Chris Sandve
Chief Regulatory Officer
Phone: 604-623-3726
Fax: 604-623-4407
bchydroregulatorygroup@bchydro.com

August 30, 2024

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)
British Columbia Hydro and Power Authority (BC Hydro)
Fiscal 2024 Annual Report to the BCUC

BC Hydro writes pursuant to BCUC Letter No. L-46-23 and subsection 45(6) of the *Utilities Commission Act* to provide BC Hydro's Fiscal 2024 Annual Report to the BCUC for the period April 1, 2023, to March 31, 2024.

BCUC Order No. G-199-23 amended the filing deadline for BC Hydro's Annual Report to the BCUC to be filed by August 31 each year.

BCUC Letter No. L-46-23 dated October 17, 2023, discontinued the annual reporting requirements prescribed by BCUC Letters No. L-36-94, L-14-95, and L-45-15. BC Hydro continues to report on the annual filing requirements established by BCUC Decisions and Orders that remain in scope of the Annual Report to the BCUC.

As a result, BC Hydro's Fiscal 2024 Annual Report to the BCUC includes some changes relative to the Fiscal 2023 Annual Report. Specifically:

- The removal of the following sections: Declaration, Directors and Officers, Control Over Utility, Corporations Controlled by Utility, Important Changes During the Year, Internal Audit Review Report, and Management Letter Topics from External Auditors (previously provided in compliance with BCUC Letter No. L-36-94 and removed in compliance with BCUC Letter No. L-46-23);
- The Financial Schedules and Variance Explanations has been modified in compliance with BCUC Letter No. L-46-23 and has been re-titled The Routine

Trouble and Storm Restoration Cost Regulatory Account.[1] This section provides the breakdown between storm restoration costs and evacuation relief costs collected in the Routine Trouble and Storm Restoration Costs Regulatory Account; in compliance with Directive 5 of BCUC Order No. G-215-20;

- Appendix A – Starting with Fiscal 2020 Annual Report, the tables for the Domestic Cost of Energy, Consolidated Statement of Operations, and Intersegment Revenues were moved to the Financial Schedules and excluded from the Annual Deferral Accounts Report to reduce redundancy across sections. With the modification of the Financial Schedules and Variance Explanations per Letter L-46-23, the Annual Deferral Accounts Report [2] has been amended to include these tables again to continue to provide the same level of detail in compliance with Directive 2 of BCUC Order No. G-140-17;
- Appendix C - Residential Service Customers Charging Zero Emission Vehicles at their Dwelling Report has been removed (previously provided in compliance with Directive 2 of BCUC Order No. G-92-19 and removed in compliance with Directive 4 of BCUC Order No. G-342-23);
- Appendix D – Annual Cybersecurity Declaration has been added in compliance with Directive 4 of BCUC Order No. G-126-23.

The following table summarizes the changes made to the Fiscal 2024 Annual Report to the BCUC:

Table 1 Comparison of Changes to the Annual Report to the BCUC from Fiscal 2023 to Fiscal 2024

Fiscal 2023 Section No.	Fiscal 2024 Section No.	Section Name	Comments
1	N/A	Declaration	Removed
2	N/A	Directors and Officers	Removed
3	N/A	Control Over Utility	Removed
4	N/A	Corporations Controlled by Utility	Removed
5	N/A	Important Changes During the Year	Removed

1 BC Hydro applied to the BCUC on June 12, 2024, seeking approval to expand the scope of the Storm Restoration Costs Regulatory Account to include variances between plan and actual Routine Trouble costs and to rename the Account from the “Storm Restoration Costs Regulatory Account” to the “Routine Trouble and Storm Restoration Costs Regulatory Account.”

2 In BCUC Order No. G-140-17 dated September 14, 2017, the BCUC approved BC Hydro’s request to modify the frequency of filing the Annual Deferral Accounts Report under Directive 17 of BCUC Order No. G-96-04 from semi-annual to annual filing and for this report to be submitted with the Annual Financial Report to the BCUC.

Fiscal 2023 Section No.	Fiscal 2024 Section No.	Section Name	Comments
6	5	Routine Trouble and Storm Restoration Costs Regulatory Account (Previously named: Financial Schedules and Variance Explanations)	Revised. Modified to include the breakdown between storm restoration costs and evacuation relief costs per Directive 5 of BCUC Order No. G-215-20.
7	1	Planned Capital Extension Projects and Anticipated Regulatory Filings	No change
8	N/A	Internal Audit review report	Removed
9	N/A	Management Letter Topics from External Auditors	Removed
10	2	The Waneta Transaction Report	No change
11	3	UNDRIP Plan Progress	No change
12	4	Annual Report Summary Information	No change
Appendix A	Appendix A	Annual Deferral Accounts Report	Revised. Modified to include three tables previously moved to the Financial Schedules to continue providing the same level of detail as the Fiscal 2016 Deferral Account Report. Per Directive 2 of BCUC Order No. G-140-17.
Appendix B	Appendix B	Debt Management Regulatory Account Annual Status Report	No change
Appendix C	N/A	Residential Service Customers Charging Zero Emission Vehicles at their Dwelling Report	Removed. Per Directive 4 of BCUC Order No. G-342-23.
Appendix D	Appendix C	Performance of the new Rate Schedule (**RS**) 1894 and RS 1895	No change
N/A	Appendix D	Annual Cybersecurity Declaration (Confidential)	Added. Per Directive 4 of BCUC Order No. G-126-23.

On August 13, 2024, BC Hydro filed with the BCUC an application to vary or rescind specific reporting requirements which includes reporting in the Annual Report to the BCUC. The approvals sought in that application are requested to be effective the date of the order and do not have an impact on this Fiscal 2024 Annual Report.

For further information, please contact Joe Maloney at
bchydroregulatorygroup@bchydro.com.

Yours sincerely,

Chris Sandve
Chief Regulatory Officer

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Enclosure

BC Hydro Fiscal 2024 Annual Report to the British Columbia Utilities Commission

April 1, 2023, to March 31, 2024

BC Hydro
Power smart

Table of Contents

List of Appendices

1 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 2024 Annual Report to the British Columbia Utilities Commission

Attachment to Section No. 1

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, 2024.

BC Hydro's current expectation regarding projects that may be subject to a future Certificate of Public Convenience and Necessity (**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, 2024.

The information provided in Table 2 follows the 2024 Major Capital Project Filing Guidelines (**2024 Guidelines**) expenditure thresholds for CPCN and section 44.2 filings, namely $250 million for Power System projects, $125 million for Buildings projects, and $50 million for Information Technology projects set out by BCUC Order G-218-24. Order G-218-24 also requires BC Hydro to file an annual compliance filing within 60 days of our fiscal year end. BC Hydro will commence this annual compliance filing following the end of fiscal year 2025. This new requirement will replace Table 1 and Table 2 for fiscal 2025 and subsequent fiscal years as these tables are no longer required considering the rescindment of paragraphs 18 and 19 of the Capital Project Filing Guidelines which is also set out by Order G-218-24.

[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 2024 Major Capital Filing Guidelines approved by the BCUC on August 15, 2024.

In compliance with Directive 2 of BCUC Order G-313-19, Table 3 provides a listing and the forecast capital cost, where available, of all capital expenditures with 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's2024 Guidelines.[2]

In compliance with BCUC Letter No. L-65-20, Table 4 provides a summary of Capital Expenditures categorized by CPCN filings, 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. Consistent with Table 2, Table 4 follows the 2024 Guidelines expenditure thresholds for CPCN and section 44.2 filings, namely $250 million for Power System projects, $125 million for Buildings projects, and $50 million for Information Technology projects.

[2] Approved by the BCUC on August 15, 2024.

1 **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	Appendix I, Site C, Line 1 Appendix J, F2023-F2025 RRA
G903005	Revelstoke – Unit 6 Installation	TBD	N/A
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	313	Appendix I, Generation, Line 59, Appendix J, F2023-F2025 RRA
TX902612	Masset - Station Upgrades for Renewable Energy Integration (Haida FN Solar North 1)[4]	14	N/A
G000183	Mica - U1 - U2 Turbine Overhaul	TBD	N/A
G003058	Kootenay Canal - U1 - U4 Generators Refurbishment	TBD	N/A

[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. For projects where an engineering estimate is not yet available, to be determined (**TBD**) is provided for the Pre-Implementation Cost Estimate; and,
- For projects in Future or Identification phase, to be determined 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] This project was formerly referred to as 'Various Sites - Grid Scale Storage & Renewable Enablement'.

Planning ID	Project Name	Total Forecast Cost[3]	Reference (from F2023 - F2025 RRA)
G004155	Seven Mile - U1 - U3 Turbine Upgrade	TBD	N/A
Transmission Growth Capital			
92423	Bridge River Transmission Project	110 - 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 Project	TBD	Appendix I, Transmission, Line 3, Appendix J, F2023-F2025 RRA
94034	Westbank Substation Upgrade	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 [5]	TBD	Appendix I, Transmission, Line 9, Appendix J, F2023-F2025 RRA
901574	Prince George to Terrace Capacitors Project	485	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

5 This project was formerly referred to as `Lower Mainland – Capacitive and Reactive Power Reinforcement'. The November 2022 CPCN application for the Lower Mainland - Reactive Power Reinforcement project was denied on January 24, 2024 (Decision and Order No. G-20-24). BC Hydro is currently evaluating next steps and may file a section 44.2 application for the revised project scope.

Planning ID	Project Name	Total Forecast Cost[3]	Reference (from 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	19 - 15	Appendix I, Transmission, Line 14, Appendix J, F2023-F2025 RRA
901580	Customer IPID – 901580	16	Appendix I, Transmission, Line 15,
901573	Customer IPID - 901573	39	Appendix I, Transmission, Line 16,
901851	Customer IPID – 901851	15	Appendix I, Transmission, Line 17,
901581	Customer IPID – 901581	89	Appendix I, Transmission, Line 18,
901940	Customer IPID - 901940	11	Appendix I, Transmission, Line 19,
902121	Customer IPID - 902121	13	Appendix I, Transmission, Line 20,
901943	Customer IPID - 901943	141 - 110	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
901930	Customer IPID - 901930	72	N/A
TX902566	Customer IPID - TX902566	12	N/A
TX902439	Customer IPID - TX902439	8	N/A
93417	Treaty Creek Terminal - Transmission Load Interconnection (KSM)	168	N/A
TX902780	Westbank - 75MVA Transformer Installation	13	N/A
902343	Customer IPID - 902343	80	N/A

Planning ID	Project Name	Total Forecast Cost[3]	Reference (from F2023 - F2025 RRA)
94016	McLellan - Substation Upgrade	TBD	N/A
TX902471	Clayburn - Substation Upgrade (2nd Phase)	TBD	N/A
TX902550	Elkford Tap - Switching Station Upgrade	TBD	N/A
901238	Kidd No. 2 - Feeder Section Addition	19 - 15	N/A
TX902838	Mount Pleasant Substation - Transformer and Feeder Sections Addition	TBD	N/A
TX902881	Mclellan - Feeder Position Addition	15 - 12	N/A
TX902910	Whalley Substation Feeder Position Addition	10 - 8	N/A
TX903300	Fraser Valley (CBN and MLN) - Capacitive Reinforcement	49 - 39	N/A
TX902567	Prince George to Glenannan Transmission	TBD	N/A
TX902665	Glenannan to Terrace Transmission	TBD	N/A
TX902956	Metro South - Transmission Reinforcement	TBD	N/A
92582	Steveston - Substation Upgrade	TBD	N/A
TX902911	Scott Road - Substation Rebuild	TBD	N/A
TX902945	Lougheed - Substation Rebuild	TBD	N/A
TX902946	Barnard - Substation Upgrade	TBD	N/A
TX902947	Goldstream - Property Purchase	TBD	N/A
TX902948	Goldstream - Substation Construction	TBD	N/A

Planning ID	Project Name	Total Forecast Cost[3]	Reference (from F2023 - F2025 RRA)
TX902949	Campbell Heights - Substation Construction	TBD	N/A
TX902951	Newell - Skid-mount Feeder Section Installation[6]	TBD	N/A
TX902954	Surrey City Centre - Property Purchase	TBD	N/A
TX902958	Willoughby - Property Purchase	TBD	N/A
93500	Customer IPID - 93500	TBD	N/A
TX902614	Customer IPID - TX902614	TBD	N/A
TX902717	Customer IPID - TX902717	TBD	N/A
TX902727	Customer IPID - TX902727	TBD	N/A
TX902728	Customer IPID - TX902728	TBD	N/A
INT903162	Customer IPID - INT903162	TBD	N/A
INT902933	Customer IPID - INT902933	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	3	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	101	Appendix I, Transmission, Line 32, Appendix J, F2023-F2025 RRA
94079	Sandspit Substation Replacement	22	Appendix I, Transmission, Line 33,

6 This project was formerly referred to as `Newell – Mobile Feeder Section Procurement'.

Planning ID	Project Name	Total Forecast Cost[3]	Reference (from F2023 - F2025 RRA)
94081	Ah-Sin-Heek - Substation Replacement	26	Appendix I, Transmission, Line 34,
92478	Mainwaring Station Upgrade	154	Appendix I, Transmission, Line 41, Appendix J, F2023-F2025 RRA
92479	Newell Substation Upgrade	243 - 160	Appendix I, Transmission, Line 42, Appendix J, F2023-F2025 RRA
901045	Canal Flats - Substation Wood Pole Replacement	12	Appendix I, Transmission, Line 55,
901049	Skookumchuck - Substation Wood Pole Replacement	15	Appendix I, Transmission, Line 56,
901002	2L146 - Cable Replacement	226 - 158	Appendix I, Transmission, Line 72, Appendix J, F2023-F2025 RRA
94057 L&I	Gulf Islands - Transmission Reinforcement	TBD	Appendix I, Transmission, Line 74, Appendix J, F2023-F2025 RRA
TX902716	2L143 - Cable Replacement	156 - 51	N/A
TX902531	Customer IPID - TX902531	TBD	N/A
Distribution Growth Capital			
DY-1545	Customer IPID DY-1545	39	Appendix I, Distribution, Line 1
901955	Customer IPID 901955	51 - 17	Appendix I, Distribution, Line 3
902128	Customer IPID 902128	40	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)	6	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

Planning ID	Project Name	Total Forecast Cost[3]	Reference (from F2023 - F2025 RRA)
901355	Norgate - Offload NOR Loads to NVR Feeders (LM-NSH-074)	48	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)	41	Appendix I, Distribution, Line 16
901949	Fleetwood - Distribution Feeder Ductbank and Feeder Installation (FV-FVW-805)	18	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)	36 - 27	Appendix I, Distribution, Line 20 Appendix J, F2023-F2025 RRA
902375	Abbotsford - Offload Mount Lehman 25F53, 25F61 and 25F33 (FV-ABT-056)	11	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)	8	N/A
900364	CAP distribution voltage conversion for 57, and 59 (LM-NSH-040)	7	N/A

Planning ID	Project Name	Total Forecast Cost[3]	Reference (from F2023 - F2025 RRA)
901137	LM-BBY-094 HPN Three New 25kV Circuits to Offload Six 12kV Circuits	5	N/A
901253	George Dickie - Voltage Conversion preparation of 4F54, 4F61, 4F64 and 4F65 and cutover to Sperling 12F64 (LM-VAN-094)	6	N/A
901354	Glenmore - Voltage conversion of GLR 452, 454, 461, 462, 463 & 464 (LM-NSH-047)	13	N/A
D902734	Surrey - New Circuit (6) in Campbell Heights (FV-FVW-836)	6	N/A
D902745	Coquitlam - BND 12F71 Voltage Conversion and 12F71 and 12F83 Cutover (LM-COQ-874)	6	N/A
D902747	Downtown Vancouver - Voltage Conversion Preparation for Customer Vaults (F24 Program – LM-VAN-224)	8	N/A
D902821	Abbotsford - CBN 25121 & 25224 Offload (FV-ABT-006)	6	N/A
DY-0758	Customer IPID - DY-0758	9	N/A
902374	Puntledge - Offload Puntledge to Buckley Bay via Feeder Load Transfers (VI-CTY-002)	8 - 7	N/A
901931	Gulf Islands - SAL 2561 Reinforcement on Salt Spring Island and North Pender Island (VI-GUL-014)	21 - 7	N/A
902380 L&I	Coquitlam - Duct Bank from Como Lake (LM-COQ-869)	12 - 9	N/A

Planning ID	Project Name	Total Forecast Cost[3]	Reference (from F2023 - F2025 RRA)
D902737	Township of Langley - New MLE feeder to backup GLT and offload MLE Feeders (FV-ABT-045)	TBD	N/A
D902741	Langley - MLN to Willoughby Ductbank Extension (FV-FVW-823)	82 - 27	N/A
D902743	Surrey-Langley - MLN to Campbell Heights Ductbank Extension & MLN Circuit Offload (FV-FVW-822)	74 - 24	N/A
D902744	Westbank - New WBK Feeder and Ductbank Extension (SI-OKA-214)	TBD	N/A
D902760	Kamloops - Two new feeder egress from WKA (SI-KAM-062)	TBD	N/A
D902834	Buckley Bay - New BKB feeder to offload BKB 25F32 & QLC 25F62 (VI-CTY-027)	15 - 5	N/A
D902912	Fleetwood - Distribution Load Interconnection (SLS Servicing)	156 - 122	N/A
900309	Burnaby - Voltage Conversion Horne Payne 12F316 & 12F59 to 25F123 (LM-BBY-075)	13 - 4	N/A
D902738	Coquitlam - COK 25F513 Offload (LM-COQ-813)	17 - 5	N/A
D902749	Coquitlam - Voltage Conversion Preparation for Customer Vaults (LM-COQ-878)	19 - 6	N/A
D902826	Campbell River - New CBL Feeder to Quadra Island (VI-CBL-002)	13 - 8	N/A
902353	Customer IPID – 902353	42 - 14	N/A
D902632	Customer IPID - D902632	TBD	N/A
901557	Customer IPID - 901557	33 - 26	N/A

Planning ID	Project Name	Total Forecast Cost[3]	Reference (from F2023 - F2025 RRA)
D902553	Customer IPID - D902553	21 - 16	N/A
D902884	Customer IPID - D902884	10 - 3	N/A
D902722	Customer IPID - D902722	TBD	N/A
Distribution Sustain Capital			
901822	Mission - Feeder 25F51 Tie (FV-ABT-039)	40	Appendix I, Distribution, Line 23

The currency date of this attachment is March 31, 2024, whereas information included in the Request to Amend Major Capital Projects Filing Guidelines (**Guidelines**) proceeding was based on information collected in April 2023. Accordingly, Table 2 includes a greater number of anticipated Major Project applications than the Guidelines proceeding due to more current information and revised project cost estimates, in some cases. Table 2 also includes projects that have yet to exceed the threshold but have a cost estimate in proximity and may eventually exceed the threshold as the project advances through its life cycle (specifically, power system projects with a cost estimate greater than $200 million are included as a project that 'may' exceed the threshold).

Table 2 Projects with Anticipated CPCN or Section 44.2 Filings

Planning ID	Project	Filing Type	Rationale for Filing Type
Generation Sustain Capital			
G000459	La Joie - Dam Improvements	Section 44.2	The project is expected to exceed the $250 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 is expected to exceed the $250 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
G000052	Cheakamus - Dam Improvements	Section 44.2	The project may exceed the $250 million threshold for Power System projects and is not considered an extension to the BC Hydro system.
G003026	Seton - Bypass Installation [7]	Section 44.2	The project is expected to exceed the $250 million threshold for Power System projects and is not considered an extension to BC Hydro’s system.
G003058	Kootenay Canal - U1 - U4 Generators Refurbishment	Potential CPCN or Section 44.2	The project may exceed the $250 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	Section 44.2	The project is expected to exceed the $250 million threshold for Power System projects and is not considered an extension to the BC Hydro system.
G000183	Mica - U1 - U2 Turbine Overhaul	CPCN	The project is expected to exceed $250 million threshold for Power System projects. The project will likely be considered an extension to the BC Hydro system due to added capacity of new replacement turbines.
G000109	Bennett Dam - Embankment Seismic Upgrade	Section 44.2	The project is expected to exceed the $250 million threshold for Power System projects and is not considered an extension to the BC Hydro system.
G000134	G.M. Shrum - U9 - U10 Generator and Turbine Refurbishment	Section 44.2	The project may exceed the $250 million threshold for Power System projects and is not considered an extension to the BC Hydro system.

[7] This project was formerly referred to as ‘Seton - Upgrade Unit’. The ‘Seton - Bypass Installation’ project does not include an extension component.

Planning ID	Project	Filing Type	Rationale for Filing Type
G000247	Revelstoke - Discharge Gate Systems Reliability Improvements	Section 44.2	The project may exceed the $250 million threshold for Power System projects and is not considered an extension to the BC Hydro system.
G000474	Bridge River - Intake Seismic Withstand Improvement	Section 44.2	The project may exceed the $250 million threshold for Power System projects and is not considered an extension to the BC Hydro system.
G000523	Strathcona - Embankment Dam Upgrades	Section 44.2	The project is expected to exceed the $250 million threshold for Power System projects and is not considered an extension to the BC Hydro system.
G000548	Duncan Dam - Embankment Dam Improvement	Section 44.2	The project is expected to exceed the $250 million threshold for Power System projects and is not considered an extension to the BC Hydro system.
G000557	Hugh Keenleyside - Embankment Dam Upgrade	Section 44.2	The project is expected to exceed the $250 million threshold for Power System projects and is not considered an extension to the BC Hydro system.
G000829	Seven Mile - U1-3 Generator Replacement	Potential CPCN or Section 44.2	The project is expected to exceed the $250 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.
G003137	Revelstoke - U1 - U4 Turbine Overhaul	Potential CPCN or Section 44.2	The project is expected to exceed the $250 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.

Planning ID	Project	Filing Type	Rationale for Filing Type
G004114	Mica - U3 - U4 Turbine Overhaul	Potential CPCN or Section 44.2	The project may exceed the $250 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.
Transmission Growth Capital			
94034	West Kelowna Transmission Project[8]	CPCN	The project is expected to exceed the $250 million threshold for Power System projects and is considered an extension to BC Hydro's system.
900598	West End - Substation Construction and System Reinforcement	CPCN	The project is expected to exceed the $250 million threshold for Power System projects and is considered an extension to BC Hydro's system.
901943	1L243 – Transmission Load Increase (Highland Valley Copper)	CPCN	This project is the BC Hydro Highland Valley Copper (HVC) Transmission Load Increase - 1L243 Application filed on May 23, 2024.
TX902717	Customer IPID - TX902717	CPCN	The project is expected to exceed the $250 million threshold for Power System projects and is considered an extension to BC Hydro's system.
TX902948	Goldstream - Substation Construction	CPCN	The project is expected to exceed the $250 million threshold for Power System projects and is considered an extension to BC Hydro's system.

[8] Per BCUC Order G-81-24, the BCUC approved a reconsideration request, to vary Directive 3(b) from the Fiscal 2017 to Fiscal 2019 RRA, to remove the requirement for BC Hydro to obtain a CPCN for the Westbank Substation Upgrade Project.

Planning ID	Project	Filing Type	Rationale for Filing Type
TX902949	Campbell Heights - Substation Construction	CPCN	The project may exceed the $250 million threshold for Power System projects and is considered an extension to BC Hydro’s system.
TX902950	Willoughby - Substation Construction	CPCN	The project may exceed the $250 million threshold for Power System projects and is considered an extension to BC Hydro’s system.
TX902952	Boundary Road - Substation Construction[9]	CPCN	The project is expected to exceed the $250 million threshold for Power System projects and is considered an extension to BC Hydro’s system.
TX902953	Surrey City Centre - Substation Construction	CPCN	The project is expected to exceed the $250 million threshold for Power System projects and is considered an extension to BC Hydro’s system.
TX902518	Vancouver Island - Transmission Reinforcement Completion	CPCN	The project is expected to exceed the $250 million threshold for Power System projects and is considered an extension to BC Hydro’s system.
TX902539	South Coast Transmission Reinforcement	CPCN	The project is expected to exceed the $250 million threshold for Power System projects and is considered an extension to BC Hydro’s system.
TX902956	Metro South - Transmission Reinforcement	CPCN	The project is expected to exceed the $250 million threshold for Power System projects and is considered an extension to BC Hydro’s system.

9 This project was formerly referred to as ‘Metrotown – 25 kV Substation Construction’

Planning ID	Project	Filing Type	Rationale for Filing Type
Transmission Sustain Capital			
900019	System Wide – Bulk Electric System Telecom Equipment Replacement	Section 44.2	The project is expected to exceed the $250 million threshold for Power System projects and is not considered an extension to the BC Hydro system.
901624	Coquitlam - 2L051 Replacement	Section 44.2	The project is expected to exceed the $250 million threshold for Power System projects and is not considered an extension to the BC Hydro system.
Distribution Sustain Capital			
D902486	Various Sites - Smart Metering and Infrastructure Asset Refresh	Section 44.2	The project is expected to exceed the $250 million threshold for Power System projects and is not considered an extension to the BC Hydro system.
Properties (Buildings) Sustain Capital			
P201901	Kamloops Field Building Redevelopment[8]	Section 44.2	The project may exceed the $125 million threshold for Building projects and is not considered an extension to the BC Hydro system.
Technology Sustain Capital			
T002122	Stations Work Management (Enterprise Resource Planning)	Section 44.2	This project is included in the BC Hydro Enterprise Resource Planning (ERP) Application filed on June 28, 2024.
T002549	Distribution Design Modernization	Section 44.2	The project may exceed the $50 million threshold for Technology projects and is not considered an extension to the BC Hydro system.
T001379	SAP Upgrade to S/4HANA (Enterprise Resource Planning)	Section 44.2	This project is included in the BC Hydro Enterprise Resource Planning (ERP) Application filed on June 28, 2024.

Planning ID	Project	Filing Type	Rationale for Filing Type
T002617	Advanced Distribution Management System Replacement	Section 44.2	The project may exceed the $50 million threshold for Technology projects and is not considered an extension to the BC Hydro system.

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

- Glenannan to Terrace Transmission Project (TX902665) and Prince George to Glenannan Transmission Project (TX902567): To meet growing industrial customer electricity demand, BC Hydro is proposing to build new 500 kV transmission lines and associated infrastructure from Prince George to Terrace and thermally upgrading the existing 500 kV transmission lines from Prince George to Terrace. Transmission system expansion also gives us the opportunity to advance reconciliation by partnering with First Nations on new approaches to infrastructure development, including Indigenous co-ownership of the new transmission lines. Although not exempt, BC Hydro and the Province are exploring potential policy considerations with First Nations and we expect to have greater clarity next year;
- 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; and
- Pursuant to the *British Columbia Hydro and Power Authority Exemption Regulation*, issued under Ministerial Order 242/2024, the following six projects are exempt from section 45 (5) of the *Utilities Commission Act*:
  - Barnard - Substation Upgrade;
  - East Vancouver - Substation Construction;
  - Lougheed - Substation Rebuild;

- Newell Substation Upgrade;
- Scott Road - Substation Rebuild; and
- Steveston - Substation Upgrade.

Table 3 provides a listing and the forecast capital cost, where available, of all capital expenditures with a total forecast or planned capital cost of $50 million or greater that meet the criteria listed on page 2.

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

Planning ID	Program Name	Total Forecast Cost[10]	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.

Table 4 provides a summary of Capital Expenditures categorized by CPCN filings, 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.

[10] 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)

	F2024 Decision	F2024 Actual	F2024 Variance	F2025 Decision	F2026 Forecast
	(a)	(b)	(a)-(b)=(c)	(d)	(e)
CPCN	119	45	74	221	364
System Extensions[11]	312	394	(82)	301	631
Other Capital:					
Section 44.2	179	189	(10)	330	306
Exempt	0	19	(19)	-	98
Other Capital Investments	875	1,192	(317)	789	1,478
Site C	1,755	2,174	(419)	1,043	433
Total	3,240	4,015	(775)	2,685	3,310

[11] 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 $250 million expenditure threshold in the 2024 Major Capital Project Filing Guidelines.

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

2.1 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 2024 Waneta Transaction Annual Report, as required by Directive 4(e) of BCUC Order No. G-130-18, is provided as Attachment 2.

BC Hydro Fiscal 2024 Annual Report to the British Columbia Utilities Commission

Attachment to Section No. 2

Fiscal 2024 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 2024. 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 2024.

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

Table 1 below provides the comparison of the fiscal 2024 Decision and actual expenditures for fiscal 2024 for BC Hydro's one-third ownership.

Table 2 provides the comparison fiscal 2024 Decision and actual expenditures for fiscal 2024 for BC Hydro's two-third'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, 2023, to March 31, 2024

($ thousand)	F2024 Decision	F2024 Actual	Variance	Variance (%)	Variance Explanation (if >10 %)
	1	2	3 = 2 - 1	4 = 3/1 x 100	
Operations and Maintenance[1]	2,607	3,233	626	24.0%	Primary due to higher labour costs as a result of inflation and higher insurance costs
Sustaining Capital	1,843	677	-1,166	-63.2%	Primary due to deferral of Dam Drainage Investigation and Superstructure Corrosion Control project which is on hold pending the results of an engineering study (3D stability analysis by Hatch) to develop the scope of work (Expected study completion date of March 31, 2025)
Water Fees	6,907	7,283	376	5.4%	

[1] Includes insurance and Teck administration.

Table 2 Comparison of Actual and Forecast Expenditures for Teck's 2/3, April 1, 2023, to March 31, 2024

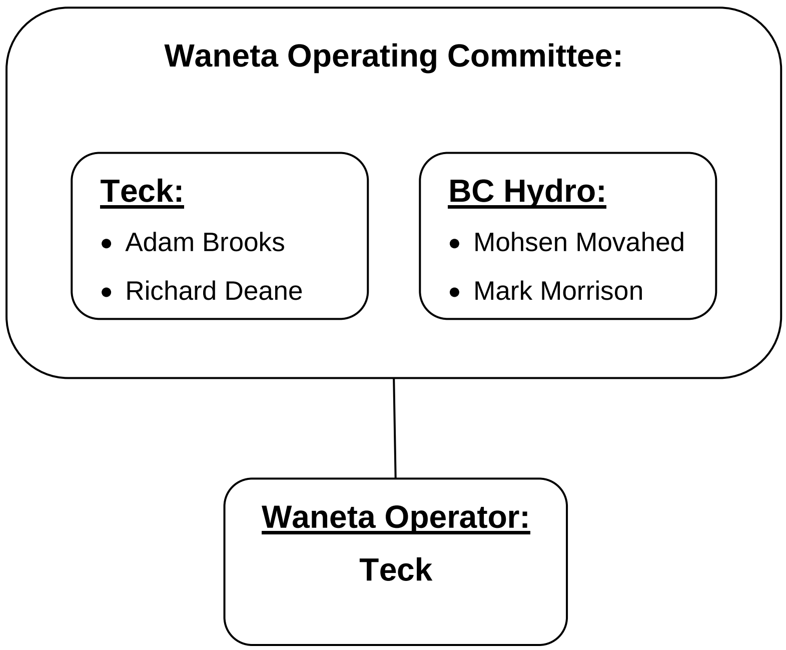
($ thousand)	F2024 Decision	F2024 Actual	Variance	Variance (%)	Variance Explanation (if >10 %)
	1	2	3 = 2 - 1	4 = 3/1 x 100	
Operations and Maintenance[1]	6,112	6,643	531	8.7%	
Sustaining Capital	3,686	1,356	-2,331	-63.2%	Primary due to deferral of Dam Drainage Investigation and Superstructure Corrosion Control project which is on hold pending the results of an engineering study (3D stability analysis by Hatch) to develop the scope of work (Expected study completion date of March 31, 2025)
Water Fees	3,694	3,694	0	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 2023 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 268 GWh of surplus energy from Teck during fiscal 2024 under section 5 of the agreement at an average price of C$102.07/MWh. The total volume of energy that was purchased in fiscal 2024 is lower than the prior year as the Unit 3 Life Extension (**U3LE**) project was completed in fiscal 2023 resulted in minimal outages during fiscal 2024 and there was no need for Teck to replace its share of lost generation subject to the outage adjustment requirements of the Canal Plant Agreement. The total value, and the average price of the transactions in fiscal 2024, was lower than prior year although extraordinarily high market prices persisted across much of fiscal 2024.

Table 3 Surplus Power Rights Agreement Purchases

	Apr 2023	May 2023	Jun 2023	Jul 2023	Aug 2023	Sep 2023	Oct 2023	Nov 2023	Dec 2023	Jan 2024	Feb 2024	Mar 2024	Total
Invoice Total ($k)	-26	5,175	19	941	1,612	2,932	1,680	3,290	1,916	1,184	7,521	1,149	27,392
Volume (MWh)	0	52,428	996	17,807	15,435	26,500	27,807	33,000	24,015	18,371	30,000	22,000	268,359

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 were 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 2024. 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 2024, with and without the Waneta 2017 Transaction, is provided in Table 4 below.

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

Fiscal 2024 (April 1, 2023 to March 31, 2024)	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 2024.

3 UNDRIP Plan Progress in Fiscal 2024

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**)[2] in collaboration with First Nations and Indigenous peoples. Our engagement approach was designed to make the Plan accessible to First Nations across the Province and support our focus on the Nations most impacted by our presence in their territories.

Engagement on the Plan continued in fiscal 2024. Key activities included:

- Seven one-on-one meetings with First Nations who requested meetings to review the draft Plan;
- Responding to questions and incorporating feedback from 11 First Nations received at BC Hydro's dedicated UNDRIP Implementation Plan email address, UNDRIPPlan@bchydro.com;
- Together with the First Nations Energy and Mining Council, co-presenting the draft Plan during an Indigenous Clean Energy Opportunities workshop, which was attended by over 75 First Nations representatives; and
- Discussing the draft Plan with the First Nations Leadership Council and revising the Plan to reflect the Council's comments.

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."

2 https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/community/bc-hydro-un-declaration-implementation-plan.pdf.

A version of the Plan incorporating all the First Nations' input we received over approximately three years of engagement was published on BC Hydro's website in March 2024. The Plan is a living document that will be updated periodically to align with changes in law, First Nations' feedback, and the evolving context of Indigenous relations in B.C., so there remains room to incorporate input from First Nations in the future as we continue our discussions on how BC Hydro can advance reconciliation.

While the Plan contemplates annual reporting on progress, the first annual report is still in development (targeted for publication in early fiscal 2026). BC Hydro will work with First Nations to co-develop the form of reporting, which we plan to make available on BC Hydro's website. In the interim, we can report that during fiscal 2024, examples of our UNDRIP Implementation Plan activities included:

Respectful Relations

- Action 1.1 – 1,110 BC Hydro employees 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, First Nations. In total, 6,079 employees (84% of BC Hydro's work force) have taken one or both of these courses to date; and
- Action 1.4 – Renewed our Relationship Agreements with three First Nations.

Social and Cultural Well-Being

- Action 2.5 – Marked the completion of a major upgrade to Camosun Substation by partnering with a local Musqueam artist to design a mural at the site that reflects the Indigenous heritage of the region; and
- Action 2.6 – Multiple First Nations participated in our energy management programs to undertake energy efficiency upgrades in individuals' homes. For

more detail, please see the Report on Demand Side Management Activities for Fiscal 2024[3] filed with the BCUC in July 2024.

Water, Land and Environment

- Action 4.3 – Approved funding for nine applications by First Nations to plant culturally significant vegetation in their communities as part of BC Hydro's Community ReGreening Program. In addition, approved $8.7 million for 81 fish and wildlife projects to be implemented in 2024 and 2025 through the Fish and 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 2024 and 2026;
- Action 4.5 – Provided funding to design, build and operate a sockeye salmon hatchery in partnership with the kʷikʷəƛ̓əm First Nation that is targeting to release 15,000 smolts (young salmon that are ready to migrate out to sea) per year over the next 10 years; and
- Action 4.6 – Pre-qualified 15 First Nations designated businesses, representing 11 First Nations, to provide BC Hydro with environmental services.

Economic Relations

- Action 5.1 – Awarded $196.8 million in directed procurement contracts to First Nations designated businesses;
- Action 5.1 – Increased the work opportunities awarded to First Nations designated businesses, including line construction work, earth moving, traffic

[3] https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/regulatory-filings/reports/2024-07-15-bchydro-dsm-f24-annual-report.pdf.

management, and vegetation management from $5 million in fiscal year 2023 to $15 million in fiscal year 2024;

- Action 5.2 – Delivered five First Nation Contractor Program workshops to 21 First Nations designated business;
- Action 5.3 – Hired 29 Indigenous employees. Indigenous employees represented 4.2% of our workforce (or 328 employees) in fiscal 2024. This percentage exceeds the available Indigenous workforce in B.C. (3.9%);
- Action 5.4 – 10 Indigenous people participated in BC Hydro's Indigenous Professionals in Development program and five Indigenous people participated in our Try-A-Trade program. BC Hydro also launched a new Indigenous Career Exploration Program to provide individual career guidance and workshops to Indigenous job seekers in understanding the roles available, setting job alerts, creating cover letters, and preparing for behavioural interviews;
- Action 5.5 – Continued to explore with First Nations the potential for co-ownership of new transmission lines located in the north coast region of B.C. as a new economic opportunity for First Nations; and
- Action 5.8 – Collaborated with First Nations on the design of the 2024 Call for Power, including on development of a First Nations economic participation model which requires that projects have a minimum percentage of equity ownership held by First Nations.

Incorporating the principles of UNDRIP into our business will be a long-term effort. Going forward, we will continue to advance the actions outlined above, as well as other actions in the Plan, in collaboration with First Nations. This will include working with the First Nations Energy and Mining Council to establish a First Nations Advisory Committee to provide guidance on how BC Hydro implements UNDRIP, and inviting all B.C. First Nations to provide feedback on our approach during an annual UNDRIP implementation meeting. 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 2024 Annual Report to the British Columbia Utilities Commission

Section 4

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, 2024 (Fiscal 2024)
Entity Website	bchydro.com
Type of Energy Provided (Electricity, Natural Gas, Propane, etc)	Electricity
Sales Revenue ($)	$7,131 million
Fixed Assests/Rate Base ($) (Total Utility Assets-public)	$23,804 million
Total Capital Additions	$4,172 million
Total Expenses	$2,926 million
Repairs and Maintenance Expenses	$306 million
Net Utility Income (loss)	$323 million
Net Utility Equity (Deficit)	$7,696 million
Return on Equity	4.29%
Cost of Capital	6%
System Average Interruption Frequency Index (SAIFI)	1.56
System Average Interruption Duration Index (SAIDI)	3.56
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	60,474 kms
Energy Delivered (GJ/MWh)	55,413 GWh
Number of Customers	2,220,056
Number of New Customer Connections	14,378
Major Customer Types (Residential, Commercial, Industrial)	Residential, Light Industrial & Commercial, Large Industrial

5 Routine Trouble and Storm Restoration Costs Regulatory Account

Rountine Trouble & Storm Restoration Regulatory Account
($ million)

		F2024		
		Decision	Actual	Diff
Line		1	2	3 = 2 - 1
	Routine Trouble and Storm Restoration Costs			
1	Beginning of Year	(7.0)	(20.9)	(13.9)
2	Adjustment to Opening Balance	**0.0**	**0.0**	0.0
3	Additions – Storm Restoration Costs	0.0	(7.0)	(7.0)
4	Additions - Routine Trouble	0.0	8.7	8.7
5	Additions - Evacuation Relief	**0.0**	**0.4**	0.4
6	Interest	**(0.2)**	**(0.7)**	(0.5)
7	Recovery	3.7	3.7	(0.0)
8	End of Year	(3.5)	(16.0)	(12.5)

BC Hydro Fiscal 2024 Annual Report to the British Columbia Utilities Commission

Appendix A

Annual Deferral Accounts Report

April 1, 2023 to March 31, 2024

List of Schedules

Appendices

Schedule A British Columbia Hydro and Power Authority Summary of Deferral Accounts For the Year Ended March 31, 2024 ($ million)

Line No.	Particulars (Note 1)	Opening Balance at April 1, 2023	Changes (Note 2)	Amortization (Note 3)	Interest (Note 4)	Net Change	Ending Balance at March 31, 2024
	(1)	(2)	(3)	(4)	(5)	(6) = (3)+(4)+(5)	(7)=(2)+(6)
1	Heritage Deferral Account	(32.2)	79.5	1.2	0.8	81.5	49.3
2	Non-Heritage Deferral Account	(110.2)	1,182.5	4.1	15.1	1,201.7	1,091.4
3	Trade Income Deferral Account	(1,190.3)	(537.3)	43.8	(51.9)	(545.4)	(1,735.8)
4	Load Variance Regulatory Account	(32.8)	44.8	1.2	(1.7)	44.4	11.6
5	Biomass Energy Program Variance Regulatory Account	(74.6)	(51.8)	2.7	(3.2)	(52.3)	(126.8)
6	Low Carbon Fuel Credits Variance Regulatory Account	(48.3)	(14.5)	1.8	(2.1)	(14.8)	(63.1)
7	Total	(1,488.4)	703.2	54.7	(43.0)	715.0	(773.4)

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 deferral accounts. The Load Variance Regulatory Account captures the variance between planned and actual domestic customer load. The Biomass Energy Program Variance Regulatory 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. In the BCUC's Decision on the Fiscal 2023 to Fiscal 2025 Revenue Requirements Application dated April 21, 2023 (Order No. G-91-23), the Commission approved to recover the balance of the Low Carbon Fuel Credits Regulatory Account through the DARR mechanism.

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 1.0 per cent for fiscal 2024 effective April 1, 2023. Commencing in fiscal 2025, the Trade Income Deferral Account balance will be recovered separately, through the Trade Income Rate Rider (TIRR).

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, 2024 ($ 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	407.4	483.4	75.9	Note 1
5	Skagit Valley Treaty & Ancillary Revenue	(30.0)	(30.1)	(0.1)	
6	Costs in Operating / Amortization	12.8	16.4	3.6	Note 2
7	Total	390.3	469.8	79.5	Schedule A Line 1 Column 3
8					
9	**Items Subject to Non-Heritage Deferral Account:**				
10	Non-Heritage Deferral Account Transactions	1,544.5	2,781.5	1,237.0	Note 3
11	Commodity Risk	-	(42.9)	(42.9)	Note 4
12	Waneta - 2/3 - Teck Portion of Capital Expenditures	-	(1.3)	(1.3)	
13	Less: IPP subject to Biomass Energy Program Variance	(115.7)	(58.8)	56.9	Note 5
14	Other	-	(67.2)	(67.2)	Note 6
15	Total	1,428.8	2,611.2	1,182.5	Schedule A Line 2 Column 3
16					
17	**Trade Income Deferral Account**				
18	Trade Income	(224.2)	(761.5)	(537.3)	Note 7, Schedule A Line 3
19	Total	(224.2)	(761.5)	(537.3)	
20					
21	**Load Variance Regulatory Account**				
22	Load Variance	5,495.3	5,450.5	44.8	Note 8
23	Total	5,495.3	5,450.5	44.8	Schedule A Line 4 Column 3
24					
25	**Biomass Energy Program Variance Regulatory Account**				
26	Cost of Energy	115.7	58.8	(56.9)	Note 5
27	Revenue	(18.6)	(13.4)	5.2	Note 9
28	Biomass Energy Program Variance	97.2	45.4	(51.8)	Schedule A Line 5 Column 3
29					
30	**Low Carbon Fuel Credits Variance Regulatory Account**				
31	Low Carbon Fuel Credits Variance	(31.4)	(45.9)	(14.5)	Note 10, Schedule A Line 6
32	Total	(31.4)	(45.9)	(14.5)	
33					
34	**Total**			703.2	Schedule A Line 7 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: Heritage Deferral Account Transactions costs were $75.9 million higher than in the Fiscal 2023 to Fiscal 2025 Revenue Requirements Application (RRA) Decision (**F23-F25 Decision**), mainly driven by higher Domestic Transmission – Export costs of $40.3 million due to higher point-to-point charges from more imports during the year as a result of low inflows, higher costs associated with the Non-Treaty Storage and Libby Coordination agreements of $17.2 million due to higher net storage of water, higher water rental costs of $17.7 million due to higher water rental rates (water rental rates are escalated by BC Consumer Price Index (CPI) and BC CPI was higher than forecast), and higher other costs of $0.7 million.

Note 2: Costs in Operating/Amortization were $3.6 million higher than in the F23-F25 Decision, primarily due to the deferral of $3.5 million of repair costs for the G2 Air Cooled Condenser at the Fort Nelson plant, emergency repairs to remove pontoons 5 & 6 of the floating guide wall at Hugh Keenleyside ("HLK") and repairs due to a rockfall in the spillway chute of Terzaghi Dam.

Note 3: Non-Heritage Deferral Account Transactions costs were $1,237.0 million higher than in the F23-F25 Decision, mainly driven by higher Market Energy costs of $1,330.9 million driven by higher net market imports to meet domestic load requirements as a result of a below average 2022/23 snowpack and persistently dry conditions across BC Hydro's basins over the summer and in subsequent months. In addition, Non-Integrated Area costs were $12.5 million higher due to higher diesel fuel costs, and Gas and Other Transportation costs were $2.8 million higher. These higher costs were partially offset by lower Independent Power Producer (IPP) costs of $109.0 million due to more outages, lower purchases from hydro IPPs due to low inflows, partially offset by higher deliveries driven by higher inflows during the fall and winter months, and lower deliveries from biomass IPPs due to fuel supply issues.

Note 4: Commodity Risk variance of ($42.9) million consists of mark-to-market gains related to transactions under the energy Transfer Pricing Agreement between BC Hydro and Powerex. These mark-to-market gains are fully offset in Trade Income with their variances deferred to the Trade Income Deferral Account and have no net impact to ratepayers.

Note 5: 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 $56.9 million lower than the F23-F25 Decision, largely due to one energy purchase agreement which was not renewed and IPP outages as well as fuel shortages and equipment failures for other IPPs.

Note 6: Other variances of ($67.2) million deferred into the NHDA include higher intersegment revenues of $58.7 million with Powerex and higher external OATT revenues totalling $9.4 million. This was partially offset by $1.9 million of higher than approved IPP capital lease expenses. Intersegment revenues are fully offset in Trade Income with their variances deferred to the Trade Income Deferral Account and have no net impact to ratepayers.

Note 7: Trade Income variance of ($537.3) 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 8: The load variance of $44.8. million is primarily due to lower sales to Residential customers of $86.2 million resulting from lower usage per account and a warmer winter in fiscal 2024, as well as unfavourable variances from Large Industrial customers of $38.1 million. The unfavourable variance is partially offset by unplanned energy sales in accordance with an energy exchange agreement with one customer of $35.3 million, higher sales to a domestic utility of $22.0 million, and higher sales to Light Industrial & Commercial customers of $20.2 million.

Note 9: Biomass Energy Program revenues were $5.2 million lower than in the F23-25 RRA Decision, mainly driven by lower volumes.

Note 10: Low Carbon Fuel Credits revenues were $14.5 million higher than Plan, which was based on a 5-year average of low carbon fuel credits. Both the volume of Low Carbon Fuel Standard 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 standard credits received in fiscal 2024.

Schedule C British Columbia Hydro and Power Authority Summary of Domestic Cost of Energy For the Year Ended March 31, 2024 ($ million)

Line No.	Particulars	Decision	Actual	Variance	Ref.
	(1)	(2)	(3)	(4) = (3) - (2)	(5)
1	**Heritage Energy**				
2	Water Rentals	384.9	401.3	16.4	
3	Natural Gas for Thermal Generation	10.7	8.1	(2.6)	
4	Domestic Transmission - Other	25.7	26.9	1.2	
5	Non-Treaty Storage and Libby Coordination Agreements	(9.4)	2.7	12.1	
6	Remissions and Other	(44.7)	(42.6)	2.1	
7	Subtotal	367.2	396.4	29.2	
8	Electrification Plan - Heritage Energy	(1.3)	-	1.3	
9	Electrification Plan - NTSA	(5.1)	-	5.1	
10	Total	360.7	396.4	35.6	Included in Schedule B Line 4
11					
12	**Non-Heritage Energy**				
13	IPPs and Long-Term Commitments	1,490.7	1,381.7	(109.0)	
14	Non-Integrated Area	30.0	42.5	12.5	
15	Gas & Other Transportation	4.5	7.3	2.8	
16	Water Rentals (Waneta 2/3)	3.7	3.7	0.0	
17	Total	1,528.9	1,435.2	(93.7)	Included in Schedule B Line 10
18					
19	**Market Energy**				
22	System Imports	149.2	1,377.5	1,228.3	Included in Schedule B Line 10
23	System Exports	(190.3)	(27.0)	163.3	Included in Schedule B Line 10
25	Domestic Transmission - Export	14.3	54.7	40.3	Included in Schedule B Line 18
26	Subtotal	(26.8)	1,405.1	1,431.9	
27	Electrification Plan - Market Energy	60.7	-	(60.7)	Included in Schedule B Line 4
28	Total	33.9	1,405.1	1,371.2	
29					
30	**Total Gross COE**	1,923.5	3,236.7	1,313.2	
31					
32	**Heritage Energy (GWh)**				
33	Hydro generation (Water Rentals)	45,620	32,973	(12,648)	
34	Natural Gas for Thermal Generation	216	105	(112)	
35	Exchange Net	(326)	(1,358)	(1,032)	
36	Subtotal	45,510	31,719	(13,791)	
37	Electrification Plan - Heritage Energy	227	-	(227)	
38	Total	45,738	31,719	(14,018)	
39					
40	**Non-Heritage Energy (GWh)**				
41	IPPs and Long-Term Commitments	16,003	13,667	(2,336)	
42	Non-Integrated Area	111	115	5	
43	Total	16,114	13,783	(2,331)	
44					
45	**Market Energy (GWh)**				
46	System Imports	3,308	14,216	10,909	
47	System Exports	(5,145)	(613)	4,532	
48	Subtotal	(1,837)	13,603	15,440	
49	Electrification Plan - Market Energy	763	-	(763)	
50	Total	(1,074)	13,603	14,677	
51					
52	**Total Sources of Supply**	60,777	59,105	(1,672)	
53	Less: Line loss and system use	(5,583)	(4,306)	1,277	
54					
55	**Total Domestic Sales Volume**	55,195	54,799	(396)	

Figure 1 **British Columbia Hydro and Power Authority Consolidated Statement of Operations for the Year Ended March 31, 2024 ($ million)**

Line No.	Particulars	Decision	Actual	Variance	Ref.
	(1)	(2)	(3)	(4) = (3) - (2)	(5)
	REVENUES				
	Domestic				
1	Residential	2,425.2	2,152.8	(272.3)	
2	Light industrial and commercial	2,001.5	1,933.2	(68.3)	
3	Large industrial (includes LNG revenues)	958.8	875.1	(83.7)	
4	Other energy sales	128.5	173.2	44.7	
5	Seattle City Light	30.0	30.1	0.1	
6	Revenue from Deferral Rider	(55.2)	(54.7)	0.4	
7	Miscellaneous	292.3	466.6	174.3	
8		5,781.1	5,576.3	(204.8)	
9	Intersegment revenues	73.4	174.9	101.6	
10		**5,854.5**	**5,751.2**	**(103.2)**	
11	**EXPENSES**				
12	Domestic energy costs	1,923.5	3,236.7	1,313.1	Schedule C Line 30
13	Operating costs	1,420.4	1,561.4	141.0	
14	Depreciation and amortization	1,058.9	1,060.2	1.3	
15	Taxes	298.3	304.2	5.9	
16	Finance charges	566.1	517.6	(48.4)	
17		5,267.2	6,680.1	1,412.9	
18	**DOMESTIC INCOME BEFORE TRANSFER**				
19	**(TO)/FROM DEFERRAL ACCOUNTS**	**587.3**	**(928.9)**	**(1,516.1)**	
20					
21	**POWEREX NET INCOME**	**224.2**	**761.5**	**537.3**	Schedule B Line 18
22	**POWERTECH NET INCOME**	**3.5**	**(0.3)**	**(3.8)**	
23	**CAPTIVE INSURANCE NET INCOME**	**0.0**	**0.4**	**0.4**	
24	**COLUMBIA HYDRO CONTRACTORS NET INCOME**	**-**	**(0.1)**	**(0.1)**	
25					
26	**TOTAL INCOME BEFORE TRANSFER (TO)/FROM**				
27	**DEFERRAL ACCOUNTS**	**814.9**	**(167.4)**	**(982.6)**	
28					
29	Heritage Deferral Account	(21.0)	81.5	102.5	
30	Non-Heritage Deferral Account	41.6	1,201.7	1,160.0	
31	Trade Income Deferral Account	54.4	(545.4)	(599.9)	
32	Load Variance	(31.3)	44.4	75.6	
33	Biomass Energy Program Variance	4.8	(52.3)	(57.1)	
34	Low Carbon Fuel Credits Variance	-	(14.8)	(14.8)	
35	Demand-Side Management Reg. Account	29.1	12.6	(16.5)	
36	First Nation Costs Regulatory Account	(17.6)	(16.8)	0.8	
37	First Nation Settlement Provisions Reg. Acct.	4.4	5.9	1.5	
38	Site C Regulatory Account	28.6	(64.2)	(92.8)	
39	Foreign Exchange Gains/Losses Reg. Account	(0.0)	(0.9)	(0.9)	
40	Pre-1996 Customer Contributions Reg. Acct.	(5.1)	(5.1)	(0.0)	
41	Storm Restoration Regulatory Account	3.5	5.0	1.5	

42	Capital Project Investigation Costs Reg. Acct.	-	-	-
43	Amortization of Capital Additions Reg. Acct.	(0.8)	(7.0)	(6.1)
44	Total Finance Charges Regulatory Account	(12.9)	43.4	56.3
45	Smart Metering and Infrastructure Reg. Acct.	(21.6)	(21.1)	0.5
46	Non-Current Pension Costs Reg. Account	(29.7)	64.7	94.4
47	Environmental Provisions Regulatory Account	(45.7)	(22.0)	23.7
48	Rock Bay Remediation Regulatory Account	-	-	-
49	IFRS Property Plant & Equipment Reg. Account	(31.6)	(31.6)	(0.0)
50	IFRS Pension Regulatory Account	(38.2)	(38.2)	0.0
51	Remediation Regulatory Account	11.3	13.3	2.0
52	Real Property Sales Regulatory Account	1.5	(0.2)	(1.7)
53	Debt Management Regulatory Account	(18.1)	(181.0)	(162.9)
54	Dismantling Costs Regulatory Account	1.5	4.0	2.5
55	PEB Current Pension Regulatory Account	8.3	(27.3)	(35.6)
56	Customer Crisis Fund Regulatory Account	(13.8)	(10.9)	2.9
57	Mining Customer Payment Plan	(2.5)	(2.5)	(0.1)
58	Project Write-off Costs	(2.3)	12.0	14.3
59	Electric Vehicle Fast Charging	5.5	5.9	0.4
60	Mandatory Reliability Standard Costs	(5.4)	(3.2)	2.1
61	Load Attraction Costs	9.2	0.8	(8.4)
62	Depreciation Study	(9.8)	(13.9)	(4.1)
63	Electrification Customer Connection Costs	0.8	0.8	0.0
64	Cloud Costs	-	35.3	35.3
65	Cloud Usage	-	3.2	3.2
66	Inflationary Pressures	-	65.2	65.2
67	Electric Vehicle Rebate	-	(70.8)	(70.8)
68	Site C Variance Costs	-	0.3	0.3
69	Flow Through Cost	-	4.9	4.9
70	Remote Community Electrification Repayment	-	14.5	14.5
71	**TOTAL NET INCOME**	**712.0**	**322.7**	**(389.3)**

Figure 2 British Columbia Hydro and Power Authority Intersegment Revenues for the Year Ended March 31, 2024 ($ million)

Line No.	Particulars	Decision	Actual	Variance	Ref.
	(1)	(2)	(3)	(4) = (3) - (2)	(5)
1	Point-to-point wheeling charges to Powerex	39.8	57.5	17.7	Note 1
2					
3	Point-to-point wheeling charges to BC Hydro	33.2	74.3	41.0	Note 2
4					
5	Allocation of BC Hydro costs to Powerex	0.3	0.3	-	Note 3
6					
7	Mark-to-market gains / (losses)	0.0	42.9	42.9	Schedule B Line 11
8					
9	Total	73.4	174.9	101.6	Appendix 1 Line 9

Due to minor rounding some totals may not add.

Note 1: These transmission revenues relate to an allocation of BC Hydro's cost of purchases of point-to-point transmission within BC for export and import transactions. These revenues are eliminated against trade cost of energy on consolidation. The variance is deferred in the NHDA. Please refer to Schedule B, Line 14 and Note 6.

Note 2: These transmission revenues relate to BC Hydro's cost of purchases of point-to-point transmission within BC for export and import transactions, after deducting Powerex's allocation (see Note 1 above), allocation for the Canadian Entitlement Agreement (OATT Schedule 01) and allocation for Scheduling, System Control & Dispatch services (OATT Schedule 03). These revenues are eliminated against domestic cost of energy on consolidation. The variance is deferred in the NHDA. Please refer to Schedule B, Line 14 and Note 6.

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

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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 in the BCUC's Decision on the Fiscal 2023 to Fiscal 2025 RRA (BCUC Order No. G-91-23);
- Directives included in the BCUC's Decision on the Fiscal 2023 to Fiscal 2025 RRA (BCUC Order No. G-154-23);
- Directives included in the BCUC's Decision on the Application for Approval to Set the Fiscal 2025 Deferral Account Rate Rider and Trade Income Rate Rider and Reconsideration Related to the Trade Income Rate Rider (BCUC Order No. G-43-24); and
- Directives included in the BCUC's Decision on the Application to establish the Electric Vehicle Rebate Regulatory Account (BCUC Order No. G-151-24).

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. 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 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**)[2] 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.

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

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

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

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

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

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

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

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

Non-Heritage Deferral Account (NHDA)

Commission Decision, October 29, 2004, Page 41:

Commission Findings

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

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

1. Cost of energy[7] - all energy costs variances not deferred to the HDA and the Biomass Energy Program Variance Regulatory account, including all System Imports and System Exports variances under the 2020 TPA with Powerex[2] 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[2] 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 Trade Income. The BC Hydro side of the entry is shown as part of domestic

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

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[2] 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[2] 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;[2]
- System Exports: represents sales of electricity to Powerex by BC Hydro under the 2020 TPA;[2] 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 or caused by weather related events; [7]

3. Significant unplanned major capital expenditures having an incremental annual impact on the Income Statement greater than $1 million related to single event equipment or infrastructure failure;[7]

4. Founding Partner Benefits and CIS Credits under the ABS Contract; [7,8]

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;[9]

6. Variances related to the Northwest Transmission Line (**NTL**) Supplemental Charge revenues in conjunction with Tariff Supplement No. 37 amendments;[10]

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

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

[10] 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;[11]

10. Variances between forecast and actual transmission service revenue[12] including External Open Access Transmission Tariff (**OATT**) revenues and point-to-point charges to Powerex;

11. An interest charge/credit[5] is applied to the monthly balance in each deferral account at BC Hydro's weighted average cost of debt for its current fiscal year;[6] 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.[13]

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

[12] 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).

[13] 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;[14]
- 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; and
    - Adding any foreign currency translation losses in the fiscal year on intercompany balances between BC Hydro and Powerex.
  - Zero.
- An interest charge/credit[5] is applied to the monthly balance in each deferral account at BC Hydro's weighted average cost of debt for its current fiscal year;[5]
- BC Hydro is authorized in fiscal 2023 to:
  - Transfer $6 million from the TIDA to the Customer Crisis Fund Regulatory Account;[15] and

[14] 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.

[15] Per BCUC Order No. G-341-22.

  - Establish an inflationary pressures regulatory account, transfer $74 million from the TIDA to this account.[15]
- BC Hydro is authorized in fiscal 2025 to:
  - Transfer an amount from the TIDA to the Rate Smoothing Regulatory Account equal to the remainder of the Trade Income Rate Rider balance that would otherwise have been refunded on the customer bills in fiscal 2025 pursuant to Directive 77 [of BCUC Order No. G 91-23].[16]

[16] Per Application for Approval to Set the Fiscal 2025 Deferral Account Rate Rider and Trade Income Rate Rider and Reconsideration Related to the Trade Income Rate Rider (BCUC Order No. G-43-24).

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.[17]

- 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[5] is applied to the monthly balance at BC Hydro's weighted average cost of debt for its current fiscal year.[6]

[17] 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. [18]

- 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[5] is applied to the monthly balance at BC Hydro's weighted average cost of debt for its current fiscal year;[6]
- In fiscal 2023, transfer the fiscal 2022 actual revenue from BC Hydro's EV fast charging service from the LVRA to the EV Public Charging Regulatory Account;[19] and
- 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 Public Charging Regulatory Account.[19]

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

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.[20]

- All revenue variances between forecast and actual miscellaneous revenue from low carbon fuel credits are deferred to the LCFCVRA;
- An interest charge/credit[5] is applied to the monthly balance at BC Hydro's weighted average cost of debt for its current fiscal year;[6]
- 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;[19]
- Commencing in fiscal 2023, and until directed otherwise by the BCUC, defer the actual Low Carbon Fuel Credits revenue to the EV Public Charing Regulatory Account;[19] and
- Exclude revenue from low carbon fuel credits required to be captured in other regulatory accounts.[21]

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

[21] Per Request to Establish the Electric Vehicle Rebate Regulatory Account (BCUC Order No. G-151-24).

BC Hydro Fiscal 2024 Annual Report to the British Columbia Utilities Commission

Appendix B

Debt Management Regulatory Account Annual Status Report

April 1, 2023 to March 31, 2024

Table of Contents

Appendices

1 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 (i.e., unrealized) and settlement (i.e., realized) gains and losses on financial contracts that hedge future long-term debt issuance 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.

2 Report as at March 31, 2024

During fiscal 2024, BC Hydro entered into an additional $0.9 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 10 months to three years and forecast borrowing yields ranging from 3.93% to 4.54%.

Since the establishment of the DMRA and as at March 31, 2024, a total of $13.63 billion of FDHs have been placed, of which $2.88 billion remained outstanding. Based on forecasts of debt requirements from BC Hydro's 2024/25 to 2026/27 Service Plan forecast, and hedges outstanding as of March 31, 2024, BC Hydro had hedged approximately 30% of forecast long-term debt issuances for fiscal 2025 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, 2024, the DMRA had a liability balance (i.e., amount owing to ratepayers) of $114 million. This balance included:

- $191 million of net unrealized gains on the $2.88 billion of outstanding FDHs; and
- $20 million of amortization related to previous net realized losses on the $8.13 billion of FDHs settled during fiscal 2017 to fiscal 2022 (the $2.63 billion of FDHs settled since fiscal 2022, i.e., in fiscal 2023 and 2024, will begin amortizing in the next test period, fiscal 2026); partially offset by,
- $97 million of net realized losses on the $10.75 billion of settled FDHs.

The net unrealized gains of $191 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, 2024, 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, 2024, net liability balance in the DMRA of $114 million was a net change of $181 million from the net asset balance of $67 million at March 31, 2023. The $181 million change was due to:

- $71 million related to increases in the value of the $900 million of FDHs that were settled during fiscal 2024;

- $92 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 FDHs settled during fiscal 2024 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.

The increase in the value of the outstanding FDHs was due to:

- An increase in long-term interest rates related to FDHs outstanding for the full duration of fiscal 2024, as well as a portion of the new FDHs entered into during fiscal 2024; partly offset by,
- A decrease in interest rates related to a portion of the new FDHs entered during fiscal 2024.

BC Hydro Fiscal 2024 Annual Report to the British Columbia Utilities Commission

Appendix B

Appendix 1

Future Debt Hedges Report

Future Debt Hedges Report

As of March 31, 2024

(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	(0.5)	2.2
FDH2A	2016-05-11	Bond Lock	F2017	2016-Sep	30 years	200	2.97%	3.00%		(11.3)	(11.3)	1.9	(9.4)
FDH2B	2016-05-12	Bond Lock	F2017	2016-Sep	30 years	100	3.01%	3.00%		(6.7)	(6.7)	1.1	(5.5)
FDH3	2016-05-18	Bond Lock	F2018	2017-Mar	10 years	300	2.36%	2.35%		8.0	8.0	(4.9)	3.1
FDH4	2016-05-24	Bond Lock	F2018	2017-Oct	10 years	200	2.38%	2.37%		7.4	7.4	(4.5)	2.9
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	(10.4)	6.7
FDH7	2016-09-23	Swap	F2018	2017-Oct	10 years	200	2.08%	1.82%		17.2	17.2	(10.5)	6.7
FDH8	2016-09-26	Swap	F2018	2017-Sep	30 years	200	2.64%	2.27%		40.9	40.9	(7.0)	33.9
FDH9	2016-09-29	Swap	F2019	2018-May	10 years	200	2.09%	1.84%		22.7	22.7	(11.7)	11.0
FDH10	2016-10-06	Swap	F2019	2018-Apr	30 years	200	2.76%	2.14%		38.7	38.7	(6.6)	32.1
FDH11	2016-06-08	Swap	F2019	2018-Sep	10 years	300	2.53%	2.16%		22.4	22.4	(11.5)	10.9
FDH12	2016-06-08	Swap	F2019	2018-Sep	10 years	200	2.54%	2.17%		14.7	14.7	(7.6)	7.1
FDH13	2016-06-14	Swap	F2020	2019-Jun	10 years	300	2.54%	2.18%		(0.4)	(0.4)	0.2	(0.2)
FDH14	2016-06-22	Swap	F2020	2019-Oct	10 years	200	2.74%	2.44%		(3.1)	(3.1)	1.0	(2.1)
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)	9.2	(19.0)
FDH17	2016-10-13	Swap	F2021	2020-Jun	10 years	200	2.60%	2.31%		(16.5)	(16.5)	5.4	(11.1)
FDH18	2016-10-20	Swap	F2021	2020-Sep	10 years	300	2.69%	2.25%		(27.9)	(27.9)	9.1	(18.8)
FDH19	2016-10-20	Swap	F2021	2020-Sep	10 years	200	2.69%	2.27%		(18.3)	(18.3)	5.9	(12.3)
Subtotal						**$4,400**			**$0.0**	**$80.1**	**$80.1**	**($41.5)**	**$38.7**
Hedges Placed F2018													
FDH20	2017-09-29	Bond Lock	F2019	2018-Jul	10 years	200	2.96%	2.88%		(1.6)	(1.6)	0.8	(0.8)
FDH21	2017-10-03	Bond Lock	F2019	2018-Jul	10 years	200	3.00%	2.92%		(2.2)	(2.2)	1.1	(1.1)
FDH22	2017-09-29	Bond Lock	F2019	2018-Jul	30 years	200	3.35%	3.36%		(17.3)	(17.3)	3.0	(14.3)
FDH23A	2017-10-04	Bond Lock	F2019	2018-Jun	10 years	100	3.01%	2.84%		(0.4)	(0.4)	0.2	(0.1)
FDH23B	2017-10-04	Bond Lock	F2019	2018-Jun	10 years	100	3.01%	2.87%		(0.4)	(0.4)	0.2	(0.2)
FDH24A	2017-10-02	Bond Lock	F2019	2018-Aug	30 years	100	3.36%	3.35%		(6.4)	(6.4)	1.0	(5.4)
FDH24B	2017-10-03	Bond Lock	F2019	2018-Aug	30 years	100	3.38%	3.37%		(6.8)	(6.8)	1.1	(5.7)
FDH25	2017-09-28	Bond Lock	F2019	2018-Aug	30 years	250	3.37%	3.36%		(16.7)	(16.7)	2.7	(14.0)
FDH26/27	2018-01-29	Swap	F2020	2019-Jun	30 years	50	3.44%	3.16%		(6.7)	(6.7)	0.7	(6.0)
FDH28	2018-02-05	Swap	F2021	2020-Jun	30 years	75	3.64%	4.01%		(30.9)	(30.9)	3.2	(27.7)
FDH29	2018-02-05	Swap	F2021	2020-Sep	30 years	75	3.64%	3.82%		(29.7)	(29.7)	3.0	(26.6)
FDH30/31	2018-02-08	Swap	F2022	2021-Jun	30 years	175	3.67%	3.56%		(27.5)	(27.5)	1.8	(25.6)
FDH32	2018-02-06	Swap	F2022	2021-Sep	30 years	100	3.60%	3.50%		(18.1)	(18.1)	1.2	(16.9)
FDH33	2018-02-07	Swap	F2022	2021-Sep	30 years	100	3.58%	3.47%		(17.7)	(17.7)	1.2	(16.5)
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)**	**$21.2**	**($105.1)**
Hedges Placed F2019													
FDH38	2018-12-07	Swap	F2022	2021-May	10 years	125	3.33%	3.16%		(9.5)	(9.5)	2.1	(7.4)
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	2023-Jun	10 years	175	3.46%	3.23%		13.9	13.9	0.0	13.9
FDH42	2018-12-06	Swap	F2024	2023-Sep	30 years	175	3.62%	3.48%		32.5	32.5	0.0	32.5
FDH43	2019-01-15	Bond Lock	F2020	2019-Jun	30 years	150	3.13%	3.07%		(18.8)	(18.8)	2.1	(16.8)
FDH44	2019-01-16	Bond Lock	F2020	2019-Sep	30 years	125	3.17%	3.24%		(23.1)	(23.1)	2.5	(20.5)
FDH45A	2019-01-17	Bond Lock	F2021	2020-Jun	30 years	200	3.20%	3.54%		(60.4)	(60.4)	6.2	(54.2)
FDH45B	2019-01-17	Bond Lock	F2021	2020-Jun	30 years	125	3.20%	3.47%		(40.4)	(40.4)	4.1	(36.2)
FDH46A	2019-01-15	Swap	F2021	2020-Sep	30 years	100	3.43%	3.51%		(34.6)	(34.6)	3.5	(31.0)
FDH46B	2019-01-16	Swap	F2021	2020-Aug	30 years	225	3.49%	3.69%		(82.2)	(82.2)	8.4	(73.7)
FDH47	2019-01-08	Swap	F2022	2021-May	10 years	275	3.15%	2.96%		(16.4)	(16.4)	3.5	(12.8)
FDH48	2019-01-09	Swap	F2022	2021-Jun	30 years	100	3.41%	3.21%		(9.5)	(9.5)	0.6	(8.9)
FDH49	2019-01-09	Swap	F2022	2021-Sep	10 years	300	3.22%	2.99%		(28.2)	(28.2)	6.1	(22.1)
FDH50	2019-01-10	Swap	F2022	2021-Aug	30 years	175	3.41%	3.22%		(24.0)	(24.0)	1.6	(22.4)
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	2023-Jun	10 years	175	3.33%	3.11%		15.7	15.7	0.0	15.7
FDH55	2019-01-08	Swap	F2024	2023-Sep	30 years	125	3.44%	3.33%		27.0	27.0	0.0	27.0
FDH56	2019-01-15	Swap	F2025		10 years	75	3.39%		5.4		5.4		5.4
Subtotal						**$3,325**			**$5.4**	**($209.6)**	**($204.2)**	**$40.9**	**($163.3)**

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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%		6.1		6.1		6.1
FDH58	2021-04-13	Swap	F2025		30 years	150	3.32%		23.2		23.2		23.2
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	2023-Sep	10 years	100	2.40%	2.41%		19.6	19.6	0.0	19.6
FDH62	2021-08-30	Swap	F2025		10 years	175	2.48%		23.1		23.1		23.1
FDH63	2021-08-17	Swap	F2025		30 years	175	2.83%		42.1		42.1		42.1
FDH64	2021-08-24	Swap	F2026		30 years	100	2.85%		21.5		21.5		21.5
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	2023-Jun	30 years	150	2.79%	2.89%		38.0	38.0	0.0	38.0
FDH67	2021-09-15	Swap	F2025		30 years	200	2.85%		45.8		45.8		45.8
FDH68	2021-09-22	Swap	F2026		10 years	75	2.61%		8.0		8.0		8.0
FDH69	2021-10-06	Swap	F2026		30 years	75	3.07%		12.9		12.9		12.9
Subtotal						**$1,850**			**$182.7**	**$158.5**	**$341.2**	**$0.0**	**$341.2**
Hedges Placed F2023													
FDH70	2022-06-02	Swap	F2025		30 years	100	3.82%		5.3		5.3		5.3
FDH71	2022-06-02	Swap	F2026		30 years	100	3.82%		3.8		3.8		3.8
FDH72	2022-06-02	Swap	F2026		30 years	50	3.82%		1.8		1.8		1.8
FDH73	2022-06-09	Swap	F2027		10 years	100	4.27%		(2.2)		(2.2)		(2.2)
FDH74	2022-08-16	Swap	F2025		10 years	50	3.52%		2.0		2.0		2.0
FDH75	2022-08-16	Swap	F2026		10 years	200	3.57%		6.0		6.0		6.0
FDH76	2022-09-13	Swap	F2027		30 years	100	4.02%		(0.6)		(0.6)		(0.6)
FDH77	2023-02-15	Swap	F2026		10 years	125	3.88%		0.6		0.6		0.6
FDH78	2023-02-15	Swap	F2026		30 years	50	3.94%		0.6		0.6		0.6
Subtotal						**$875**			**$17.3**	**$0.0**	**$17.3**	**$0.0**	**$17.3**
Hedges Placed F2024													
FDH79	2023-06-14	Swap	F2025		10 years	350	3.96%		1.2		1.2		1.2
FDH80	2023-06-20	Swap	F2026		30 years	150	3.93%		2.7		2.7		2.7
FDH81	2023-09-12	Swap	F2025		30 years	225	4.39%		(10.5)		(10.5)		(10.5)
FDH82	2023-09-12	Swap	F2027		30 years	75	4.28%		(3.4)		(3.4)		(3.4)
FDH83	2023-09-26	Swap	F2026		10 years	100	4.54%		(4.7)		(4.7)		(4.7)
						$900			**($14.7)**	**$0.0**	**($14.7)**	**$0.0**	**($14.7)**
Total						**$13,625**			**$190.7**	**($97.3)**	**$93.4**	**$20.6**	**$114.0**

[1] Actual debt was a 30 year issue

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

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BC Hydro Fiscal 2024 Annual Report to the British Columbia Utilities Commission

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. Settlement value is also referred to as realized gain or loss.

[1] A Canadian Interest Rate Swap is an agreement between two counterparties that agree to exchange an interest payment based on a Canadian floating reference rate. The Canadian floating reference rate is CDOR Canadian Dollar Offer Rate index for all FDH Swaps executed up to June 30, 2023, and Canadian Overnight Repo Rate Average (**CORRA**) for all FDH Swaps executed after June 30, 2023. The change of the floating reference rate is a result of interest rate reform in Canada, involving the cessation of CDOR and its replacement with CORRA as the Canadian floating interest rate benchmark.

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.
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.

BC Hydro Fiscal 2024 Annual Report to the British Columbia Utilities Commission

Appendix C

Performance of Rate Schedules 1894 and 1895

Fiscal 2024

PUBLIC

Table of Contents

1 Summary / Background

On January 29, 2021, BC Hydro filed an application with the BCUC in accordance with the Government of British Columbia's Direction to the BCUC Respecting Industrial Electrification (Order in Council No. 657 issued on December 21, 2020, BC Reg. 295/2020)[1] 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.[2] Directive 3 of that order 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.

The Clean Industry and Innovation Rate (RS 1894) is intended to encourage the construction of new customer facilities that will either remove greenhouse gases from the atmosphere, produce renewable/low-carbon fuels or provide data storage services (not including cryptocurrency exchange). The Fuel Switching Rate (RS 1895) is intended to encourage the permanent conversion to electricity of all or a portion of a new or existing customer facility where hydrocarbon fuel would

1 https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/regulatory-filings/tariff/2021-01-29-bchydro-consent-ts37-rs-1895-1895.pdf.

2 https://www.ordersdecisions.bcuc.com/bcuc/orders/en/item/492458/index.do?q=Industrial+electrification.

otherwise be used as the power source. Both rate schedules offer a discount on the otherwise applicable rate energy charge and demand charge[3] for a period of seven years from the project's In-service Date. The discount is 20% for the first five years, 13% in year six, and 7% in year seven. Both rates are closed to new customers effective March 31, 2030.

2 Progress Report

In the following sub-sections, BC Hydro provides the information with respect to the performance of RS 1894 and RS 1895 in fiscal 2024 as ordered by Directive 3 of Order G-38-21. In accordance with section 42 of the *Administrative Tribunals Act* and Part 4 of BCUC's Rules of Practice and Procedure, BC Hydro is filing the complete version of this Appendix C with the BCUC only and has redacted certain information in the public version which we believe could reveal commercially sensitive information about a specific customer or customers.

2.1 Number of Customer Projects Receiving Service Under RS 1894 and RS 1895

As of March 31, 2024, there were two customers receiving service under RS 1895 and no customers receiving service under RS 1894. A summary of customer projects receiving service under RS 1894 and RS 1895 during fiscal 2024 is provided in Table 1 below.

[3] The rate schedules were recently amended and approved effective July 18, 2024, to reflect changes to BC Hydro's default transmission service rate (RS 1830 replaces RS 1823). These rate schedule amendments were initiated by Order in Council (**OIC**) No. 441 on July 6, 2024, and deposited on July 8, 2024 which amends the Direction to the British Columbia Utilities Commission (BCUC) Respecting Industrial Electrification, B.C. Reg. 295/2020 and which requires the BCUC issue an order setting the amended rates as attached in the OIC effective the date of the BCUC order. BCUC Order G-193-24 approved the amended rate schedules effective July 18, 2024. The BCUC order also approved on a permanent basis BC Hydro's interim treatment of allowing RS 1895 to be available to customers taking service on RS 1830 starting April 1, 2024 and for BC Hydro to apply RS 1830 energy and demand charges as the basis for billing customers on RS 1894 and RS 1895.

- https://www.bclaws.gov.bc.ca/civix/document/id/oic/oic_cur/0441_2024.
- https://www.ordersdecisions.bcuc.com/bcuc/orders/en/522354/1/document.do.

Table 1 Number of Customer Projects Receiving Service Under RS 1894 and RS 1895 during Fiscal 2024

Number of Customer Projects by Rate Schedule	RS 1894	RS 1895
Number of Customer Projects in years 1 - 5	0	2
Number of Customer Projects in year 6	0	0
Number of Customer Projects in year 7	0	0
Total	**0**	**2**

Additional projects with requested loads under these two rate schedules are progressing through the interconnection process with projected In-Service Dates ranging from fiscal 2025 to fiscal 2030.

2.2 Incremental Load Obtained Under RS 1894 and RS 1895

Table 2 below shows the incremental loads obtained under RS 1894 and RS 1895 in fiscal 2024.

Table 2 Incremental Load Obtained under RS 1894 and RS 1895 in Fiscal 2024

Incremental Load Supplied by Rate Schedule (GWh)	RS 1894	RS 1895
Incremental Load Supplied to Customer Project in years 1 - 5	0	[redacted]
Incremental Load Supplied to Customer Projects in year 6	0	0
Incremental Load Supplied to Customer Projects in year 7	0	0
Total	**0**	[redacted]

Based on applications received to date, we expect that the aggregate energy cap of 5,000 GWh for RS 1894 and RS 1895 will be reached over time.

2.3 Incremental Revenues Associated with RS 1894 and RS 1895

Table 3 below shows the incremental revenues associated with RS 1894 and RS 1895 in fiscal 2024.

Table 3 Incremental Revenues Associated with RS 1894 and RS 1895 in Fiscal 2024

Incremental Revenues by Rate Schedule ($000)	RS 1894	RS 1895
Incremental Revenues for Customer Projects in years 1 - 5	0	[redacted]
Incremental Revenues for Customer Projects in year 6	0	0
Incremental Revenues for Customer Projects in year 7	0	0
Total	**0**	[redacted]

2.4 Greenhouse Gas Reduction Related to RS 1894 and RS 1895

Table 4 below shows the greenhouse gas emission reductions estimated from customer electrification projects receiving service under RS 1894 and RS 1895 in fiscal 2024.

Table 4 Greenhouse Gas Reduction Related to RS 1894 and RS 1895 in Fiscal 2024

Greenhouse Gas Reduction by Rate Schedule (tCO_2e)	RS 1894	RS 1895
Fiscal 2024 Greenhouse Gas Reduction (Estimated)	0	150,591

The fiscal 2024 greenhouse gas emission reduction values represent prorated annual greenhouse gas emission reduction estimates that are based on the engineering review completed by BC Hydro of the information provided by the customer as part of their application to participate in the rate. The original GHG reduction estimates were prorated based on actual electricity consumption for the customer electrification project during fiscal 2024, compared to projected electricity consumption over the same time period.

A more detailed assessment of the achieved fiscal 2024 greenhouse gas emission reductions will be completed in collaboration with each RS 1895 customer following completion of their first Billing Year (i.e., 12 months following the Project In-service Date) and any updated results will be provided in BC Hydro's Fiscal 2025 Annual Report.

CONFIDENTIAL APPENDIX

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