances resulting from variances between planned and actual domestic customer load (excluding variances attributable to the Biomass Energy Program) are deferred to the LVRA;
- The same mechanisms for recovery that are applicable to the NHDA are applied to the LVRA;
- An interest charge/credit[6] is applied to the monthly balance at BC Hydro's weighted average cost of debt for its current fiscal year;[7]
- In fiscal 2023, transfer the fiscal 2022 actual revenue from BC Hydro's EV fast charging service from the LVRA to the EV Fast Charging Regulatory Account;[21] and

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[20] Per Fiscal 2020 to Fiscal 2021 RRA Decision, Directive 15 (BCUC Order No. G-246-20).
[21] Per Fiscal 2023 to Fiscal 2025 RRA Decision, Directive 63 (BCUC Order No. G-91-23).

- Commencing in fiscal 2023, and until directed otherwise by the BCUC, defer the actual revenue related to BC Hydro's EV fast charging service to the EV Fast Charging Regulatory Account.[21]

Low Carbon Fuel Credits Variance Regulatory Account (LCFCVRA)

Commission Decision, August 19, 2021:

Commission Findings:

> ***"The Low Carbon Fuel Credits Variance Regulatory Account is approved to capture, on an ongoing basis, the difference between forecast and actual miscellaneous revenue from low carbon fuel credits. BC Hydro is to apply interest on the balance of this regulatory account based on BC Hydro's current weighted average cost of debt."[22]***

- All revenue variances between forecast and actual miscellaneous revenue from low carbon fuel credits are deferred to the LCFCVRA;
- An interest charge/credit[6] is applied to the monthly balance at BC Hydro's weighted average cost of debt for its current fiscal year;[7]
- Remove the Test Period forecast revenue, including the Low Carbon Fuel Credits revenue associated with the EV fast charging capital assets, from the revenue requirement;[23] and
- Commencing in fiscal 2023, and until directed otherwise by the BCUC, defer the actual Low Carbon Fuel Credits revenue to the EV Fast Charing Regulatory Account.[21]

[22] Per Request to Establish the Low Carbon Field Credits Variance Regulatory Account (BCUC Order No. G-248-21).

[23] Per Fiscal 2023 to Fiscal 2025 RRA Decision, Directive 63 (BCUC Order No. G-91-23)

BC Hydro Fiscal 2023 Annual Report to the British Columbia Utilities Commission

Appendix B

Debt Management Regulatory Account Annual Status Report

April 1, 2022 to March 31, 2023

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Appendices

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 and settlement gains and losses on financial contracts that hedge future long-term debt to mitigate interest rate risk related to future long-term debt that BC Hydro intends to issue. In compliance with Directive 4 of that Order, BC Hydro provides below its annual report on the DMRA.

Report as at March 31, 2023

During fiscal 2023, BC Hydro entered into an additional $0.88 billion of new future debt hedges (**FDHs**) to mitigate interest rate risk related to future long-term debt that BC Hydro intends to issue. The hedges consisted of 10-year and 30-year Canadian interest rate swaps, with contract maturity dates ranging from approximately two to four years and forecast borrowing yields ranging from 3.52% to 4.27%.

Since the establishment of the DMRA and as at March 31, 2023, a total of $12.73 billion of FDHs have been placed, of which $2.88 billion remain outstanding. Based on BC Hydro's 2023/24 to 2025/26 Service Plan forecast, at March 31, 2023, BC Hydro had hedged approximately 35% of forecast long-term debt issuances for fiscal 2024 to fiscal 2027. The details of all FDHs are included in Appendix 1.

Higher (lower) long-term interest rates result in higher (lower) interest costs on the associated future long-term debt issues when issued. These higher (lower) interest costs on the associated debt issues have an offset provided by the impact of the FDH gains (losses). This results in the net effect of increasing financing cost certainty and mitigating interest rate risk related to future long-term debt that BC Hydro intends to issue.

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.

At March 31, 2023, the DMRA had a balance of $67 million (after amortization). This balance included:

- $244 million of net realized losses on the $9.85 billion of settled FDHs; partially offset by:
  - $2 million of net realized loss amortization on the $8.13 billion of FDHs settled during fiscal 2017 to fiscal 2022; and,
  - $175 million of net unrealized gains on the $2.88 billion of outstanding FDHs.

The net unrealized gains of $175 million relating to the $2.88 billion in outstanding FDHs remain sensitive to changes in long-term yields and will continue to change until the hedges are settled. At March 31, 2023, a 100-basis point change in long-term yields would result in a change of approximately $325 million to $400 million in the value of the $2.88 billion in outstanding FDHs.

The March 31, 2023 balance of $67 million was a net decrease of $219 million from the balance at March 31, 2022 of $286 million. The $219 million decrease was due to:

- $132 million related to increases in the value of the $1.73 billion of FDHs that were settled during fiscal 2023;
- $69 million related to net increases in the unrealized mark-to-market value of the $2.88 billion of outstanding FDHs; and,

- $18 million related to the amortization of net realized losses on the $8.13 billion of FDHs settled during fiscal 2017 to fiscal 2022.

The increase in the value of the outstanding FDHs was due to an increase in long-term interest rates during fiscal 2023, partly offset by a decrease in long-term interest rates since new FDHs were entered into during the fiscal year. The increase in the value of the FDHs settled during fiscal 2023 was a result of an increase in long-term interest rates at the time the FDHs were settled relative to the beginning of the fiscal year.

BC Hydro Fiscal 2023 Annual Report to the British Columbia Utilities Commission

Appendix B

Appendix 1

Future Debt Hedges Report

Future Debt Hedges Report

As of March 31, 2023

(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	2016-Nov	10 years	200	2.24%	3.01%		2.7	2.7	(0.4)	2.3
FDH2A	2016-05-11	Bond Lock	F2017	2016-Sep	30 years	200	2.97%	3.00%		(11.3)	(11.3)	1.5	(9.7)
FDH2B	2016-05-12	Bond Lock	F2017	2016-Sep	30 years	100	3.01%	3.00%		(6.7)	(6.7)	0.9	(5.8)
FDH3	2016-05-18	Bond Lock	F2018	2017-Mar	10 years	300	2.36%	2.35%		8.0	8.0	(3.9)	4.1
FDH4	2016-05-24	Bond Lock	F2018	2017-Oct	10 years	200	2.38%	2.37%		7.4	7.4	(3.6)	3.8
FDH5	2016-05-31	Bond Lock	F2018	2017-Jun	30 years	200	3.04%	2.87%		0.1	0.1	(0.0)	0.1
FDH6	2016-09-23	Swap	F2018	2017-Oct	10 years	200	2.09%	1.83%		17.0	17.0	(8.3)	8.7
FDH7	2016-09-23	Swap	F2018	2017-Oct	10 years	200	2.08%	1.82%		17.2	17.2	(8.4)	8.8
FDH8	2016-09-26	Swap	F2018	2017-Sep	30 years	200	2.64%	2.27%		40.9	40.9	(5.6)	35.3
FDH9	2016-09-29	Swap	F2019	2018-May	10 years	200	2.09%	1.84%		22.7	22.7	(9.3)	13.3
FDH10	2016-10-06	Swap	F2019	2018-Apr	30 years	200	2.76%	2.14%		38.7	38.7	(5.3)	33.4
FDH11	2016-06-08	Swap	F2019	2018-Sep	10 years	300	2.53%	2.16%		22.4	22.4	(9.2)	13.2
FDH12	2016-06-08	Swap	F2019	2018-Sep	10 years	200	2.54%	2.17%		14.7	14.7	(6.1)	8.7
FDH13	2016-06-14	Swap	F2020	2019-Jun	10 years	300	2.54%	2.18%		(0.4)	(0.4)	0.1	(0.3)
FDH14	2016-06-22	Swap	F2020	2019-Oct	10 years	200	2.74%	2.44%		(3.1)	(3.1)	0.7	(2.4)
FDH15	2016-10-12	Swap	F2020	2019-Oct	10 years	200	2.57%	2.24%		0.7	0.7	(0.2)	0.5
FDH16	2016-10-13	Swap	F2021	2020-May	10 years	300	2.60%	2.44%		(28.2)	(28.2)	6.1	(22.1)
FDH17	2016-10-13	Swap	F2021	2020-Jun	10 years	200	2.60%	2.31%		(16.5)	(16.5)	3.6	(12.9)
FDH18	2016-10-20	Swap	F2021	2020-Sep	10 years	300	2.69%	2.25%		(27.9)	(27.9)	6.1	(21.9)
FDH19	2016-10-20	Swap	F2021	2020-Sep	10 years	200	2.69%	2.27%		(18.3)	(18.3)	4.0	(14.3)
Subtotal						**$4,400**			**$0.0**	**$80.1**	**$80.1**	**($37.2)**	**$42.9**
Hedges Placed F2018													
FDH20	2017-09-29	Bond Lock	F2019	2018-Jul	10 years	200	2.96%	2.88%		(1.6)	(1.6)	0.7	(0.9)
FDH21	2017-10-03	Bond Lock	F2019	2018-Jul	10 years	200	3.00%	2.92%		(2.2)	(2.2)	0.9	(1.3)
FDH22	2017-09-29	Bond Lock	F2019	2018-Jul	30 years	200	3.35%	3.36%		(17.3)	(17.3)	2.4	(14.9)
FDH23A	2017-10-04	Bond Lock	F2019	2018-Jun	10 years	100	3.01%	2.84%		(0.4)	(0.4)	0.2	(0.2)
FDH23B	2017-10-04	Bond Lock	F2019	2018-Jun	10 years	100	3.01%	2.87%		(0.4)	(0.4)	0.1	(0.2)
FDH24A	2017-10-02	Bond Lock	F2019	2018-Aug	30 years	100	3.36%	3.35%		(6.4)	(6.4)	0.8	(5.6)
FDH24B	2017-10-03	Bond Lock	F2019	2018-Aug	30 years	100	3.38%	3.37%		(6.8)	(6.8)	0.9	(5.9)
FDH25	2017-09-28	Bond Lock	F2019	2018-Aug	30 years	250	3.37%	3.36%		(16.7)	(16.7)	2.1	(14.5)
FDH26/27	2018-01-29	Swap	F2020	2019-Jun	30 years	50	3.44%	3.16%		(6.7)	(6.7)	0.5	(6.2)
FDH28	2018-02-05	Swap	F2021	2020-Jun	30 years	75	3.64%	4.01%		(30.9)	(30.9)	2.1	(28.8)
FDH29	2018-02-05	Swap	F2021	2020-Sep	30 years	75	3.64%	3.82%		(29.7)	(29.7)	2.0	(27.6)
FDH30/31	2018-02-08	Swap	F2022	2021-Jun	30 years	175	3.67%	3.56%		(27.5)	(27.5)	0.9	(26.5)
FDH32	2018-02-06	Swap	F2022	2021-Sep	30 years	100	3.60%	3.50%		(18.1)	(18.1)	0.6	(17.5)
FDH33	2018-02-07	Swap	F2022	2021-Sep	30 years	100	3.58%	3.47%		(17.7)	(17.7)	0.6	(17.1)
FDH34/35	2018-02-01	Swap	F2023	2022-Jun	30 years	250	3.52%	3.25%		25.1	25.1	0.0	25.1
FDH36/37	2018-01-24	Swap	F2023	2022-Sep	30 years	200	3.40%	3.23%		30.9	30.9	0.0	30.9
Subtotal						**$2,275**			**$0.0**	**($126.2)**	**($126.2)**	**$14.8**	**($111.5)**
Hedges Placed F2019													
FDH38	2018-12-07	Swap	F2022	2021-May	10 years	125	3.33%	3.16%		(9.5)	(9.5)	1.0	(8.4)
FDH39	2018-12-06	Swap	F2023	2022-Jun	10 years	100	3.40%	3.18%		7.3	7.3	0.0	7.3
FDH40	2018-12-07	Swap	F2023	2022-Aug	10 years	125	3.41%	3.24%		3.9	3.9	0.0	3.9
FDH41	2018-12-07	Swap	F2024		10 years	175	3.46%		5.0		5.0		5.0
FDH42	2018-12-06	Swap	F2024		30 years	175	3.62%		12.0		12.0		12.0
FDH43	2019-01-15	Bond Lock	F2020	2019-Jun	30 years	150	3.13%	3.07%		(18.8)	(18.8)	1.4	(17.5)
FDH44	2019-01-16	Bond Lock	F2020	2019-Sep	30 years	125	3.17%	3.24%		(23.1)	(23.1)	1.7	(21.4)
FDH45A	2019-01-17	Bond Lock	F2021	2020-Jun	30 years	200	3.20%	3.54%		(60.4)	(60.4)	4.1	(56.3)
FDH45B	2019-01-17	Bond Lock	F2021	2020-Jun	30 years	125	3.20%	3.47%		(40.4)	(40.4)	2.8	(37.6)
FDH46A	2019-01-15	Swap	F2021	2020-Sep	30 years	100	3.43%	3.51%		(34.6)	(34.6)	2.4	(32.2)
FDH46B	2019-01-16	Swap	F2021	2020-Aug	30 years	225	3.49%	3.69%		(82.2)	(82.2)	5.6	(76.5)
FDH47	2019-01-08	Swap	F2022	2021-May	10 years	275	3.15%	2.96%		(16.4)	(16.4)	1.8	(14.6)
FDH48	2019-01-09	Swap	F2022	2021-Jun	30 years	100	3.41%	3.21%		(9.5)	(9.5)	0.3	(9.2)
FDH49	2019-01-09	Swap	F2022	2021-Sep	10 years	300	3.22%	2.99%		(28.2)	(28.2)	3.1	(25.2)
FDH50	2019-01-10	Swap	F2022	2021-Aug	30 years	175	3.41%	3.22%		(24.0)	(24.0)	0.8	(23.2)
FDH51	2019-01-14	Swap	F2023	2022-May	10 years	250	3.26%	3.07%		15.5	15.5	0.0	15.5
FDH52	2019-01-10	Swap	F2023	2022-Aug	10 years	125	3.27%	3.10%		5.4	5.4	0.0	5.4
FDH53	2019-01-11	Swap	F2023	2022-Sep	30 years	100	3.42%	3.19%		16.1	16.1	0.0	16.1
FDH54	2019-01-09	Swap	F2024		10 years	175	3.33%		6.9		6.9		6.9
FDH55	2019-01-08	Swap	F2024		30 years	125	3.44%		12.5		12.5		12.5
FDH56	2019-01-15	Swap	F2025		10 years	75	3.39%		1.7		1.7		1.7
Subtotal						**$3,325**			**$38.1**	**($298.6)**	**($260.5)**	**$24.9**	**($235.6)**

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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 F2022													
FDH57	2021-04-13	Swap	F2025		10 years	75	3.14%		2.4		2.4		2.4
FDH58	2021-04-13	Swap	F2025		30 years	150	3.32%		13.0		13.0		13.0
FDH59	2021-08-09	Bond Lock	F2023	2022-Jun	10 years	175	2.04%	2.43%		28.6	28.6	0.0	28.6
FDH60A	2021-08-09	Bond Lock	F2023	2022-May	30 years	100	2.64%	2.67%		21.7	21.7	0.0	21.7
FDH60B	2021-09-01	Bond Lock	F2023	2022-Jun	30 years	100	2.65%	2.65%		29.2	29.2	0.0	29.2
FDH61	2021-09-02	Swap	F2024		10 years	100	2.40%		9.7		9.7		9.7
FDH62	2021-08-30	Swap	F2025		10 years	175	2.48%		14.4		14.4		14.4
FDH63	2021-08-17	Swap	F2025		30 years	175	2.83%		29.7		29.7		29.7
FDH64	2021-08-24	Swap	F2026		30 years	100	2.85%		15.5		15.5		15.5
FDH65	2021-10-06	Bond Lock	F2023	2022-Sep	10 years	200	2.35%	2.65%		21.3	21.3	0.0	21.3
FDH66	2021-09-20	Swap	F2024		30 years	150	2.79%		29.4		29.4		29.4
FDH67	2021-09-15	Swap	F2025		30 years	200	2.85%		32.2		32.2		32.2
FDH68	2021-09-22	Swap	F2026		10 years	75	2.61%		5.4		5.4		5.4
FDH69	2021-10-06	Swap	F2026		30 years	75	3.07%		8.6		8.6		8.6
Subtotal						**$1,850**			**$160.4**	**$100.8**	**$261.2**	**$0.0**	**$261.2**
Hedges Placed F2023													
FDH70	2022-06-02	Swap	F2025		30 years	100	3.82%		(2.0)		(2.0)		(2.0)
FDH71	2022-06-02	Swap	F2026		30 years	100	3.82%		(2.2)		(2.2)		(2.2)
FDH72	2022-06-02	Swap	F2026		30 years	50	3.82%		(1.1)		(1.1)		(1.1)
FDH73	2022-06-09	Swap	F2027		10 years	100	4.27%		(5.2)		(5.2)		(5.2)
FDH74	2022-08-16	Swap	F2025		10 years	50	3.52%		(0.3)		(0.3)		(0.3)
FDH75	2022-08-16	Swap	F2026		10 years	200	3.57%		(1.3)		(1.3)		(1.3)
FDH76	2022-09-13	Swap	F2027		30 years	100	4.02%		(5.7)		(5.7)		(5.7)
FDH77	2023-02-15	Swap	F2026		10 years	125	3.88%		(3.7)		(3.7)		(3.7)
FDH78	2023-02-15	Swap	F2026		30 years	50	3.94%		(2.4)		(2.4)		(2.4)
Subtotal						**$875**			**($24.0)**	**$0.0**	**($24.0)**	**$0.0**	**($24.0)**
Total						**$12,725**			**$174.6**	**($244.0)**	**($69.4)**	**$2.5**	**($67.0)**

[1] Actual debt was a 30 year issue

[2] Gain / (loss) deferred to the Debt Management Regulatory Account

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Appendix B

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 Government of B.C. 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 FDH 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.

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Appendix C

Residential Service Customers Charging Zero Emission Vehicles at their Dwelling Annual Report

Fiscal 2023

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List of Tables

1 Summary / Background

On January 15, 2019, BC Hydro filed an Electric Tariff Terms and Conditions Amendments Application (**Amendments**) to facilitate charging of Zero Emissions Vehicles (**ZEV**) by Residential Service Customers at their Dwelling. The Amendments were to:

1. Clarify that a Dwelling may include spaces such as parking stalls, storage areas, garage areas, and similar spaces or areas used for the benefit of the customer;
2. Allow more than one meter to be installed at a Dwelling; and,
3. Implement aggregate billing for consumption from multiple meters under one account so that customers would pay one Basic Charge and so that the Step 1 Energy Charge threshold of 675 kWh per month would apply to all consumption in aggregate.

BC Hydro proposed these Amendments in consideration of the growing number of Residential Service Customers residing in multi-unit residential buildings and the increasing number of ZEVs being brought to the market.

On April 29, 2019, the BCUC approved the Amendments by Order No. G-92-19[1] and directed BC Hydro to file information regarding its experience resulting from the amended terms and conditions starting in the Fiscal 2020 Annual Report to the Commission.

The BCUC directed that the reporting should include, but not be limited to, the following:

[1] BC Hydro Electric Tariff Terms and Conditions Amendments Application, BCUC Order No. G-92-19, Directive No. 2

a. Number of accounts that have installed additional meters and whether BC Hydro is meeting the needs of customers;

b. Analysis of having one Basic Charge per account with additional meters and any plans to review the Basic Charge in a future process; and,

c. Analysis as to whether additional amendments to the Electric Tariff are appropriate for other rate classes that may have similar multi-unit characteristics such as commercial strata developments.

In August 2020, BC Hydro filed the first annual report regarding its experience from the amended terms and conditions. At that time, the small number of participating customers did not yield a sufficiently large dataset to conduct a meaningful assessment of points (b) and (c). BC Hydro filed the second and third annual report on this matter in August 2021 and August 2022. The number of participating customers continues to be too low to yield meaningful analysis.

On February 27, 2023, we submitted a request to the Commission to rescind the reporting requirements; included as Appendix I to our proposed Optional Residential Time-of-Use Rate Application.[2] As BC Hydro's proposed Optional Residential Time-of-Use Rate does not require participating customers to install a separate meter for electric vehicle charging, we anticipate the number of customers installing an additional meter will remain low. Therefore, we proposed to include reporting that the Commission still considers helpful as part of the proposed evaluation report on the Optional Residential Time-of-Use Rate, to be filed in fiscal 2029.

[2] Please refer to Appendix I of BC Hydro's Optional Residential Time-of-Use Rate Application, which is still under review as of the date of this filing: https://docs.bcuc.com/Documents/Proceedings/2023/DOC_70443_B-1-BCH-Optional-Residential-TOU-Rate-Application.pdf

2 BCUC Order No. G-92-19 Compliance Information

The sub-sections below summarize the reporting information that has been provided to the Commission in accordance with Directive No. 2 of Order No. G-92-19.

a. Number of accounts that have installed additional meters and whether BC Hydro is meeting the needs of customers

BC Hydro determines the annual number of accounts with an additional meter by the change in the number of active residential accounts being billed in aggregate. This approach allows for the exclusion of accounts that have closed during the year. Additionally, in October 2019, BC Hydro implemented a tracking mechanism to identify secondary meter installations for the purpose of electric vehicle charging.

In our Fiscal 2020 Annual Report to the BCUC, BC Hydro reported that there were 287 customers who had requested an additional meter. In our Fiscal 2021 Annual Report to the BCUC, we reported that there were 641 customers who had requested an additional meter. We have since determined that there was an error in the data extraction and the correct numbers are 496 customers and 599 customers, respectively. As reported, the number of customers with an additional meter for electric vehicle charging was 13 and 36, respectively.

BC Hydro notes that a further correction was provided in Appendix I to the Optional Residential Time-of-Use Rate Application, to update the number of customers who have an additional meter for electric vehicle charging from what was previously provided in our Fiscal 2020, Fiscal 2021, and Fiscal 2022 Annual Reports to the Commission. The corrections are a result of an update to the data and the removal of non-residential service accounts. Accordingly, the change in number of customers with an additional meter for electric vehicle charging has been updated from 13 to 16, from 36 to 35, and from 32 to 18, respectively.

In Table C–1 below, we have corrected the numbers for fiscal 2020, fiscal 2021, fiscal 2022 and provided the results for fiscal 2023.

Table C–1 Number of Residential Service Accounts with an Additional Meter

Fiscal Year	Cumulative Total of Active Aggregate Billing Accounts	Change in Number of Active Aggregate Billing Accounts	Cumulative Total of Active Aggregate Billing Accounts for EV Charging	Change in Number of Active Aggregate Billing Accounts for EV Charging
2020[1]	496	496	16	16
2021	1,095	599	51	35
2022	1,903	808	69	18
2023	2,556	653	88	19

[1] As of April 29, 2019, i.e., the effective date of BCUC Order No. G-92-19.

In order to help assess whether customer needs are being met, we surveyed customers who have an account with an additional meter for the Fiscal 2020 and Fiscal 2021 Annual Reports to the BCUC. We did not issue surveys to all of these customers as some do not have an available email address or have requested that BC Hydro not contact them. Table C–2 below summarizes the response rate for these surveys.

Table C–2 Survey of Residential Customers with an Additional Meter

Fiscal Year	Number of Surveys Issued	Total Number of Responses Received	Response Rate (%)	Number of Responses Received for Electric Vehicle Charging	Response Rate (%)
2020	210	28	13	3	1
2021	492	72	15	7	1

Given the low number of responses from customers with an additional meter for electric vehicle charging, BC Hydro is unable to accurately determine the level of satisfaction with the program, but notes that:

- In fiscal 2020, the three electric vehicle charging respondents felt the installation of the second meter met their needs and two indicated they were extremely satisfied with the service;
- In fiscal 2021, the seven electric vehicle charging respondents felt the installation of the second meter met their needs, five indicated they strongly agreed and two indicated they somewhat agreed; and,
- General comments included concerns about the costs to install an additional meter and some dissatisfaction with aggregate billing.

Given that the two previous surveys had a low response rate and provided little insight into the customer experience, a survey was not conducted in fiscal 2022 or fiscal 2023. Instead, an analysis of customer complaints to BC Hydro was undertaken to determine if dual meters (secondary meters) installed for electric vehicle charging were the subject of any comments received. In looking at all customer complaints between April 29, 2019 to March 31, 2023, it was determined that no complaints or escalations were related to secondary meters installed for electric vehicle charging.

b. Analysis of having one Basic Charge per account with additional meters and any plans to review the Basic Charge in a future process

In our Fiscal 2020 and Fiscal 2021 Annual Reports to the Commission, BC Hydro noted that the number of additional meters used for electric vehicle charging purposes was small and, therefore, BC Hydro was unable to perform meaningful analysis with respect to having one Basic Charge per account with additional meters. To date, there continues to be insufficient data available to conduct useful analysis.

c. Analysis as to whether additional amendments to the Electric Tariff are appropriate for other rate classes that may have similar multi-unit characteristics such as commercial strata developments

BC Hydro's Street Lighting Rate Application, approved by Commission Order No. G-312-21, amended the Electric Tariff for mixed use loads. BC Hydro expects these amendments to have a favourable economic impact on all ratepayers because they remove barriers to electrification and load growth.[3] Specifically, for electric vehicle growth, the amendments facilitate metering and billing for multiple end-uses, including electric vehicle charging, which allows for options other than potentially costly, single use installations. BC Hydro believes such a change will support future load configurations and respond to the growing need for curbside electricity use. BC Hydro will continue to consider and propose further amendments where appropriate.

[3] BC Hydro's Street Lighting Application, pages 63 to 66. BCUC Order No. G-312-21.

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Appendix D

Performance of Rate Schedules 1894 and 1895

Fiscal 2023

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1 Summary / Background

On January 29, 2021, BC Hydro filed an application with the BCUC seeking approval of:

- Rate Schedule (**RS**) 1894 – Transmission Service – Clean B.C. Industrial Electrification Rate – Clean Industry and Innovation;
- RS 1895 – Transmission Service – Clean B.C. Industrial Electrification Rate – Fuel Switching; and to
- Rescind TS No. 97 - Northwest Transmission Line Supplemental Charge.

On February 5, 2021, the BCUC approved the application by Order No. G-38-21 and directed BC Hydro to provide an annual report to the BCUC on the performance of the new RS 1894 and RS 1895, including the number of new customers on each new rate schedule, the incremental load obtained under each new rate schedule, the incremental revenues associated with each new rate schedule, and the quantification of greenhouse gas reduction related to each new rate schedule.

1.1 Progress Report

As at March 31, 2023, BC Hydro confirms there are no customers receiving service under RS 1894 or RS 1895.