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

August 31, 2021

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

Dear Mr. Wruck:

RE: British Columbia Utilities Commission (BCUC or Commission)
British Columbia Hydro and Power Authority (BC Hydro)
Fiscal 2023 to Fiscal 2025 Revenue Requirements Application

BC Hydro writes to file the attached Fiscal 2023 to Fiscal 2025 Revenue Requirements Application (the **Application**).

BC Hydro is requesting various approvals from the BCUC which, if approved, would result in a net bill decrease of 1.4 per cent on April 1, 2022, followed by net bill increases of 2.0 per cent on April 1, 2023 and 2.7 per cent on April 1, 2024. This represents an average annual increase of 1.1 per cent.[1]

BC Hydro is providing the Application as follows:[2]

Exhibit B-2	Application (Public)
Exhibit B-2-1	Appendices A to II (Public)
Exhibit B-2-2	Chapter 6 (Confidential Version)
Exhibit B-2-3	Chapter 10, Appendices U, V and W (Confidential until further notice)
Exhibit B-2-4	Appendices I and V (Confidential Version)
Exhibit B-2-5	Appendix JJ (Confidential)

BC Hydro has previously proposed a timetable for review of the Application.[3]

1 The net bill increase for a given year is the combination of the rate increase and the change in the Deferral Account Rate Rider for that year.

2 Appendix H is marked “confidential” but is now public.

3 Refer to Exhibit B-1.

BC Hydro requests the following information to be held confidential in accordance with Part IV of the BCUC's Rules of Practice and Procedure, for the reasons explained below:

1. Certain information in Chapter 6, Appendix I, and Appendix V, which is either customer-specific and/or commercially sensitive;
2. The entirety of Chapter 10, Appendix U, Appendix V, and Appendix W, which is to be released through a public announcement in mid to late September and needs to remain confidential until that time; and
3. The entirety of Appendix JJ related to Mandatory Reliability Standards.

Chapter 6, Appendix I and Appendix V - Customer-Specific / Commercially Sensitive Information

In Chapter 6 and Appendix I, BC Hydro has redacted the name of a BC Hydro project where the project either:

- Is driven by, or specially for, a customer (disclosure of such information may prejudice a customer's commercial or competitive position); or
- Pertains to a substation acquisition (disclosure of such information may prejudice BC Hydro's position in future negotiations).

In Appendix V, the information redacted pertains to the name or identifiable information of a customer. If disclosed, the information may potentially prejudice the customer's competitive position. BC Hydro has a contractual obligation to keep the information specifically related to the customer and the customer's project confidential.

For the purpose of this proceeding and on appropriate undertakings, as contemplated by the BCUC's Rules of Practice and Procedure, BC Hydro is able to make non-customer specific project information in Chapter 6 and Appendix I available to registered interveners. BC Hydro reserves the right to object to a request for access to confidential information on a case-by-case basis.

Chapter 10, Appendix U, Appendix V, and Appendix W – Information to be Released Soon Through Public Announcement

At this time, BC Hydro is filing Chapter 10 and Appendices U, V and W confidentially with the BCUC and can make this information available to registered interveners upon request and upon signing an appropriate undertaking to keep the information confidential. This information relates to BC Hydro's Electrification Plan.

The Electrification Plan will be released through a public announcement in mid to late September. Once that public announcement has been made, BC Hydro will provide notice to the BCUC so that these materials can be posted publicly and form part of the public record. Providing this information confidentially to the BCUC and interveners in advance of the public announcement will allow all parties to review the materials and draft information requests, on the same timeline as the rest of the Application.

Appendix JJ – Confidential Mandatory Reliability Standards Information

In the Application, we have split the discussion on Mandatory Reliability Standards (**MRS**) between public content in Chapter 5 and nine pages of confidential content in Appendix JJ. Appendix JJ is confidential and made available to the BCUC only for two related reasons:

- First, information related to the protection of cyber infrastructure is highly security sensitive and could compromise the safety and reliability of the Bulk Electric System by exposing it to physical attacks by malicious actors or cyberattacks; and
- Second, the BCUC's MRS Rules of Procedure, including the Compliance Monitoring Program Rules and Penalty Guidelines, make the framework and processes for reporting, auditing and oversight of MRS compliance confidential. While certain information about an entity's violations, if confirmed, may become public after the fact, there remains a presumption of confidentiality. The presumption of confidentiality is especially important where the subject-matter relates to a cyber-security incident or may otherwise jeopardize the security of the Bulk Electric System.

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

Yours sincerely,

Chris Sandve
Chief Regulatory Officer

st/rh

Enclosure

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Chapter 1

Introduction

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1.1 Introduction

British Columbia Hydro and Power Authority (**BC Hydro**) is a Crown corporation established under the *Hydro and Power Authority Act* and regulated by the British Columbia Utilities Commission (**BCUC**) under the *Utilities Commission Act*. Our sole shareholder is the Government of B.C. BC Hydro's mission is to safely provide reliable, affordable, clean electricity throughout British Columbia. This mission recognizes that we have a responsibility to our customers to keep bill increases as low as possible while making investments so that our system is resilient and our service is reliable.

This Revenue Requirements Application (**Application**) acts on this responsibility and requests various approvals from the BCUC for fiscal 2023, fiscal 2024 and fiscal 2025 (**Test Period**). These requests will:

- Result in a net bill decrease of 1.4 per cent on April 1, 2022, followed by net bill increases of 2.0 per cent on April 1, 2023 and 2.7 per cent on April 1, 2024 (representing an average annual increase of 1.1 per cent over the three-year Test Period);[1]
- Support continued investments in capital projects, Mandatory Reliability Standards (**MRS**), vegetation management and cybersecurity. Among other things, these investments support our ability to provide reliable service to our customers and recover quickly from unexpected events; and
- Advance important initiatives, such as our Electrification Plan. The Electrification Plan will reduce rate increases for customers, while also lowering greenhouse gas (**GHG**) emissions and providing provincial economic benefits.

[1] These net bill increases reflect BC Hydro's proposal to continue to recover the Cost of Energy Variance Accounts through the Deferral Account Rate Rider (**DARR**), as discussed further in Chapter 7, section 7.3.3.3. In other words, the net bill increase for a given year is the combination of the rate increase and the change in the DARR for that year. A breakdown of the rate increase and DARR by year is provided in section 1.5 below.

We respectfully submit that our requested orders, as set out in full in section 1.4 below, are just and reasonable and should be approved as sought.

1.1.1 Test Period Average Annual Bill Increases Are 1.1 Per Cent Per Year

BC Hydro's requests in this application will result in an average annual bill increase of 1.1 per cent over the three-year Test Period. The key cost drivers in the Test Period vary depending on the specific fiscal year:[2]

- In fiscal 2023, there is a net bill decrease of 1.4 per cent. It is primarily driven by a refund of a credit balance in the cost of energy variance accounts, which occurs by way of the Deferral Account Rate Rider (**DARR**). This favourable impact is partially offset, primarily by an increase in finance charges, largely due to recoveries from the Total Finance Charges Regulatory Account, increases in net debt and a forecast increase in interest rates;
- In fiscal 2024, there is a net bill increase of 2.0 per cent. It is primarily driven by a decrease in the amount of the credit balance in the cost of energy variance accounts being refunded to ratepayers in that year and increases to amortization, operating costs and taxes;
- In fiscal 2025, there is a net bill increase of 2.7 per cent. It is primary driven by a further decrease in the amount of the credit balance in the cost of energy variance accounts being refunded to ratepayers in that year and by the Site C Clean Energy Project (**Site C Project**) coming into service. Costs related to the Site C Project in fiscal 2025 include a partial year of amortization of capital additions ($28.3 million), a partial year of regulatory account amortization due to the proposed commencement of the amortization of the Site C Regulatory Account ($5.6 million), increased finance charges because interest associated

[2] While the Cost of Energy is increasing during the Test Period, the increase is offset, and primarily driven by higher forecast load. For further discussion, refer to Chapter 4.

with the project can no longer be capitalized (approximately $78 million), and forecast operating costs related to the Site C assets ($11 million).[3]

As discussed further in section 1.4.1.3 below, BC Hydro has proposed to leave fiscal 2025 rates interim following the conclusion of this proceeding so that the BCUC can complete this proceeding without having to assess or make any determinations regarding the extent to which BC Hydro can recover Site C Project capital and deferred costs in rates. The recoverability of these costs can and should be determined only after the entire Site C Project is completed, and the proposed approach of leaving fiscal 2025 rates interim allows this to occur in a fair and efficient manner.

1.1.2 We View this Application as Being Part of an Ongoing Dialogue with the BCUC and Interveners

We view this application, and the regulatory process for it, as part of an ongoing dialogue with the BCUC and interveners.

This Application is the third Revenue Requirements Application that BC Hydro has submitted to the BCUC during the two and a half years since the Government of B.C. took steps to restore the BCUC's oversight of BC Hydro in a number of key areas.[4] This ongoing process has provided the BCUC and interveners with an opportunity to become more familiar with BC Hydro's operations.

The proceedings for the Fiscal 2020 to Fiscal 2021 Revenue Requirements Application (**F2020-F2021 RRA**) and the Fiscal 2022 Revenue Requirements Application (**Previous Application**) addressed a wide variety of issues, including

3 Further information with regard to Site C Project costs is provided as follows: construction capital additions (Chapter 6, section 6.6), Site C Regulatory Account (Chapter 7, section 7.3.3.4), finance charges (Chapter 8, section 8.6) and forecast operating costs (Chapter 5, section 5.10).

4 Refer to the Comprehensive Review of BC Hydro: Phase 1 Report: https://www2.gov.bc.ca/assets/gov/farming-natural-resources-and-industry/electricity-alternative-energy/electricity/bc-hydro-review/final_report_desktop_bc_hydro_review_v04_feb12_237pm-r2.pdf.

the reasonableness of our budgeting approach, capital planning and delivery processes and aspects of our load forecasting methodology.[5]

The BCUC's decisions in these two proceedings also included a number of directives and recommendations. We have considered and acted upon these directives and recommendations in drafting this application. Intervener input has also informed our approach on certain issues as well as our presentation of information in this application.

1.1.3 Organization of this Chapter

This Introduction chapter is organized around the following points:

- Section 1.2 explains how BC Hydro's Five-Year Strategy has informed the Application;
- Section 1.3 explains how the Application responds to, and is informed by, BCUC directives and BCUC and intervener feedback from the F2020-F2021 RRA and the Previous Application;
- Section 1.4 sets out the specific approvals that we are seeking in the Application, which we submit are just and reasonable; and
- Section 1.5 summarizes our forecast revenue requirements, which total $5,328.5 million for fiscal 2023, $5,529.4 million for fiscal 2024 and $5,782.6 million for fiscal 2025. The support for the forecast revenue requirements is set out in the other Chapters and Appendices of this application.

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5 For example, refer to BCUC Decision and Order No. G-246-20, Fiscal 2020 to 2021 Revenue Requirements Application (October 2, 2020), pages 14, 74, 75 and 78.

1.2 BC Hydro's New Five-Year Strategy Informs the Application

In July 2021, BC Hydro finalized a new strategic plan. This new Five-Year Strategy, provided as Appendix D, lays out BC Hydro's plan for the next five years (until 2026). It identifies four goals, with key targets under each goal. The Five-Year Strategy informs the Application and will help to guide the development of BC Hydro's future Service Plans.[6]

The Five-Year Strategy goals are:

- **Grow our load:** specifically, low-carbon electrification, successfully completing Site C, attracting new industry to B.C., and adopting a 100 per cent Clean Energy Standard;
- **Control our costs:** specifically, maintain the cost management culture that we've developed, achieving benefits in our procurement and supply chain, and continuing to advance compelling Revenue Requirements Applications;
- **Strengthen our resilience and agility:** specifically, investing in MRS and cybersecurity; and
- **Advance reconciliation with Indigenous Peoples:** Mutually-beneficial relationships with Indigenous Nations are critical to operating and growing our system of clean electricity. We need to reduce reliance on diesel generation, increase opportunities for Indigenous employment, and develop and implement a plan for the United Nations Declaration on the Rights of Indigenous Peoples (**UNDRIP**).

6 Appendix C provides BC Hydro's current Service Plan, which was released in February 2021, prior to BC Hydro's Five-Year Strategy being finalized. Future Service Plans, starting with the Service Plan to be released in February 2022 will be updated to reflect BC Hydro's new Five-Year Strategy.

The sub-sections below describe how the goals in the Five-Year Strategy are reflected in the Application.

1.2.1 Goal 1: Grow our Load

Maintaining and efficiently growing load is a critical part of how we keep our rates affordable and competitive for our customers. The Application reflects a number of initiatives that advance this goal.

Over the last number of years, we’ve seen load declining in some sectors due to economic factors and shifts in how we use energy. Adding to this pressure is the loss of load due to the COVID-19 pandemic.

Our rates are the result of dividing the costs to run the system by the volume of electricity we sell. As with other utilities, many of our costs are fixed, which means they stay the same whether we sell more or less electricity. When electricity demand falls, it puts upward pressure on future rates as our system costs need to be recovered through a lower volume of electricity sales. When costs increase without load growth, we see a negative impact on affordability.

Our Five-Year Strategy sets out our plans to grow our load. These plans include our Electrification Plan, which is set out in Chapter 10. The Electrification Plan will reduce rate increases for customers, while also lowering GHG emissions and providing provincial economic benefits.

1.2.2 Goal 2: Control our costs

Managing costs is critical to providing affordable and competitive rates that our customers expect. It allows us to address new demands on the business and make investments where they’re needed most. The Application reflects the benefits of past steps to control costs, as well as ongoing initiatives that advance this goal.

Our ability to absorb cost increases is being challenged and tested by the growing complexity of the business, particularly in areas such as critical infrastructure protection, MRS and cybersecurity. The COVID-19 pandemic has further reduced our revenues adding more pressure to our ability to manage costs.

We have an opportunity to build on the cost-control measures already taken as part of Phase One of the Comprehensive Review of BC Hydro. Our Five-Year Strategy sets out our plans to control our costs. These plans are reflected in the Application and include ongoing efforts to promote a culture of sustained cost management throughout the organization. Further information on our budgeting process, which the BCUC has found to be reasonable,[7] is provided in Chapter 5, section 5.4.

1.2.3 Goal 3: Strengthen our resilience and agility

We need to be prepared for threats ranging from cybersecurity attacks and impacts of climate change, to natural disasters and global pandemics. Training and development, robust compliance, financial discipline, and strong safety performance all support resilience and ensure our people, assets and facilities are safe.

In its Decision on the Previous Application, the BCUC encouraged BC Hydro to define the term “resilience” in this application so that it could be considered by the BCUC as a factor in its deliberations.[8] **Resilience** is the capacity to recover quickly from difficulties. It means being set up to manage through challenges, incorporating lessons learned into our business processes and preventing disruptions to the important services we provide. Being resilient enables reliability – something our customers count on – and gives us the space to be agile, while knowing our core functions continue to operate successfully.

[7] BCUC Decision and Order No. G-187-21, Fiscal 2022 Revenue Requirements Application (June 17, 2021), page 27: “The Panel considers BC Hydro’s budgeting process involving top-down and bottom-up elements goes beyond the examination of incremental changes from the prior year and continues to be reasonable for forecasting operating costs. Therefore, for these reasons, the Panel finds the F2022 operating costs requested for recovery to be reasonable.”

[8] BCUC Decision and Order No. G-187-21, BC Hydro Fiscal 2022 Revenue Requirements Application (June 17, 2021), page 57.

Our Five-Year Strategy sets out our plans to strengthen our resilience and agility. These plans are reflected in the Application and include investments to support MRS (Chapter 5, section 5.7), for vegetation management, based on our new Vegetation Management Strategy (Chapter 5, section 5.8), and to defend against cybersecurity threats (Chapter 5, section 5.9).

1.2.4 Goal 4: Advance reconciliation with Indigenous Peoples

Advancing reconciliation is an important part of the role BC Hydro plays in the province. The Truth and Reconciliation Commission defines reconciliation as establishing and maintaining a mutually respectful relationship between Indigenous and non-Indigenous peoples.[9]

We recognize that mutually-beneficial relationships with Indigenous Nations are critical to operating and growing our system of clean electricity. As a Crown corporation, BC Hydro has an important role to play supporting the province's commitment to reconciliation. In 2019, the provincial government passed the Declaration on the Rights of Indigenous Peoples Act, to adopt UNDRIP, which the Truth and Reconciliation Commission confirms as the framework for reconciliation.

The foundation of our approach to working with Indigenous communities is our Statement of Indigenous Principles.[10] This set of 10 principles is designed to support our move towards true and lasting reconciliation with all Indigenous Nations in British Columbia. To build understanding amongst our employees on how to apply our Statement of Indigenous Principles, we launched our Indigenous Awareness 101 and 201 courses with over 2100 and 1300 employees completing each course, respectively.

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9 Refer to Honouring the Truth, Reconciling for the Future, Summary of the Final Report of the Truth and Reconciliation Commission of Canada, page 6 (https://publications.gc.ca/collections/collection_2015/trc/IR4-7-2015-eng.pdf).

10 Refer to BC Hydro Statement of Indigenous Principles: https://www.bchydro.com/community/indigenous-relations/principles.html

For those Indigenous Nations most impacted by our infrastructure and operations we entered into 13 Relationship Agreements, three historic grievance settlements and other opportunities related to procurement and employment.

We recognize that many remote communities not connected to our integrated system are Indigenous Nations. Due to many of these communities being serviced by diesel generation, they often face high electricity costs and reliability issues. This represents a significant opportunity for us to help address social and environmental concerns created by lack of access to reliable, clean electricity.

Our Five-Year Strategy sets out our plans to advance reconciliation with Indigenous Peoples. These plans are reflected in the Application and include developing an UNDRIP implementation plan and advancing our diesel reduction strategy for the Non-Integrated Areas. Further information is provided in Chapter 5, section 5.5.3.4.

1.3 BC Hydro Has Considered and Acted Upon Previous Directives and Feedback

While drafting the Application, we considered recent BCUC directives as well as recent feedback from the BCUC and interveners. The following sections indicate how the Application reflects recent directives and feedback.

The BCUC's Decision on BC Hydro's F2020-F2021 RRA contained 68 directives:

- 38 were either accepted requests, required no further action or were addressed through a Compliance Filing that BC Hydro submitted to the BCUC in December 2020.[11]
- Four were addressed through the Previous Application;[12]

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[11] Specifically, Directives 1, 5, 6, 7, 8, 11, 12, 13, 14, 15, 16, 19, 25, 26, 27, 28, 30, 31, 32, 33, 37, 38, 42, 43, 44, 45, 50, 51, 52, 53, 54, 56, 58, 59, 60, 61, 63 and 64. Refer to: https://www.bcuc.com/Documents/Proceedings/2021/DOC_61069_2020-12-01-BCH-F2020-21RRA-Compliance-to-G-246-20-Directives-.pdf.

[12] Specifically, Directives 21, 22, 67 and 68.

- Seven were addressed through separate filings as follows:
  - A compliance filing on the energy studies models;[13]
  - The Bridge River Projects Application;[14]
  - Two interconnections compliance filings;[15]
  - The DSM annual report;[16] and
  - A rate design progress report.[17]
- Two were rescinded subsequent to amendments by government to Direction No. 8 to the BCUC;[18]
- One will be addressed in a future filing;[19] and
- 16 are addressed in this application and are discussed further in the sub-sections below.

The BCUC's Decision on BC Hydro's Previous Application contained 27 directives.

- Nine were either accepted requests, required no further action or were addressed through a Compliance Filing that BC Hydro submitted to the BCUC in July 2021, which is provided as Appendix Z;[20]

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13 Specifically, Directives 9 and 10. Refer to: https://www.bcuc.com/Documents/Proceedings/2021/DOC_62010_2021-04-01-BCH-F20-F21-RRA-Decision-Compliance-Directives-9-and-10.pdf. Directive 10 also directed BC Hydro to provide a report on the results of backtesting and benchmarking once the activities have been completed. BC Hydro expects to complete these activities by the end of fiscal 2024. Further information is provided in Appendix DD.

14 Specifically, Directive 29 (https://www.bcuc.com/ApplicationView.aspx?ApplicationId=923).

15 Specifically, Directive 34 (https://www.bcuc.com/Documents/Proceedings/2021/DOC_62008_2020-12-23-BCH-F20-F21-RRA-Decision-Directive34-Compliance.pdf) and Directive 35 (https://www.bcuc.com/Documents/Proceedings/2021/DOC_63311_2021-06-30-BCH-F20-21-RRA-G-246-20-Dir35-Compliance.pdf).

16 Specifically, Directive 49. Refer to Appendix AA.

17 Specifically, Directive 66.

18 Specifically Directive 17 (rescinded by BCUC Order No. G-32-21) and Directive 62 (rescinded by BCUC Order No. G-197-21).

19 Specifically, Directive 46 will be addressed when BC Hydro files its 2021 Integrated Resource Plan.

20 Specifically, Directives 1, 14, 16, 17, 18, 21, 22, 23, and 24.

- Two will be addressed in future filings;[21] and
- 16 are addressed in this application and are discussed further in the sub-sections below.

Table 1-1 below provides a summary of the 31 directives addressed in this application with reference to the sub-section below where further information is provided.

21 Specifically, Directives 8 and 9.

Table 1-1 Summary of Recent RRA Directives Addressed in the Application

Directive Number	Section References
Fiscal 2020 to Fiscal 2021 Revenue Requirements Application	
2	Chapter 1, Section 1.3.1.1 / Chapter 3, Section 3.3.1 / Appendix CC
3	Chapter 1, Section 1.3.1.2 / Chapter 3, Section 3.3.2
4	Chapter 1, Section 1.3.1.3 / Chapter 3, Section 3.3.3
18	Chapter 1, Section 1.3.3.2 / Chapter 5, Section 5.14
20	Chapter 1, Section 1.3.3.3 / Chapter 5, Section 5.12.3
23	Chapter 1, Section 1.3.3.4 / Chapter 5D, Section 5D.3
24	Chapter 1, Section 1.3.3.5 / Chapter 5, Section 5.15.4
36	Chapter 1, Section 1.3.6.2 / Chapter 8, Section 8.3.1 / Appendix T
39	Chapter 1, Section 1.3.6.2 / Chapter 8, Section 8.4 / Appendix T
40	Chapter 1, Section 1.3.6.2 / Chapter 8, Section 8.4 / Appendix T
41	Chapter 1, Section 1.3.5.3 / Chapter 7, Section 7.3.3.7
47	Chapter 1, Section 1.3.9.1 / Appendix AA
48	Chapter 1, Section 1.3.5.4 / Schedule 2.2 of Appendix A
55	Chapter 1, Section 1.3.5.5 / Appendix S
57	Chapter 1, Section 1.3.6.2 / Chapter 8, Section 8.3.1.2.2 / Appendix T
65	Chapter 1, Section 1.3.10
Fiscal 2022 Revenue Requirements Application	
2	Chapter 1, Section 1.3.1.6
3	Chapter 1, Section 1.3.1.4 / Chapter 3, Sections 3.3.4 and 3.3.5
4	Chapter 1, Section 1.3.2.1 / Appendix DD
5	Chapter 1, Section 1.3.2.2 / Appendix A, Section 6, Attachment 1
6	Chapter 1, Section 1.3.2.2 / Appendix A, Section 6, Attachment 1
7	Chapter 1, Section 1.3.2.2 / Appendix A, Section 6, Attachment 1
10	Chapter 1, Section 1.3.3.6 / Appendix G
11	Chapter 1, Section 1.3.3.6 / Chapter 5, Section 5.8.3
12	Chapter 1, Section 1.3.4.1 / Appendix FF
13	Chapter 1, Section 1.3.4.3 / Chapter 6, Figure 6-8
15	Chapter 1, Section 1.3.5.2 / Chapter 7, Section 7.3.2.2
19	Chapter 1, Section 1.3.9.2 / Appendix AA
20	Chapter 1, Section 1.3.7.1 / Chapter 10, Section 10.4.3.1
25	Chapter 1, Section 1.3.6.2 / Chapter 8, Section 8.3.1.2.1 / Appendix T
26	Chapter 1, Section 1.3.6.1 / Chapter 8, Sections 8.8 and 8.10
27	Chapter 1, Section 1.3.7.3 / Chapter 10, Section 10.4.3.2

1.3.1 Load Forecast (Chapter 3)

1.3.1.1 Industry Experts Confirm BC Hydro's Approach to Price Elasticity

Directive 2 of the BCUC's Decision on the F2021-F2022 RRA directed BC Hydro to provide, in this application, an analysis of any difference in elasticity between nominal versus real changes in price in the short term and any difference in elasticity between a price increase versus a price decrease.[22]

BC Hydro engaged two North American utility experts from The Brattle Group to address this directive. Their report is provided as Appendix CC.

BC Hydro's load forecast methodology uses a price elasticity value of -0.10 applied to real rate changes for all sectors and the same elasticity value for rate increases and rate decreases. The Brattle Group's review confirmed that this approach is consistent with industry standards. Further information is provided in Chapter 3, section 3.3.1.

1.3.1.2 Large Industrial Binary Forecast Methodology Performs Well

Directive 3 of the BCUC's Decision on the F2021-F2022 RRA directed BC Hydro to provide, in this application, a report on how the performance of the industrial load forecast compares under the probability weighted approach (which BC Hydro used for the load forecast in the Fiscal 2017 to Fiscal 2019 Revenue Requirements Application) versus the binary approach (which BC Hydro started using with the load forecast in the F2020-F2021 RRA).[23]

BC Hydro's analysis found that, for most sub-sectors, the binary methodology yields results that are closer to actuals than the probability-weighted methodology. Further information is provided in Chapter 3, section 3.3.2.

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22 Directive 2; BCUC Decision and Order No. G-246-20, BC Hydro Fiscal 2020 to Fiscal 2021 Revenue Requirements Application (October 2, 2020), page 13.

23 Directive 3; BCUC Decision and Order No. G-246-20, BC Hydro Fiscal 2020 to Fiscal 2021 Revenue Requirements Application (October 2, 2020), page 18.

1.3.1.3 Fiscal 2021 Load Forecast Variance is Attributable to the COVID-19 Pandemic

Directive 4 of the BCUC's Decision on the F2020-F2021 RRA directed BC Hydro to provide, in this application, a report on the source of any load forecast variance and where possible, clearly distinguish the extent of any variance that is attributable to and independent from the COVID-19 pandemic, respectively.[24]

For fiscal 2020, the total load variance was (27) GWh, which is negligible. We believe any variance that might be attributed to the COVID-19 pandemic is also negligible, as the pandemic began to impact British Columbia in late March 2020 (i.e., at the end of fiscal 2020).

For fiscal 2021, the total load variance was (801) GWh, or 2 per cent lower than the fiscal 2021 decision amount. BC Hydro believes that this variance can be largely attributed to the COVID-19 pandemic. Further information is provided in Chapter 3, section 3.3.3.

1.3.1.4 BC Hydro Is Providing Further Information on Electric Vehicle Load

Directive 3 of the BCUC's Decision on the Previous Application directed BC Hydro to provide the historical actuals or estimated actuals related to electric vehicle energy consumption over the previous five load forecasts.[25] This information is provided in Chapter 3, section 3.3.4. In addition, the BCUC encouraged BC Hydro to provide further commentary on the impact of government policy on electric vehicle load in this application.[26] We have provided this discussion in Chapter 3, section 3.3.5.

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[24] Directive 4; BCUC Decision and Order No. G-246-20, BC Hydro Fiscal 2020 to Fiscal 2021 Revenue Requirements Application (October 2, 2020), page 21.

[25] Directive 3; BCUC Decision and Order No. G-187-21, BC Hydro Fiscal 2022 Revenue Requirements Application (June 17, 2021), page 13.

[26] BCUC Decision and Order No. G-187-21, BC Hydro Fiscal 2022 Revenue Requirements Application (June 17, 2021), page 13.

1.3.1.5 Load Forecast Used for this application is a Comprehensive Load Forecast

Due to the streamlined nature of the Previous Application proceeding and the need to use scenarios to reflect the impact of the COVID-19 pandemic on electricity load, BC Hydro did not provide the same level of detail on the load forecast in the Previous Application as had been provided in the F2020-F2021 RRA. In its Decision on the Previous Application, the BCUC encouraged BC Hydro to provide a more comprehensive load forecast to provide context to inform the review of this application.[27]

BC Hydro prepared a comprehensive 20-year load forecast (the **December 2020 Load Forecast**) to support this application and BC Hydro's 2021 Integrated Resource Plan. Chapter 3 provides further information on the December 2020 Load Forecast. Our detailed Electric Load Forecast Report for fiscal 2021 to fiscal 2041 is provided as Appendix F.

1.3.1.6 BC Hydro Will Provide the Results of its Backtesting Analysis in this Proceeding

Directive 2 of the BCUC's Decision on the Previous Application directed BC Hydro to backtest and compare whether developing uncertainty bands around the distribution load only and using discrete high and low cases for transmission load has improved the accuracy of the large industrial forecast and to provide the results of this analysis, for the previous five load forecasts, by December 31, 2021.[28] BC Hydro is in the process of conducting this analysis and will submit the results as evidence in this proceeding once the work is completed.[29]

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27 BCUC Decision and Order No. G-187-21, BC Hydro Fiscal 2022 Revenue Requirements Application (June 17, 2021), page 14.

28 Directive 2; BCUC Decision and Order No. G-187-21, BC Hydro Fiscal 2022 Revenue Requirements Application (June 17, 2021), page 13.

29 This analysis will be submitted no later than December 31, 2021. BC Hydro will propose a review process for this evidence at the time that it is filed.

1.3.2 Cost of Energy (Chapter 4)

1.3.2.1 BC Hydro Has Advanced the Schedule for Energy Study Backtesting

Directive 9 of the BCUC's Decision on the F2020-F2021 RRA directed BC Hydro to file the following information with regard to the Energy Studies models:

- A summary of the model improvements required;
- A plan to fully update the models in the monthly Energy Studies; and
- A plan to have an independent third-party test the Energy Studies Market Model.[30]

Directive 10 of the BCUC's Decision on the F2020-F2021 RRA directed BC Hydro to file its plan to review recommendations and priorities on backtesting and benchmarking from the Energy Studies Internal Audit.[31] BC Hydro provided this information to the BCUC in April 2021.[32]

In its Decision on the Previous Application, the BCUC noted its concern about the length of time to complete the benchmarking and backtesting. Directive 4 of the BCUC's Decision on the Previous Application directed BC Hydro to provide an update on the timeline in this application.[33] BC Hydro has considered the BCUC's feedback and has advanced the schedule for backtesting, which is now planned to be completed by the end of fiscal 2024. In accordance with Directive 10 of the BCUC's Decision on the F2020-F2021 RRA, BC Hydro will provide the results to the

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30 Directive 9; BCUC Decision and Order No. G-246-20, BC Hydro Fiscal 2020 to Fiscal 2021 Revenue Requirements Application (October 2, 2020), page 35.

31 Directive 10; BCUC Decision and Order No. G-246-20, BC Hydro Fiscal 2020 to Fiscal 2021 Revenue Requirements Application (October 2, 2020), page 36.

32 Refer to: https://www.bcuc.com/Documents/Proceedings/2021/DOC_62010_2021-04-01-BCH-F20-F21-RRA-Decision-Compliance-Directives-9-and-10.pdf.

33 Directive 2; BCUC Decision and Order No. G-187-21, BC Hydro Fiscal 2022 Revenue Requirements Application (June 17, 2021), page 13.

BCUC once these activities are completed. Further information is provided in Appendix DD.

1.3.2.2 BC Hydro Has Provided Requested Information on the Cost of Energy

In the Previous Application proceeding, BC Hydro, in response to feedback from the Residential Consumer Intervener Association, committed to considering opportunities to provide a more detailed explanation of the relationship between increased water rental costs due to water inflows and the corresponding energy cost offsets resulting from reduced System Imports or increased System Exports.[34] BC Hydro has provided this information in Chapter 4, section 4.5.1.

Directive 5 of the BCUC's Decision on the Previous Application directed BC Hydro to report on the historic actual system imports/exports divided into flexible and non-flexible imports/exports.[35] Directive 6 of the BCUC's Decision on the Previous Application directed BC Hydro to identify the cost of market purchases of electricity to meet domestic requirements based on actual outcomes.[36] As BC Hydro had an Annual Flexible Surplus in fiscal 2021, the cost of market purchases to meet domestic requirements is the cost of non-flexible imports. Directive 7 of the BCUC's Decision on the Previous Application directed BC Hydro to include the actual cost of energy information for fiscal 2021 in this application. [37] This information was not available in time for the Previous Application because the fiscal 2021 year had not yet completed when that application was filed.

34 BCUC Decision and Order No. G-187-21, BC Hydro Fiscal 2022 Revenue Requirements Application (June 17, 2021), pages 20-21.

35 Directive 5; BCUC Decision and Order No. G-187-21, BC Hydro Fiscal 2022 Revenue Requirements Application (June 17, 2021), page 24.

36 Directive 6; BCUC Decision and Order No. G-187-21, BC Hydro Fiscal 2022 Revenue Requirements Application (June 17, 2021), page 24.

37 Directive 7; BCUC Decision and Order No. G-187-21, BC Hydro Fiscal 2022 Revenue Requirements Application (June 17, 2021), page 24.

All of the information requested by Directives 5, 6 and 7 is provided in section 3 of Attachment 1 to section 6 of Appendix X.

1.3.3 Operating Costs (Chapter 5)

1.3.3.1 BC Hydro Has Provided Information on Baseline, as Well as Incremental, Operating Costs

In its Decision on the Previous Application, the BCUC found that BC Hydro's budgeting process involving top-down and bottom-up elements goes beyond the examination of incremental changes from the prior year and continues to be reasonable for forecasting operating costs. The BCUC acknowledged that the Previous Application was designed for an expedited review and stated that this application should provide a more appropriate opportunity to review the baseline level of operating costs.[38]

Accordingly, consistent with our approach in the F2020-F2021 RRA, BC Hydro has provided detailed support for the forecast operating costs, by Business Group, in Chapters 5A through 5G. Each of these Chapters includes information on the full budget and total FTEs of each Key Business Unit within the Business Groups (i.e., the discussion is not limited to incremental costs).

1.3.3.2 BC Hydro Has Requested Operating Cost Increases to Address Cost Pressures

Directive 18 of the BCUC's Decision on the F2020-F2021 RRA directed BC Hydro to summarize, in this application, the operating cost pressures experienced during the fiscal 2020 to fiscal 2021 test period and how those costs pressures were alleviated and, in cases where BC Hydro was unable to alleviate the cost pressure, the activities BC Hydro had to forego and the risks resulting from not doing the activity.[39]

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[38] BCUC Decision and Order No. G-187-21, BC Hydro Fiscal 2022 Revenue Requirements Application (June 17, 2021), page 27.

[39] Directive 18; BCUC Decision and Order No. G-246-20, BC Hydro Fiscal 2020 to Fiscal 2021 Revenue Requirements Application (October 2, 2020), page 59.

With the exception of the operating cost impacts from the COVID-19 pandemic, most operating cost pressures BC Hydro faced in the fiscal 2020 to fiscal 2021 test period are expected to persist over a long period of time. Therefore, BC Hydro included operating cost increases in the Previous Application to address these pressures, net of identified savings. We have done the same in this application. Further discussion is provided in Chapter 5, section 5.14.

1.3.3.3 Estimated Actual Vacancy Factor Savings Reinforce Reasonableness of Forecast Savings

BC Hydro applies a “vacancy factor” reduction to its forecast operating costs to recognize the savings that occur from positions being vacant for periods of time due to various factors. Directive 20 of the BCUC’s Decision on the F2020-F2021 RRA directed BC Hydro to begin tracking, measuring and reporting on the annual actual vacancy factor savings and to provide a rationale for any significant differences from the forecast savings.[40]

In the Previous Application, BC Hydro showed that the estimated fiscal 2020 vacancy factor savings were reasonable relative to the planned amount. In this application, the estimated fiscal 2021 vacancy factor savings actual results further reinforce the reasonableness of the forecast savings included in the F2020-F2021 RRA and the appropriateness of using the same forecast savings in the Test Period. Further information is provided in Chapter 5, section 5.12.3.

1.3.3.4 BC Hydro Is Focused on Zero Fatalities and Serious Disabling Injuries

In its Decision on the Previous Application, the BCUC expressed concern that BC Hydro’s results on Lost Time Injury Frequency and All Injury Frequency remained above the Canadian Electricity Association average.[41] The BCUC also

[40] Directive 20; BCUC Decision and Order No. G-246-20, BC Hydro Fiscal 2020 to Fiscal 2021 Revenue Requirements Application (October 2, 2020), page 69-70.

[41] BCUC Decision and Order No. G-187-21, BC Hydro Fiscal 2022 Revenue Requirements Application (June 17, 2021), page 57.

asked BC Hydro to explain how a declining trend in targets on the Lost Time Injury Frequency metric demonstrated improvement.[42] Directive 23 of the BCUC's Decision on the F2020-F2021 RRA directed BC Hydro to evaluate, in this application, whether more aggressive Lost Time Injury Frequency and Lost Time Injury Duration results could be achieved and the additional costs required to achieve those results.[43]

BC Hydro's performance on Lost Time Injury Frequency has improved while our performance on Lost Time Injury Duration has remained relatively stable. During the Test Period, we will maintain our efforts to improve performance on these metrics. Rather than target more aggressive improvements on metrics that are influenced significantly by lower severity injuries, we are focused on preventing fatalities and serious disabling injuries which we believe we can achieve through targeted investments, identified through our Safety Framework, and funded within existing budgets. Further information is provided in Chapter 5D, section 5D.3.

1.3.3.5 Additional Maintenance Spending Due to Reduced Sustainment Capital Spending in Fiscal 2020 and Fiscal 2021 Was Minimal

Directive 24 of the BCUC's Decision on the F2020-F2021 RRA directed BC Hydro to report, in this application, on any additional maintenance spending that has occurred as a result of the reduced sustainment capital spending during the fiscal 2020 to fiscal 2021 test period and to present a trend analysis of maintenance spending on capital for the 10 most recently completed fiscal years.[44]

The additional maintenance spending as a result of the reduced sustainment capital spending during the fiscal 2020 to fiscal 2021 test period was minimal. Further

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[42] BCUC Decision and Order No. G-187-21, BC Hydro Fiscal 2022 Revenue Requirements Application (June 17, 2021), page 58.

[43] Directive 23; BCUC Decision and Order No. G-246-20, BC Hydro Fiscal 2020 to Fiscal 2021 Revenue Requirements Application (October 2, 2020), page 74.

[44] Directive 24; BCUC Decision and Order No. G-246-20, BC Hydro Fiscal 2020 to Fiscal 2021 Revenue Requirements Application (October 2, 2020), page 86.

discussion, as well as a trend analysis and an explanation of the key drivers of the changes, is provided in Chapter 5, section 5.15.4.

1.3.3.6 Vegetation Management Budget is Informed by New Vegetation Management Strategy Which Considers BCUC Feedback

BC Hydro has always used a combination of area clearing and targeted removals to address vegetation. The relative mix varies over time based on the type of vegetation and its proximity to power lines.[45] During the Previous Application proceeding, we informed the BCUC that we were developing a new Vegetation Management Strategy which would consider the best mix of vegetation management approaches going forward. We assessed four different approaches to vegetation management and determined that the Stable Annual Vegetation Maintenance Approach is the best approach.

The Vegetation Management Strategy provides the basis for the planned vegetation management expenditures during the Test Period. The funding will support the required annual work volumes for a Stable Annual Vegetation Maintenance Approach to vegetation management. The approach that BC Hydro is taking under the Vegetation Management Strategy is consistent with industry practices and the planned expenditures for the Test Period are in line with industry benchmarks. The planned approach is expected to deliver improved outcomes.

Directive 10 of the BCUC's Decision on the Previous Application directed BC Hydro to file the new Vegetation Management Strategy with the BCUC as part of this application.[46] The strategy is provided as Appendix G. BC Hydro was also directed to file any revisions to the strategy. Appendix G, section 2 defines a revision to the strategy and BC Hydro will file any revisions to the strategy with the BCUC.

[45] Fiscal 2022 Revenue Requirements Application, Transcript Volume 1, Ms. Daschuk, page 24, line 15 to page 25, line 9.

[46] Directive 10; BCUC Decision and Order No. G-187-21, BC Hydro Fiscal 2022 Revenue Requirements Application (June 17, 2021), page 42.

Directive 11 of the BCUC's Decision on the Previous Application directed BC Hydro to provide a breakdown of the vegetation management budget in a format similar to the Previous Application, expanded to include historical costs.[47] This breakdown is provided in Chapter 5, section 5.8.3.

In its Decision on the Previous Application, the BCUC also highlighted key considerations, which BC Hydro has addressed through the Vegetation Management Strategy and the planned vegetation management budgets for fiscal 2023 to fiscal 2025. Specifically:

- **Distribution system work is increasing:** The BCUC asked BC Hydro to elaborate on its long-term plan to address vegetation risk and reliability on the distribution system and provided feedback on the allocation of spending between transmission and distribution vegetation management.[48] BC Hydro is increasing spending on distribution vegetation management in the Application. We also plan to increase annual pruning volumes on the distribution system by approximately 25 per cent compared to fiscal 2022 amounts and remove approximately 40,000 hazard trees in fiscal 2023 so that the documented inventory is fully cleared. Distribution vegetation maintenance is also moving to an average five-year cycle, increasing frequency from the status quo. Further information is provided in Chapter 5, section 5.8.2.5; and
- **Addressing transmission accumulation:** The BCUC also expressed a desire to better understand how BC Hydro plans to clear accumulation on the transmission system in a timely fashion.[49] BC Hydro had increased transmission maintenance volumes in fiscal 2021 and fiscal 2022 to begin to

[47] Directive 11; BCUC Decision and Order No. G-187-21, BC Hydro Fiscal 2022 Revenue Requirements Application (June 17, 2021), page 42.
[48] BCUC Decision and Order No. G-187-21, BC Hydro Fiscal 2022 Revenue Requirements Application (June 17, 2021), page 41.
[49] BCUC Decision and Order No. G-187-21, BC Hydro Fiscal 2022 Revenue Requirements Application (June 17, 2021), page 41.

address the highest risk accumulation. This approach is expected to continue during the Test Period and the system will experience a full maintenance cycle during these five years. This will address the accumulation and support a shift to a stable approach in the years following. Further information is provided in Chapter 5, section 5.8.2.4.

1.3.3.7 BC Hydro Is Following-Up on Previous Assessments of Remaining Cybersecurity Risks to its Industrial Control Systems

In March 2019, the Office of the Auditor General issued an audit report on BC Hydro's cybersecurity practices and controls related to Industrial Control Systems at our generation, transmission and distribution facilities that do not fall under the North American Electric Reliability Corporation (**NERC**) Critical Infrastructure Protection (**CIP**) standards and are not considered critical to the operation of the Bulk Electric System. As recommended by the audit, BC Hydro initiated a third-party risk assessment of the Industrial Control Systems environment. BC Hydro addressed the highest risk recommendations immediately following the results of the external assessment. Further information is provided in Chapter 5, section 5.9.7.

In its Decision on the Previous Application, the BCUC expressed concern that the remaining areas covered by the recommendations may provide potential cybersecurity vulnerabilities and suggested that BC Hydro should afford the same or similar level of protection across all cyber assets.[50] BC Hydro is addressing the audit recommendations as they relate to the remainder of these Industrial Control Systems facilities:

[50] BCUC Decision and Order No. G-187-21, BC Hydro Fiscal 2022 Revenue Requirements Application (June 17, 2021), page 32.

- Identified risks at 131[51] Industrial Control Systems sites will be addressed by October 1, 2023 through the completion of the NERC CIP v7 project; and
- BC Hydro plans to then complete activities at the remaining 150 sites, on a prioritized basis, by March 31, 2027. These sites are not considered critical to the operation of the Bulk Electric System and represent much lower cybersecurity risks. Many of the sites are smaller distribution substations that are not connected to the internet and have systems that can only be accessed if someone actually gains physical access into the facility.

Appendix EE provides further information on BC Hydro's plan to address the Office of the Auditor General audit findings with respect to cybersecurity controls for Industrial Control Systems at sites not covered by NERC CIP requirements.

While we believe that the sequencing and timing of our work to address the audit recommendations is appropriate, we recognize the BCUC's concerns and have sought independent validation of our approach. Specifically, the Cyber Risk Assessment and Cyber Security Plan that we are undertaking pursuant to the BCUC's Directives 8[52] and 9[53] from the Previous Application provide an opportunity to follow-up on previous assessments and work with regard to the Office of the Auditor General audit recommendations. BC Hydro has included this work within the scope of the assessment and plan directed by the BCUC and will inform the BCUC of the results.

[51] There are a further two sites that are not yet in service and are therefore not included in the project but will be addressed as they are put into service.

[52] Directive 8; BCUC Decision and Order No. G-187-21, BC Hydro Fiscal 2022 Revenue Requirements Application (June 17, 2021), page 33. Directive 8 directed BC Hydro to undertake a Cyber Risk Assessment of all its cyber assets within three months, file it with the BCUC and notify the BCUC of any required actions in response to immediate or time-sensitive concerns.

[53] Directive 9; BCUC Decision and Order No. G-187-21, BC Hydro Fiscal 2022 Revenue Requirements Application (June 17, 2021), page 33. Directive 9 directed BC Hydro to develop a company-wide Cyber Security Plan that encompasses BC Hydro, its subsidiaries and third-parties that interface with BC Hydro and file the plan with the BCUC within one year.

1.3.4 Capital Expenditures and Projects (Chapter 6)

1.3.4.1 BC Hydro Is Investing Extensively in Dam Safety

In its Decision on the Previous Application, following a review of information provided by BC Hydro with regard to dam safety risks, the BCUC stated that it was satisfied with BC Hydro's analysis and mitigation of risks associated with dam safety. Directive 12 of the BCUC's Decision on the Previous Application directed BC Hydro to file its dam safety vulnerability index for all dams and its aggregate dam safety vulnerability index in this application and to provide a long-term capital plan for ensuring the sustainable safety of all BC Hydro's dams by December 31, 2021.[54] BC Hydro has provided this information, including the requested long-term capital plan, in Appendix FF. As discussed further in Appendix FF, BC Hydro is investing extensively in the safety of its dams so that its overall dam safety risk profile is maintained.

1.3.4.2 BC Hydro Continues to Maintain Strong Reliability Performance

In its Decision on the Previous Application, the BCUC expressed concern that BC Hydro's previous reduction in sustainment capital spending may be contributing to a reduction in system reliability. The BCUC recommended that it examine BC Hydro's system reliability statistics when the fiscal 2021 data become available to determine whether a declining trend in system performance is emerging.[55]

BC Hydro's performance as measured by reliability metrics compares favourably to the Canadian Electricity Association benchmark and has been within acceptable thresholds of our Service Plan targets. While performance on specific metrics varies from year to year, all regions are generally maintaining their level of reliability. While these variations in regional performance are monitored, investments are identified

[54] Directive 12; BCUC Decision and Order No. G-187-21, BC Hydro Fiscal 2022 Revenue Requirements Application (June 17, 2021), page 58.

[55] BCUC Decision and Order No. G-187-21, BC Hydro Fiscal 2022 Revenue Requirements Application (June 17, 2021), page 58.

and prioritized at an individual circuit level to ensure customers with lower reliability, compared to similar customers, are targeted for reliability improvements. Overall, BC Hydro is also increasing spending on sustainment capital year-over-year during the Test Period, as more assets reach end of life. Further discussion is provided in Chapter 6, section 6.3.1.

1.3.4.3 Industrial Key Accounts Satisfaction with Reliability Has Improved

Directive 13 of the BCUC's Decision on the Previous Application directed BC Hydro to provide an updated figure for the customer satisfaction index on reliability in this application.[56] This is provided in Chapter 6, Figure 6-8. While the BCUC's Decision noted there had been a continuous decline in reported satisfaction from industrial key accounts from fiscal 2014 to fiscal 2018, the most recent results show that this decline has reversed and that overall, customers continue to be satisfied with the level of reliability that they are receiving.[57]

1.3.4.4 Asset Investment Planning Tool Project Has Been Cancelled and the Project Write-Off Costs are Prudent

In its Decision on the Previous Application, the BCUC requested that BC Hydro clarify, in this application, whether the Asset Investment Planning Tool project had been deferred or cancelled.[58] Under International Financial Reporting Standards, a project can be placed into "on-hold" or "deferred" status for a period time while reconsideration of the project need or other alternatives occurs. If a project is not expected to be re-initiated within a reasonable timeframe or the work completed to date no longer has value, then the project must be cancelled and any capital costs to-date written off. The latter was the case with the Asset Investment Planning Tool

[56] Directive 13; BCUC Decision and Order No. G-187-21, BC Hydro Fiscal 2022 Revenue Requirements Application (June 17, 2021), page 58.

[57] Directive 25 of the BCUC's Decision on the F2020-F2021 RRA directed BC Hydro to provide a proposal for including customers from Non-Integrated Areas in the index of customer satisfaction with reliability. BC Hydro is implementing this proposal for fiscal 2022.

[58] BCUC Decision and Order No. G-187-21, BC Hydro Fiscal 2022 Revenue Requirements Application (June 17, 2021), page 61.

project. BC Hydro has included the costs of the Asset Investment Planning Tool project in the Project Write-off Costs Regulatory Account for recovery from ratepayers. Further information is provided in Chapter 6, section 6.1.3.4 and in Appendix P, BC Hydro has provided an explanation of why the project expenditures are prudent and should be recovered in rates.

1.3.4.5 Capital Forecasts in this application are Based on Our Latest Capital Plan

In its Decision on the Previous Application, the BCUC expressed concern with regard to the length of time between December 2020, when the Previous Application was filed, and the April 2019 (July 2019 for technology capital) currency date of the forecasts in the capital plan that informed the Previous Application. The BCUC stated its expectation that BC Hydro's capital plan be updated and approved annually.[59] BC Hydro agrees that its capital plan should be updated and approved on an annual cycle, and this application reflects a return to that approach.

The amount of time between the capital plan currency date and the Previous Application was an anomaly. BC Hydro was developing a capital plan in alignment with the timetable of our annual capital planning process but adjusted this schedule initially in response to the COVID-19 pandemic and subsequently, in order to allow the timing of future revenue requirements applications to be re-aligned. As BC Hydro stated in Exhibit B-59 of the F2020-F2021 RRA proceeding, which provided comments on the BCUC's proposal to re-align the timing of future revenue requirements applications, "work on both the capital plan and load forecast is currently underway as part of their annual cycles, under which drafts are completed in the late fall and approved in January 2021. Those iterations will not be available in time to incorporate into the December 2020 filing, since the load and capital inputs

[59] BCUC Decision and Order No. G-187-21, BC Hydro Fiscal 2022 Revenue Requirements Application (June 17, 2021), page 61.

are required months in advance to complete the company's budget and forecast revenue requirements."

The capital forecasts in this application are derived from BC Hydro's updated Capital Plan, which is established based on a portfolio of multi-year project forecasts as of January 2021. The Capital Plan was approved by the Executive Team in May 2021 and was presented to the Capital Projects Committee of the Board of Directors in June 2021. BC Hydro expects to present the next capital plan update to the Capital Projects Committee of the Board of Directors in November 2022 in alignment with the timetable of our annual capital planning process.

1.3.5 Regulatory Accounts (Chapter 7)

1.3.5.1 DARR Table Mechanism Continues to Provide Principled and Structured Approach to Clearing Cost of Energy Variance Accounts

In the Previous Application, BC Hydro proposed to return to the DARR table mechanism to recover the balances in the Cost of Energy Variance Accounts going forward, and also proposed to determine the level of the DARR based on the forecast net balance of the Cost of Energy Variance Accounts at the end of the preceding fiscal year.

Directive 14 of the BCUC's Decision on the Previous Application approved this request for fiscal 2022 only. The BCUC cited the streamlined manner in which the Previous Application was reviewed. The BCUC also stated that it was not persuaded that the 5 per cent cap proposed in the DARR table mechanism was necessary to avoid the potential for rate shock and expressed concern that the proposed cap could result in significant balances not being cleared quickly enough.[60]

As set out in section 1.4 below, in this application, BC Hydro is proposing to continue to utilize the DARR table mechanism to recover the balances in the Cost of Energy

[60] Directive 14; BCUC Decision and Order No. G-187-21, BC Hydro Fiscal 2022 Revenue Requirements Application (June 17, 2021), page 67.

Variance Accounts going forward. We believe that the DARR table mechanism continues to provide a principled and structured approach to clearing the net balances in the Cost of Energy Variance Accounts in a reasonable and transparent manner.

With regard to the BCUC's concern with the 5 per cent cap, BC Hydro considers that capping the DARR percentage at +/- 5 per cent achieves a reasonable balance between maintaining rate stability, avoiding potential rate shock and promoting intergenerational equity. BC Hydro has conducted modeling which shows that, with a cap of +/- 5 per cent, a balance of $750 million clears in six years and an atypical balance of $1 billion clears in seven years. BC Hydro considers that having a higher (or no) cap to clear the balances faster could lead to volatility and even rate shock, and would outweigh any benefits in terms of intergenerational equity.

We also note that, even if the BCUC agrees with the proposed DARR table mechanism, BC Hydro will still seek BCUC approval in revenue requirements applications for proposed rate increases and the specifically requested DARR percentages. The BCUC may choose to approve, deny or alter BC Hydro's DARR proposal and/or the DARR mechanism in any such application. We believe it is most appropriate to return to the proposed DARR mechanism and deal with potential outlier events, if and when they arise. Further discussion is provided in Chapter 7, section 7.3.3.3.

1.3.5.2 BC Hydro Has Proposed a Recovery Mechanism for the Depreciation Study Impact Regulatory Account

Directive 15 of the BCUC's Decision on the Previous Application directs BC Hydro to propose a recovery mechanism for the Depreciation Study Impact Regulatory Account in this application. As discussed further in Chapter 7, section 7.3.2.2, BC Hydro is proposing to recover the forecast balance of the account at March 31, 2022 over the Test Period.

1.3.5.3 BC Hydro Continues to Make Progress on Property Sales Which Are Expected to Result in Realized Net Gains in Excess of Current Regulatory Account Balance

Directive 41 of the BCUC's Decision on the F2020-F2021 RRA disallowed BC Hydro's forecast of $10 million net gains from the sale of surplus real property in each of fiscal 2020 and fiscal 2021 and instead directed a forecast of $0 in both fiscal years. It also directed BC Hydro to provide, in this application, a proposal on how to recover the balance in the Real Property Sales Regulatory Account, if a balance recoverable from ratepayers is still expected to exist in this account at the end of fiscal 2022.[61] In accordance with Directive 41, BC Hydro did not forecast any net gains from the sale of surplus real property in the Previous Application and has not forecast any net gains from the sale of surplus real property in this application.

BC Hydro's proposal for recovery of the $47 million balance in the Real Property Sales Regulatory Account is to continue to recover the balance through realization of actual net gains over the Test Period. BC Hydro continues to make progress in its active property sales. For example, this fall, BC Hydro expects to remove its subject conditions and complete the sale of one property with net gains of $15 million. BC Hydro also expects to complete other sales by end of the fiscal 2024, consistent with the target presented in the F2020-F2021 RRA of a net gain of $100 million. Over the Test Period, BC Hydro expects these sales to result in realized net gains in excess of the current account balance of $47 million at March 31, 2021. BC Hydro proposes to refund any liability balance in the account at the end of the Test Period to ratepayers, or recover any asset balance from ratepayers, over the next test period. Further information is provided in Chapter 7, section 7.3.3.7.

[61] Directive 41; BCUC Decision and Order No. G-246-20, BC Hydro Fiscal 2020 to Fiscal 2021 Revenue Requirements Application (October 2, 2020), page 127.

1.3.5.4 Low Carbon Electrification Expenditures Are Separately Tracked

Directive 48 of the BCUC's Decision on the F2020-F2021 RRA directed BC Hydro to separately track Low Carbon Electrification expenditures deferred to the DSM Regulatory Account.[62] This information is provided in Schedule 2.2 of Appendix A.

1.3.5.5 BC Hydro Is Reporting on the Debt Management Regulatory Account

Directive 55 of the BCUC's Decision on the F2020-F2021 RRA directed BC Hydro to provide in all future revenue requirements applications an updated Debt Management Regulatory Account Annual Status Report.[63] This report is provided as Appendix S.

1.3.6 Other Revenue Requirements (Chapter 8)

1.3.6.1 BC Hydro Has Forecast Revenue from Low Carbon Fuel Credits

Directive 26 of the BCUC's Decision on the Previous Application directed BC Hydro to record in all future revenue requirements applications, the forecast revenue from low carbon fuel credits based on an estimate of the value of the credits BC Hydro plans to transfer to other parties.[64]

In accordance with this directive, BC Hydro has included forecast low carbon fuel credits revenue as part of Miscellaneous Revenues. To offset the inclusion of these revenues, BC Hydro has reduced forecast Trade Income by the same amount that is now forecast in BC Hydro miscellaneous revenue. Further information on miscellaneous revenue is provided in Chapter 8, section 8.8 and further information on Trade Income is provided in Chapter 8, section 8.10. For further discussion on

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[62] Directive 48; BCUC Decision and Order No. G-246-20, BC Hydro Fiscal 2020 to Fiscal 2021 Revenue Requirements Application (October 2, 2020), page 150.

[63] Directive 55; BCUC Decision and Order No. G-246-20, BC Hydro Fiscal 2020 to Fiscal 2021 Revenue Requirements Application (October 2, 2020), page 170.

[64] Directive 26; BCUC Decision and Order No. G-187-21, BC Hydro Fiscal 2022 Revenue Requirements Application (June 17, 2021), page 105.

Low Carbon Fuel Credits, refer to BC Hydro's Compliance Filing to the Previous Application, which is provided as Appendix Z.

1.3.6.2 BC Hydro Has Provided a Depreciation Study and Net Salvage Report

Directive 36 of the BCUC's Decision on the F2020-F2021 RRA directed BC Hydro to file a depreciation study with this application.[65] Directive 39 directed BC Hydro to provide, in the Previous Application, an assessment of whether its current practice of expensing dismantling costs as they occur would result in intergenerational equity and to provide options on how dismantling costs could be calculated and collected to better promote intergenerational equity.[66] Directive 40 directed BC Hydro to include a net salvage study in its depreciation study and to report on the results and recommendations, as well as BC Hydro's plan to implement those recommendations, in this application.[67] In its Decision on the Previous Application, the BCUC accepted BC Hydro's submission that the net salvage study was required to provide the requested assessment on the different approaches to recovering forecast dismantling costs.[68]

In accordance with the directives outlined above, BC Hydro engaged Concentric Advisors, ULC (Concentric) to:

- Perform a depreciation study that reviewed existing depreciation rates and positive salvage value percentages;

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65 Directive 36; BCUC Decision and Order No. G-246-20, BC Hydro Fiscal 2020 to Fiscal 2021 Revenue Requirements Application (October 2, 2020), page 114.

66 Directive 39; BCUC Decision and Order No. G-246-20, BC Hydro Fiscal 2020 to Fiscal 2021 Revenue Requirements Application (October 2, 2020), page 124.

67 Directive 40; BCUC Decision and Order No. G-246-20, BC Hydro Fiscal 2020 to Fiscal 2021 Revenue Requirements Application (October 2, 2020), page 124.

68 BCUC Decision and Order No. G-187-21, BC Hydro Fiscal 2022 Revenue Requirements Application (June 17, 2021), page 71.

- Perform a negative net salvage study for determination of negative salvage rates and to evaluate whether the implementation of negative net salvage rates is appropriate for BC Hydro;
- Perform an assessment of methodologies used for recovery of dismantling costs in rates and to make a recommendation of an appropriate methodology for BC Hydro that would promote intergenerational equity; and
- Provide an assessment on the appropriateness of BC Hydro's use of Average Service Life methodology.

The Depreciation Study prepared by Concentric is provided in Appendix T, section 1. Chapter 8, section 8.3.1 provides a summary of the recommendations from the Depreciation Study and the approvals that BC Hydro is seeking as a result.

A Report On Applicability of Inclusion of Net Salvage in the Depreciation Rate Calculation prepared by Concentric is provided in Appendix T, section 2. BC Hydro is proposing to implement the traditional method to recovering dismantling costs in accordance with the recommendations from Concentric. Chapter 8, section 8.4 provides a summary of BC Hydro's proposed approach and implementation plan.

Directive 25 of the BCUC's Decision on the Previous Application denied the depreciation rates for BC Hydro's EV charging stations.[69] While the Panel recommended that the depreciation rates be reviewed in the BC Hydro Public Electric Vehicle Fast Charging Rate Application proceeding, the Depreciation Study filed in the Application includes recommended depreciation rates for electric vehicle charging stations which BC Hydro is proposing to adopt. Further information is provided in Chapter 8, section 8.3.1.2.1.

[69] Directive 25; BCUC Decision and Order No. G-187-21, BC Hydro Fiscal 2022 Revenue Requirements Application (June 17, 2021), page 104.

Directive 57 of the BCUC's Decision on the F2020-F2021 RRA directed BC Hydro to review the expected useful life of infrastructure rights in the Depreciation Study in this application.[70] Concentric reviewed asset class C11650 - Infrastructure Rights (Contributions - Infrastructure Rights) and recommended that the useful life remain at 35 years. Further information is provided in Chapter 8, section 8.3.1.2.2.

1.3.6.3 BC Hydro Has Considered the Appropriate Amount of Forecast Interconnection Revenue

In its Decision on the Previous Application, the BCUC stated that it expects BC Hydro to justify, in this application, any estimate of interconnection revenue not consistent with recent historical trends.[71] Directive 22 directed BC Hydro to amend its forecast interconnection revenue to $4.6 million, the same as BC Hydro's most recent forecast for fiscal 2021, and to make any corresponding adjustments to forecast costs required to generate this level of interconnection revenue.[72]

BC Hydro's forecast interconnection revenue for fiscal 2022 is $6.1 million and BC Hydro has included planned interconnection revenue of the same amount for fiscal 2023. Historical interconnection revenue has been driven in part by project study work to support interconnection requests from the liquified natural gas industry. For fiscal 2024 and fiscal 2025, BC Hydro is forecasting a decline in interconnection revenue, compared to recent historical trends, due to an expected decline in the level of interconnection work related to the liquified natural gas industry. Further information is provided in Chapter 8, section 8.8.

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70 Directive 57; BCUC Decision and Order No. G-246-20, BC Hydro Fiscal 2020 to Fiscal 2021 Revenue Requirements Application (October 2, 2020), pages 172-173.

71 BCUC Decision and Order No. G-187-21, BC Hydro Fiscal 2022 Revenue Requirements Application (June 17, 2021), page 96.

72 Directive 22; BCUC Decision and Order No. G-187-21, BC Hydro Fiscal 2022 Revenue Requirements Application (June 17, 2021), page 96.

1.3.7 Electrification (Chapter 10)

1.3.7.1 All Ratepayers Benefit from Low Carbon Electrification Expenditures

Directive 20 of the BCUC's Decision on the Previous Application directed BC Hydro to provide, in this application, a discussion of whether Low Carbon Electrification expenditures deferred to the DSM Regulatory Account should be recovered only from the beneficiaries of these expenditures, and if so by what methods this could be accomplished.[73] BC Hydro submits that Low Carbon Electrification expenditures deferred to the DSM Regulatory Account should continue to be recovered from all ratepayers over a 15-year amortization period because:

- Low Carbon Electrification actions under sections 4(3)(a) to (d) of the GGRR are undertaken for the benefit of all customers and all customers benefit from the more efficient use of BC Hydro's system and reduced GHG emissions as a result; and
- To the extent that a subset of customers could be identified that more directly benefit from Low Carbon Electrification actions under sections 4(3)(a) to (d) of the GGRR, recovering the costs from these customers would undermine the prescribed undertaking, which the BCUC is prohibited from doing under section 18 of the *Clean Energy Act.*

Accordingly, BC Hydro is not proposing any change to the recovery of the low carbon electrification component of the DSM Regulatory Account. Further discussion is provided in Chapter 10, section 10.4.3.1.

[73] Directive 20; BCUC Decision and Order No. G-187-21, BC Hydro Fiscal 2022 Revenue Requirements Application (June 17, 2021), page 91.

1.3.7.2 Recovery of the Electric Vehicle Costs Regulatory Account Should Commence

In its Decision on the Previous Application, the BCUC approved the establishment of an Electric Vehicle Costs Regulatory Account but denied BC Hydro's request to recover the forecast account balance at the end of a test period over the next test period and directed BC Hydro apply for a recovery mechanism for the account in this application. The BCUC also directed BC Hydro to defer all fiscal 2022 costs related to EV charging stations that meet the definition of a prescribed undertaking under the GGRR to the Electric Vehicle Costs Regulatory Account.[74] As a result, fiscal 2020, fiscal 2021 and fiscal 2022 costs related to EV charging stations that meet the definition of a prescribed undertaking under the GGRR have been deferred to the Electric Vehicle Costs Regulatory Account.

In its Decision on the Previous Application, the BCUC stated that it was deferring these costs to the Electric Vehicle Costs Regulatory Account since BC Hydro currently has an application before the BCUC for public EV fast charging rates, which could examine the revenue and costs related to BC Hydro's EV fast charging stations in a holistic manner.[75] The BCUC stated that BC Hydro would be allowed to recover its costs incurred with respect to its EV charging stations that meet the definition of a prescribed undertaking pending the conclusion of the proceeding to review BC Hydro's public EV fast charging rate.[76]

Accordingly and as no further transfers are expected to be made to this account after March 31, 2022, BC Hydro proposes to recover the forecast balance of the account at March 31, 2022 over the Test Period and recover any balance remaining at the end of the Test Period, as a result of actual fiscal 2022 costs varying from

[74] Directive 24; BCUC Decision and Order No. G-187-21, BC Hydro Fiscal 2022 Revenue Requirements Application (June 17, 2021), page 102.

[75] For further information on the proceeding underway to review this application refer to: https://www.bcuc.com/ApplicationView.aspx?ApplicationId=861

[76] Directive 24; BCUC Decision and Order No. G-187-21, BC Hydro Fiscal 2022 Revenue Requirements Application (June 17, 2021), pages 102.

forecast, over the next test period. Further information on this request is provided in Chapter 7, section 7.3.3.8.

1.3.7.3 BC Hydro Has Provided the Requested Breakdown of Electric Vehicle Costs and Revenues

For the Test Period, costs and revenues with respect to the EV charging stations are included in the revenue requirements in the categories to which they relate. Directive 27 of the BCUC's Decision on the Previous Application directed BC Hydro to track all of its revenues and costs related to its EV charging stations that are deemed prescribed undertakings under the GGRR and to provide this information broken down by year and by revenue and cost categories in all future revenue requirements applications.[77] BC Hydro has provided this information in Chapter 10, section 10.4.3.2. The information provides the BCUC and interveners with an indication of the extent to which forecast revenues from EV charging station users are expected to offset the associated costs.

1.3.8 Application Includes Elements of Performance Based Regulation

This Application includes proposals to improve the existing regulatory regime by incorporating aspects of Performance Based Regulation. As described below, these changes will augment existing incentives to control costs, improve productivity and achieve superior performance.

1.3.8.1 Longer Test Period, Benchmarking and Performance Metrics are Types of Performance Based Regulation

In response to a directive in the BCUC's decision on the Fiscal 2017 to Fiscal 2019 Revenue Requirements Application, we prepared and filed with the BCUC a Report on Performance Based Regulation. BCUC Order No. G-244-19 established a separate proceeding to review BC Hydro's Report (**PBR Report Proceeding**).

[77] Directive 27; BCUC Decision and Order No. G-187-21, BC Hydro Fiscal 2022 Revenue Requirements Application (June 17, 2021), page 105.

In the PBR Report Proceeding, we identified the following three improvements to the existing regulatory framework that could be advanced as part of this application:

- A three-year test period;
- Regularly scheduled statistical cost benchmarking; and
- Expanded use of information-only performance metrics.

The BCUC's independent expert in the PBR Report Proceeding, Dr. Lowry of Pacific Economics Group, characterized each of these concepts as falling under the umbrella of Performance Based Regulation. BC Hydro's independent expert, Dr. Weisman, agreed with this characterization.

While the BCUC has yet to issue its decision in the PBR Report Proceeding, BC Hydro has taken steps to implement these three improvements. We elaborate below on the nature of the proposals and the benefits they bring in terms of augmenting existing incentives to control costs, improve productivity and achieve superior performance.

1.3.8.2 Proposed Three-Year Test Period Provides Benefits

We are applying for rates for a three year Test Period covering fiscal 2023, fiscal 2024 and fiscal 2025.

BC Hydro's proposal to adopt a three-year test period was based on expert evidence in the PBR Report Proceeding. Notably, all three experts who provided evidence in the proceeding (Dr. Lowry, Dr. Weisman and Mark Kolesar, the former Chair of the Alberta Utilities Commission) agreed that moving to a three-year test period would provide benefits. We summarize the benefits as follows:

- Provides stronger incentives to perform efficiently and reduce costs because it extends the length of time over which BC Hydro must manage upward cost pressures within a pre-defined revenue envelope to achieve performance measures and its allowed return on equity;

- Protects ratepayers from further rate increases because upward cost pressures that would be passed on to customers in the form of rate increases at the end of a two-year test period would generally be absorbed by BC Hydro for another year under a three-year test period;
- Improves regulatory efficiency by providing an additional year to allow BC Hydro to focus more of its efforts on operating the business and finding additional efficiencies and performance improvements to the benefit of ratepayers; and
- Maintains adequate protections to impose discipline around forecasting future costs.

Several interveners in the PBR Report proceeding expressed support for a three-year test period. However, BCOAPO and the Clean Energy Association favoured a two-year test period at this time, citing forecasting uncertainty.[78] CEABC cited, among other things, that the COVID-19 pandemic may continue to impact the demand for electricity, the Site C Project remains under construction, BC Hydro is experiencing cost pressures with regard to MRS and the 2021 Integrated Resource Plan has not yet been filed. BC Hydro submits that the uncertainties are manageable and are outweighed by the benefits of a longer test period. Specifically:

- While there is always some uncertainty with regard to the load forecast and this uncertainty is increased due to the COVID-19 pandemic, actual fiscal 2021 load was close to BC Hydro's COVID-19 Scenario A. Further discussion is provided in Chapter 3, section 3.4.1;

[78] AMPC, Ms. Gjoshe, CEC, Zone II RPG and BCSEA supported. RCIA did not object. For citations refer to BC Hydro Reply Submissions from the Previous Application proceeding, paragraph 23.

- As discussed in section 1.4.1.3 below, a shorter Test Period would not solve the concern identified by CEABC with regard to the recovery of costs associated with the Site C Project. BC Hydro's proposal that fiscal 2025 rates remain interim following this proceeding for the purpose of permitting a review of Site C capital and deferred costs upon completion of the Site C Project is a better solution to manage uncertainty related to Site C capital costs;
- There is uncertainty regarding MRS regardless of the length of the Test Period, as illustrated by the fact that unplanned costs emerged during fiscal 2022 (a one-year test period). BC Hydro's proposal to continue to use the MRS Costs Regulatory Account beyond fiscal 2022 is an appropriate way to manage this uncertainty, as discussed in Chapter 7, section 7.3.4; and
- BC Hydro agrees that the 2021 Integrated Resource Plan will inform forecasts associated with the cost of future resource acquisitions, and we are not seeking acceptance of a demand-side measures expenditure schedule as part of this application. We have proposed (as discussed further in section 1.4.1.1 below) that rates should remain interim following the BCUC's determination of this application pending the BCUC's consideration of our demand-side measures expenditure schedule in the context of the 2021 Integrated Resource Plan proceeding. Further, BC Hydro is not seeking acceptance of any Electricity Purchase Agreements in this application. In accordance with the 2018 Capital Filing Guidelines, major capital projects will be reviewed through separate regulatory proceedings.

1.3.8.3 BC Hydro Has Proposed a Terms of Reference to Guide Future Statistical Cost Benchmarking Studies

We have proposed a terms of reference to guide future statistical cost benchmarking studies, which have been reviewed by an independent expert in benchmarking.

Table 1-2 below provides our proposed terms of reference.

Table 1-2 Proposed Terms of Reference for Future Statistical Cost Benchmarking

Item	Type of Statistical Cost Benchmarking	Frequency
1	Comparisons across various maintenance categories, including distribution, transmission, vegetation and stations, to help compare performance and identify areas of opportunity in comparison to industry peers, substantially in the form of the First Quartile report dated December 10, 2020 which BC Hydro discussed in the Fiscal 2020 to Fiscal 2021 Revenue Requirements Application.	Each Revenue Requirements Application (i.e., approximately every three years), starting with the Revenue Requirements Application covering fiscal 2026
2	Comparisons of cost and performance of generation facilities to define specific steps to improve the cost or performance of those facilities relative to other utilities, substantially in the form of the Guidehouse (formerly Navigant) Generation Knowledge Services report dated January 2020, which BC Hydro discussed in the Fiscal 2020 to Fiscal 2021 Revenue Requirements Application.	Each Revenue Requirements Application (i.e., approximately every three years), starting with the Revenue Requirements Application covering fiscal 2026
3	An assessment of employee compensation relative to median market rates, substantially in the form of the Morneau Shepell report dated April 2018, which BC Hydro discussed in the F2020-F2021 RRA.	Alternating Revenue Requirements Applications (i.e., approximately every five to six years), with the next reports being provided as part of the Revenue Requirements Application covering fiscal 2026
4	A cost benchmarking study of operations and maintenance costs against a peer panel of electric utilities, substantially in the form of the benchmarking report dated February 18, 2019 provided by The Brattle Group which BC Hydro filed as part of the F2020-F2021 RRA (Appendix T).	Alternating Revenue Requirements Applications (i.e., approximately every five to six years), with the next reports being provided as part of the Revenue Requirements Application covering fiscal 2026
5	A review of the operating costs of other Canadian integrated electric utilities, substantially in the form of the study which BC Hydro provided as part of the F2020-F2021 RRA (Appendix U).	Alternating Revenue Requirements Applications (i.e., approximately every five to six years), with the next reports being provided as part of the Revenue Requirements Application covering fiscal 2026

BC Hydro asked William P. Zarakas of The Brattle Group, who authored the cost benchmarking study provided by The Brattle Group in the F2020-F2021 RRA to evaluate BC Hydro's proposal for future statistical cost benchmarking. Mr. Zarakas' report is provided as Appendix Y. Among other things, Mr. Zarakas states:

> "I find that BC Hydro's proposed terms of reference is appropriate for the BCUC to adopt because the proposed suite of studies are more transparent, understandable and replicable than the alternative econometrically based cost benchmarking studies. In addition, BC Hydro's proposed suite of benchmarking studies provides value to BC Hydro's managers and is informative to the BCUC in their review of cost forecasts during the Revenue Requirements Application process. BC Hydro's proposed suite of benchmarking studies can also be updated on a regular basis, which will allow the BCUC to have access to current data and analysis during its deliberations."[79]

1.3.8.4 BC Hydro Has Expanded the Use of Information-Only Performance Metrics

BC Hydro uses a variety of performance metrics and targets to monitor the performance of our operations and our progress towards meeting certain objectives. We have previously provided performance metrics and targets to the BCUC in various forms, including as part of revenue requirements applications.[80] In the PBR Report Proceeding, we suggested that information-only performance metrics, determined through a BCUC process, could help to achieve the goals of BCUC regulation of BC Hydro. Accordingly, this application includes information about performance metrics that we use, and propose to use in the context of BCUC proceedings going forward. We believe these metrics will both assist the BCUC and interveners in evaluating BC Hydro's revenue requirements, and augment performance incentives in priority areas.[81]

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[79] Refer to Appendix Y, paragraph 10.

[80] Specifically, BC Hydro has provided Annual Service Plan performance metrics as part of Revenue Requirements Applications, annual reports on reliability indices, and metrics used to manage its operations in accordance with Directive 68 of BCUC Order No. G-246-20.

[81] For further discussion, refer to BC Hydro's response to Question 12 and Dr. Weisman's response to Question 4 in BC Hydro's Supplementary Evidence (Exhibit B-8 of the proceeding to review BC Hydro's Performance Based Regulation Report) and to BC Hydro's response to BCUC IR 1.3.2 (Exhibit B-9 of the proceeding to review BC Hydro's Performance Based Regulation Report).

The Application includes several views of metrics and targets from BC Hydro's performance measurement framework:

- **Five-Year Strategic Plan:** Performance metrics and targets in our Five-Year Strategic Plan will measure our success in achieving specific outcomes over the next five years. BC Hydro's Five-Year Strategic Plan, containing these performance metrics and targets, is provided in Appendix D;
- **Service Plan:** Performance metrics and targets in our annual Service Plan will measure our success in achieving the expectations of our shareholder, the Government of B.C. BC Hydro's 2021/22 – 2023/24 Service Plan, containing these performance metrics and targets, is provided in Appendix C;
- **Business Groups:** Business Group performance metrics and targets are used by the Executive Team to monitor how BC Hydro is performing. Business Group performance metrics and targets for the three fiscal years comprising the Test Period of the Application are provided in Appendix E; and
- **Reliability and Other Initiatives:** Specific Business Group performance metrics and targets show the increased performance that BC Hydro intends to achieve as a result of increased investment in reliability and other initiatives outlined in this application. These performance metrics and targets are highlighted in Chapter 5, section 5.6.

This proceeding provides an opportunity for the BCUC and interveners to review the information put forward by BC Hydro, and provide input on the specific performance metrics that BC Hydro should include in future revenue requirements applications.

As a starting point, BC Hydro considered feedback from some interveners that have previously expressed an interest in performance metrics. Specifically:

- **Commercial Energy Consumers Association of BC** provided their views on the purpose and application of performance metrics. A key insight from these discussions for BC Hydro was the benefit of providing performance metrics that allow inputs, outputs and outcomes to be quantified. In other words, using performance metrics to measure the amount of resources being invested and the relative efficiency of that investment, the outputs achieved from that investment and the improved outcomes for customers realized as a result. BC Hydro has applied this approach to its presentation of performance metric information in areas where investment is increasing. This is shown in Chapter 5, section 5.6. In addition, we provide further detail with regard to performance metrics related to increased investments in vegetation management in Chapter 5, section 5.8.5;

- **Residential Consumer Intervener Association** suggested specific metrics in section 1.3.3 of their Final Argument in the PBR Report Proceeding. In this application, the performance metrics used to inform the evaluation of BC Hydro's investment and reliability trends, reflect some of these suggestions;[82] and
- **British Columbia Old Age Pensioners' Organization** provided feedback on affordability metrics. We recognize that many of our low-income customers face significant challenges and that, while comparisons to other jurisdictions and general inflationary trends are important metrics of affordability and cost control, they do not measure the ability for low-income customers to pay for essential goods such as electricity. We have not provided a specific affordability metric in this application because we believe further discussion and consultation is required. BC Hydro hopes that through this proceeding and further discussions,

[82] Specifically, Power System historical sustaining capital and OMA expenditures are included in Chapter 5, section 5.15.4; historical SAIDI and SAIFI performance data is included in Chapter 6, section 6.3.1 and Appendix Q provides reliability indices for distribution, transmission and generation performance through fiscal 2021 with comparisons to Canadian Electricity Association averages where available.

we can identify opportunities to provide information that informs an evaluation of electricity affordability from this perspective.[83]

1.3.8.5 Load Attraction Actions in Electrification Plan Align with the Performance Based Regulation Concept of "Marketing Flexibility"

In addition to BC Hydro's three proposals from the PBR Report Proceeding, we note that BC Hydro's Load Attraction actions are consistent with the concept of "marketing flexibility" discussed in the PBR Report Proceeding.

In his report commissioned by BCUC Staff, Dr. Lowry identified marketing flexibility as a feature of Performance Based Ratemaking. He indicated that marketing flexibility "is encouraged to the extent that new offerings are likely to benefit target customers and may also benefit other customers by, for example, increasing contributions to fixed costs so that their own contribution can be reduced."[84] His description of why marketing flexibility is needed[85] is consistent with the focus of BC Hydro's Load Attraction actions.

BC Hydro's Load Attraction programs, which are part of our Electrification Plan, will target customers with relatively elastic demand, who have options for where they operate, have large energy needs, and that may be attracted to BC Hydro's clean electricity offering. Attracting these types of loads will benefit ratepayers and should be encouraged. Further discussion is provided in Chapter 10, section 10.3.3.6.

[83] In BC Hydro's view, an August 2019 Staff Proposal from the California Public Utilities Commission Staff on Essential Service and Affordability Metrics may provide a useful starting point for further discussions on this topic. The report is available at: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M311/K290/311290268.PDF.

[84] Consultant Report by Pacific Economics Group Research LLC - Performance-Based Regulation: Basic Features and Possible Applications to BC Hydro, page 55. Online: https://www.bcuc.com/Documents/Proceedings/2020/DOC_57375_A2-5-Staff-Consultant-Report.pdf.

[85] For a discussion of these reasons refer to Consultant Report by Pacific Economics Group Research LLC - Performance-Based Regulation: Basic Features and Possible Applications to BC Hydro, page 54.

1.3.9 Demand-Side Management

As discussed in section 1.4.1.1 below, BC Hydro is not seeking acceptance of a demand-side measures expenditure schedule as part of this application. However, as discussed further in the sub-sections below, BC Hydro has responded to previous BCUC directives with regard to demand-side management in this application, in instances where a response in this application was required.

In its Decision on the Previous Application, the BCUC stated that it expects BC Hydro to provide evidence in this application to support any proposed spending on capacity-focused DSM beyond fiscal 2022.[86] As BC Hydro is not seeking acceptance of a demand-side measures expenditure schedule as part of this application, this evidence is not provided. However, BC Hydro will provide this evidence when it submits its demand-side measures expenditure schedule for approval, as discussed further in section 1.4.1.1 below.

1.3.9.1 Participation in Non-Integrated Areas DSM Program Increased by 30 Per Cent in Fiscal 2021

Directive 47 of the BCUC's Decision on the F2020-F2021 RRA directed BC Hydro to report on progress with regards to the Non-Integrated Areas DSM program, including an assessment of whether that program has been effective in reducing barriers for Non-Integrated Area customers in accessing DSM offerings.[87]

BC Hydro has provided this progress report in Appendix AA. The barriers that BC Hydro has identified and is trying to address with the Non-Integrated Areas program include awareness, acceptability, affordability, availability, and accessibility. A definitive assessment of the program's effectiveness is challenging to provide at this time, due to the impact of the COVID-19 pandemic. That said, in fiscal 2021,

[86] BCUC Decision and Order No. G-187-21, BC Hydro Fiscal 2022 Revenue Requirements Application (June 17, 2021), page 81.

[87] Directive 47; BCUC Decision and Order No. G-246-20, BC Hydro Fiscal 2020 to Fiscal 2021 Revenue Requirements Application (October 2, 2020), page 147.

despite the COVID-19 pandemic, there was continued interest and a 30 per cent increase in program participation over fiscal 2020. BC Hydro is in the process of developing a performance measurement framework with Indigenous communities for the Non-Integrated Areas program, which it expects to use to report on how the program is addressing community goals and barriers.

BC Hydro will provide additional information on the Non-Integrated Areas DSM program in December 2021, when we will file demand side measures expenditure schedules for fiscal 2023, fiscal 2024 and fiscal 2025, which will allow the demand side measures expenditure schedule to reflect, and be considered within the context of, the 2021 Integrated Resource Plan. The expenditure schedules will include planned expenditures for the Non-Integrated Areas for fiscal 2023, fiscal 2024 and fiscal 2025. Accordingly, BC Hydro respectfully requests that any information requests related to demand side measures for the Non-Integrated Areas be made during the regulatory proceeding to review those expenditure schedules and the 2021 Integrated Resource Plan.

1.3.9.2 Most Recent Evaluation of DSM Effectiveness Has Been Provided

Directive 19 of the BCUC's Decision on the Previous Application directed BC Hydro to include its most recent evaluation of its DSM effectiveness, as part of this application.[88] In response to various past BCUC directives, BC Hydro files an annual report to the BCUC on DSM activities, providing information on DSM expenditures, electricity savings, plan performance and mitigation measures for each fiscal year. BC Hydro's report on DSM activities for the 2021 fiscal year is included in Appendix AA. BC Hydro also evaluates its DSM initiatives to improve its estimates of realized DSM electricity savings and to improve their effectiveness. In compliance with Directive 66 of the BCUC Decision's on BC Hydro's Fiscal 2005 to Fiscal 2006 Revenue Requirements Application, BC Hydro submits an annual DSM Milestone

[88] Directive 19; BCUC Decision and Order No. G-187-21, BC Hydro Fiscal 2022 Revenue Requirements Application (June 17, 2021), page 81.

Evaluation Summary Report to the BCUC. BC Hydro's two most recent summary reports, covering fiscal 2019 and fiscal 2020, are also included in Appendix AA.

In December 2021, BC Hydro will file the documents in Appendix AA in the proceeding to review the 2021 Integrated Resource Plan and will also submit the fiscal 2023 to fiscal 2025 demand-side measures expenditures for acceptance. Accordingly, BC Hydro respectfully requests that any information requests related to the documents in Appendix AA be made during the regulatory proceeding to review those expenditure schedules and the 2021 Integrated Resource Plan.

1.3.10 COVID-19 Pandemic

Directive 65 of the BCUC's Decision on the F2020-F2021 RRA directed BC Hydro to report in all future revenue requirements applications, until directed otherwise, on the impact of the COVID-19 pandemic.[89] BC Hydro has provided this discussion throughout this application. Specifically:

- Chapter 5, section 5.13 provides a discussion of the impact of the COVID-19 pandemic on BC Hydro's operating costs. With the exception of permanent travel cost savings of $2.1 million in the Test Period, BC Hydro has not included any additional cost pressures or savings caused by the COVID-19 pandemic in the Test Period;
- Chapter 6, section 6.2.4 provides a discussion of the impact of the COVID-19 pandemic on BC Hydro's capital expenditures and projects; and
- With regard to BC Hydro's fiscal 2021 DSM plan, the primary impact associated with the COVID-19 pandemic was the four-month suspension of the Energy Conservation and Assistance Program. The COVID-19 pandemic also impacted delivery of similar components of the Non-Integrated Areas program. BC Hydro will provide fiscal 2021 performance results for DSM with its fiscal 2023 to

[89] Directive 65; BCUC Decision and Order No. G-246-20, BC Hydro Fiscal 2020 to Fiscal 2021 Revenue Requirements Application (October 2, 2020), page 181.

fiscal 2025 DSM expenditure schedule request, which, as discussed further in section 1.4.1.1 below, will be filed with the BCUC in December 2021.

1.4 Orders Sought

This section outlines the orders we are seeking in this application. We have included a draft final order in Appendix B. Chapter 2, section 2.4 of provides a summary of the legislation and regulations applicable to the orders sought and the role of the BCUC within that framework.

1.4.1 Rate Approvals and the Need to Leave Rates Interim at the Conclusion of the Proceeding for Limited Purposes

BC Hydro requests the following approvals pursuant to sections 59 to 61 and 89 of the *Utilities Commission Act* and section 15 of the *Administrative Tribunals Act* to amend its rate schedules.

- Interim and, after certain future determinations in other proceedings described below in this section, permanent approval to reflect general rate increases as set out in Appendix II, Table II-1, of:
  - 0.62 per cent, effective April 1, 2022, for fiscal 2023;
  - 0.97 per cent, effective April 1, 2023, for fiscal 2024; and
  - 2.18 per cent, effective April 1, 2024, for fiscal 2025.
- Interim and, after certain future determinations in other proceedings described below in this section below, permanent approval to reflect changes to BC Hydro's Open Access Transmission Tariff (**OATT**) rates, Appendix II, Table II-2.
- As discussed further in Chapter 7, section 7.3.3.3, interim and permanent approval to set the Deferral Account Rate Rider (**DARR**) at:
  - (2.0) per cent, effective April 1, 2022, for fiscal 2023;

- (1.0) per cent, effective April 1, 2023, for fiscal 2024; and
- (0.5) per cent, effective April 1, 2024, for fiscal 2025.

The general rate increases and DARR rates set out above would result in a net bill decrease of 1.4 per cent on April 1, 2022, followed by net bill increases of 2.0 per cent on April 1, 2023 and 2.7 per cent on April 1, 2024 (representing an average annual increase of 1.1 per cent over the three-year Test Period).

As reflected in the above rate requests, we are proposing that general and OATT rates (not the DARR)[90] remain interim at the conclusion of this proceeding for the limited purpose of addressing three issues that will remain outstanding:

- The BCUC's determination of the fiscal 2023 to fiscal 2025 demand-side measures expenditure schedule;
- The BCUC's determination of BC Hydro's cost of capital for fiscal 2024 and fiscal 2025; and
- The BCUC's assessment of the extent to which BC Hydro can recover Site C Project capital and deferred costs in rates, which could impact the fiscal 2025 revenue requirements and should await the completion of the Site C Project.

We explain these circumstances below, and articulate how leaving rates interim at the conclusion of this proceeding for these limited purposes ensures the fair treatment of customers and BC Hydro. The BCUC has previously used this approach to address the potential for future determinations to affect revenue requirements in a test period.

[90] Since the DARR only addresses the amortization from the Cost of Energy regulatory accounts, it is unaffected by the three outstanding issues identified below.

1.4.1.1 Rates Should Remain Interim Until BCUC Accepts a Demand-Side Measures Expenditure Schedule

BC Hydro is proposing that general and OATT rates for the Test Period remain interim at the conclusion of this proceeding, pending the BCUC's approval of a demand-side management expenditure schedule for fiscal 2023, fiscal 2024 and fiscal 2025 in another proceeding.

Unlike the previous three revenue requirements applications, this application does not include a request for approval of a demand-side measures expenditure schedule. The change in approach for this application recognizes that BC Hydro will file its 2021 Integrated Resource Plan with the BCUC in December 2021. The 2021 Integrated Resource Plan will consider the demand-side measures required to meet BC Hydro's future resource needs, and is still in development. BC Hydro is planning to wait until December 2021 to file a demand-side measures expenditure schedule for fiscal 2023, fiscal 2024 and fiscal 2025, which will allow the demand-side measures expenditure schedule to reflect, and be considered within the context of, the 2021 Integrated Resource Plan. The expenditure schedule will include planned expenditures for the Non-Integrated Areas for fiscal 2023, fiscal 2024 and fiscal 2025.

For the purpose of presenting the forecast revenue requirements in the Application, BC Hydro has included placeholder demand-side measures expenditures based on BC Hydro's most recently approved DSM plan. The placeholder amounts are generally consistent with previous fiscal years: $83 million for fiscal 2023, $85 million for fiscal 2024 and $87 million for fiscal 2025. BC Hydro is proposing that rates be kept interim, based on the placeholder amounts, until the BCUC accepts a demand-side measures expenditure schedule for fiscal 2023, fiscal 2024 and fiscal 2025.

BC Hydro is considering options to expedite the review of its fiscal 2023 demand-side measures expenditure schedule so that the BCUC can set final rates for fiscal 2023 when it issues its decision on this application. BC Hydro expects the demand-side measures expenditure schedule for fiscal 2024 and fiscal 2025 to be reviewed through the normal course of the 2021 Integrated Resource Plan proceeding.

BC Hydro respectfully requests that any information requests related to demand-side measures be made during the regulatory proceeding to review those expenditure schedules and the 2021 Integrated Resource Plan. This is an efficient approach that will avoid complications from splitting the evidentiary record on demand-side measures between two proceedings. In addition, information requests on demand-side measures that are submitted during the 2021 Integrated Resource Plan proceeding will benefit from being informed by the broader context of that proceeding.

1.4.1.2 Fiscal 2024 and Fiscal 2025 Rates Should Remain Interim Until BCUC Decision on BC Hydro's Future Cost of Capital Application

BC Hydro is proposing that fiscal 2024 and fiscal 2025 rates remain interim following this proceeding, pending the BCUC's final order in the upcoming BC Hydro Cost of Capital application.

The cost of capital for the first year of this Test Period is determined by legislation, and can be made permanent at the conclusion of this proceeding. Section 3 of Direction No. 8 to the BCUC states that in regulating and setting rates for fiscal 2023, the BCUC must ensure that those rates allow BC Hydro to collect sufficient revenue in each fiscal year to achieve an annual rate of return on deemed equity that would yield a distributable surplus of $712 million.

As no such direction is in place for the fiscal years beyond 2023, BC Hydro will need to submit a Cost of Capital Application to the BCUC so that the BCUC can determine BC Hydro's allowed net income, starting in fiscal 2024 (i.e., April 1, 2023). BC Hydro would likely need to file this application by no later than March 31, 2022.

For the purpose of determining the forecast revenue requirements in the Application, BC Hydro has included a placeholder net income amount of $712 million for fiscal 2024 and fiscal 2025, consistent with the current direction to the BCUC. BC Hydro is proposing that rates for fiscal 2024 and fiscal 2025 based on this placeholder amount remain interim at the conclusion of this revenue requirements proceeding until the BCUC determines BC Hydro's allowed net income for fiscal 2024 and fiscal 2025, through the proceeding to review BC Hydro's future Cost of Capital Application.

1.4.1.3 Fiscal 2025 General and OATT Rates Should Remain Interim Until Outcome of BCUC's Future Assessment of Recoverable Amount of Site C Project Costs

BC Hydro is proposing that fiscal 2025 rates remain interim at the conclusion of this proceeding pending the BCUC's consideration of the extent to which Site C Project capital and deferred costs are recoverable in rates. This approach allows the BCUC to determine rates for fiscal 2025, without having to consider the prudence of Site C capital costs piecemeal and before the Site C Project is complete.

BC Hydro's Site C Project will be a third dam and hydroelectric generating station on the Peace River in northeast B.C. As with all capital projects, the expenditures associated with the Site C Project do not impact rates until the associated assets are put into service. At that time, the capital expenditures associated with those assets become capital additions, which are then amortized into rates over the life of the associated assets.

The Site C Project is managed as a single project. However, given its size and scope, some aspects are expected to be completed before others. The fact that some aspects of the Site C Project affect rates before the entire project is finished creates a challenge for the BCUC rate setting process; although rates are being affected by amortization, it will be several years before the overall project is completed and the prudence of its execution can be reviewed. It also raises the potential for multiple reviews of different aspects of a project that is, in fact, a single project and managed accordingly.

While BC Hydro believes that its forecast Site C Project costs for fiscal 2025 are reasonable and should be recovered in full, we also recognize that the BCUC and interveners will likely be interested in reviewing BC Hydro's execution of the Site C Project.

Accordingly, BC Hydro is requesting that fiscal 2025 rates remain interim at the conclusion of this proceeding pending the outcome of the BCUC's future assessment of the recoverable amount of total Site C Project costs. Any variances between fiscal 2025 interim rates (set at the conclusion of the current proceeding) and permanent rates (set following a review of the recoverable amount of total Site C Project costs) due to a disallowance of any Site C Project costs, could be refunded to customers when fiscal 2025 rates are made permanent.

This approach recognizes the need to await the completion of the Site C Project, in full, before conducting an assessment of the recoverable amount of total Site C Project costs. While this approach means that fiscal 2025 rates could be held interim for an extended period of time, there are other examples where the BCUC has held rates interim for extended periods for specific purposes.[91]

BC Hydro considered an alternative approach of shortening the test period for the Application to two years (i.e., fiscal 2023 and fiscal 2024). However, shortening the test period does not avoid the need for interim rates in fiscal 2025 as a result of Site C, it only defers the need to the next revenue requirements application. This is because an assessment of the recoverable amount of total Site C Project costs could likely not begin until fiscal 2026 and it would then take some time to assemble evidence and conduct the review. In addition, a two-year test period foregoes the

[91] Refer to section 1.4.1.4 below.

benefits associated with a three-year test period, as discussed in section 1.3.8.2 above.

BC Hydro also considered the alternative of deferring all forecast fiscal 2025 costs associated with Site C to a regulatory account for future recovery. While this would avoid the need for interim rates in fiscal 2025 and would have a favourable impact on fiscal 2025 rates, it would create a significant rate pressure in subsequent years by deferring the recovery of costs that are part of the fiscal 2025 revenue requirement.[92] Using this approach across multiple years, which would be required to allow a future assessment of the recoverable amount of total Site C Project costs to be completed, would lead to a larger rate increase in the year that the costs begin to be recovered. BC Hydro expects that deferring recovery of Site C costs for multiple years would lead to a significant rate impact once recovery is commenced.

The interim rates proposal suggested above relates only to capital additions and deferred capital additions associated with the Site C Project. The operating costs to operate and manage the Site C assets that would be the same regardless of the outcome of any review of the recoverable amount of total Site C Project costs.

1.4.1.4 Precedent for Leaving Rates Interim Pending Future Determinations

The BCUC has used this approach of leaving rates interim pending future determinations in past proceedings. For instance, this approach has been used to facilitate separate proceedings for determining cost of capital.[93]

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92 These consequences are similar to those associated with the former Rate Smoothing Regulatory Account which the BCUC expressed concern about in its decision on the Fiscal 2017 to Fiscal 2019 Revenue Requirements Application. Refer to pages 99-100 of BCUC Decision and Order No. G-47-18.

93 Refer to, for example, Order No. G-187-12 in the Generic Cost of Capital Phase 1 proceeding. The order, issued early in the proceeding, made all existing rates interim for the affected utilities pending the final determination.

1.4.2 Regulatory Account Approvals

BC Hydro requests approval pursuant to sections 59 to 61 of the *Utilities Commission Act* to make changes to its regulatory accounts as set out in Chapter 7, section 7.3.

1.4.3 Depreciation Rates

BC Hydro requests BCUC approval, pursuant to sections 59-61 of the *Utilities Commission Act* to implement for ratemaking purposes:

- The updated useful lives and positive salvage rates and changes in asset classes, effective fiscal 2022,[94] as set out in Chapter 8, section 8.3; and
- Net salvage rates beginning in the next test period, using a phased-in approach, as set out in Chapter 8, section 8.4.

1.5 Overview of BC Hydro's Revenue Requirements

This section provides an overview of our revenue requirements for fiscal 2023, fiscal 2024 and fiscal 2025 and shows the revenue shortfall that will result from the existing rates. BC Hydro requires a rate increase to generate the necessary revenues to provide safe and reliable service during the Test Period.

There are two ways to summarize BC Hydro's revenue requirements:

- **Gross View:** The Gross View shows the total costs for each component of the revenue requirements before any forecast transfers to/from regulatory accounts and then shows the regulatory account transfers as a separate total. In other words, "Gross View" shows the total costs *incurred* in the Test Period; and
- **Current View:** The Current View shows the total costs for each component of the revenue requirements after any forecast transfers to/from regulatory

[94] The impact of implementing the Depreciation Study in fiscal 2022 has been approved to be deferred to the Fiscal 2022 Depreciation Study Impact regulatory account.

accounts. In other words, the "Current View" shows the actual costs *being recovered from* customers in rates during the Test Period.

As was the case in previous revenue requirements applications, Appendix A contains the detailed financial schedules of our revenue requirements model and is intended to provide a single location for all costs contained in the Application. The working revenue requirements model that produces these schedules is also provided in electronic form as part of this filing. A reconciliation of the Gross View and the Current View for each component of the revenue requirements is provided in Schedule 3.0 of Appendix A.

Table 1-3 below shows BC Hydro's revenue requirements for the Test Period from a Gross View.

Table 1-3 Gross View of BC Hydro's Revenue Requirements

	($ million)	Schedule Reference	F2021 Actual	F2022 Decision	F2023 Plan	F2024 Plan	F2025 Plan
			1	2	3	4	5
1	Cost of Energy	1.0 L1	1,522.4	1,670.1	1,781.6	1,943.3	2,001.4
2	Operating Costs	1.0 L2	1,128.7	1,228.5	1,286.8	1,314.4	1,348.4
3	Provisions & Other	1.0 L3	163.7	101.4	104.9	96.7	95.3
4	Taxes	1.0 L4	256.8	263.8	283.5	298.3	309.2
5	Amortization	1.0 L5	999.5	1,023.7	1,023.3	1,050.0	1,101.0
6	Finance Charges	1.0 L6	251.6	555.6	581.2	564.5	704.1
7	Return on Equity	1.0 L7	687.5	712.0	712.0	712.0	712.0
8	Miscellaneous Revenue	1.0 L8	(261.1)	(289.0)	(288.5)	(292.9)	(295.3)
9	Inter-Segment Revenue	1.0 L9	15.0	(83.5)	(71.8)	(73.4)	(74.8)
10	Deferral Account Transfers	1.0 L13	(49.1)	16.2	(98.7)	(48.8)	(24.6)
11	Other Regulatory Account Transfers	1.0 L17	620.9	195.8	165.0	167.6	135.3
12	Subsidiary Net Income	1.0 L22	(385.5)	(160.7)	(227.2)	(227.7)	(228.2)
13	Other Utilities Revenue	1.0 L23	(30.0)	(30.2)	(30.0)	(30.0)	(30.0)
14	Deferral Rider Revenue	1.0 L25	(0.0)	0.0	106.5	55.3	28.9
15	Total Rate Revenue Requirement	1.0 L26	4,920.4	5,203.6	5,328.5	5,529.4	5,782.6
16	Less Revenue at F2022 Rates	1.0 L31	(4,920.4)	(5,152.2)	(5,295.7)	(5,442.8)	(5,570.8)
17	Revenue Shortfall	1.0 L32	0.0	51.5	32.7	86.6	211.8
18	Annualized Rate Increase	1.0 L33	(1.62%)	1.00%	0.62%	0.97%	2.18%
19	Deferral Account Rate Rider	1.0 L34	0.00%	0.00%	(2.00%)	(1.00%)	(0.50%)
20	Net Bill Increase	1.0 L35	(1.62%)	1.00%	(1.39%)	2.00%	2.69%

Table 1-4 below shows BC Hydro's revenue requirements for the Test Period from a Current View.

Table 1-4 Current View of BC Hydro's Revenue Requirements

	($ million)	Schedule Reference	F2021 Actual	F2022 Decision	F2023 Plan	F2024 Plan	F2025 Plan
			1	2	3	4	5
1	Cost of Energy	3.0 L5	1,365.8	1,669.8	1,788.4	1,945.5	2,001.0
2	Operating Costs	3.0 L11	1,247.9	1,352.3	1,320.5	1,340.3	1,360.2
3	Provisions & Other	3.0 L17	154.0	165.3	137.8	135.6	108.6
4	Taxes	3.0 L20	256.8	263.8	283.5	298.3	309.2
5	Amortization	3.0 L26	1,120.0	1,134.2	1,150.9	1,182.4	1,236.6
6	Finance Charges	3.0 L33	695.7	454.1	556.9	537.7	680.5
7	Return on Equity	3.0 L37	687.5	712.0	712.0	712.0	712.0
8	Miscellaneous Revenue	3.0 L42	(256.1)	(273.5)	(285.7)	(289.2)	(292.8)
9	Inter-Segment Revenue	3.0 L47	15.0	(83.5)	(71.8)	(73.4)	(74.8)
10	Subsidiary Net Income	3.0 L68	(336.1)	(160.7)	(340.6)	(285.1)	(256.7)
11	Other Utilities Revenue	3.0 L69	(30.0)	(30.2)	(30.0)	(30.0)	(30.0)
12	Deferral Rider Revenue	3.0 L71	(0.0)	0.0	106.5	55.3	28.9
13	Total Rate Revenue Requirement	3.0 L72	4,920.4	5,203.6	5,328.5	5,529.4	5,782.6
14	Less Revenue at F2022 Rates	1.0 L31	(4,920.4)	(5,152.2)	(5,295.7)	(5,442.8)	(5,570.8)
15	Revenue Shortfall	1.0 L32	0.0	51.5	32.7	86.6	211.8
16	Annualized Rate Increase	1.0 L33	(1.62%)	1.00%	0.62%	0.97%	2.18%
17	Deferral Account Rate Rider	1.0 L34	0.00%	0.00%	(2.00%)	(1.00%)	(0.50%)
18	Net Bill Increase	1.0 L35	(1.62%)	1.00%	(1.39%)	2.00%	2.69%

BC Hydro
Power smart

BC Hydro Fiscal 2023 to Fiscal 2025
Revenue Requirements Application

Chapter 2

Legal Framework

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2.1 Introduction

This chapter provides an overview of the three statutes and specific regulations that will inform the BCUC's consideration of the approvals that BC Hydro is seeking in the Application.

This chapter is organized around the following key points:

- Section 2.2 explains that provisions of the *Hydro and Power Authority Act*, the *Clean Energy Act*, and the *Utilities Commission Act* defining the BCUC's jurisdiction in this Application remain unchanged from when the Previous Application was filed;
- Section 2.3 identifies a number of regulations relevant to BC Hydro's revenue requirements for the Test Period, including amendments to Direction No. 8 to the BCUC that were made after the Previous Application was filed. In this section we discuss the Greenhouse Gas Reduction (Clean Energy) Regulation (**GGRR**) and the impact of some prescribed undertaking investments and expenditures, with other details to be discussed in other chapters of the Application; and
- Section 2.4 explains why the BCUC has the legal authority to grant the approvals that BC Hydro is seeking in the Application.

2.2 Statutes Governing BCUC Rate Setting Jurisdiction Remain Unchanged

In Chapter 2 of the Previous Application, BC Hydro provided an overview of the statutes relevant to the review of BC Hydro's revenue requirements. They are still in force and applicable to the Application and are identified below for ease of reference.

2.2.1 The Hydro and Power Authority Act

The *Hydro and Power Authority Act* mandates BC Hydro to generate, manufacture, conserve, supply, acquire and dispose of power and related products, and to supply and acquire related services.

BC Hydro acts as an agent of the Government of B.C. and reports to the Government through the Minister of Energy, Mines, and Low Carbon Innovation. The Minister of Finance is the fiscal agent of BC Hydro. The Lieutenant Governor in Council appoints BC Hydro's Board of Directors and Chair. The Board is responsible for managing the affairs of BC Hydro or supervising the management of those affairs and may delegate its responsibilities to the President and Chief Executive Officer.

Section 32 (Application of other statues) of the *Hydro and Power Authority Act*, sets out, among other things, certain provisions of the *Utilities Commission Act* that are not applicable to BC Hydro, including section 52 (Restraint on disposition) of that Act. Recently, the *Professional Governance Act* has been made applicable to BC Hydro.

2.2.2 The Utilities Commission Act

Sections 59 to 61 of the *Utilities Commission Act* provide the fundamental legal framework for the BCUC to review BC Hydro's revenue requirements and to set rates for the Test Period. These sections require the BCUC, when setting a rate, to consider factors prescribed in section 60(1)(b) of the *Utilities Commission Act*, including setting a rate that is not unjust or unreasonable within the meaning of section 59(5) of the Act, while still providing the BCUC with discretion in setting rates.

Section 44.2 (Expenditure schedule) and section 45 (Certificate of Public Convenience and Necessity) allow the BCUC to review BC Hydro's capital projects and associated expenditures and additions, unless the project is exempted from BCUC review. Whether the project has been or will be subject to a separate CPCN or section 44.2 application and process may influence the scope of BCUC review of the capital expenditures and additions in a revenue requirements application proceeding. In Appendix I, BC Hydro identifies the projects exempted from regulation as well as the projects that may be subject to a separate section 44.2 or CPCN application. In the Application, BC Hydro is not seeking any approval under section 44.2 or section 45 of the *Utilities Commission Act* for any capital projects.

Section 44.2 (Expenditure schedule) also provides the BCUC with the authority to accept BC Hydro's demand-side measures expenditure schedule. In the Application, we have included forecast demand-side management expenditures, but BC Hydro is not seeking BCUC acceptance of any demand-side management expenditures in this proceeding. BC Hydro will be including such a request with its Integrated Resource Plan as discussed in Chapter 1.

Section 71 provides the BCUC with authority to review BC Hydro's Electricity Purchase Agreements (**EPAs**). In the Application, BC Hydro is not seeking BCUC acceptance of any EPAs. BC Hydro files separate applications pursuant to section 71 of the *Utilities Commission Act* seeking acceptance of any non-exempt EPAs that constitute energy supply contracts pursuant to section 68 of the *Utilities Commission Act*. The cost of energy associated with the EPAs is included in the revenue requirements for the Test Period. Further information on BC Hydro's EPAs is provided in Chapter 4, section 4.6.1.

In addition, section 1(2) provides that the *Utilities Commission Act* does not apply to Powerex Corp. In other words, Powerex (including its costs, revenues and trading activities) is not regulated by the BCUC. Directive No. 8, discussed below, addresses how Powerex net income is to be reflected in BC Hydro rates.

2.2.3 The Clean Energy Act

Section 7 (Exempt projects, programs, contracts and expenditures), section 8 (Rates), and section 18 (Greenhouse gas reduction) of the *Clean Energy Act* continue to have direct relevance to BC Hydro's revenue requirements.

- Section 7 exempts various BC Hydro projects, programs, contracts and expenditures from BCUC review under sections 45 to 47 and 71 of the *Utilities Commission Act*. Section 8 requires the BCUC to ensure that BC Hydro collects sufficient revenue to recover the costs associated with these projects, programs, contracts and expenditures. Appendix I identifies the projects exempted under section 7 of the *Clean Energy Act*. The Site C project is among the projects that are exempted.
- Section 18 requires that the BCUC allow BC Hydro to collect sufficient revenue to recover costs incurred for implementing prescribed undertakings. Prescribed undertakings are projects, programs, contracts or expenditures prescribed by regulation for the purpose of reducing greenhouse gas emissions in British Columbia. A public utility that chooses to engage in prescribed undertakings is entitled to "recover its costs incurred with respect to the prescribed undertaking" in its rates, and the BCUC "must not exercise a power under the *Utilities Commission Act* in a way that would directly or indirectly prevent [the] public utility … from carrying out a prescribed undertaking".[95]

  The GGRR issued under the *Clean Energy Act* sets out various classes of prescribed undertakings, including low carbon electrification infrastructure projects, low carbon electrification programs and expenditures, and electric vehicle charging stations. In Chapter 10 and Appendix U, V and W, BC Hydro provides information on how low carbon electrification programs/initiatives and electric vehicle charging stations fall within classes of prescribed undertakings.

[95] *Clean Energy Act*, section 18(2) and section 18(3).

2.3 Many Regulations Remain Effective and Relevant to this Application

Most of the regulations enacted under the *Utilities Commission Act*, the *Clean Energy Act* and other Acts that were discussed in the Previous Application continue to impact the Application. Amendments to Direction No. 8 to the BCUC, including new provisions addressing trade income and BC Hydro's return on equity, represent the most noteworthy change in the regulations that is applicable to the Application.

2.3.1 Summary of Regulations Impacting the Application

Table 2-1 below provides a summary of the regulations impacting the Application as well as regulations that were relevant to the Previous Application but have no impact on BC Hydro's revenue requirements in the Test Period.

Table 2-1 Summary of Regulations Relevant to this Application

Name of the Regulation	Purpose/Description of the Regulation	Impact on the Application
New Regulations Since Filing of Fiscal 2022 Revenue Requirements Application		
Direction to the British Columbia Utilities Commission Respecting the Customer Crisis Fund Program (B.C. Reg. 163/2021)[96]	The BCUC must allow BC Hydro to defer to the Customer Crisis Fund Regulatory Account to a total amount that must not exceed $5 million: (a) the amounts incurred by the authority in administering the Customer Crisis Fund program, and (b) grants provided to residential customers experiencing a temporary financial crisis and facing termination of service for failure to pay for that service.	BC Hydro's COVID-19 pandemic relief measures for residential customers are deferred to the Customer Crisis Fund Regulatory Account. The total amount deferred related to this program is set out in Chapter 7, section 7.3.3.5.

96 https://www.bclaws.gov.bc.ca/civix/document/id/oic/oic_cur/0365_2021

Name of the Regulation	Purpose/Description of the Regulation	Impact on the Application
Direction to the British Columbia Utilities Commission Respecting Industrial Electrification (B.C. Reg. 295/2020)[97]	The regulation requires the BCUC to rescind Tariff Supplement No. 37 – Northwest Transmission Line Supplemental Charge, and set Rate Schedule 1894 – Transmission Service – Clean B.C. Industrial Electrification Rate - Clean Industry and Innovation and Rate Schedule 1895 – Transmission Service – Clean B.C. Industrial Electrification Rate – Fuel Switching.	The Clean B.C. Industrial Electrification Rate Schedules are intended to support BC Hydro's electrification activities, which are further described in Chapter 10.

97 https://www.bclaws.gov.bc.ca/civix/document/id/oic/oic_cur/0657_2020

Name of the Regulation	Purpose/Description of the Regulation	Impact on the Application
Direction No. 8 to the BCUC[98]		
Section 3	This section, as amended in 2021, requires the BCUC to ensure that BC Hydro collects sufficient revenue in fiscal 2020 through fiscal 2023 to achieve an annual rate of return on deemed equity that would yield a distributable surplus of $712 million.	The BCUC must set rates to allow BC Hydro to collect sufficient revenue to enable BC Hydro to achieve an annual rate of return on deemed equity that would yield a distributable surplus of $712 million in fiscal 2023. BC Hydro will need to file a Cost of Capital application to recommend an appropriate return on equity that would apply beginning in fiscal 2024. For the purpose of determining the forecast revenue requirements in the Application, BC Hydro has included a placeholder net income amount of $712 million for fiscal 2024 and fiscal 2025, consistent with the current direction to the BCUC. BC Hydro is proposing that rates for fiscal 2024 and fiscal 2025 based on this placeholder amount remain interim at the conclusion of this revenue requirements proceeding until the BCUC determines BC Hydro's allowed net income for fiscal 2024 and fiscal 2025, through the proceeding to review BC Hydro's future Cost of Capital Application. For further discussion, refer to Chapter 8, section 8.5.

98 https://www.bclaws.gov.bc.ca/civix/document/id/crbc/crbc/24_2019

<table>
<tr><th>Name of the Regulation</th><th>Purpose/Description of the Regulation</th><th>Impact on the Application</th></tr>
<tr><td>Section 4</td><td>This section states that the BCUC must not disallow recovery in rates, for any reason, of:
The balance of BC Hydro’s regulatory accounts as at March 31, 2019;
Costs incurred for the construction of extensions to BC Hydro’s plant or system that came into service before fiscal 2017;
Costs incurred for energy supply contracts entered into before fiscal 2017; and
Debt servicing costs related to the Rate Smoothing Regulatory Account approved by Order No. G-48-14.
This section, as amended in 2021, also states that in setting rates for BC Hydro for a fiscal year, the BCUC must subtract from the costs to be recovered in rates an amount equal to the net incomes, for the fiscal year, of Powerex Corp. and Powertech Labs Inc. and that for the purposes of doing so:
The net income of Powerex Corp. for the fiscal year is the amount equal to the trade income forecast by BC Hydro for that fiscal year; and
The net income of Powertech Labs Inc. for the fiscal year is the amount forecast by BC Hydro.</td><td>Information on BC Hydro’s regulatory accounts is provided in Chapter 7.

Information on BC Hydro’s system extensions is provided in Chapter 6 and Appendix I and Appendix J.

Information on BC Hydro’s EPAs is provided in Chapter 4.

Subsidiary net income is described in Chapter 8, section 8.10. The inclusion of subsidiary net income in BC Hydro’s revenue requirements reduces the overall revenue requirements.</td></tr>
<tr><td>Section 5</td><td>This section prohibits the BCUC from setting rates for the purpose of changing the revenue-cost ratio for a class of customers for fiscal 2020 and fiscal 2021.</td><td>This section is now codified as section 58.1 of the Utilities Commission Act, without limiting to certain fiscal years.</td></tr>
</table>

Name of the Regulation	Purpose/Description of the Regulation	Impact on the Application
Section 6	This section states that the BCUC must not comply with section 4(5) of the *Clean Energy Act* (expenditures for export) when setting rates for fiscal 2020 and fiscal 2021.	Section 4(5) of the *Clean Energy Act* has now been rescinded.
Section 7	This section states that, except on application by BC Hydro, the BCUC must not set rates for BC Hydro that would result in the direct or indirect provision of unbundled transmission services to retail customers in British Columbia, or to those who supply such customers.	BC Hydro is not making any application relating to retail access in the Application.
Section 8	The section prohibits the BCUC from exercising any power under Part 3 of the *Utilities Commission Act* in regard to Powerex Corp.	This section is now codified as section 1(2) of the *Utilities Commission Act*.
Section 9	In regulating and setting rates for BC Hydro, the BCUC must allow BC Hydro to continue to defer to the trade income deferral account the variances between actual and forecast trade income.	Information on BC Hydro's regulatory accounts is provided in Chapter 7.
Section 10	The BCUC may not exercise its powers under section 71(1)(b) and (3) of the *Utilities Commission Act* in respect of the 2020 Transfer Pricing Agreement.	BC Hydro files separate applications for non-exempted EPAs pursuant to section 71 of the *Utilities Commission Act*. The 2020 Transfer Pricing Agreement is not subject to BCUC approval. The revenue requirements thus reflect the application of the 2020 Transfer Pricing Agreement. See Chapter 4, section 4.3.2.

Name of the Regulation	Purpose/Description of the Regulation	Impact on the Application
Other Existing Regulations Applicable to the Application		
Direction to the BCUC Respecting COVID-19 Relief (B.C. Reg. 76/2020, amended by B.C. Reg. 137/2020)[99]	This regulation requires the BCUC to approve or consent to various regulatory mechanisms relating to BC Hydro's implementation of COVID-19 customer relief programs, and to allow BC Hydro to recover costs for those programs. The regulation specifies that in setting rates, the BCUC must not disallow, for any reason, the recovery in rates of: • The balance of the Customer Crisis Fund Regulatory Account; and • Despite section 3(3) of the Direction to the BCUC Respecting Mining Customers, the balance of the Mining Customer Payment Plan Regulatory account.	BC Hydro's COVID-19 pandemic relief measures for residential and commercial customers are deferred to the Customer Crisis Fund Regulatory Account and the Mining Customer Payment Plan Regulatory Account, respectively. The total amount deferred related to these programs is set out in Chapter 7, section 7.6.
Direction to the BCUC Respecting the Biomass Energy Program (B.C. Reg. 71/2019)[100]	This regulation prohibits the BCUC from exercising its power under section 71(1)(b) or (3) of the *Utilities Commission Act* with regard to energy supply contracts with seven specified biomass facilities. The regulation specifies that, in setting rates for BC Hydro, the BCUC may not disallow, for any reason, the recovery in rates of BC Hydro's costs with respect to these energy supply contracts.	The Biomass Energy Program Variance Regulatory Account captures all variances between forecast and actual amounts related to these energy supply contracts. The balance of the account is provided in Chapter 7, Table 7-5.

99 https://www.bclaws.gov.bc.ca/civix/document/id/crbc/crbc/76_2020
100 https://www.bclaws.gov.bc.ca/civix/document/id/crbc/crbc/71_2019

Name of the Regulation	Purpose/Description of the Regulation	Impact on the Application
Greenhouse Gas Reduction (Clean Energy) Regulation (B.C. Reg. 102/2012, amended by B.C. Reg. 139/2020[101] and B.C. Reg. 134/2021[102])	This regulation makes certain electrification infrastructure projects (subsection 4(2)), electrification programs/projects (subsection 4(3)) and eligible electric vehicle charging stations constructed or purchased and operated by a public utility as prescribed undertakings (subsection 5) for the purpose of section 18 of the *Clean Energy Act*.	Under section 18 of the *Clean Energy Act*, the BCUC must set rates that allow BC Hydro to collect sufficient revenue to recover costs incurred for implementing prescribed undertakings. The Peace Region Electrification Project remains the only infrastructure project under section 4(2) of the GGRR. The nature of the project has not changed since the Fiscal 2020 to Fiscal 2021 Revenue Requirement Application, and the project was put into service in May 2021. In Chapter 10, BC Hydro provides information on how its low carbon electrification actions and its electric vehicle fast charging stations are prescribed undertakings under section 4 and section 5 of the GGRR, respectively.
Direction No. 4 to the BCUC (B.C. Reg. 203/2013)[103]	This regulation concerns the Meter Choices Program. It requires the BCUC to allow BC Hydro to collect sufficient revenue to recover the costs for the Meter Choices Program, which allows customers to retain or install legacy or radio-off meters instead of smart meters under certain conditions specified under BC Hydro's Electric Tariff. Standard charges relating to legacy meters and radio-off meters are also set out in the Electric Tariff.	BC Hydro is not seeking to change any of the charges relating to legacy or radio-off meters in the Application. The costs of the Meter Choices Program are included in the forecast revenue requirements for the Test Period.

101 https://www.bclaws.gov.bc.ca/civix/document/id/crbc/crbc/102_2012

102 The further amendments to the GGRR made in May 2021 address renewable natural gas, hydrogen, synthesis gas and lignin prescribed undertakings and are not directly relevant to the Application.

103 https://www.bclaws.gov.bc.ca/civix/document/id/complete/statreg/203_2013

Name of the Regulation	Purpose/Description of the Regulation	Impact on the Application
Direction to the BCUC Respecting Mining Customers (B.C. Reg. 47/2016)[104]	BC Hydro's Mining Customer Payment Plan (approved as Tariff Supplement No. 90) allows eligible mining customers to defer payment of a portion of their account under specified conditions. This regulation requires the BCUC to allow BC Hydro to establish a regulatory account for any impaired balances of participating mining customers. It also requires the BCUC to allow BC Hydro to recover the balance of this regulatory account in rates over a period determined by BC Hydro, after the closing date.	Chapter 7, section 7.3.3.6 discusses BC Hydro's proposed recovery mechanism for the Mining Customer Payment Plan Regulatory Account.
Direction to the BCUC Respecting the Authority's TMP Program (B.C. Reg. 139/2015)[105]	Under this regulation, the BCUC must not disallow, for any reason, the recovery in rates of the costs incurred by BC Hydro in carrying out the Thermo-Mechanical Pulp (**TMP**) program, subject to a $100 million cost recovery limit. The costs incurred as a result of carrying out the TMP program are deferred to the DSM Regulatory Account.	The TMP program is no longer active. The balance of the DSM Regulatory Account is amortized into rates over 15 years, on an ongoing basis, as before, without any changes.
Direction to the BCUC Respecting the Iskut Extension Project (B.C. Reg. 137/2013, amended by B.C. Reg. 24/2019)[106]	This regulation exempts the Iskut Extension Project from the CPCN requirement under the *Utilities Commission Act*. It also requires the BCUC, when setting rates, to allow BC Hydro to collect sufficient revenue to recover its costs incurred in relation to the project, including costs incurred for negotiating, entering into and carrying out agreements with First Nations.	The project was completed in March 2020 with a final cost of $110 million now being amortized into rates.

104 https://www.bclaws.gov.bc.ca/civix/document/id/complete/statreg/47_2016
105 https://www.bclaws.gov.bc.ca/civix/document/id/complete/statreg/139_2015
106 https://www.bclaws.gov.bc.ca/civix/document/id/crbc/crbc/137_2013

Name of the Regulation	Purpose/Description of the Regulation	Impact on the Application
Direction to the BCUC Respecting Undertaking Costs (B.C. Reg. 77/2017)[107]	This regulation requires the BCUC to allow BC Hydro to defer to the DSM Regulatory Account its costs for implementing the prescribed undertaking programs under section 4(3)(a), (b), (c) or (d) of the GGRR.	The programs meeting the requirements of these subsections of the GGRR are the low-carbon electrification programs/initiatives and expenditures discussed in Chapter 10, sections 10.3.2 and 10.4.3.1 and Appendix V. In accordance with Directive 48 of the BCUC's Decision on the Fiscal 2020 to Fiscal 2021 Revenue Requirements Application,[108] the balance of low-carbon electrification expenditures in the DSM Regulatory Account, for the Test Period, is provided in Appendix A, Schedule 2.2. A discussion of whether low carbon electrification expenditures deferred to the DSM Regulatory Account should be recovered from the beneficiaries of these expenditures, in response to Directive 20 of BCUC Decision on the Previous Application, is provided in Chapter 10, section 10.4.3.1.
Electricity Self-Sufficiency Regulation (B.C. Reg. 315/2010)[109]	For the purpose of the definition of "electricity supply obligations" and "heritage energy capability" in section 6(1) of the *Clean Energy Act*, this regulation specifies that they are to be determined based on the mid-level load forecasts and the maximum amount of annual energy generated under average water conditions.	Information on the load forecast is provided in Chapter 3. Information on the cost of energy, including cost of Heritage Energy, is provided in Chapter 4.

107 https://www.bclaws.gov.bc.ca/civix/document/id/complete/statreg/77_2017

108 Directive 48 of the BCUC's Decision on the Fiscal 2020 to Fiscal 2021 Revenue Requirement Application approved BC Hydro's request to defer low-carbon electrification expenditures up to the undertaking costs to the DSM Regulatory Account and directed BC Hydro to separately track these expenditures in the DSM Regulatory Account.

109 https://www.bclaws.gov.bc.ca/civix/document/id/complete/statreg/1906578493

Name of the Regulation	Purpose/Description of the Regulation	Impact on the Application
Remote Communities Regulation (B.C. Reg. 240/2007)[110]	This regulation requires BC Hydro to provide services to specified remote communities.	Under Special Direction No. 10 to the BCUC, BC Hydro is allowed to recover costs for providing service to those remote communities. The costs of providing this service are included in the Test Period revenue requirements.
Shore Power Regulation (B.C. Reg. 291/2008)[111]	This regulation encourages operators of cruise ships docked at Canada Place wharf in Vancouver to use port electricity instead of on-board, diesel-generated electricity. In setting the rate for shore power service, the BCUC must ensure that the rate allows BC Hydro to collect sufficient revenue to recover the costs incurred as a result of providing that service.	BC Hydro's shore power rates for fiscal 2023 to fiscal 2025 are set out in Appendix II.
Special Direction – B.C. Hydro No. 2 Regulation (B.C. Reg. 390/85)[112]	This regulation concerns the Skagit Agreement between the Government of B.C. and the City of Seattle and subsequently assigned by the Government of B.C. to BC Hydro. It requires the BCUC to consider all payments related to the assignment as revenue to BC Hydro.	Volumes delivered to, and the related revenues received from, Seattle City Light, which is the electricity provider for the City of Seattle, are recorded as domestic revenue as shown in Appendix A, Schedule 14, line 24.
Special Direction No. 10 to the BCUC (B.C. Reg. 245/2007)[113]	This regulation, among other things, requires that the BCUC ensure that BC Hydro collects sufficient revenue in each fiscal year to recover costs related to providing service under the Remote Communities Regulation.	The costs related to serving the 11 remote communities specified in the Remote Communities Regulation are included in the revenue requirements for the Test Period.

110 https://www.bclaws.gov.bc.ca/civix/document/id/complete/statreg/240_2007
111 https://www.bclaws.gov.bc.ca/civix/document/id/complete/statreg/291_2008
112 https://www.bclaws.gov.bc.ca/civix/document/id/complete/statreg/390_85
113 https://www.bclaws.gov.bc.ca/civix/document/id/complete/statreg/245_2007

Name of the Regulation	Purpose/Description of the Regulation	Impact on the Application
Transmission Upgrade Exemption Regulation (B.C. Reg. 140/2013, amended by B.C. Reg. 140/2021)[114]	The regulation exempts the following projects from section 45(5) of the *Utilities Commission Act*: • A series capacitor station and related facilities and equipment in the vicinity of the District of Vanderhoof, the Village of Burns Lake and the Village of Telkwa; • Various upgrades and additions at the Skeena and Minette substations; and • Construction, operation, upgrades or extensions, reasonably expected to come into service before October 1, 2025, to provide service to an LNG facility in the vicinity of the District of Kitimat and to provide service to facilities necessary for the construction of that LNG facility.	In its Decision on the Fiscal 2020 to Fiscal 2021 Revenue Requirement Application, the BCUC confirmed that the Minette to LNG Canada Interconnection Project is an exempted project under this regulation. The forecast capital expenditures for this project for the Test Period are provided in Appendix I.

2.4 Summary of Legal Authority for Orders Sought

The approvals that BC Hydro is seeking in the Application are set out in Chapter 1, section 1.4. Table 2-2 below provides the legal authority governing our requests and the role of the BCUC within that framework.

[114] https://www.bclaws.gov.bc.ca/civix/document/id/crbc/crbc/140_2013

Table 2-2 Summary Approvals Sought and Legal/Regulatory Framework

Approvals Sought	Applicable Legislation and Regulations	BCUC's Role
Interim and permanent general rate changes.	Sections 59-61 and 89 of the *Utilities Commission Act*	The BCUC must approve rates that are just and reasonable, with reference to BC Hydro's forecast revenue requirements. BC Hydro's forecast revenue requirements reflect a variety of other legislative and regulatory requirements as discussed in this chapter. The BCUC may make interim orders and reserve further direction.
Regulatory account approvals (including new accounts, changes to accounts, discontinuing account, recovery mechanism).	Sections 59-61 of the *Utilities Commission Act*	The BCUC has the power to direct that certain components of the forecast revenue requirements be deferred by recording the amount in a regulatory account for future recovery. The approved rates/revenue requirements must reflect reasonable amortization expense from previously deferred amounts. Certain accounts are also subject to directions discussed above.
Setting depreciation rates.	Sections 59-61 of the *Utilities Commission Act*	The BCUC must set proper and adequate rates of depreciation in order to ensure that rates allow the utility a reasonable opportunity to earn a return both on and of its invested capital. This is a requirement of just and reasonable rates.
Open Access Transmission Tariff rates.	Sections 59-61 of the *Utilities Commission Act*	The BCUC must approve rates that are just and reasonable, with reference to BC Hydro's forecast revenue requirements. BC Hydro's forecast revenue requirements reflect a variety of other legislative and regulatory requirements.

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BC Hydro Fiscal 2023 to Fiscal 2025
Revenue Requirements Application

Chapter 3

Load and Revenue Forecast

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3.1 Introduction

The forecast loads for fiscal 2023 through fiscal 2025 derived from our established forecasting methodologies (**Load Forecast**),[115] as well as additional loads associated with BC Hydro's 5-Year Electrification Plan (**Electrification Plan**), are reflected in the Revenue Forecast. The Revenue Forecast is, in turn, used in the calculation of the Test Period revenue requirements. This chapter describes the Load Forecast, while the additional load associated with the Electrification Plan is described in Chapter 10. Revenue associated with the Load Forecast and the Electrification Plan is captured as separate line items in the Revenue Forecast provided in section 3.8 below.

BC Hydro prepared a comprehensive 20-year load forecast (**December 2020 Load Forecast**)[116] to support this application and BC Hydro's Integrated Resource Plan (**IRP**) which will be filed with the BCUC in December 2021. The methodologies used to develop the December 2020 Load Forecast are substantially the same as those used to develop BC Hydro's previous comprehensive load forecasts with the exception of adjustments related to the COVID-19 pandemic which are discussed in sections 3.4.3 and 3.4.4. These methodologies have shown reliable short-term results over the past five years and have been improved under the oversight of the BCUC through the last three revenue requirements applications.

The information provided in this chapter is supplemented by BC Hydro's Electric Load Forecast Report Fiscal 2021 to Fiscal 2041 (December 2020) which is provided in Appendix F. Appendix F provides a comprehensive description of the methods and results of the Load Forecast discussed in this chapter.

[115] For the purposes of this application, the term "Load Forecast" refers to the test period years of the December 2020 reference load forecast, which is the reference energy forecast after adjustments for rate impacts, volt-ampere reactive and voltage optimization (**VVO**) energy savings, and demand side management (**DSM**) savings. The terms load forecast and electricity sales are used interchangeably.

[116] The December 2020 Load Forecast includes a suite of forecasts including reference, high, and low cases for both energy and peak, before and after various adjustments. Unless otherwise specified "December 2020 Load Forecast" refers to the reference energy forecast after adjustments.

Collectively, the information provided demonstrates why the Load Forecast and the associated Revenue Forecast are reasonable for the purposes of setting rates in the Test Period.

This chapter is organized around the following key points:

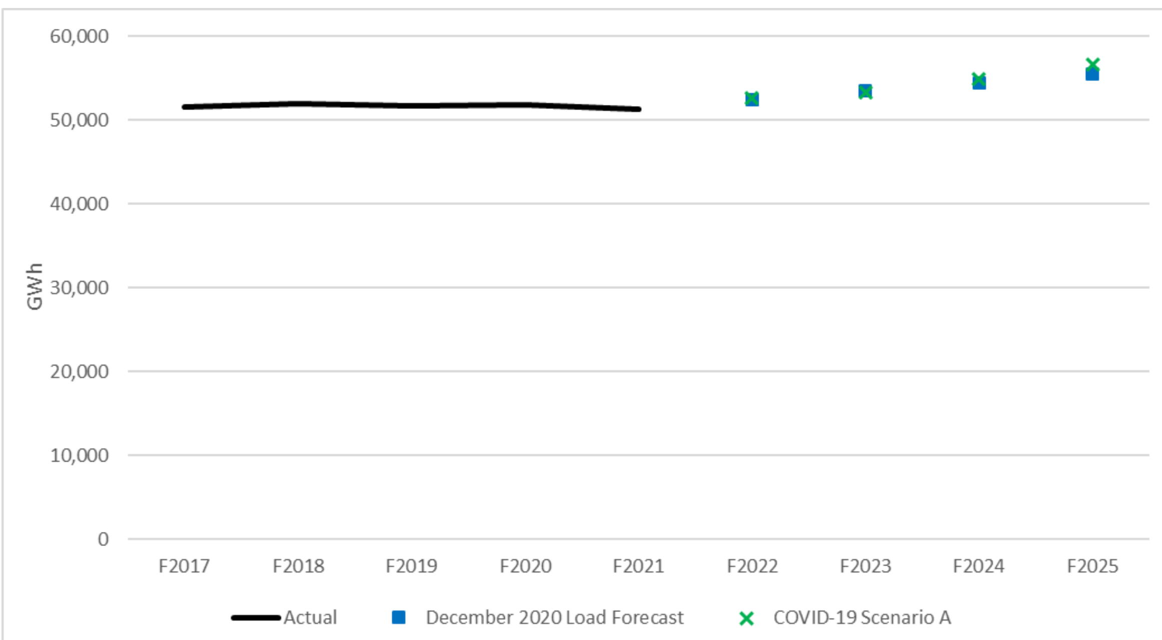
- Section 3.2 provides an overview of the December 2020 Load Forecast;
- Section 3.3 describes how BC Hydro has responded to the BCUC's directives and recommendations in its Decisions on the F2020-F2021 RRA and the Previous Application;
- Section 3.4 describes how BC Hydro has largely used its established methodology for the December 2020 Load Forecast, which has provided reliable short-term results. The only changes to methodology were adjustments to incorporate our understanding of the COVID-19 pandemic's estimated impacts on the provincial economy;
- Section 3.5 presents the results of the Load Forecast by customer sector. Aggregate load is forecast to return to pre-COVID-19 pandemic levels before the Test Period, and we are forecasting modest growth during the Test Period;
- Section 3.6 summarizes load forecast uncertainties, and explains how we use low and high forecast uncertainty bands to reflect load forecast uncertainties. We only use uncertainty bands in planning to ensure sufficient resources are available to meet various load scenarios, not in the derivation of the Test Period revenue requirements;
- Section 3.7 describes electrification loads related to the Government of B.C.'s CleanBC Plan for reducing GHG emissions which are included in the Load Forecast. These electrification loads reflected in the Load Forecast are distinct from any load associated with the Electrification Plan described in Chapter 10; and

- Section 3.8 presents the results of the Revenue Forecast by customer sector for the Test Period. The Revenue Forecast methodology is relatively unchanged from the Previous Application, with the notable difference being that we have added revenues associated with the Electrification Plan as a distinct revenue line item.

3.2 Load Forecast Overview

Figure 3-1 below shows recent actual results, the COVID-19 Scenario A used in the Previous Application, and the initial years of the December 2020 Load Forecast. It shows that the December 2020 Load Forecast provides an outlook for the next four years that is similar to COVID-19 Scenario A.

Figure 3-1 Total Domestic Billed Sales[117] History and Forecast



[117] Total Domestic Sales is the sum of the loads from the main customer sectors (Residential, Commercial, Light Industrial, and Large Industrial) and Other Loads (Irrigation, Street Lighting, City of New Westminster, FortisBC). Forecast values include all adjustments for rate impacts, VVO energy savings, and DSM savings.

While the historical load shown in Figure 3-1 has been relatively flat, the Load Forecast is showing growth of approximately 3,000 GWh during the Test Period, relative to the fiscal 2022 Decision. This growth is driven primarily by growth in the large industrial sector due to oil and gas and Liquified Natural Gas (**LNG**) projects coming into service and growth in the residential sector which is primarily due to light duty Electric Vehicles (**EVs**). Table 3-1 below shows the breakdown of Test Period load growth which is further explained in section 3.5 and Appendix F.

Table 3-1 Test Period Growth Total Domestic Sales

Sector or Sub-Sector	F2022 Decision per COVID-19 Scenario A (GWh)	F2025 Forecast per December 2020 Load Forecast (GWh)	Test Period Growth (F2025 Forecast - F2022 Decision) (GWh)
Residential	18,836	20,033	1,197
Commercial	14,366	13,820	(546)
Light Industrial	4,546	4,825	279
Large Industrial			
Forestry	5,000	4,714	(286)
Mining	3,987	4,072	85
Oil & Gas and LNG	2,806	5,042	2,236
Other	1,189	1,154	(35)
Other Loads	1,701	1,753	52
Total Test Period Growth	**52,431**	**55,413**	**2,982**

Table Notes:

1. Forecast values are billed sales and include all adjustments for rate impacts, Volt-ampere reactive and VVO energy savings, and DSM savings.

The December 2020 Load Forecast accounts for developments related to the COVID-19 pandemic and a number of electrification activities that are distinct from the Electrification Plan described in Chapter 10. Sections 3.3 through 3.7 of this chapter discuss the Load Forecast before the additional load from the Electrification Plan.

- **COVID-19 pandemic:** Work on the December 2020 Load Forecast began in mid April 2020, in the early stages of the COVID-19 pandemic. While the

December 2020 Load Forecast incorporates the estimated impacts of the COVID-19 pandemic on electricity demand, considerable uncertainty remains.

- **Electrification:** Electrification is a term used to refer to switching from the use of fossil fuels to the use of electricity from clean energy sources. This reduces greenhouse gas (**GHG**) emissions. The Government of B.C.'s CleanBC Plan sets out a path towards meeting the province's 2030 GHG emissions reduction targets. BC Hydro has been supporting electrification to reduce rate increases for customers, lower GHG emissions and provide economic benefits for the province of B.C. since 2018. The Load Forecast includes components which capture BC Hydro's Low Carbon Electrification (**LCE**) Projects/Programs, provincially-funded fuel switching programs, large industrial fuel switching loads, and specific policies and measures related to the Government of B.C.'s CleanBC plan, such as the *Zero Emission Vehicles Act* (**ZEV Act**).

  BC Hydro's Electrification Plan, described in Chapter 10, builds on existing government-funded actions and addresses remaining barriers with BC Hydro funded electrification actions that support provincial clean energy and economy development objectives. The estimated loads associated with the Electrification Plan are provided in Chapter 10 and are incremental to the Load Forecast.

3.3 BC Hydro has Considered and Addressed the BCUC's Directions and Recommendations

In the BCUC's Decision and Order No. G-246-20 on the F2020-F2021 RRA, the BCUC provided three directives pertaining to the load forecast to be included in this application. In the BCUC's Decision and Order No. G-187-21 on the Previous Application, the BCUC provided one directive pertaining to the load forecast to be included in this application as well as one recommendation. This section describes how BC Hydro considered and responded to these directives and the recommendation.

3.3.1 Industry Experts Confirm BC Hydro's Approach to Price Elasticity

In Directive 2 from the BCUC's Decision on the Fiscal 2020 to Fiscal 2021 Revenue Requirements Application the Panel directed BC Hydro to provide an analysis of:

(i) Any difference in elasticity between nominal versus real changes in price in the short-term; and

(ii) Any difference in elasticity between a price increase versus a price decrease.

BC Hydro engaged two North American utility experts from The Brattle Group to address this directive. Their report is included as Appendix CC.

The following definitions are relevant to understanding this section:

- **Price elasticity**– measures the change in demand for a product when the price of that product changes;
- **Price elasticity value**– the percentage change in electricity consumption caused by a 1 per cent change in price;
- **Nominal rates** – the rate (price per unit of electricity) before taking inflation into account; and
- **Real rates** – the adjusted rate after removal of inflation which reflects the real cost to the customer.

BC Hydro's load forecast methodology uses a price elasticity value of -0.10 applied to real rate changes for all sectors and the same elasticity value for rate increases and rate decreases. The Brattle Group confirmed this approach is consistent with industry standards.

3.3.1.1 Industry Standard is to Consider Real Price Impacts, as BC Hydro Does

Brattle Group took a variety of approaches to assess the approach to elasticity.

First, Brattle Group conducted a survey of North American utilities. All respondents confirmed they use real prices in their price elasticity calculations.

Second, Brattle Group performed a regression analysis. It concluded the elasticity value would differ if nominal rates were considered instead of real rates. This means that if BC Hydro was to change its methodology to consider nominal rate changes instead of real rate changes, the elasticity value of -0.10 would need to be updated to reflect the relationship between nominal rate changes and electricity consumption. BC Hydro's use of real rate changes and the elasticity value of -0.10 was recommended in a study by DNV GL Consulting in 2018 which was included in the F2020-F2021 RRA.[118]

Third, Brattle Group confirmed the elasticity methodology by a review of available literature. It concluded that *"(s)everal studies show that estimation of price elasticity is usually performed in real terms, in other words, by using inflation-adjusted values."*[119]

As previously noted by BC Hydro and acknowledged by the BCUC,[120] price elasticity adjustments have very little effect on the overall load forecast. Based on this we agree with The Brattle Group's conclusion that "…*adding complexity to the price elasticity estimations would not add value to the load forecast, especially for the short-run forecast due to the small effect of price elasticity, and may in fact hinder the regulatory process."*[121]

3.3.1.2 Industry Standard is to Use the Same Price Elasticity Value for Rate Increases and Decreases

The second area investigated by the Brattle Group in response to the BCUC directive was the difference in elasticity for rate increases versus rate decreases. All

118 Appendix Q, page 18, of the Fiscal 2020 to Fiscal 2021 Revenue Requirements Application.
119 Refer to Appendix CC, page 11.
120 Section 4.1.2.1 of BCUC's Decision on the Fiscal 2020 to Fiscal 2021 Revenue Requirements Application.
121 Refer to Appendix CC, page 16.

respondents to their survey confirmed they use the same elasticity value for rate increases and decreases.

The report shows that literature on the subject has varying theories and conclusions. Upon review of the literature and the survey results, Brattle Group stated "*(a)s a practical matter, in the utilities sector, real prices and the symmetry assumption have been the standard practice in load forecasting.*"[122]

Based on The Brattle Group's review and the previous review by DNV GL,[123] BC Hydro sees no reason to modify its current methodology.

3.3.2 Large Industrial Binary Forecast Methodology Performs Well

In the October 2018 Load Forecast (which was used in the F2020-F2021 RRA), BC Hydro modified the large industrial forecast methodology to provide a binary assessment of the likelihood an existing customer would operate or new customer would start-up in the first three years of the forecast period. Specifically, rather than applying a probability weighting to the customer load, BC Hydro considered the same risk assessment used in the probability-weighted approach to make a binary "in/out" determination in the first three years of the forecast to reflect the fact that operational shutdowns or start ups are binary in nature – the facility either operates or it doesn't.

In Directive 3 of the BCUC's Decision on the F2020-F2021 RRA, the BCUC directed BC Hydro to replicate the fiscal 2020 and fiscal 2021 load forecast using a probability-weighted approach and report on its performance relative to the binary approach. The comparative analysis provided in this section shows that, in most sub-sectors, the binary methodology yields results closer to actuals than the probability-weighted methodology.

[122] Refer to Appendix CC, page 16.
[123] Appendix Q of the Fiscal 2020- Fiscal 2021 Revenue Requirements Application

As indicated in the information provided in Table 3-2 and Table 3-3 below, with the exception of the forestry sub-sector for fiscal 2020 and the mining sub-sector for fiscal 2021, the forecast accuracy using the binary approach is similar to or somewhat better than the probability-weighted approach.

Table 3-2 Comparison of October 2018 Large Industrial Forecast to Actual Load for Fiscal 2020

	Fiscal 2020						
		Binary Forecast			Probability-Weighted Forecast		
	Actual F2020	October 2018 Binary Forecast	Actual - Forecast	Actual - Forecast	October 2018 Prob. Wtd Forecast	Actual - Forecast	Actual - Forecast
Sub-Sector	**GWh**	**GWh**	**GWh**	**%**	**GWh**	**GWh**	**%**
Forestry	5,893	6,540	(647)	(11)	6,083	(190)	(3)
Mining	3,863	3,884	(21)	(1)	3,829	33	1
Oil and Gas, LNG	2,334	2,741	(407)	(17)	2,752	(417)	(18)
Other	1,146	1,537	(391)	(34)	1,638	(492)	(43)
Total	**13,236**	**14,702**	**(1,466)**	**(11)**	**14,302**	**(1,066)**	**(8)**

Table Notes:

1. Actual and forecast loads are billed sales, after adjustments.

Table 3-3 Comparison of October 2018 Large Industrial Forecast to Actual Load for Fiscal 2021

	Fiscal 2021						
		Binary Forecast			Probability-Weighted Forecast		
	Actual F2021	October 2018 Binary Forecast	Actual - Forecast	Actual - Forecast	October 2018 Prob. Wtd Forecast	Actual - Forecast	Actual - Forecast
Sub-Sector	**GWh**	**GWh**	**GWh**	**%**	**GWh**	**GWh**	**%**
Forestry	5,149	5,761	(612)	(12)	5,783	(634)	(12)
Mining	3,779	3,936	(157)	(4)	3,881	(102)	(3)
Oil and Gas, LNG	2,267	2,959	(692)	(31)	2,984	(717)	(32)
Other	1,105	1,588	(483)	(44)	1,689	(584)	(53)
Total	**12,300**	**14,244**	**(1,944)**	**(16)**	**14,337**	**(2,037)**	**(17)**

Table Notes:

1. Actual and forecast loads are billed sales, after adjustments.

3.3.2.1 Analysis by Sub-sector

In the October 2018 Load Forecast, we modified large industrial sector probabilistic approach to apply a binary method for specific accounts for the first three years of the forecast horizon. The binary method results in a discrete projection (i.e., in or out) of load and revenues. This approach resulted in forecast differences to 13 of the approximately 190 large industrial customer accounts and was applied to the following circumstances:

- To existing customer facilities where the probability weighting is entirely driven by closure risk;
- For potential new customer facilities or expansions of existing facilities where the probability weighting is entirely driven by whether and when the proposed facilities come into service; and
- For existing non-operational customer facilities where the probability weighting is driven by whether the facilities will restart operations.

For the **forestry sub-sector**, the analysis indicates the probability-weighted approach performed better than the binary approach. However, in assessing the results, BC Hydro observes the following:

- For fiscal 2020, the binary approach made the correct “in/out” assumption of operating mills facing closure risk probabilities and non-operational mills facing restart probabilities. However, electricity sales to a number of operating mills were lower than forecast for reasons not reflected in either the binary or probability approaches. In particular, a malware attack substantially reduced production (and associated electricity sales) at three pulp and paper mills. The probability-weighted approach resulted in a more accurate forecast because the closure risk adjustments lowered the forecast which coincidentally resulted in a forecast that was closer to the reduced operating loads;

- For fiscal 2021, the binary and probabilistic approaches produced similar results. However, the binary ‘in/out” assumptions for two mills were incorrect. One mill that was assumed to close remained operational and another mill closed due to the COVID-19 pandemic. The variances for these mills were offsetting so the overall results favoured the binary approach. The binary outlooks for these mills were revised in BC Hydro’s subsequent June 2019 and March 2020 Load Forecasts and BC Hydro’s COVID-19 Scenario A. COVID-19 Scenario A, which was used in BC Hydro’s Previous Application, made the correct binary ‘in/out” assumptions on all mills.

In summary, the forestry sub-sector results are inconclusive for determining whether the binary approach will result in more accurate three-year forecasts relative to the probabilistic approach. BC Hydro will continue to assess both approaches in future load forecasts.

For the **mining sub-sector**, the fiscal 2020 and fiscal 2021 binary approach incorrectly assumed a certain mine would remain operational while the probability-weighted forecast included a fractional load for that mine based on closure risk. This made the probability-weighted forecast lower than the binary forecast in both years. The mine in question closed during fiscal 2020 and remained closed through fiscal 2021. The load reduction from the mine closure was offset by positive variances in other mining operations in fiscal 2020. For fiscal 2021, the positive variances in other mining operations had less of an offsetting impact.

For the **oil and gas (including LNG) sub-sector** in fiscal 2020 and fiscal 2021, the binary approach was more accurate because the binary approach assumed the probability-weighted in-service dates for three new projects/expansions would occur at later dates.

For the **other sub-sector** in fiscal 2020 and fiscal 2021, the binary approach was more accurate because the binary approach correctly assumed the addition of a new cryptocurrency project would not occur. The fractional load for that project in the probability-weighted forecast made the forecast much higher than actual load.

3.3.2.2 Impacts of the Covid-19 Pandemic on Binary vs. Probability-Weighted Analysis

It is important to note that the October 2018 and subsequent June 2019 and March 2020 Load Forecasts did not consider a global pandemic. The COVID-19 pandemic resulted in additional load disruptions within the large industrial sector in fiscal 2021, particularly within the pulp and paper segment of the forestry sub-sector.

To estimate the impacts of the COVID-19 pandemic, BC Hydro developed two scenarios: COVID-19 Scenario A and COVID-19 Scenario B. COVID-19 Scenario A was used in the Previous Application and included adjustments to industrial customer loads to account for closures based on the binary approach, as well as operational impacts. This produced results very close to actual load for fiscal 2021, as shown in Table 3-4 below.

Table 3-4 Comparison of COVID-19 Scenario A Large Industrial to Actual Load for Fiscal 2021

	Fiscal 2021			
	Actual F2021	COVID-19 Scenario A	Actual - Forecast	Actual - Forecast
Sub-Sector	**GWh**	**GWh**	**GWh**	**%**
Forestry	5,149	4,971	178	4
Mining	3,779	3,753	26	1
Oil and Gas, LNG	2,267	2,369	-102	(4)
Other	1,105	1,014	91	9
Total	**12,300**	**12,107**	**193**	**2**

Table Notes:
1. Actual and forecast loads are billed sales, after adjustments.

Given there are only two years of available data to compare forecast methodologies, including a year impacted by the pandemic, it is premature to draw definitive conclusions on which method produces more accurate results. BC Hydro will continue to monitor the performance of this methodology as part of its ongoing commitment to improving load forecast methodologies and results.

3.3.3 Fiscal 2020 and Fiscal 2021 Load Variances Explained

In Directive 4, of the BCUC's Decision on the F2020-F2021 RRA Decision, the BCUC directed BC Hydro to adjust its load forecast for the entire fiscal 2020 and fiscal 2021 test period by the percentage variance experienced between April 1, 2019 and December 31, 2019 for each customer class. It also directed BC Hydro to (ii) report on the variance in this application, and (iii) where possible, clearly distinguish the extent of any variance that is attributable to and independent from the COVID-19 pandemic. This section addresses the reporting directive.

3.3.3.1 The Fiscal 2020 Variance Is Negligible

The fiscal 2020 load variance explanation relative to the adjusted load forecast in Directive 4 is provided below.

Table 3-5 provides the fiscal 2020 load variance.

Table 3-5 Fiscal 2020 Domestic Energy Accrued Sales Variance

	(GWh)	Schedule Reference	F2020 Decision	Actual	Difference	% Diff
			1	2	3	4
1	Residential	14.0 L1	17,751	17,993	242	1%
2	Light Industrial and Commercial	14.0 L2	18,631	18,692	60	0%
3	Large Industrial	14.0 L3+L9	13,533	13,398	(135)	-1%
4	Other	14.0 L4:L8+L10	2,042	1,848	(194)	-10%
5	Total	14.0 L16	51,958	51,931	(27)	0%

Table Notes:

1. Actual sales are accrued sales.

The total load variance for fiscal 2020 was 27 GWh, which is negligible. We believe any variance that might be attributed to the COVID-19 pandemic is also negligible, as the pandemic began to impact B.C. in late March 2020 (i.e., at the end of fiscal 2020).

The negligible overall variance results from small positive variances in the residential, commercial and light industrial sectors offset by small negative variances in the large industrial and other sales sectors. BC Hydro is not able to provide a definitive variance explanation by customer sector, in large part because the variances are relative to the load forecast as adjusted by the BCUC's F2020-F2021 RRA Decision, and not to the October 2018 Load Forecast on which that application was based.

In general, the small sector variances for fiscal 2020 are likely due to some combination of the following uncertainty factors:

- Temperature;
- Account growth;
- Economic activity;
- Other utility sales; and
- Industrial operations.

3.3.3.2 The Fiscal 2021 Variance is Attributable to the COVID-19 Pandemic

Unlike the variance for fiscal 2020, we believe the fiscal 2021 variance is attributable to the COVID-19 pandemic.

Table 3-6 below provides the variance in domestic energy sales for fiscal 2021.

Table 3-6 Fiscal 2021 Domestic Energy Sales Variances

	(GWh)	Schedule Reference	F2021 Decision	Actual	Diff	% Diff
			1	2	3=2-1	4=3/1
1	Residential	14.0 L1	17,927	18,982	1,055	6%
2	Light Industrial and Commercial	14.0 L2	18,744	18,091	(653)	-3%
3	Large Industrial	14.0 L3	13,203	12,438	(765)	-6%
4	Other	14.0 L4:L10	2,066	1,628	(438)	-21%
5	**Total Domestic Energy Sales**	14.0 L11	**51,940**	**51,139**	(801)	-2%

The following explanation is from the BC Hydro Fiscal 2021 Annual Report to the British Columbia Utilities Commission, Attachment 1 to Section 6, which is provided as Appendix X.

Pursuant to Directive 4 of the BCUC's F2020-F2021 RRA Decision, this variance analysis includes an estimate of the extent of any variance that is attributed to and independent from the COVID-19 pandemic. Developing a precise estimate of load variance due to the COVID-19 pandemic is difficult because it involves a comparison of "what if" scenarios and forecasts, for which there are no measurable "after-the-fact" metrics. In particular, the COVID-19 Scenario A used to estimate the potential load impacts in fiscal 2021 was developed relative to the March 2020 Load Forecast whereas the F2020-F2021 RRA was based on the October 2018 Load Forecast, but then reduced by 2.6 per cent in accordance with the BCUC's decision on the F2020-F2021 RRA. Since the March 2020 Load Forecast was a comprehensive forecast with updates to all input assumptions, the extent to which these assumptions differ from assumptions underpinning the F2020-F2021 RRA make it difficult to attribute variances due to the pandemic relative to the October 2018 Load Forecast.

For the purpose of responding to Directive 4, BC Hydro applied a simplified approach. We compared fiscal 2021 actual energy (GWh) consumption against fiscal 2020 actual consumption by major customer group. We then compared those differences to the net effect of COVID-19 Scenario A load impacts on the March 2020 Load Forecast for fiscal 2021. This comparison indicates that the differences between fiscal 2021 actuals and fiscal 2020 actuals are similar to the net effect of the assumed load declines reflected in the COVID-19 Scenario A on the March 2020 Load Forecast.

Following this, we assessed the variance results against our typical variance factors such as residential account growth, temperature, and specific large industrial account information to determine whether any variances can be clearly attributed to factors other than the COVID-19 pandemic.

Overall, actual domestic energy sales in fiscal 2021 were 801 GWh (or 2 per cent) lower than the fiscal 2021 Decision. This was due to:

- Line 1 - Actual residential sales were 1,055 GWh (or 6 per cent) higher than the fiscal 2021 Decision. Variances in residential sales are driven by three main factors: electricity sales per account (use per account), temperature, and number of accounts. In fiscal 2021, the residential sales variance was driven primarily by higher than expected use per account. Higher use per account variance can be driven by many different factors. While the exact drivers in this case are not known, the likely primary driver is the COVID-19 pandemic, which saw residential customers spend more time at home, working from home, and studying from home, resulting in higher consumption. The number of accounts was slightly favourable. The total number of residential accounts was 10,600 (less than 1 per cent) higher than plan and did not contribute significantly to the sales variance. There was a small offsetting variance for temperature, which was slightly unfavourable. Temperatures were close to normal, with warmer temperatures in December and January offset by colder temperatures in February and several other months of the year.

  Actual fiscal 2021 sales are higher than fiscal 2020 actual sales and both the October 2018 and March 2020 Load Forecast sales expectations for fiscal 2021. Actual fiscal 2021 sales are directionally consistent with the COVID-19 Scenario A projection that residential sales would increase relative to the pre-pandemic March 2020 Load Forecast. While the net increase was not as large as projected, it was still higher relative to the fiscal 2021 Decision. Based on the above comparisons and consideration of temperature and account information, BC Hydro believes the positive fiscal 2021 sales variance can be largely attributed to the COVID-19 pandemic;

- Line 2 - Actual light industrial and commercial sales were 653 GWh (or 3 per cent) lower than the fiscal 2021 Decision. The commercial sector is comprised of a diverse group of business classes and the lower energy consumption can generally be attributed to many different factors. For fiscal 2021 we expected the primary factor was closures and curtailments due to public health orders relating to the COVID-19 pandemic. To confirm this, BC Hydro compared fiscal 2021 actual load to fiscal 2020 actual load. The business classes with the largest reduction in their load were offices, accommodations, food services, entertainment, recreation, shopping centers, and educational services. Actual fiscal 2021 sales are lower than fiscal 2020 actual sales and both the October 2018 and March 2020 Load Forecast sales expectations for fiscal 2021. Actual fiscal 2021 sales are directionally consistent with the COVID-19 Scenario A projection that sales would decline relative to the pre-pandemic March 2020 Load Forecast. While the net decline was not as large as projected, it was still lower relative to the fiscal 2021 Decision. Based on the above comparison BC Hydro believes the negative fiscal 2021 sales variance is largely attributable to the COVID-19 pandemic;
- Line 3 - Actual large industrial sales were 765 GWh (or 6 per cent) lower than the fiscal 2021 Decision. Actual fiscal 2021 sales are lower than fiscal 2020 actual sales and both the October 2018 and March 2020 Load Forecast sales expectations for fiscal 2021. Actual fiscal 2021 sales are also consistent with COVID-19 Scenario A sales projections and underlying account assumptions. Based on the above comparison BC Hydro believes the negative fiscal 2021 sales variance is largely attributable to the COVID-19 pandemic; and
- Line 4 – The original forecast for the Other customer sector was 1,650 GWh. In response to Directive 4 of Order No. G-246-20, BC Hydro increased the forecast by 25.2 per cent for a revised forecast of 2,066 GWh in the fiscal 2021 Decision. Actual energy sales to the Other customer sector of 1,628 GWh were

more consistent with the original forecast and were 438 GWh or 21 per cent lower than the revised forecast.

3.3.4 Estimated Historical Electric Vehicle Consumption is Provided

Directive 3 of the BCUC's Decision on the Previous Application directed BC Hydro to provide the historical actuals or estimated actuals related to electric vehicle (**EV**) energy consumption over the five previous load forecasts (i.e., fiscal 2017 to fiscal 2021).

BC Hydro's estimated actual energy consumption related to light duty electric vehicles is shown in Table 3-7 below.

Table 3-7 Estimated Actual Light Duty EV Load

Fiscal Year	Estimated Light Duty EV Load (GWh)
F2017	17
F2018	30
F2019	59
F2020	106
F2021	145

The values in Table 3-7 above, are estimated values based on the actual number of plug-in battery electric vehicles and plug-in hybrid electric vehicles in B.C. each year multiplied by the estimated distance driven and vehicle efficiency assumptions in the December 2020 EV forecast model. The estimated values in this table demonstrate that EVs are currently a small part of our overall load. However, as further discussed in this chapter and Appendix F, we expect EV sales and the associated load to grow over time, making EVs a major contributor to load growth in our 20-year load forecast.

3.3.5 EV Model Accounts for Government Policy Influence on EV Usage and Associated Load

As part of its Decision on the Previous Application, the BCUC encouraged BC Hydro to closely monitor the impact of government policy on emission reduction, customer uptake on government incentives and any impact conservation and efficiency may have on the EV forecast in preparing its future load forecasts. The BCUC also encouraged BC Hydro to provide further commentary on the impact of government policy on EV load in this application.

BC Hydro's EV energy model (**EV model**) reflects government policy both explicitly and implicitly through the different model variables that are explained below. We will continue to monitor government policy developments and make any necessary updates to the model.

3.3.5.1 EV Model Explicitly Accounts for Government Policies

BC Hydro's EV model is designed to explicitly account for provincial and federal government incentives for purchasing EVs and home charging stations. BC Hydro only considers programs and timing committed by government and does not develop a forecast for incentives. If the incentives are extended beyond the committed budget, making EVs more economical, the actual number of EVs being purchased exceed what has been forecasted by BC Hydro.

The December 2020 low EV energy forecast follows the schedule set by the ZEV Act, which mandates that by 2040, 100 per cent of new vehicles sold in B.C. are to be electric. In contrast, the high EV forecast assumes the natural uptake of EVs will be higher than the minimum requirements set out in the ZEV Act, as the purchase costs decline, and consumers' preferences change over time. BC Hydro developed its reference EV forecast by taking the average of the high and low EV forecasts.

3.3.5.2 EV Model Implicitly Accounts for Other Government Initiatives

There are also some model inputs that indirectly capture government initiatives. For example, the EV model includes both electricity and gasoline price forecasts when developing the EV forecast. The gasoline prices are assumed to implicitly include the government policies around carbon tax, which in turn, disincentivizes the purchase of gasoline-fueled vehicles, making EVs more economical. The EV model also implicitly captures government’s policies for auto manufacturer to produce EVs, and for enhancing the province’s public charging infrastructure. These are captured by the model’s market and desirability constraints, which are explained below.

The **market constraint** is designed to capture the impact of the limited availability of EVs that auto manufacturers will produce overall and then ultimately allocate to the British Columbia market. Our professional judgement in setting the market constraint is also informed by previous adoption rates for hybrid vehicles. This constraint is relaxed after the forecast’s early years as more electric vehicle types and larger quantities of each become available.

The **desirability constraint** in the model indirectly captures initiatives to enhance the province’s public charging infrastructure, as it is intended to include the potential purchaser’s perception of:

- Kilometres per charge and associated range anxiety;
- Charging speeds;
- Public charging station availability; and
- The cost and ease of installation of charging stations in a home.

The desirability constraint reflects that a certain percentage of the population may be hesitant to buy an EV even if their driving needs can be met. This constraint is relaxed over time to reflect the change in purchaser’s perception of the factors mentioned above.

3.4 Comprehensive Load Forecast was Developed using Proven Methodologies

As described in this section, BC Hydro has largely used its established methodology for the December 2020 Load Forecast, which has provided reliable short-term results. The only adjustments were to incorporate our understanding of the COVID-19 pandemic’s estimated impacts on the provincial economy.

A report further describing the methodologies and results is provided as Appendix F.

3.4.1 Previous Load Forecasts have been Reliable

BC Hydro's established methodology forms a sound basis for the December 2020 Load Forecast. An independent audit in 2017 concluded our load forecasting methodologies are robust and compare well to industry best practices.[124] The methodology has been reviewed and improved under the oversight of the BCUC through the last three revenue requirements applications. As discussed below, our load forecasts have consistently provided reliable short-term results and year-to-date actual results are tracking closely to the December 2020 Load Forecast.

Table 3-8 below, shows that with the exception of forecasts not accounting for COVID-19, BC Hydro's load forecasts of Total Domestic Sales have been within 3 per cent of actual load over the past five years and five forecast vintages.

[124] Appendix P, page 15 of the Fiscal 2020 to Fiscal 2021 Revenue Requirements Application,.

Table 3-8 History and Forecast Variance for Total Domestic Sales

	Total Domestic Sales History and Forecast Vintages (GWh)						Actual - Forecast (GWh)					% Variance				
Fiscal Year	Actual	May 2016	October 2018	June 2019	COVID-19 Scenario A	December 2020	May 2016	October 2018	June 2019	COVID-19 Scenario A	December 2020	May 2016	October 2018	June 2019	COVID-19 Scenario A	December 2020
F2017	51,895	51,860					35					0.1%				
F2018	52,102	51,838					264					0.5%				
F2019	52,413	52,664					(251)					(0.5%)				
F2020	51,931	53,004	53,567	53,103			(1,073)	(1,636)				(2%)	(3%)	(2%)		
F2021	51,139	53,332	53,253	53,652	50,406	51,002	(2,193)	(2,114)	(2,513)	733	137	(4%)	(4%)	(5%)	1%	0.3%

Table Notes

1. Actual sales are accrued sales as reported in BC Hydro's Annual Reports to the BCUC.

The variance for all three forecasts in fiscal 2020 was largely due to large industrial sales being lower than expected due to operational curtailments, project delays or cancellations, and production slowdowns due to poor market conditions. As previously indicated,[125] the large industrial sector is the most volatile and usually results in higher variances, even though the methodology is robust.

The higher variance for the May 2016, October 2018, and June 2019 forecasts in fiscal 2021 was because those forecasts did not account for the COVID-19 pandemic. The two forecasts that did account for the impacts of COVID-19 pandemic (COVID-19 Scenario A and the December 2020 Load Forecast) were within 1 per cent of actual load.

Excluding the pre-COVID-19 pandemic fiscal 2021 forecasts, all forecast variances are within the expected range based on industry benchmarks.

To address the fact that actual load may be higher or lower than forecast, BC Hydro has a load forecast variance account, which captures variances between planned and actual customer load.[126]

3.4.2 December 2020 Load Forecast is a Comprehensive Load Forecast

The December 2020 Load Forecast is a comprehensive load forecast which includes updates to all key inputs and model calibration periods. In addition to being used to estimate future electricity sales revenues and as an input into our energy studies,[127] the December 2020 Load Forecast is also used in the 2021 Integrated Resource Plan which will be filed with the BCUC in December 2021. Given its variety of uses, the December 2020 Load Forecast consists of a suite of energy and peak demand forecasts, consisting of a reference forecast as well as low and high forecasts, which represent the uncertainty band around the reference forecast.

[125] Appendix P, page 16 of the Fiscal 2020 to Fiscal 2021 Revenue Requirements Application.
[126] The load forecast variance account was established per BCUC Order No. G-246-20, directive 15 relating to the Fiscal 2020 to Fiscal 2021 Revenue Requirements Application.
[127] As described in Chapter 4, section 4.3.

Key inputs were updated for the December 2020 reference load forecast, as outlined in Table 3-9 below.

Table 3-9 Input Assumptions for December 2020 Load Forecast

Sector	Input	Reference or Assumption
Residential & Commercial	Economic Forecast	Conference Board of Canada (**CBoC**) 2020
	Energy Information Administration Data	2020
	Calibration Period	Fiscal 2011 to Fiscal 2020
	Light Duty EVs	Refer to Appendix F, section 7
Light Industrial	GDP Forecast	Fiscal 2021 and fiscal 2022: BC Ministry of Finance September 2020 Q1 Report
		Fiscal 2023 to fiscal 2041 to BC Hydro's provincial projection based on the Conference Board's 2020 economic outlook
	Account by Account Assessment	Comprehensive Assessment
Large Industrial	Account by Account Assessment	Comprehensive Assessment
Additions	Low Carbon Electrification (**LCE**)/Fuel Switching Projects/Programs	As described in Appendix N of the Previous Application
Adjustments	Rate Impacts	Previous Application Rates Plan
	DSM[128] Savings	Fiscal 2022 to Fiscal 2024 Annual Business Plan.

3.4.3 Forecast Includes updated Economic Forecast which Accounts for COVID-19 Impacts

Each year the Conference Board provides BC Hydro with a 30-year economic outlook and a detailed regional forecast of various economic drivers, which is an input to our residential, commercial, and light industrial load forecast models. The 2020 forecast cycle was disrupted by the onset of the COVID-19 pandemic. BC Hydro worked closely with the Conference Board so that the forecast information received was as current as possible, while still meeting our forecast development

[128] The DSM plan used in the December 2020 Load Forecast was approved in the Fiscal 2022 to Fiscal 2024 Annual Business Plan. It does not include any potential recommended actions from the 2021 Integrated Resource Plan.

timelines. At the time, the COVID-19 pandemic and the international, national, and provincial responses to it were changing. Therefore, while the Load Forecast incorporates the estimated impacts of the COVID-19 pandemic on electricity demand, considerable uncertainty remains. Determining the full impact of the pandemic to the economy (and by extension, BC Hydro's load) over the next few years will continue to be a challenge.

Further details are provided below and in the Conference Board's report titled "B.C. Economic Outlook 2020" which is provided as part of Appendix F.

3.4.4 The only Methodological Changes made relate to COVID-19 Pandemic Impacts

The only methodology changes between BC Hydro's previous March 2020 Load Forecast and the current Load Forecast, were those required as a result of efforts to quantify and incorporate the most up to date COVID-19 pandemic-related impacts in the Load Forecast. The changes are summarized below and further details are provided in Appendix F.

- Due to timing constraints associated with developing an economic outlook that reflected the most current COVID-19 pandemic impacts (see previous section), the Conference Board economic forecast was provided only for the Metro Vancouver area. Normally, the Conference Board calibrates its customized BC Hydro regional economic forecast model to its provincial forecast model. However, in order to leverage their updated view of COVID-19 impacts and meet BC Hydro's load forecast schedule, the Conference Board determined it could use its Metro Vancouver area economic model to provide a smaller suite of the economic drivers used in BC Hydro's load forecast models in lieu of their regional economic forecast model. This economic forecast is contained in the Conference Board of Canada's "B.C. Economic Outlook 2020" report, which is included as an appendix to Appendix F.

- Using the more current Metro Vancouver area economic forecast, BC Hydro developed a method to extrapolate the forecast results to each of BC Hydro's regional residential and commercial forecast models. Similarly, the Metro Vancouver GDP projections were converted into a provincial projection and used in our light industrial model. The necessary trade-off in favour of using the Conference Board's more current economic forecast over geographic specificity introduces additional uncertainty to the Load Forecast. However, this uncertainty is mitigated by the fact that the Metro Vancouver area represents the largest portion of BC Hydro's overall load.
- The Smart Meter Infrastructure (**SMI**) data was used to assess the overall impact of COVID-19. Our billed sales data was used to quantify impacts of the COVID-19 pandemic on electricity usage and make adjustments to the residential and commercial forecast model outputs so that the Load Forecast aligned with observed trends in actual usage. This information was also used to estimate the impacts of a long-term assumption that 10 per cent of people would continue to work or study from home, following the pandemic.
- The December 2020 Load Forecast uncertainty bands were developed using discrete cases in lieu of the Monte Carlo model used in developing previous forecast uncertainty bands. This change was made to capture uncertainty related to COVID-19 and does not reflect a permanent deviation from the Monte Carlo model. BC Hydro is reviewing its approach to forecasting uncertainty and will include results of that review in future load forecasts. The uncertainty bands are described in section 3.6 below and Appendix F, section 8.

3.5 Load Forecast Results

This section provides specific details about the December 2020 Load Forecast, which forms the basis for the Test Period revenue requirements. As we describe below, aggregate load is forecast to return to pre-COVID-19 pandemic levels before the Test Period, and we are forecasting modest growth during the Test Period.

3.5.1 Note Regarding Billed Versus Accrued Sales

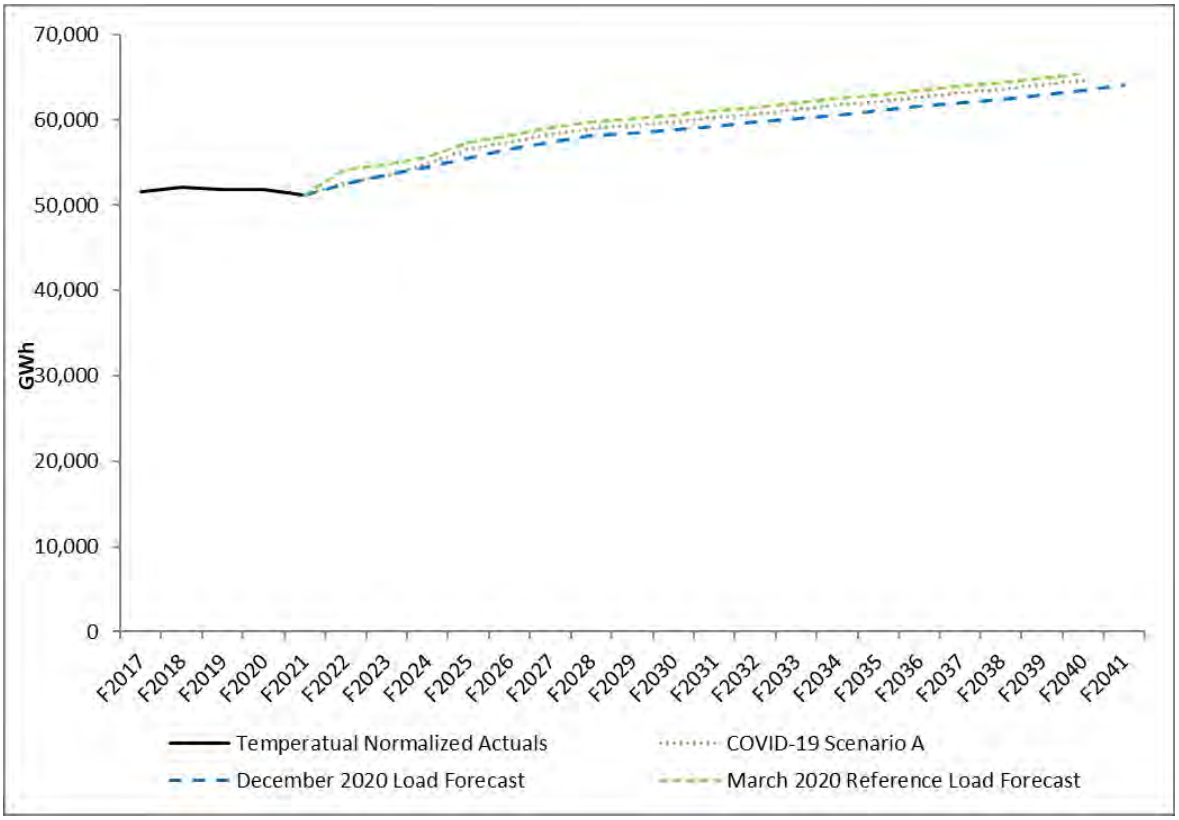
Throughout the Chapter, there are tables and figures which specify billed or accrued sales. In general terms, billed sales represent what was billed to our customers in a month or over a fiscal year in line with our billing cycle, which may span several months. Accrued sales represent the electricity consumed during a calendar month, which involves accruals of an estimate of the unbilled sales in that month, in accordance with accounting standards.

Our load forecasts are based on relationships between load drivers and billed sales. As such, the forecast of future customer loads shown in the chapter are usually in the form of billed sales projections. However, revenue projections from these future loads are based on accrued sales as BC Hydro’s rates are set on an accrual basis in accordance with accounting principles.

3.5.2 Aggregate Load is Expected to Return to Pre-pandemic Growth Rates by the Start of the Test Period

Figure 3-2 below shows the current, December 2020 Load Forecast and COVID-19 Scenario A which formed the basis of the Previous Application. The December 2020 Load Forecast is similar to COVID-19 Scenario A during the Test Period. The forecast assumes a gradual economic recovery beginning in fiscal 2021 with a full economic recovery and return to pre-pandemic load growth levels in all major sectors by the beginning of the Test Period.

Figure 3-2 Total Domestic Sales History and Forecast



While uncertainty associated with the pandemic's short- and long-term impacts on the provincial economy and BC Hydro's load remains, the province's restart plan[129] is consistent with the Conference Board's economic assumptions informing the Load Forecast.

Over the long term, the December 2020 Load Forecast largely assumes a return to pre-pandemic economic growth rates and reflects some offsetting structural changes in the residential and commercial sectors, related to increased work-from-home and study-from-home assumptions.

The December 2020 Load Forecast projects a moderate long-term growth in total firm sales averaging 1.0 per cent per year from fiscal 2020 through fiscal 2040, after

[129] https://www2.gov.bc.ca/gov/content/covid-19/info/restart

adjusting for planned DSM and rate impacts. This growth rate is similar to the March 2020 Load Forecast. However, the absolute load level in fiscal 2040 is lower than the March 2020 Load Forecast due to load declines attributed to the COVID-19 pandemic in fiscal 2021. In other words, BC Hydro does not expect future electricity sales to return to the pre-pandemic load forecast levels even though the growth rates are similar because the lower starting point yields a lower end point.

Medium-term growth is primarily due to oil and gas and LNG growth in the industrial sector and Light Duty EVs growth, which is allocated to the residential and commercial sectors. This growth is partially offset by declines in the forestry sector.

3.5.3 Load Forecast Shows Moderate Growth over the Test Period

This section provides specific details about our Load Forecast over the Test Period. As described in section 3.5.2 above, the December 2020 Load Forecast projects a moderate annual average growth rate of approximately 1.0 per cent from fiscal 2020 to fiscal 2040. Over the short to medium-term, BC Hydro's load is forecasted to grow by approximately 3,000 GWh during the Test Period, relative to the fiscal 2022 Decision. While this forecast does include some electrification related growth (as explained in section 3.7), this growth does not include incremental load that would result from BC Hydro's Electrification Plan, which is described in Chapter 10.

A detailed breakdown of the Load Forecast by major customer sector is provided in Table 3-10 below. A comparison against COVID-19 Scenario A is also provided in the table. Over the Test Period, the Load Forecast is not substantially different than COVID-19 Scenario A used in the Previous Application.

Table 3-10 Total Domestic Sales (After Adjustments)

	Temperature Normalized Actuals					December 2020 Load Forecast				COVID-19 Scenario A			
Fiscal Year	**F2017**	**F2018**	**F2019**	**F2020**	**F2021**	**F2022**	**F2023**	**F2024**	**F2025**	**F2022**	**F2023**	**F2024**	**F2025**
Residential	17,952	17,997	17,876	18,349	19,273	19,789	19,678	19,892	20,033	18,836	19,123	19,380	19,683
Commercial	14,582	14,513	14,557	14,336	13,664	13,654	13,968	13,921	13,820	14,366	14,313	14,239	14,159
Light Industrial	4,275	4,364	4,422	4,311	4,498	4,628	4,825	4,810	4,825	4,546	4,554	4,955	4,978
Commercial & Light Industrial[2] (General)	18,856	18,877	18,979	18,648	18,162	18,282	18,794	18,730	18,645	18,911	18,867	19,193	19,136
Large Industrial	13,106	13,513	13,766	13,235	12,299	12,437	13,183	14,042	14,982	12,982	13,511	14,435	15,877
Other Loads[3]	1,684	1,638	1,510	1,646	1,628[4]	1,748	1,730	1,728	1,754	1,700	1,725	1,747	1,786
Total Domestic Sales[5]	**51,599**	**52,025**	**52,131**	**51,877**	**51,362**	**52,256**	**53,384**	**54,393**	**55,414**	**52,430**	**53,226**	**54,756**	**56,483**

Table Notes:

1. All actual and forecast values are on a billed sales basis.
2. Light Industrial/Commercial is the sum of the loads in the light industrial sector and commercial sector.
3. Other Loads include irrigation, street lighting, BC Hydro sales to City of New Westminster, FortisBC Inc, Seattle City Light and Hyder Alaska.
4. Preliminary estimate based on accrued sales data.
5. Total Domestic Sales is the sum of the loads from the Main Customer Sectors and Other Loads. BC Hydro own use is not included.

A detailed discussion of the individual sector results for the Test Period follows.

3.5.4 Residential Sector Results for Test Period

The residential sector consists of approximately 1.9 million accounts and represented 37 per cent of total domestic sales in fiscal 2021. The billed sales residential forecast history and forecast to fiscal 2025 is presented in Table 3-11 below.

Table 3-11 Residential Sales History and Forecast

Temp. Normalized Billed Sales	COVID-19 Scenario A	December 2020 Load Forecast			
F2021 Actual	F2022 Decision	F2022 Forecast	F2023 Plan	F2024 Plan	F2025 Plan
(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)
19,273	18,836	19,789	19,678	19,892	20,033

1. Forecast is billed sales after adjustments for rate impacts, volt-ampere reactive and voltage optimization (**VVO**) energy savings, and DSM savings

As shown in Table 3-11 above, over the Test Period, sales to the residential sector are forecasted to grow by approximately 245 GWh. This sales profile is driven by a number of offsetting factors with a small amount of growth over the Test Period. Over the near term, higher electricity sales are primarily driven by the number of residential customers assumed to be spending more time at home due to COVID-19 pandemic measures. By fiscal 2023, residential sector growth is driven by more traditional growth drivers, such as use per account and EV growth, which are partially offset by DSM savings and end use efficiency increases which have a downward impact on average use per account.

Residential accounts are expected to grow by approximately 82,000 accounts and residential EV stock is expected to grow by nearly 117,000 vehicles during the Test Period.

The residential forecast is the estimated use-per-account multiplied by the number of accounts. The pre-adjustments 'use-per-account projection' is determined by using

BC Hydro's industry-standard SAE model. The model uses economic drivers of the load such as population growth, personal income, and end-use appliance stock efficiency. The forecasted number of accounts is driven by the Conference Board's population growth and housing demand forecasts. BC Hydro has a separate model to forecast potential load from EVs. Eighty-five per cent of the total forecasted load for light-duty electric vehicles is added to the residential load forecast. As in previous applications, further adjustments are made to account for:

- Codes and Standards overlap between SAE model assumptions and BC Hydro's DSM plan;
- Load additions related to BC Hydro's LCE Projects/Programs and provincial government-funded fuel switching programs administered by BC Hydro;
- Assumed load reductions/additions that result from rate impacts;
- Volt-ampere reactive and VVO energy savings at our distribution substations; and
- Incremental savings from our DSM plan.

A detailed view of the forecast build-up is provided in Appendix F.

3.5.5 Commercial Sector Results for Test Period

The commercial sector consists of approximately 180,000 accounts and represented 27 per cent of total domestic sales in fiscal 2021. The commercial sector is diverse, including everything from small corner stores to large warehouses, schools, office buildings, restaurants, and health care facilities. For the past 10 years, the commercial sector load has been relatively flat as growth in some sub-sectors has been offset by declining activity or improved electrical efficiency in others.

The commercial forecast history and sales to fiscal 2025 is presented in Table 3-12 below.

Table 3-12 Commercial Sales History and Forecast

Temp. Normalized Billed Sales	COVID-19 Scenario A	December 2020 Load Forecast			
F2021 Actual	F2022 Decision	F2022 Forecast	F2023 Plan	F2024 Plan	F2025 Plan
(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)
13,759	14,366	13,654	13,968	13,921	13,820

Table Notes:

1. Forecast is billed sales after adjustments for rate impacts, volt-ampere reactive and VVO energy savings, and DSM savings

As shown in Table 3-12 above, the commercial load is expected to slowly recover from the load decline that occurred in fiscal 2021 as a result of the COVID-19 pandemic; however, the commercial sector load is not expected to return to pre-pandemic load levels by the end of the Test Period.

Over the Test Period the commercial forecast is forecasted to grow by approximately 170 GWh. This reflects economic recovery expectations from the Conference Board, commercial EV load growth, and low carbon electrification (fuel switching) additions, which are offset by planned DSM savings.

The forecast drivers for this sector include the efficiency of end-use equipment, retail sales projections, employment, and commercial GDP output. The commercial forecast uses BC Hydro's industry-standard SAE model. Fifteen per cent of the total forecast load for light-duty EVs is added to the commercial load forecast. As in previous applications, further adjustments are made to account for:

- Codes and Standards overlap between SAE model assumptions and BC Hydro's DSM plan;
- Load additions related to BC Hydro's LCE Projects/Programs and provincial government-funded fuel switching programs administered by BC Hydro;
- Assumed load reductions/additions that result from rate impacts;
- VVO energy savings at our distribution substations; and

- Incremental savings from our DSM plan.

A detailed view of the forecast build-up is provided in Appendix F.

3.5.6 Light Industrial Sector Results for Test Period

The light industrial sector represents a relatively small component of the overall load forecast (approximately 9 per cent of total domestic sales in fiscal 2021). The sector consists of approximately 30,000 accounts in a diverse range of industries. Examples include agriculture, construction and manufacturing activities (collectively referred to as other light industrial sub-sector), as well as customer accounts in coal mining, forestry (wood products), small oil and gas facilities, cannabis facilities, and construction power for LNG facilities. By definition, light industrial customers are connected at distribution voltage. The light industrial history and forecast to fiscal 2025 is shown in Table 3-13 below.

Table 3-13 Light Industrial Sales History and Forecast

Temp. Normalized Billed Sales	COVID-19 Scenario A	December 2020 Load Forecast			
F2021 Actual	F2022 Decision	F2022 Forecast	F2023 Plan	F2024 Plan	F2025 Plan
(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)
4,498	4,546	4,628	4,825	4,810	4,825

Table Notes:

1. Forecast is billed sales after adjustments for rate impacts, volt-ampere reactive and VVO energy savings, and DSM savings

Over the Test Period, sales to the light industrial sector are forecast to grow by approximately 200 GWh. The light industrial forecast is an aggregation of light industrial GDP regression model's projection and account specific load additions. The light industrial forecast includes forecast incremental loads for cannabis customers connected at the distribution voltage. As cannabis is an emerging industry, the forecast is developed with consideration of customer requested loads that are deemed highly probable based on their advanced stage of progress in

BC Hydro's interconnection process. The December 2020 Load Forecast for incremental cannabis loads is lower than previous forecasts due to revised expectations and timing for specific projects. The incremental cannabis load before adjustments is forecasted to increase to about 200 GWh through fiscal 2023 and remain around this level for the rest of the Test Period.

As in previous applications, further adjustments to the light industrial forecast are made to account for:

- Load additions related to BC Hydro's LCE Projects/Programs and provincial government-funded fuel switching programs administered by BC Hydro;
- Assumed load reductions/additions that result from rate impacts;
- VVO energy savings at our distribution substations; and
- Incremental savings from our DSM plan.

A detailed view of the forecast build-up is provided in Appendix F.

3.5.7 Large Industrial Sector Results for Test Period

BC Hydro has approximately 190 large industrial accounts connected at transmission voltages, which in fiscal 2021 represented approximately 24 per cent of total domestic sales. The individual customers are organized into four main sub-sectors: mining, forestry, oil and gas (including LNG), and other large industrial customers. While light industrial customers are connected at distribution voltages, large industrial customers are connected at transmission voltages. Most of our large industrial customers are involved in extracting, processing and manufacturing resource-based commodities, which are largely exported outside British Columbia. Export volumes can vary from year to year in response to market forces and consequently, electricity sales to this sector can vary.

Due to commercial sensitivities, individual account assessments are kept confidential. To maintain this confidentiality, the large industrial forecast is aggregated by sub-sector. Each of the sub-sector forecasts is primarily developed from multiple quantitative and qualitative analyses provided by both internal and external experts in addition to information provided by our customers. Checks exist so that the forecast is not biased by information provided by our customers and so that the forecast reflects market information and third-party industry outlooks at the time of forecast development.

Consistent with our more recent load forecasts, we apply a binary approach for the first three years of the forecast (fiscal 2021 to fiscal 2023) and a probability-weighted approach for the remaining years. The binary method results in a discrete projection (i.e., in or out) of load and revenues. We will continue to assess the relative accuracy of the binary and probability-weighted approaches and incorporate any learnings in future load forecasts. Further information on the large industrial forecast methodology is provided in Appendix F.

The Large Industrial forecast by sub-sector and segment is shown in Table 3-14 below.

Table 3-14 Large Industrial History and Sales Forecast

Billed Sales	COVID-19 Scenario A	December 2020 Load Forecast			
F2021 Actual	F2022 Decision	F2022 Forecast	F2023 Plan	F2023 Plan	F2023 Plan
(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)
12,300	12,982	12,437	13,183	14,042	14,982

Table Notes:

1. Forecast is billed sales after adjustments for rate impacts, and DSM savings.

As shown in Table 3-14 above, following load declines which occurred in fiscal 2021 due to the COVID-19 pandemic, the large industrial sector load is forecast to grow by 2,545 GWh over the Test Period. The COVID-19 pandemic impacted each of the large industrial sub-sectors differently, ranging from negligible impacts in mining, chemicals, wood products and other large oil and gas operations, to modest adverse impacts in shale gas and other large industrial operations (e.g., airports, universities, cement plants), to significant adverse impacts in pulp and paper.

The Test Period forecast by sub-sector and segment is provided in Table 3-15 below.

Table 3-15 Large Industrial History and Sales Forecast

		Actual Sales	COVID-19 Scenario A	December 2020 Load Forecast			
		F2021 Actual	F2022 Decision	F2022 Forecast	F2023 Plan	F2024 Plan	F2025 Plan
Sub-Sector	**Segment**	**(GWh)**	**(GWh)**	**(GWh)**	**(GWh)**	**(GWh)**	**(GWh)**
Mining	Metal Mines	3,242	3,356	3,367	3,405	3,388	3,443
	Metallurgical Coal Mines	536	632	627	628	634	629
Forestry	Pulp and Paper	2,966	2,543	2,476	2,449	2,370	2,284
	Wood Products	976	1,097	1,100	1,157	1,094	1,060
	Chemical	1,207	1,359	1,307	1,371	1,372	1,370
Oil and Gas	Oil and Gas and LNG	2,268	2,806	2,395	2,958	3,964	5,042
Other	Other Large Industrial	1,105	1,189	1,165	1,215	1,220	1,154
Total	**Large Industrial**	**12,300**	**12,982**	**12,437**	**13,183**	**14,042**	**14,982**

Table Notes:

1. Forecast is billed sales after adjustments for rate impacts, and demand side management (**DSM**) savings

A discussion of the Test Period forecast for the major large industrial sub-sectors is provided below.

Mining

Total mining sales are forecast to grow by approximately 80 GWh over the Test Period. Most of this growth is related to equipment upgrades at existing metal mining operations.

Forestry (chemicals, wood products, pulp and paper)

Total forestry sales declined in fiscal 2021 as a result of fibre supply challenges, operating inefficiencies and weak demand. The industry challenges are consistent with assumptions reflected in declining sales projections in previous load forecasts, which have been exacerbated by the impacts on customer demand associated with the COVID-19 pandemic. Beyond fiscal 2021, sales are assumed to remain relatively stable as global markets return to pre-pandemic growth trends and pulp and paper prices increase in response to increasing demand of tissue, hygiene and packaging products.

The wood products segment is forecast to remain resilient following the COVID-19 pandemic as pandemic-induced and sustained wood product price increases have improved the sector's relative competitiveness. Even so, long-term fibre supply challenges remain, which preclude substantive expansion and load growth within wood products segment.

Overall, the forestry sector load is forecast to decline by 169 GWh over the Test Period.

Oil and Gas (including LNG)

Total oil and gas (including LNG) sales are forecast to grow by 2,646 GWh from fiscal 2022 to fiscal 2025. Most of the Test Period growth is attributed to expected LNG terminal load coming into service and new upstream natural gas production and processing facilities, some of which will be supplying natural gas feedstock to LNG facilities.

Consistent with our practice of not publishing specific customer history and forecasts, terminal-specific LNG loads are not disclosed. However, the following publicly available information on LNG projects is reflected in the December 2020 Load Forecast:

- FortisBC Tilbury is in operation and we included forecast sales to this LNG facility;
- LNG Canada phase 1 is currently under construction;

- Woodfibre LNG's decision to proceed with the project has not been yet announced. The forecast reflected a probability-weighted assessment which is not relevant to the Application because the in-service date is assumed to be after the Test Period;
- Kitimat LNG load reflected a probability-weighted assessment which is not relevant to the Application because the in-service date is assumed to be after the Test Period; and
- Other activities contributing to oil and gas sub-sector load growth include new pipelines and propane terminals.

Other Large Industrial

Total other large industrial sales are expected to recover from COVID-19 pandemic impacts by fiscal 2022 then load is forecast to decline by 12 GWh over the Test Period. This sub-sector includes forecast loads for cryptocurrency and data centres customers connected at transmission voltage. As emerging industries, the forecast is developed with consideration of customer-requested loads that are deemed highly probable based on their advanced stage of progress in BC Hydro's interconnection process. The December 2020 Load Forecast for cryptocurrency and data centres is lower than previous forecasts due to a number of project cancellations and updated load requests. The cryptocurrency and data centres load are forecast to increase to about 100 GWh through fiscal 2024 before returning to fiscal 2021 levels by fiscal 2025. Given the segment's continued uncertainty and volatility, the forecast assumes these facilities are not long lived.

As with the other customer sectors, the large industrial sector build-up includes low carbon electrification adjustments for BC Hydro's LCE programs (fuel switching), rate impacts, and DSM savings. The LCE (fuel switching) adjustment is a relatively small portion of the overall forecast large industrial LCE loads that relate to the CleanBC Plan. The larger component is loads that are imbedded in the large industrial forecast which reflect fuel switching projects at our customers' facilities. For example, the oil and gas (including LNG) sub-sector forecast also includes electrification loads associated with confidential LCE Customer Project 1 and LCE Customer Project 2, which are described in the Previous Application. Forecast growth in this sub-sector is driven by both low carbon electrification and economic growth where existing plant expansions and new facilities are expected to use clean electricity to meet their work energy requirements instead of fossil fuels. While it is difficult to allocate this load growth between these two main drivers, we include an estimate of the electrification portion of this growth in section 3.7. Detailed information about the large industrial forecast build-up is provided in Appendix F.

3.5.8 Other Sector Results for Test Period

Other sales represented 3 per cent of the total domestic sales in fiscal 2020. Demand in this sub-sector comes from irrigation and street light customers, sales to other utilities (City of New Westminster and FortisBC Inc.), and firm exports (Seattle City Light and Hyder, Alaska).

The Test Period forecast for the other sector is shown in Table 3-16 below.

Table 3-16 Other Sector History and Sales Forecast

Actual Sales	COVID-19 Scenario A	December 2020 Load Forecast			
F2021 Actual	F2022 Decision	F2022 Forecast	F2023 Plan	F2023 Plan	F2023 Plan
(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)
1,628	1,700	1,748	1,730	1,728	1,754

Load from this sector is forecasted to grow by an average of 1.2 per cent per year from fiscal 2021 to fiscal 2025, including through the Test Period. Most of this growth is attributed to increased expected sales to the City of New Westminster and FortisBC Inc.

3.6 Uncertainty Bands are used in Planning, not the RRA Revenue Forecast

The Load Forecast described in sections 3.1 through 3.5 was used in preparation of the Application. As in prior applications, BC Hydro's load forecasting methodology continues to incorporate high and low uncertainty bands to account for sources of forecasting uncertainty. The uncertainty bands and additional scenario described in this section are provided here for context and completeness only. They form part of the broader suite of forecasts described as the December 2020 Load Forecast in Appendix F but are not used in revenue requirements calculations. Rather, we consider them in our planning to ensure sufficient resources are available to meet load scenarios other than the reference load forecast over a 20-year time horizon. These will be further discussed in the 2021 IRP.

3.6.1 There are Several Sources of Uncertainty at Present

Load forecasts are sensitive to many input variables that drive the forecasts, which have varying degrees of uncertainty associated with them. These uncertainties influence the risk that future loads will be lower or higher than forecast.

There are uncertainties inherent in load forecasting, which are reflected in the uncertainty bands. Examples of these uncertainties include:

- Unanticipated circumstances at a customer-specific level, sector-wide level or economy-wide level;
- Uncertainties associated with the various models used to develop load forecasts, such as the accuracy of using statistically determined relationships between drivers and load to forecast loads at a point in time where the nature of those relationships may be changing; and
- Uncertainties associated with having limited history from which to develop future projections. These uncertainties exist where there are new or emerging sectors, such as EVs, LNG, cannabis and cryptocurrency/data centres. This

type of uncertainty also occurs where there are new public policies, such as those related to climate change mitigation actions (climate action) that drive market transformation towards increased electricity use.

3.6.2 The Uncertainty Bands Account for much of the Uncertainty

The December 2020 Load Forecast includes low and high uncertainty bands as well as an accelerated electrification scenario that are intended to capture the following risks and uncertainties:

- Economic risk, particularly as it relates to how global, national and provincial economies are impacted by, and recover from, the COVID-19 pandemic, and potential long-term structural changes that might result;
- The future of emerging sectors of cryptocurrency/data centres and cannabis within British Columbia;
- Customer and project-specific uncertainties in each of the large industrial sub-sectors, and;
- The possibility of a large and rapid increase in low carbon electrification through climate action policies. This could impact the oil and gas and mining sub-sectors, light duty EV sales, and the entire transportation sector.

The high and low bands account for much of the uncertainty. Additional detail on the methodology and results is included in Appendix F, section 8.

3.6.2.1 High Uncertainty Band

For the December 2020 Load Forecast, the high uncertainty band is the sum of the following discrete scenarios:

- High EV forecast;
- High large industrial forecast developed on an account-by-account basis; and

- High distribution customer load (i.e., residential, commercial, light industrial) derived using the high to reference bandwidth from the March 2020 Load Forecast Monte Carlo modelling.

3.6.2.2 Low Uncertainty Band

Due to the COVID-19 pandemic, it was important to capture the potential for adverse impacts and a scenario with little or no growth. The December 2020 low uncertainty band is the sum of the following discrete scenarios:

- Low EV forecast;
- Low large industrial forecast developed on an account-by-account basis;
- Low distribution customer load (i.e., residential, commercial, other sub-sector of light industrial) was assumed to remain at fiscal 2021 forecasted level; and
- Low light industrial forecast for wood, oil and gas, and metallurgical coal sub-sectors using market assumptions aligned with low large industrial forecast.

3.6.2.3 Accelerated Electrification Load Scenario for the IRP

In addition to the low and high uncertainty bands, BC Hydro worked with a consultant to develop an Accelerated Electrification Scenario for use in the 2021 IRP. It is included in the December 2020 Load Forecast report (Appendix F) but was not used in the preparation of the Load Forecast for this application. As described below, is distinct from the Electrification Plan described in Chapter 10. It is provided in Appendix F of the Application for information only.

BC Hydro engaged Navius Research to develop an electrification scenario that estimates the impact on load growth if all of the provincial GHG reduction targets are met over the milestone years of 2025, 2030 and 2040. The estimated loads in this scenario are incremental to the December 2020 Load Forecast. The details of the study are presented in Appendix F and illustrate that by fiscal 2025, electricity consumption could be approximately 1,000 GWh higher than the December 2020

Load Forecast. By fiscal 2030 electricity demand could be approximately 8,000 GWh higher, with most of the incremental growth in electricity demand coming from the natural gas sector and electrification of residential and commercial sector buildings and transportation.

The Accelerated Electrification Scenario is distinct from BC Hydro's Electrification Plan described in Chapter 10. However, the increased low carbon electrification actions included in the Electrification Plan will help to achieve provincial GHG emission reduction targets.

3.6.3 Residual Uncertainty Exists beyond the High and Low Bands and Accelerated Electrification Scenario

While many uncertainties and risks are accounted for in the high and low bands and Accelerated Electrification Scenario, it is normal that they will not capture every possible outcome. Some uncertainties and risks remain unaccounted for. Examples include:

- Colder or warmer than anticipated temperatures which could lead to higher or lower sales;
- Specific customer start-ups or closures not captured in the industrial low and high forecasts; and
- Housing stock growth that maybe higher or lower than Conference Board forecasts as a result of various factors impacting the housing market such as taxes, interest rates and affordable housing policies.

3.7 The Load Forecast Includes Loads Related to the CleanBC Plan

As with previous load forecasts, the December 2020 Load Forecast includes electrification loads that result from activities which reduce or avoid GHG emissions. The estimated electrification loads presented in this section encompass a specific set of initiatives and customer-specific assumptions, which are directly related to actions and strategies outlined in the CleanBC Plan. These initiatives, and the associated load, are distinct from the Electrification Plan loads discussed in Chapter 10.

The December 2020 Load Forecast captures the following:

- EV load – The CleanBC Plan made a firm commitment to a Zero Electric Vehicle (**ZEV**) mandate that was enacted in legislation on May 20, 2019. Accordingly, the EV forecast is included in our electrification estimate;
- BC Government-Funded Fuel Switching – The estimated impact of the fuelswitching component of the government-funded CleanBC Better Buildings/Homes program, which BC Hydro is administering on behalf of the Government of B.C;
- BC Hydro LCE – BC Hydro's LCE projects/programs, described in Appendix N of our Previous Application.
- Large Industrial Electrification – The CleanBC Plan includes providing clean electricity supply to natural gas production in the Peace region and increasing access to clean electricity for large operations with new transmission lines and interconnectivity to existing lines. Accordingly, forecast load growth from specific projects in the oil and gas (including LNG) sub-sector is included in the electrification estimate. The completed phases of confidential customer projects 1 and 2 (noted in Appendix N of the Previous Application) are included at their current in-service loads. New and expansion loads are estimated using the large industrial probability-weighted methodology.

There are likely to be other electrification actions which have been or will be undertaken by some of our customers that also support provincial GHG emission reduction targets, but are not included in our estimate.

The estimated electrification load in the Load Forecast over the Test Period from the areas listed above, allocated by major customer sector, is provided in Table 3-17. By fiscal 2025, we estimate the December 2020 Load Forecast includes approximately 3,300 GWh of electrification load related to the CleanBC Plan.

Table 3-17 Estimated Electrification Load Included in the Load Forecast

Electrification Loads (GWh)	Fiscal Year	Load Forecast Sector Allocation				
		Total	Residential	Commercial	Light Industrial	Large Industrial
Light Duty EV Forecast	F2023	363	309	54	0	0
	F2024	471	400	71	0	0
	F2025	593	504	89	0	0
LCE Program Loads	F2023	147	36	48	28	36
	F2024	147	36	48	28	36
	F2025	147	36	48	28	36
Large Industrial LCE Project Loads	F2023	791	0	0	0	791
	F2024	1,423	0	0	0	1,423
	F2025	2,573	0	0	0	2,573
Total CleanBC Related Load in Load Forecast	F2023	1,300	344	102	28	826
	F2024	2,041	436	119	28	1,458
	F2025	3,313	539	137	28	2,609

Our estimated electrification load reflected in the Load Forecast is provided again in Table 3-18, allocated by the following CleanBC Plan categories: Transportation, Built Environment and Industry.

Table 3-18 Estimated Electrification Load in Load Forecast by Category

Fiscal Year	Transportation (GWh)	Built Environment (GWh)	Industry (GWh)	Total (GWh)
F2023	367	80	854	1,301
F2024	474	80	1,486	2,041
F2025	596	80	2,637	3,313

3.8 Revenue Forecast Accounts for Load Forecast Plus Electrification Plan

The Revenue Forecast is used to determine the revenue shortfall and the proposed rate increase to meet BC Hydro's forecast revenue requirements. The forecast methodology uses sales projections and applies the approved fiscal 2022 tariff rates to calculate revenue. The Revenue Forecast is a relatively straightforward calculation. The methodology is largely unchanged from the Previous Application, with the notable difference being the incorporation of revenues from the Electrification Plan.

Table 3-19 below summarizes the Domestic Revenue Forecast for the Test Period. This calculation, including forecast sales volumes, the applicable rates and the resulting revenue forecast are shown in Appendix A, Schedule 14.0. The revenues associated with the Load Forecast, and those incremental revenues associated with the Electrification Plan are presented as distinct line items:

- Lines 1 through 4 represent the revenue based on the Load Forecast (described in section 3.5 above).
- Line 6 shows the revenue from the BC Hydro Electrification Plan as described further in section 10.4 of Chapter 10.
- Line 7 represents a reduction of revenue resulting from the deferral account rate rider mechanism, which is described in Chapter 7, section 7.3.3.3.

Table 3-19 F2023-F2025 Domestic Revenues - Plan

	($ million)	Schedule Reference	F2021 Actual	F2022 Decision	F2022 Forecast	F2023 Plan	F2024 Plan	F2025 Plan
			1	2	3	4	5	6
1	Residential	14.0 L17	2,210.2	2,234.0	2,367.6	2,355.2	2,383.9	2,400.4
2	Light Industrial and Commercial	14.0 L18	1,830.4	1,954.1	1,910.4	1,961.4	1,956.3	1,947.2
3	Large Industrial	14.0 L19+L25	761.7	842.3	785.6	831.6	891.9	948.4
4	Other	14.0 L20:L24+L26	148.2	152.0	159.6	157.8	157.8	160.0
5	Subtotal	14.0 L27	4,950.4	5,182.4	5,223.2	5,306.0	5,389.8	5,456.0
6	Electrification Plan	14.0 L31	0.0	0.0	(7.6)	19.7	82.9	144.9
7	Revenue from Deferral Rider	14.0 L32	0.0	0.0	0.0	(106.5)	(55.3)	(28.9)
8	Total	14.0 L33	4,950.4	5,182.4	5,215.7	5,219.2	5,417.5	5,571.9

Total Domestic Revenue is forecast to increase each year of the Test Period, compared to the fiscal 2022 Decision amounts. Year-over-year increases are $3.5 million (or 0.1 per cent) in fiscal 2023, $198.3 million (or 3.8 per cent) in fiscal 2024, and $154.5 million (or 2.9 per cent) in fiscal 2025. These revenue increases are due to the increases in sales described in section 3.5 of this Chapter, the sales impacts from the Electrification Plan described in Chapter 10, partially offset by forecast refunds per the deferral account rate rider mechanism. The $7.6 million reduction in Electrification Plan forecast revenue in fiscal 2022 is due to some of the projects included in the December 2020 Load Forecast being delayed, as described further in Chapter 10, section 10.4.2.1.

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BC Hydro Fiscal 2023 to Fiscal 2025 Revenue Requirements Application

Chapter 4

Cost of Energy

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4.1 Introduction

This chapter discusses BC Hydro's Cost of Energy and provides the necessary information to demonstrate that the planned fiscal 2023 to fiscal 2025 Cost of Energy is reasonable for the purpose of setting rates for the Test Period.

BC Hydro's total Cost of Energy, as shown in Table 4–2 below, is planned to be $1,781.6 million in fiscal 2023, $1,943.3 million in fiscal 2024, and $2,001.4 million in fiscal 2025. BC Hydro's regulatory accounts capture variances between actual and planned costs so that customers pay the actual Cost of Energy.[130]

BC Hydro's total Cost of Energy is increasing over the Test Period primarily due to higher forecast load. Load is forecast to increase over the Test Period because:

- Under BC Hydro's December 2020 Load Forecast, electricity sales increase by approximately 3,000 GWh by fiscal 2025, relative to the fiscal 2022 Decision amounts. As discussed further in Chapter 3, this growth is primarily driven by increased sales to the oil and gas sector, including Liquified Natural Gas (**LNG**) facilities, as well as increased load associated with electric vehicles; and
- BC Hydro's Electrification Plan, if fully realized, would result in approximately 2,200 GWh of additional load relative to the December 2020 Load Forecast amounts. As discussed further in Chapter 10, while this load growth increases the Cost of Energy, it also results in higher revenues from sales to domestic customers and results in an overall benefit for ratepayers.

This chapter is organized around the following topics:

- Section 4.2 summarizes how BC Hydro has considered and responded to the BCUC's directives and feedback related to Cost of Energy;

[130] A discussion of the regulatory accounts related to Cost of Energy is provided in Chapter 7, section 7.3.3.3 and Appendix R, section 3.1.

- Section 4.3 describes BC Hydro's Monthly Energy Studies and the 2020 Transfer Pricing Agreement (**2020 TPA**) between BC Hydro and Powerex, which came into effect on April 1, 2020. Information and background on BC Hydro's Monthly Energy Studies which are used to forecast the Cost of Energy are provided in Appendix DD of this application;
- Section 4.4 provides BC Hydro's planned Cost of Energy for the Test Period. The Cost of Energy over the Test Period is planned to increase compared to the fiscal 2022 Decision amounts primarily due to higher forecast load. Increased load reduces BC Hydro's revenue from System Exports, resulting in an increase to the Cost of Market Energy;
- Section 4.5 discusses the components of BC Hydro's Cost of Heritage Energy. The planned Cost of Heritage Energy over the Test Period is relatively consistent compared to the fiscal 2022 Decision amounts;
- Section 4.6 discusses the components of BC Hydro's Cost of Non-Heritage Energy, which is planned to increase over the Test Period compared to the fiscal 2022 Decision amounts. The planned increase is primarily due to predetermined factors, such as terms included in existing EPAs and increased forecast energy deliveries as permitted under existing agreements reaching commercial operations; and
- Section 4.7 discusses the components of BC Hydro's Cost of Market Energy, which is planned to increase over the Test Period compared to the fiscal 2022 Decision amounts. As discussed above, this is due to reduced revenue from System Exports as a result of higher forecast load.

4.2 BC Hydro Has Responded to BCUC's Directives

In its Decision on the Previous Application, the BCUC found BC Hydro's fiscal 2022 Cost of Energy to be reasonable but included directives and feedback that we have considered.

Table 4–1 below summarizes the BCUC's directives on Cost of Energy and our response. It also indicates where further information on BC Hydro's response can be found.

Table 4–1 Response to BCUC Directives on Cost of Energy

Topic	BCUC Directives	Summary and Location of BC Hydro's Response
Decision on Previous Application (Order No. G-187-21)		
Improvements to Energy Studies Models	In compliance with Directives 9 and 10 of the BCUC's Decision on theF2020-F2021 RRA, BC Hydro provided its plan and timeline on model improvements and backtesting.[131] **Directive 4** directed BC Hydro to provide an update on the timeline referenced in Table 11 of the Decision on the Previous Application and explain any changes to the timeline.	BC Hydro provides an updated timeline in Appendix DD, section 3, Table DD-1 and explains changes to the timeline. BC Hydro has considered the BCUC's feedback and has advanced the schedule for backtesting, which is now planned to be completed by the end of fiscal 2024.

[131] BC Hydro's Compliance Filing to BCUC Decision and Order No. G-246-20 to BC Hydro's Fiscal 2020 to Fiscal 2021 Revenue Requirements Application, Directives 9 and 10 (April 1, 2021). https://www.bcuc.com/Documents/Proceedings/2021/DOC_62010_2021-04-01-BCH-F20-F21-RRA-Decision-Compliance-Directives-9-and-10.pdf

Topic	BCUC Directives	Summary and Location of BC Hydro’s Response
Cost of Market Energy (2020 TPA)	In BC Hydro’s Reply Submission on the Previous Application, BC Hydro noted that while the 2020 TPA does not conduct an hourly allocation, it does distinguish between flexible imports/exports and non-flexible imports/exports and sets out how BC Hydro’s actual Annual Flexible Surplus/Deficit is determined. BC Hydro can identify the cost of market purchases of electricity to meet domestic requirements based on the 2020 TPA pricing methodology and provide this information based on the actual outcomes in subsequent RRAs.[132] **Directive 5** directed BC Hydro to report on the historic actual system imports/exports divided into flexible and non-flexible (i.e., according to the format in the 2020 TPA). **Directive 6** directed BC Hydro to identify the cost of market purchases of electricity to meet domestic requirements based on the 2020 TPA pricing methodology and provide this information based on the actual outcomes.	Appendix X, Attachment 1 to Section 6 (refer to section 3, Table 5) provides the historical actual system imports/exports divided into flexible and non-flexible (i.e., according to the format in the 2020 TPA) for fiscal 2021, which is the fiscal year that the 2020 TPA came into effect. Under the 2020 TPA the cost of market purchases to meet domestic requirements is the cost for the Annual Flexible Deficit and the cost for non-flexible imports. As fiscal 2021 had an Annual Flexible Surplus, the cost of market purchases to meet domestic requirements is the cost of non-flexible imports as shown in Appendix X, Attachment 1 to Section 6 (refer to section 3, Table 5).

[132] BC Hydro Reply Submission, Fiscal 2022 Revenue Requirements Application, page 8, paragraph 24.

Topic	BCUC Directives	Summary and Location of BC Hydro's Response
Fiscal 2021 Actual Cost of Energy	In its Decision on the Previous Application, the BCUC noted that it is routine for BC Hydro to include an appendix in each RRA explaining any variance between forecast and actual cost of energy in the past fiscal year(s). The Previous Application did not provide such a table. Further, there is no actual fiscal 2021 cost of energy, only forecast. **Directive 7** directed BC Hydro to include the actual cost of energy information for fiscal 2021.	BC Hydro's practice is to provide variance explanations for the past fiscal year(s) in an appendix. In the Fiscal 2022 Revenue Requirements Application, BC Hydro provided variance explanations between forecast and actual Cost of Energy for fiscal 2020 in Appendix P of that application. BC Hydro's fiscal 2021 year end was not complete at the time of the Fiscal 2022 Revenue Requirements Application was filed, and therefore fiscal 2021 actual results and variance explanations between forecast and Actual Cost of Energy are provided in this Application. Appendix X, Attachment 1 to Section 6 of (refer to section 3) provides BC Hydro's fiscal 2021 actual Cost of Energy and explains variances between forecast and actual amounts. BC Hydro's actual Cost of Energy for fiscal 2021 is also provided in Schedule 4.0 of Appendix A.

4.3 Monthly Energy Studies Process and Transfer Pricing Agreement

This section describes BC Hydro's Monthly Energy Studies, which are prepared using a methodology consistent with that described in the Previous Application. We also describe the 2020 TPA between BC Hydro and Powerex, which came into effect on April 1, 2020.

4.3.1 Monthly Energy Studies Methodology is Consistent with Previous Application

BC Hydro uses the Monthly Energy Studies to inform operational dispatch decisions and Cost of Energy forecasts for financial reporting purposes.

BC Hydro's objective function in the Energy Studies is to maximize expected Consolidated Net Revenue from Operations (**CNRO**).

The Monthly Energy Studies support operational decisions to optimize the use of BC Hydro's large reservoirs over the operating time horizon.[133] The studies consider a wide range of factors including wholesale electricity trade opportunities, which are a necessary and valuable tool to manage deficits and surpluses and increase overall benefits for ratepayers in a hydroelectric system.

While the methodology to conduct the Energy Studies has not changed from the methodology used in the Previous Application, BC Hydro is advancing improvements to the Energy Studies models. Further information on the Energy Studies methodology and planned improvements to the Energy Studies models are provided in Appendix DD.

4.3.2 2020 Transfer Pricing Agreement

The 2020 TPA came into effect on April 1, 2020, replacing the previous Transfer Pricing Agreement (**2003 TPA**). In accordance with an amendment to Direction No. 8 to the BCUC, the BCUC accepted the 2020 TPA by Order No. G-127-21.

Energy transactions (the sale and purchase of electricity) between BC Hydro and Powerex under the 2020 TPA are included as components of Cost of Energy and are included in lines 17, 18, 54 and 55 of Schedule 4.0 of Appendix A.

The 2020 TPA governs the transactions between BC Hydro and Powerex associated with the sale and purchase prices for electricity as well as for natural gas for BC Hydro's Thermal Generation Plants.[134] It allows BC Hydro to cost-effectively

[133] The operating time horizon is the balance of the current fiscal year plus the next two fiscal years. An additional two years are modeled so that the forecast for the first three years accounts for the impact of any longer-term operational constraints. Please refer to BC Hydro's responses to BCUC Panel IRs 2.5.2.1 and 2.5.3 (Exhibit B-31) in the Fiscal 2020 to Fiscal 2021 Revenue Requirements Application.

[134] Thermal plants where BC Hydro purchases natural gas include the Fort Nelson generating facility and Prince Rupert generating facility.

meet its domestic requirements[135] (purchase energy and sell surplus energy) while maximizing the value of its Residual System Capability[136] (for example, Powerex trade activity using the Residual System Capability generates trade income by importing during low price periods and exporting during high price periods) in the operating time horizon of the BC Hydro system.

Under the 2020 TPA, energy transactions under the Cost of Market Energy are classified under the following two categories:

- **System Exports** – represents sales of electricity by BC Hydro to Powerex; and
- **System Imports** – represents purchases of electricity by BC Hydro from Powerex and thermal generation run for Powerex.[137]

BC Hydro is financially accountable for the sale of surplus energy and the purchase of energy to meet domestic load requirements. Powerex is financially accountable for purchases and sales to generate Trade Income.[138]

4.4 Cost of Energy Overview

BC Hydro categorizes its Cost of Energy into the following components for financial reporting, which align with the source of the energy supply:

- Heritage Energy;
- Non-Heritage Energy; and

[135] Domestic requirements is used to refer collectively to domestic load, interutility agreements and system constraints.

[136] Residual System Capability is defined in the 2020 TPA as "…at any time and as determined by BC Hydro in its sole discretion, the capability of the BC Hydro System while all Domestic Load requirements and Inter utility Agreement obligations (including pursuant to operating procedures) are being satisfied and System Constraints are being responded to, to allow purchases of electricity products and services by BC Hydro from Powerex and/or to allow sales of electricity products and services from BC Hydro to Powerex…".

[137] Thermal generation that can be run for Powerex includes the Prince Rupert and Island Generation facilities; however, in practice only Island Generation has been used for this purpose. If thermal generation is run for Powerex, then Powerex purchases the gas at its cost and receives the electricity from such thermal generation as an import into the Transfer Volume Account under the 2020 TPA. BC Hydro notes that the EPA for Island Generation expires in fiscal 2023 as further discussed in section 4.6.1.1.

[138] BC Hydro's Trade Income forecast is discussed further in Chapter 8, section 8.10.

- Market Energy.

BC Hydro's Cost of Energy for the fiscal 2023 to 2025 Plan is provided in Table 4–2 below, classified by the three categories. Additional discussion on each of the three categories is provided in sections 4.5, 4.6, and 4.7 below, to explain the drivers of cost increases or decreases in each category.

Table 4–2 Cost of Energy (Integrated System and Non-Integrated Areas)

($ million)	Schedule Reference	F2021 Actual	F2022 Decision	F2022 Forecast	F2023 Plan	F2024 Plan	F2025 Plan
		1	2	3	4	5	6
Heritage Energy	4.0 L43	273.4	350.6	386.2	353.5	367.2	359.1
Non-Heritage Energy	4.0 L51	1,438.5	1,511.5	1,461.1	1,508.2	1,528.7	1,543.0
Market Energy	4.0 L58	(189.4)	(191.9)	(183.7)	(83.7)	(23.2)	11.6
Total		1,522.5	1,670.1	1,663.7	1,778.0	1,872.7	1,913.7
Cost of Energy for Electrification Plan	4.0 L44 + L45 + L59	-	-	-	3.6	70.7	87.7
Total	4.0 L61	1,522.5	1,670.1	1,663.7	1,781.6	1,943.3	2,001.4

Overall, by fiscal 2025, BC Hydro's total Cost of Energy is planned to increase by $331.3 million compared to the fiscal 2022 Decision amounts. This includes $87.7 million in costs related to the Electrification Plan, if fully realized. Planned increases to Non-Heritage Energy of $31.5 million primarily relate to IPPs and Long-Term Commitments (described further in section 4.6) and planned increases to Market Energy of $203.5 million are primarily due to reduced revenue from System Exports as a result of higher forecast load.

4.4.1 Regardless of Planned Cost of Energy, Customers Pay the Actual Cost

It is expected that BC Hydro's cost of energy will vary from planned amounts for a number of reasons, including weather and load, water inflows, and market conditions. The planned amounts in BC Hydro's revenue requirements are based on the forecast Cost of Energy for the Test Period. Customers, however, will pay the actual costs of energy and not the planned costs. This is because the BCUC has approved Cost of Energy Variance Accounts to capture any variances so that customers pay the actual energy costs. Variances between planned and actual costs of energy are deferred to one of the Heritage Deferral Account, the Non-Heritage Deferral Account, or the Biomass Energy Program Variance Regulatory Account. The balances in these accounts are amortized into rates in subsequent years. These accounts are discussed further in Chapter 7, section 7.3.3.3 and in Appendix R, section 3.1.

4.5 Cost of Heritage Energy

Heritage Energy costs are generally related to the operation of heritage assets listed in Schedule 1 of the *Clean Energy Act*. Table 4–3 below provides a detailed breakdown of the components of the Cost of Heritage Energy.

Table 4–3 Cost of Heritage Energy

($ million)	Schedule Reference	F2021 Actual	F2022 Decision	F2022 Forecast	F2023 Plan	F2024 Plan	F2025 Plan
		1	2	3	4	5	6
Water Rentals	4.0 L38	333.2	375.4	385.0	389.0	384.9	385.7
Natural Gas for Thermal Generation	4.0 L39	6.5	11.8	8.2	9.7	10.7	10.7
Domestic Transmission - Other	4.0 L40	25.5	25.5	24.6	25.1	25.7	26.2
Columbia River Treaty Related Agreements	4.0 L41	(49.9)	(19.0)	10.0	(26.3)	(9.4)	(19.5)
Remissions and Other	4.0 L42	(42.0)	(43.2)	(41.5)	(44.0)	(44.7)	(44.0)
Total	4.0 L43	273.4	350.6	386.2	353.5	367.2	359.1
Cost of Energy for Electrification Plan	4.0 L44 + L45	-	-	-	2.5	(6.5)	(2.1)
Total	4.0 L46	273.4	350.6	386.2	356.0	360.7	357.0

Over the Test Period, total planned Cost of Heritage Energy is relatively consistent compared to the fiscal 2022 Decision amounts with some fluctuations in costs associated with Columbia River Treaty related agreements. The Electrification Plan results in $6.1 million lower Heritage Cost of Energy from fiscal 2023 to fiscal 2025 Plan, mostly driven by changes in the timing of hydro generation. Each component identified in Table 4–3 above is discussed in more detail below.

4.5.1 Water Rentals

Water rental fees include fees paid to the Government of B.C. on the generation output (GWh) and capacity (MW) of the hydroelectric heritage assets, including

BC Hydro's one-third interest in the Waneta generation facility.[139] They also include water rental fees paid on reservoir storage as well as miscellaneous water licences for the use of water for purposes other than power generation, including, for example, conservation fish flows, permits to use Crown Land for reservoirs, and irrigation. Further, water rentals also include the financial impact of reimbursements or payments of water rental fees related to BC Hydro's entitlement obligations under the Canal Plant Agreement and the Keenleyside Entitlement Agreement.[140] These entitlement obligations are energy transfers, not financial transactions; however, they may result in reimbursement or the payment of water rental fees.[141]

In BC Hydro's Reply Submission in the Previous Application, BC Hydro indicated that we would consider feedback from the Residential Consumer Intervener Association and look for opportunities to provide a more detailed explanation of the calculation of fiscal year water rental fees and the relation to fiscal year generation. A more detailed explanation is as follows:

- Water rental fees are primarily driven by hydro generation, which accounts for approximately 84 per cent of total water rentals.
- Water rental fees on the hydro generation of energy are paid to the Province on a calendar year basis. For the current fiscal year, BC Hydro calculates the actual energy output of the license holder from the prior calendar years multiplied by the current year water rental rates and then apportioned to the

139 Consistent with BCUC Order No. G-130-18, water rental fees paid on the generation output and capacity of BC Hydro's other two-thirds interest in the Waneta Generation Facility, purchased in 2017 and now leased to Teck, are classified as Non-Heritage Energy. For further information, refer to section 4.6.4.

140 The Canal Plant Agreement is a coordination agreement where BC Hydro plans the dispatch of generating plants on the Kootenay and Pend-d'Oreille rivers that are owned and/or operated by parties to the agreement (FortisBC Inc., Teck, Brilliant Power Corp, Brilliant Expansion Power Corp and Waneta Expansion Limited Partnership) and optimizes the generation of the system. The plant owners/operators make the actual generation available to BC Hydro in exchange for a fixed monthly energy and capacity entitlement. Similarly, the Keenleyside Entitlement Agreement provides the project owner (Arrow Lakes Power Corporation) with an energy and capacity entitlement associated with the Arrow Lakes Hydro project on the Columbia River.

141 These energy transfers are reported as Exchange Net in Appendix A, Schedule 4.0, line 8. For reporting of actuals, Exchange Net also includes energy that is used to reconcile the total sources of supply to the total recorded load, for financial statement purposes.

appropriate fiscal year. Due to the way water rentals are billed, costs do not occur in the same year as the generation.

- For clarity an example is provided below for generation water rental fees for fiscal 2021:
  - Fiscal 2021 generation water rental fees are based on 3/12th of the calendar year 2021 generation water rental fees and 9/12th of the calendar year 2020 generation water rental fees;
  - The water rental fees paid to the Province in calendar year 2021 are based on actual generation from calendar year 2020. Similarly, the water rental fees paid to the Government of B.C. in calendar year 2020 are based on actual generation from calendar year 2019;
  - Therefore, water rental fees for generation in fiscal 2021 are based on 3/12th of calendar year 2020 generation and 9/12th of calendar year 2019 generation; and
  - As water rental fees for generation lag by a full fiscal year, there is no direct link between generation in fiscal 2021 to water rental fees in fiscal 2021.

Plant capacity charges, which accounts for approximately 15 per cent of total water rentals, are fees paid on the operating and construction capacity of a plant. Water rental fees on operating capacity are calculated as the maximum sustained capacity for the current calendar year times the current year rate and then apportioned to the appropriate fiscal year. These rates are calculated as the previous year rate times the annual percentage change in the B.C. Consumer Price Index.

Water rental fees on construction capacity are for new projects that have not yet been placed in service (e.g., Site C) and are calculated based on the expected in-service capacity of a generating unit.

The water rental fees across the Test Period are relatively consistent and similar to the fiscal 2022 forecast amount.

Table 4–4 below provides a breakdown of actual and forecast water rental rates.

Table 4–4 Water Rental Rates

Water Rental: General Power Use	Calendar Year				
	Actual	Forecast			
	2021	2022	2023	2024	2025
Output (Tier 1) ($/MWh) < 160,000 MWh	1.447	1.472	1.501	1.533	1.564
Output (Tier 1) ($/MWh) > 160,000 MWh	6.751	6.866	7.003	7.150	7.293
Operating Capacity ($/kW)	4.824	4.906	5.004	5.109	5.211
Construction Capacity ($/kW)	0.482	0.490	0.500	0.511	0.521
B.C. CPI (%)	1.7	2.0	2.1	2.0	2.0

4.5.2 Natural Gas for Thermal Generation

Natural Gas for Thermal Generation includes the natural gas purchases, gas transportation, carbon tax, motor fuel tax and other related costs associated with BC Hydro's Prince Rupert and Fort Nelson generation facilities. The breakdown for each facility is provided in Table 4–5 below.

Table 4–5 Natural Gas for Thermal Generation

($ million)	Schedule Reference	F2021 Actual	F2022 Decision	F2022 Forecast	F2023 Plan	F2024 Plan	F2025 Plan
		1	2	3	4	5	6
Fort Nelson		6.1	11.8	8.2	9.7	10.7	10.7
Rupert		0.4	0.0	0.0	0.0	0.0	0.0
Total	4.0 L39	6.5	11.8	8.2	9.7	10.7	10.7

The decrease in costs of $2.1 million from fiscal 2023 Plan to fiscal 2022 Decision amounts is driven by lower forecast generation at Fort Nelson due to more planned outages in fiscal 2023. Costs are $1.0 million higher in fiscal 2024 and fiscal 2025 Plan compared to fiscal 2023 Plan due to less planned outages at Fort Nelson.

Total natural gas costs for the Prince Rupert facility are planned to be zero over the Test Period. This is because the Prince Rupert facility only runs for testing or to supply or support area load when transmission lines associated with Prince Rupert are out of service or restricted for maintenance. The facility is not modelled in the Energy Study.

4.5.3 Domestic Transmission – Other

This category includes transmission costs associated with BC Hydro's obligations in relation to the Skagit River Valley Treaty.[142] These costs are generally stable from year to year. Approximately 75 per cent of costs are for wholesale transmission in British Columbia[143] to deliver energy to the B.C./U.S. border, and the remainder is for wholesale transmission in the United States to deliver energy from the B.C./U.S. border to the City of Seattle.

4.5.4 Columbia River Treaty Related Agreements

The Non-Treaty Storage Agreement (**NTSA**)[144] and a short-term coordination agreement related to the Libby Coordination Agreement[145] are coordination agreements related to the operation of the Columbia River Treaty reservoirs in Canada. These water coordination agreements provide for the release and storage of water to create mutual operational benefits in both Canada and the United States. The agreements are intended to create an average annual positive financial benefit

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[142] The Government of B.C. and the City of Seattle signed an agreement in 1984 concerning the supply of electricity to the City of Seattle which was confirmed by the Skagit River Valley Treaty. The Government of B.C. subsequently assigned certain rights and obligations under this agreement to BC Hydro. BC Hydro's domestic customers receive the benefit of revenues from sales to Seattle City Light, offset by the costs of serving this obligation. These revenues are included as Other Sector revenue as shown in Appendix A, Schedule 14, line 24.

[143] These domestic transmission costs are included in BC Hydro's Transmission Revenue Requirement and are recovered under the Open Access Transmission Tariff. These costs represent BC Hydro's use of point-to-point transmission service for the Skagit River Valley Treaty. In the Transmission Revenue Requirement, these costs are allocated to Cost of Energy via intersegment revenues which are reported in Appendix A, Schedule 3.4, line 20. This allocation of intersegment revenues ensures that costs are only recovered from ratepayers once.

[144] The Non-Treaty Storage Agreement is a coordination agreement between BC Hydro and the Bonneville Power Administration to operate non-treaty volume in Kinbasket Reservoir.

[145] The Columbia River Treaty Short-term Entity Agreement on Coordination of Libby Project Operations is between BC Hydro and Bonneville Power Administration and the U.S. Army Corps of Engineers.

to BC Hydro. For clarity, a negative cost in Table 4–3 above represents a payment to BC Hydro.

The revenue for fiscal 2022 forecast is $29.0 million lower than the fiscal 2022 Decision amount due to the higher amount of expected NTSA storage in fiscal 2022. Costs related to Columbia River Treaty related agreements are highly variable because revenue is generated during releases, and correspondingly, costs are incurred during storage. Moreover, the revenue and costs depend on the market price at the time of the release and storage.

4.5.5 Remissions and Other

The *Water Sustainability Act* specifies remissions that are available to be applied against water rental payments. These remissions are compensation for restrictions or regulations imposed on the BC Hydro water licences arising from Water Use Plans. Remissions are capped at $50 million per calendar year, with any excess associated with physical works requirements carried forward into future years.

Water Use Planning Remissions include:

- Remissions associated with the value of foregone energy, which are shown as a credit under Heritage Cost of Energy in Table 4–3 above; and
- Remissions associated with the recovery of operating costs incurred in delivery of monitoring and physical works programs, which are shown as a credit under operating costs.[146]

Total remissions associated with the value of foregone energy (offset in Cost of Energy) are expected to be stable over the Test Period.

[146] The fiscal 2023 to fiscal 2025 Plan amounts are $9.2 million, $8.2 million and $7.6 million, respectively.

4.6 Cost of Non-Heritage Energy

The cost of Non-Heritage Energy includes costs associated with EPAs for the integrated system and the non-integrated area communities.

Table 4–6 below provides a breakdown of the components of the Cost of Non-Heritage Energy. The cost increases over the Test Period compared to the fiscal 2022 Decision amounts are generally driven by increases in the planned cost of IPPs and Long-Term Commitments primarily due to predetermined factors such as terms included in existing EPAs and increased forecast energy deliveries as permitted under existing agreements.

Table 4–6 Cost of Non-Heritage Energy

($ million)	Schedule Reference	F2021 Actual	F2022 Decision	F2022 Forecast	F2023 Plan	F2024 Plan	F2025 Plan
		1	2	3	4	5	6
IPPs and Long-Term Commitments	4.0 L47	1,404.0	1,475.7	1,426.9	1,471.9	1,490.5	1,504.3
Non-Integrated Area	4.0 L48	26.0	27.4	26.5	28.4	30.0	30.4
Gas & Other Transportation	4.0 L49	5.3	4.9	4.3	4.4	4.5	4.5
Water Rentals (Waneta 2/3)	4.0 L50	3.2	3.5	3.4	3.5	3.7	3.8
Total	4.0 L51	1,438.5	1,511.5	1,461.1	1,508.2	1,528.7	1,543.0

The fiscal 2022 forecast is expected to be approximately $50 million lower than the fiscal 2022 Decision amounts. This variance is primarily due to lower forecast deliveries or costs for certain IPP projects and the termination of two EPAs that had not yet reached commercial operation.

The cost of Non-Heritage Energy components are discussed in further detail in this section below.

4.6.1 IPPs and Long-Term Commitments

The IPPs and Long-Term Commitments category includes the costs of BC Hydro's EPAs with IPPs connected to BC Hydro's integrated system. For the integrated system, as of April 2021, there are 121 projects in commercial operation[147] and three projects in development with existing EPAs.

The planned costs over the Test Period are primarily associated with existing EPAs, and because the terms of these agreements are already set, the planned costs for these EPAs are largely prescribed. During the Test Period, for each EPA, there may be a number of factors which may cause the planned costs to either increase or decrease, such as a change in operation as may be allowed under the EPA and price escalation as defined in the EPA.

As discussed in section 4.6.1.1 below, other than a small number of new Indigenous Nations energy projects and expected EPA renewals,[148] BC Hydro is not acquiring new resources from IPPs during the Test Period. BC Hydro is not seeking approval of any EPA renewals in this application and will be filing separate applications, pursuant to section 71 of the *Utilities Commission Act*, seeking acceptance of energy supply contracts.

In addition, as discussed in section 4.6.1.1 below, BC Hydro is taking steps to reduce costs related to EPA renewals.

IPPs and Long-Term Commitments costs for the integrated system are planned to increase by $28.6 million (or approximately 2 per cent) over the Test Period compared to the fiscal 2022 Decision amounts.

4.6.1.1 BC Hydro is Proactively Managing IPP Energy Costs

BC Hydro proactively manages its energy costs from IPPs, as opportunities arise.

During the Test Period, there are 16 potential EPA renewals in relation to the integrated system. Consistent with the Draft 2021 Integrated Resource Plan, the

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147 Since April 2021, there was one EPA which was terminated in June 2021.

148 EPA renewals are new contracts that replace existing EPAs and are not extensions of existing agreements. Generally, BC Hydro pursues the renewal of expiring EPAs to meet future energy needs where it is cost effective.

planned Cost of Energy for the Test Period assumes that any potential EPA renewals during the Test Period will be at market-based prices and that the EPA for the Island Generation facility, which is set to expire in fiscal 2023, will not be renewed.

For existing EPAs, although the terms of the EPAs are generally prescribed, opportunities arise to reduce costs. Among other things, we are reducing the volume of IPP energy in accordance with the terms of our agreements and where there are cost savings to BC Hydro; and we are reducing energy costs where the terms of the EPA allow us to do so. For example, for certain biomass IPP projects, BC Hydro actively enforces its rights and obligations in these EPAs by exercising turn down rights when it is cost effective for BC Hydro. Another example is that some EPAs allow BC Hydro to reduce its firm energy obligations under certain circumstances and we exercise these rights as they become available to BC Hydro.

As noted above, Non-Heritage Cost of Energy is increasing over the Test Period, primarily due to increasing IPP energy costs under existing agreements, partially offset by a reduction in costs associated with expected lower EPA renewal costs. BC Hydro does not have any active programs for the procurement of new energy resources from IPPs on the integrated system. Other than EPA renewals, including one remaining EPA renewal under the Biomass Energy Program expected to be executed during fiscal 2022,[149] the only expected new EPAs are a small number of

[149] Under the Biomass Energy Program BC Hydro has renewed six EPAs and expects to execute the seventh (and last) Biomass Energy Program EPA in December 2021. As part of the Comprehensive Review, the Government of B.C. announced the Biomass Energy Program. As discussed in the Comprehensive Review, the Biomass Energy Program is a cost and volume limited program for biomass EPAs expiring prior to December 2021. Under the Biomass Energy Program, BC Hydro procures energy through a combination of load offset and/or energy purchases with a priority given first to load offset. A load offset is energy generated by a BC Hydro customer at its customer site to offset the energy purchased from BC Hydro to serve the load at this same site. The total estimated impact of the cost and energy volumes for the load offset and energy purchase contracts are included in the Application under Cost of Energy.

potential new Indigenous Nations energy projects, including two potential EPAs remaining from the Standing Offer Program (**SOP**).[150]

4.6.1.2 IPPs and Long-term Commitments are Largely Prescribed and Reflect Long-term Acquisitions Undertaken over Time

The planned cost of IPP energy in the Test Period reflects long-term EPA commitments that occurred over a number of years. BC Hydro has purchased electricity from IPPs since the mid 1980s and contract terms generally are between 10 to 40 years. More recently, however, BC Hydro has been entering into shorter term renewal EPAs at market-based prices and, as referenced in BC Hydro's Draft 2021 Integrated Resource Plan, BC Hydro generally expects to renew EPAs at market-based prices in the next five years.

The electricity supplied by IPPs on BC Hydro's integrated system is approximately 25 per cent of BC Hydro's electricity supply and helps to meet BC Hydro's load requirements. IPP projects are developed by companies specializing in power production, as well as by municipalities, Indigenous Nations and BC Hydro customers, using resources such as wind, water, biomass, solar and waste heat. BC Hydro's EPA portfolio includes a significant amount of hydro generation. The amount of generation under these contracts is driven by water inflows and other operational factors which may cause actual energy deliveries to vary significantly from year to year. Approximately 75 per cent of BC Hydro's EPA portfolio is comprised of hydro and wind generation, and the amount of generation under these contracts is driven primarily by the weather, and other operational factors, which may cause actual energy deliveries to vary significantly from year to year.

[150] In February 2019, as part of the Comprehensive Review, the Government of B.C. issued a regulation which allowed BC Hydro to indefinitely suspend the SOP. BC Hydro will not be executing any other SOP EPAs, except for five Indigenous Nations' clean energy projects that are part of Impact Benefit Agreements with BC Hydro and/or are mature projects that have significant Indigenous Nations involvement. To date, BC Hydro has executed three of these five agreements.

Table 4–7 below provides the IPP and Long-Term Commitment costs for the integrated system broken down into various call processes. Each IPP project is categorized under its existing EPA call process.

Table 4–7 IPP and Long-Term Purchase Costs for the Integrated System

Call Process ($ million)	No. of EPAs[1]	F2021 Actual	F2022 Decision	F2022 Forecast	F2023 Plan	F2024 Plan	F2025 Plan
Pre-2005 Electricity Purchase Agreements[2]	25	267.8	268.8	270.9	222.0	217.3	211.8
2006 Open Call	17	200.1	195.3	195.6	197.1	199.6	201.9
2008/2010 Bioenergy, and Biomass Energy Program	16	258.8	297.4	294.3	299.2	306.5	313.0
2008/2010 SOP	25	47.9	61.4	55.8	56.8	57.4	58.1
2010 Clean Power Call	20	352.6	349.0	346.6	361.3	365.1	368.8
NEPA[3]	21	399.1	429.4	389.3	429.0	434.2	441.5
Expected Standing Offer Program Projects and other First Nations Commitments[4]	-	-	-	-	0.7	4.9	4.9
Total	**124**	**1,526.2**	**1,601.3**	**1,552.5**	**1,566.2**	**1,585.1**	**1,600.0**
Accounting Adjustments		(122.2)	(125.6)	(125.6)	(94.3)	(94.6)	(95.7)
IPPs and Long-Term Commitments	**124**	**1,404.0**	**1,475.7**	**1,426.9**	**1,471.9**	**1,490.5**	**1,504.3**

1 Number of EPAs with IPPs on the integrated system as of April 9, 2021. The numbers in this column may not align with the number of EPAs in the Previous Application because some EPAs expired/terminated, some EPAs became operational since the Previous Application was filed, and the categorization of EPAs by Call Process has changed since the filing of the Previous Application so that IPPs are categorized now under their existing call (and not their original call which was our past practice).

2 The costs in this row (Pre-2005 Electricity Purchase Agreements) also include miscellaneous energy purchases, such as energy purchases for border accommodations.

3 The costs in this row (Negotiated Electricity Purchase Agreements) also includes two other energy supply contracts which are not considered to be IPP EPAs. These are the Surplus Power Rights Agreement between Teck and BC Hydro and the Residual Capacity Agreement between FortisBC Inc. and BC Hydro.

4 The costs shown in this row are expected costs for future potential EPAs. Once an EPA is executed, the costs are included in the appropriate call process.

The Accounting Adjustments shown in Table 4–7 above largely reflect energy costs for EPAs which are accounted for as leases under the current accounting standards. For those EPAs that are deemed to be leases, for accounting purposes, their costs are recorded as amortization and finance charges as well as Cost of Energy.

4.6.2 Non-Integrated Areas

BC Hydro serves 14 non-integrated areas.[151] Non-Integrated Area communities are not connected to BC Hydro's integrated system and are served by local generating facilities, primarily diesel, and distribution networks. Generating capacity in these areas is provided by a combination of BC Hydro owned diesel generating stations, as well as four hydro IPP facilities and one biomass IPP facility, and one BC Hydro owned hydro facility[152] in the Bella Coola region. Table 4–8 below provides a breakdown of these costs.

Table 4–8 Non-Integrated Areas Generation Costs

($ million)	Schedule Reference	F2021 Actual	F2022 Decision	F2022 Forecast	F2023 Plan	F2024 Plan	F2025 Plan
		1	2	3	4	5	6
NIA - BC Hydro Diesel Generating Stations		14.3	17.6	16.4	17.2	17.7	17.8
NIA - IPPs		11.7	9.9	10.1	11.1	12.3	12.5
Total	4.0 L48	26.0	27.4	26.5	28.4	30.0	30.4

Non-Integrated Area generation costs are relatively stable over the Test Period.

For the Non-Integrated Area, the variability in costs for BC Hydro's Diesel Generating Stations are primarily driven by fluctuations in fuel costs and whether there is a need to run the diesel generating stations which is dependent upon load variability and IPP deliveries. The increase in costs associated with IPPs is due to updated forecast costs for certain facilities related to EPA renewals during the Test Period.

151 Non-Integrated Areas: Zone IB is Bella Bella and Zone II is Anahim Lake, Atlin, Bella Coola, Dease Lake, Elhlateese, Fort Ware, Good Hope Lake, Haida Gwaii, Hartley Bay, Jade City, Telegraph Creek, District of Toad River and Tsay Keh Dene.

152 There are no forecast energy costs for BC Hydro's Clayton Falls Generating Station in the Bella Coola Non-Integrated Area, as the annual costs are quite small. Actual water rental costs for the Clayton Falls Generating Station, which are approximately $0.1 million per year, are included with Water Rentals for ease of reporting.

There are currently five non-integrated IPPs in operation.[153] BC Hydro has been pursuing the renewal of its EPA with the Moresby Lake IPP which serves the Non-Integrated Area of Haida Gwaii. The Moresby Lake EPA expires in August 2022 and BC Hydro expects to have a renewal EPA with this IPP.

4.6.2.1 Opportunities to Reduce Supply Cost Commitments in Non-Integrated Areas are More Limited

In support of CleanBC and BC Hydro's clean energy commitment, we actively look for opportunities to displace diesel generation with clean or renewable resources in Non-Integrated Area communities when it is cost effective to do so. In Non-Integrated Area communities, IPPs may displace a portion of diesel generation. However, diesel generation facilities must be in place for reliability purposes in all 14 Non-Integrated Areas.

As noted in Table 4–8 above, there are two types of energy costs related to serving these communities: costs from BC Hydro diesel generating facilities and IPP costs. Given the remoteness of these communities and the lack of connection to the integrated system, there are limited opportunities to reduce supply costs.

4.6.3 Gas and Other Transportation Costs

Gas and other transportation costs, as shown in Table 4–6 above, include wheeling charges to serve the domestic load in the Goodlow (Boundary Lake), Rogers Pass, and Duck Lake areas, costs related to the service of domestic load in Fort Nelson from energy imported from Alberta, fuel costs related to certain generation agreements for transmission-related issues, and fuel costs for temporary generation.

Gas and other transportation costs are planned to be relatively stable over the Test Period.

[153] Non-integrated Area IPPs: Hluey Lake (Dease Lake), Moresby Lake (Haida Gwaii), Ocean Falls (Bella Bella), Pine Creek (Atlin) and Kwadacha Bioenergy Project (Fort Ware) are operational facilities. The Gabion River EPA (Hartley Bay) EPA was terminated by mutual agreement in 2019 and had not reached commercial operation. BC Hydro notes that for the Ocean Falls IPP, BC Hydro is provided with electricity service under a rate as approved by the BCUC pursuant to BCUC Order No. G-270-20.

4.6.4 Water Rentals (Waneta Two-Thirds)

Water rentals associated with BC Hydro's two-thirds interest in Waneta are shown in Table 4–6 above. However, BC Hydro's two third interest in Waneta is leased to Teck.[154] Teck is responsible for all operating costs, including paying for its share of water rentals. These costs are shown as an offset in Miscellaneous Revenues (Appendix A, Schedule 15.0, line 28).

4.7 Cost of Market Energy

BC Hydro engages in energy transactions with Powerex to optimize system storage, and these imports and exports are referred to as Market Energy. Transactions between BC Hydro and Powerex under the 2020 TPA are summarized in Schedule 4.0 of Appendix A and are included as components of Cost of Energy.

Table 4–9 Cost of Market Energy[155]

($ million)	Schedule Reference	F2021 Actual	F2022 Decision	F2022 Forecast	F2023 Plan	F2024 Plan	F2025 Plan
		1	2	3	4	5	6
System Imports	4.0 L54	26.9	77.1	69.0	125.6	149.2	157.9
System Exports	4.0 L55	(227.9)	(296.5)	(266.5)	(223.3)	(186.7)	(160.9)
Net System Imports / (Exports)		(201.0)	(219.4)	(197.4)	(97.7)	(37.5)	(3.0)
Domestic Transmission – Export	4.0 L57	11.6	27.5	13.8	14.1	14.3	14.6
Total	4.0 L58	(189.4)	(191.9)	(183.7)	(83.7)	(23.2)	11.6
Cost of Energy for Electrification Plan	4.0 L59	-	-	-	1.1	77.1	89.8
Total	4.0 L60	(189.4)	(191.9)	(183.7)	(82.6)	53.9	101.4

Cost of Market Energy is planned to increase by $293.3 million by the end of the Test Period compared to the fiscal 2022 Decision amounts primarily due to higher forecast load. This includes $89.8 million due to increased load from the Electrification Plan, if fully realized. Higher forecast load results in an increase to the Cost of Market Energy because it means there is less surplus to export (i.e., reduced

[154] In 2017, BC Hydro entered into a purchase agreement with Teck for the remaining two-thirds interest of the Waneta Generating Facility. The BCUC approved this purchase by BCUC Order No. G-130-18. The 2017 Waneta transaction includes a long-term lease agreement with Teck. Under the arrangements with Teck, BC Hydro continues to use its one-third interest in Waneta to serve its domestic load obligations.

[155] For clarity, a negative System Export cost in Table 4–9 represents revenue.

revenue from System Exports) and more imports are required (i.e., increased cost of System Imports).

Overall, load is expected to increase during the Test Period because:

- Under BC Hydro's December 2020 Load Forecast, electricity sales increase by approximately 3,000 GWh by fiscal 2025, relative to the fiscal 2022 Decision amounts. As discussed further in Chapter 3, this growth is primarily driven by increased sales to the oil and gas sector, including LNG facilities, as well as increased load associated with electric vehicles; and
- BC Hydro's Electrification Plan, if fully realized, would result in approximately 2,200 GWh of additional load relative to the December 2020 Load Forecast amounts. As discussed further in Chapter 10, while this load growth increases the Cost of Energy, it also results in higher revenues from sales to domestic customers and results in an overall benefit for ratepayers.

4.7.1 Net System Imports and System Exports

The fiscal 2022 Forecast revenue from Net System Exports decreases from the fiscal 2022 Decision amounts primarily due to the lower average prices for exports.

The Net System Exports are decreasing from $219.4 million in the fiscal 2022 Decision amounts to $3.0 million in fiscal 2025 Plan due to higher forecast load.

4.7.2 Domestic Transmission - Export

The costs associated with the use of BC Hydro's transmission system for System Export pursuant to the Open Access Transmission Tariff (**OATT**) are referred to as Domestic Transmission – Export.

Domestic transmission costs for fiscal 2022 are forecast to be $13.7 million lower than fiscal 2022 Decision amounts and for fiscal 2023 are planned to be $13.4 million lower than fiscal 2022 Decision amounts. This is primarily due to a decrease in the total point-to-point costs forecast, reducing the allocation to

Domestic Transmission – Export. In addition, in fiscal 2021, a revised calculation of the allocation of revenue recovered through the point-to-point allocation between BC Hydro and Powerex was developed to implement the 2020 TPA, as the 2020 TPA differs from the 2003 TPA. The revised calculation reflects the requirements of section 6.2 of the 2020 TPA to provide a reasonable allocation of the point-to-point transmission costs incurred by BC Hydro[156] in respect of Powerex's trading activities. The allocation of point-to-point charges between BC Hydro and Powerex is discussed in Chapter 9, section 9.2.7.

[156] In particular, BC Hydro is responsible for losses, ancillary services and the point-to-point transmission costs associated with serving Domestic Load requirement, satisfying Interutility Agreement obligations (including under any operating procedures), responding to System Constraints, satisfying BC Hydro's obligation to manage the Annual Flexible Surplus/Deficit and delivering electricity pursuant to Non-Flexible Export Schedules, and receiving and/or delivering the Canadian Entitlement.

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BC Hydro Fiscal 2023 to Fiscal 2025 Revenue Requirements Application

Chapter 5

Operating Costs

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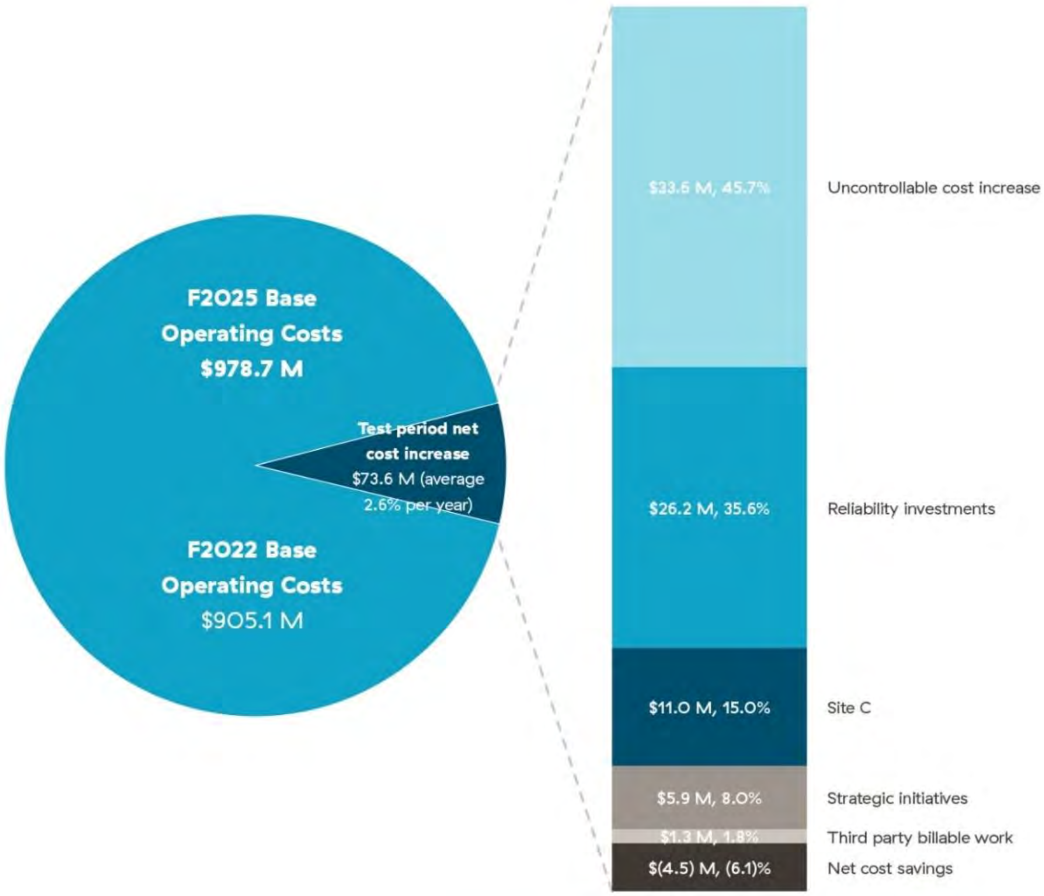
5.1 Introduction

This chapter describes our planned operating costs and full-time equivalents (**FTEs**) for the Test Period. Compared to the fiscal 2022 Decision amounts, BC Hydro's base operating costs[157] are increasing by $21.5 million (or 2.4 per cent) for fiscal 2023, a further $20.4 million (or 2.2 per cent) for fiscal 2024, and a further $31.7 million (or 3.4 per cent) for fiscal 2025, for a total net increase of $73.6 million (or 2.6 per cent on average per year). As shown in Figure 5-1 below, while BC Hydro has identified six drivers of increased base operating costs, over three-quarters (81.3 per cent) of the increase is associated with uncontrollable costs and reliability investments.

[157] Base operating costs continue to be, in BC Hydro's view, the relevant measure for the assessment of our efforts to control operating costs because they exclude costs that, among other things, vary according to changes in accounting rules and the mechanisms in place to recover regulatory account balances. This is discussed further in section 5.5.4 below.

Figure 5-1 Summary of Test Period Base Operating Costs Increases – Fiscal 2025 Compared to Fiscal 2022 Decision



Base Operating Costs—$ million[1]	Starting point	Current fiscal year	$ increase	% increase	Average % increase per year
F2023	905.1	926.6	21.5	2.4%	
F2024	926.6	947.0	20.4	2.2%	
F2025	947.0	978.7	31.7	3.4%	
Test period total	**905.1**	**978.7**	**73.6**	**8.1%**	**2.6%**
[1] Appendix A, Schedule 5.0, line 14	a	b	c=b−a	d=c/a	

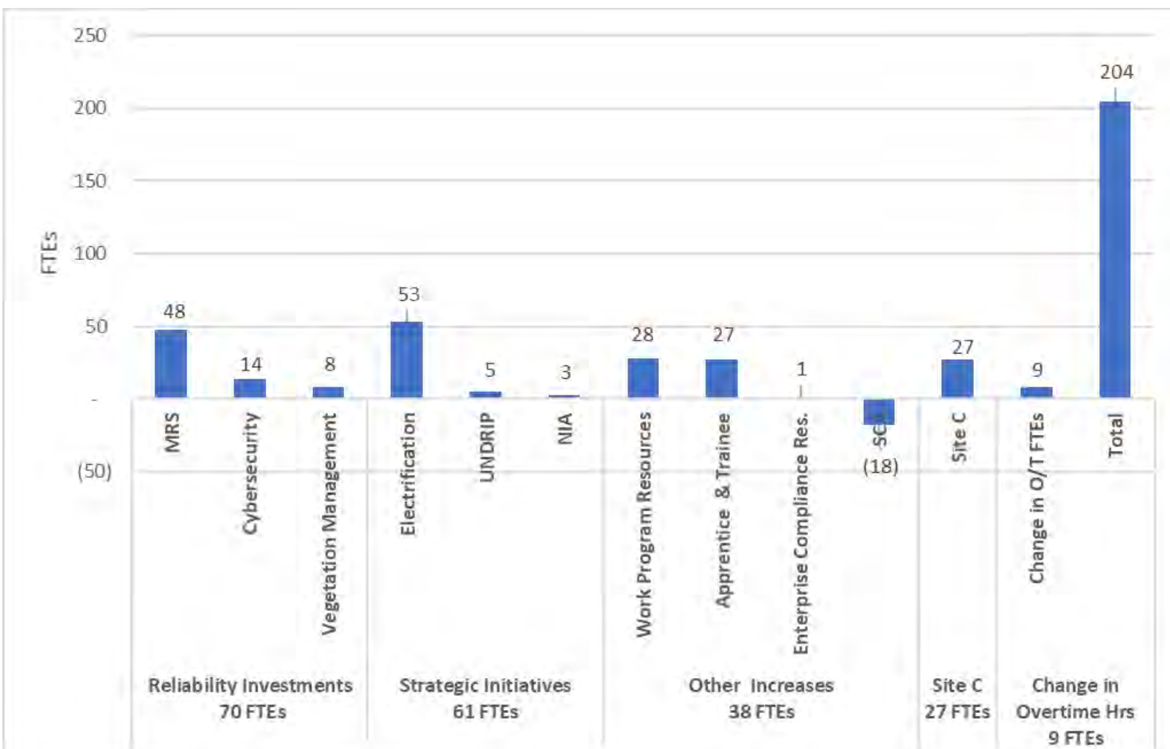
May not add due to rounding

Compared to the fiscal 2022 Decision, BC Hydro's total FTEs are expected to increase by 125 FTEs for fiscal 2023, a further 42 FTEs for fiscal 2024, and a further

38 FTEs for fiscal 2025, for a total increase of 204[158] FTEs. As shown in Figure 5-2 below, the largest increases in FTEs are in relation to:

1. Reliability investments to support Mandatory Reliability Standards (**MRS**), cybersecurity and vegetation management, further described in section 5.5.3 and section 5.12.1; and
2. Strategic initiatives to support the implementation of our Electrification Plan, the United Nations Declaration on the Rights of Indigenous Peoples (**UNDRIP**), and our Non-Integrated Area (**NIA**) diesel reduction strategy; further described in section 5.5.3 and section 5.12.1.

Figure 5-2 Summary of FTE Increase – Fiscal 2025 Compared to Fiscal 2022 Decision



This chapter is organized around the following points:

[158] May not add due to rounding. FTEs are further discussed in section 5.12.1.

- Section 5.2 summarizes how we have considered and responded to the directives and comments related to operating costs in the BCUC's Decisions on the F2020-F2021 RRA and the Previous Application;
- Section 5.3 explains that BC Hydro has maintained the Plan-Build-Operate-Support organizational structure, with only limited organizational changes since the Previous Application;
- Section 5.4 explains how BC Hydro's budgeting process for the Test Period was consistent with the process used in the F2020-F2021 RRA and the Previous Application, which the BCUC has found to be reasonable;
- Section 5.5 provides an overview of BC Hydro's operating costs during the Test Period, focussing on the key changes identified in Figure 5-1 above. Over three-quarters (81.3 per cent) of the base operating cost increases over the Test Period are associated with uncontrollable costs and reliability investments;
- Section 5.6 describes how we are using performance metrics for reliability investments and strategic initiatives over the Test Period, consistent with our recent proposal in the Performance Based Regulation proceeding;
- Section 5.7 explains that increased funding over the Test Period is driven by investments to strengthen our MRS program and to implement and sustain new standards and functions;
- Section 5.8 outlines the additional investments required for vegetation management during the Test Period. The investments reflect our new Vegetation Management Strategy provided in Appendix G, which is focused on an ongoing stable approach where work levels match vegetation growth on the system;
- Section 5.9 outlines our robust cybersecurity program and explains the additional improvements we are making to address cybersecurity risk and

implement recommendations from cybersecurity capability self-assessments and audits;

- Section 5.10 describes the transition of the Site C Project to operations. We require additional operating costs in the Test Period to support the operations of the plant in anticipation of the expected December 2024 in-service date of the first generating unit;
- Section 5.11 describes the incremental resources required to ensure adequate project and field resources and support are in place for the Operations Business Group to deliver the workplans and to address increased compliance requirements across most work categories;
- Section 5.12 provides an overview of BC Hydro's FTEs and Labour Costs. Our operating FTEs have remained relatively flat since fiscal 2012 with changes during that period occurring within a relatively tight band. This section further provides an overview of standard labour costs, post employment benefit costs, and the vacancy factor savings;
- Section 5.13 describes how the COVID-19 pandemic has impacted BC Hydro's operating costs, satisfying Directive 65 of the BCUC's Decision on the F2020-F2021 RRA;
- Section 5.14 provides an overview of the operating cost pressures experienced in the Fiscal 2020 to Fiscal 2021 test period, satisfying Directive 18 of the BCUC's Decision on the F2020-F2021 RRA;
- Section 5.15 provides an overview of BC Hydro's Power System maintenance work necessary for assets to achieve their expected performance throughout their lifecycle and the ongoing maintenance necessary to support improvements to vegetation management. This section also responds to Directive 24 of the BCUC's Decision on the F2020-F2021 RRA; and

- Section 5.16 outlines the content of Chapters 5A to 5G, which provide operating costs and FTEs by Business Group. These Chapters address the composition of the full (versus incremental) budgets and FTEs of every Key Business Unit (**KBU**) in these Business Groups. The format and level of granularity is consistent with the F2020-F2021 RRA (i.e., considerably more detail than in the Previous Application).

5.2 BC Hydro's Approach to Operating Costs Reflects the BCUC's Directives and Comments

The BCUC accepted BC Hydro's operating costs in its previous two Decisions. In its Decision on the Previous Application, the BCUC acknowledged that operating cost increases were potentially lasting, as a large component of the increase is to fund reliability investments essential for the protection of the Bulk Electric System.[159] However, the BCUC also issued directives and made comments related to operating costs, to which BC Hydro has responded in this chapter.

BC Hydro's approach to operating costs in the Application aligns with the BCUC's commentary. Specifically, BC Hydro continues to focus on cost control, while investing in areas highlighted in the F2020-F2021 RRA proceeding and targeted in the Previous Application – notably, MRS, cybersecurity and vegetation management.

Table 5-1 below summarizes the BCUC's directives and comments on operating costs and our response. It also indicates where further information on BC Hydro's response can be found.

[159] BCUC Decision and Order No. G-187-21, BC Hydro Fiscal 2022 Revenue Requirements Application (June 17, 2021), page 27.

Table 5-1 Response to BCUC Directives and Comments on Operating Costs

Topic	BCUC Directives / Comments	Summary and Location of BC Hydro's Response
F2020-F2021 RRA Decision (Order No. G-246-20)		
Operating Cost Pressures	**Directive 18** directed BC Hydro to summarize: 1. The operating cost pressures it experienced during the fiscal 2020 to fiscal 2021 test period and how it alleviated those costs pressures; and 2. Where it was unable to alleviate the cost pressure, describe the activities BC Hydro had to forego and the risks resulting from not doing the activity.	Section 5.14 provides a summary of the strategies BC Hydro implemented to mitigate cost pressures during the fiscal 2020 to fiscal 2021 test period. With the exception of the operating cost impacts of the COVID-19 pandemic, most operating cost pressures BC Hydro faced in the fiscal 2020 to fiscal 2021 test period are expected to persist over a long period of time. Therefore, BC Hydro included operating cost increases in the Previous Application to address these pressures, net of identified savings. We have done the same in this application.
Vacancy Factor Savings	BC Hydro applies a "vacancy factor" reduction to its forecast operating costs to recognize the savings that occur from positions being vacant for periods of time due to various factors. **Directive 20** directed BC Hydro to begin tracking, measuring and reporting on the annual actual vacancy factor savings and to provide a rationale for any significant differences from the forecast savings.	Section 5.12.3 provides a summary of the estimated fiscal 2021 vacancy factor savings actual results, which reinforce the reasonableness of the forecast savings included in the F2020-F2021 RRA and the appropriateness of using the same forecast savings in the Test Period.
Safety Targets	**Directive 23** directed BC Hydro to evaluate its safety data to determine whether it could achieve more aggressive lost time injury frequency and lost time injury duration targets, and if so, the additional costs, if any, that achieving such more aggressive targets may entail.	Chapter 5D, section 5D.3 explains that BC Hydro's performance on lost time injury frequency has improved while our performance on lost time injury duration has remained relatively stable and that, going forward, BC Hydro's priority is to focus on preventing fatalities and serious disabling injuries. BC Hydro expects to be able to manage this approach within our existing budgets.

Topic	BCUC Directives / Comments	Summary and Location of BC Hydro's Response
Maintenance Expenditures	**Directive 24** directed BC Hydro to report on any additional maintenance spending that has occurred as a result of the reduced sustainment capital spending during the fiscal 2020 to fiscal 2021 test period and to present a trend analysis of maintenance spending on capital for the 10 most recently completed fiscal years.	Section 5.15 provides the additional maintenance spending as a result of the reduced sustainment capital spending during the fiscal 2020 to fiscal 2021 test period; the additional maintenance was minimal. It also provides a trend analysis of maintenance spending over fiscal 2012 to fiscal 2021 and sustaining capital spending over fiscal 2015 to fiscal 2021 and explains the key drivers of the changes.
Impact of the COVID-19 Pandemic	**Directive 65** directed BC Hydro to report on the impact of the COVID-19 pandemic and plans to handle the resulting impact.	Section 5.13 describes the operating cost pressures and savings caused by the COVID-19 pandemic. The cost reduction strategies implemented by BC Hydro in fiscal 2021 to further mitigate these cost pressures were temporary in nature and spending in a number of areas has returned to budgeted levels. With the exception of permanent travel cost savings of $2.1 million in the Test Period, further described in Table 5-6, BC Hydro has not included any additional cost pressures or savings caused by the COVID-19 pandemic in the Test Period.
Previous Application Decision (Order No. G-187-21)		
Vegetation Management Strategy	**Directive 10** directed BC Hydro to file the new Vegetation Management Strategy and any revisions to it thereafter.	Appendix G provides BC Hydro's Vegetation Management Strategy. Section 2 of the strategy defines changes that would result in a revision.
Vegetation Management Budget	**Directive 11** directed BC Hydro to provide a breakdown of the vegetation management budget in a format similar to that provided in Table 5-11 of the F2020-F2021 RRA and expanded to include historical costs for the most recent five years.	Table 5-27 in section 5.8 provides the requested breakdown of the vegetation management budget. Table 5-29 includes historical costs for the most recent five years (fiscal 2017 to fiscal 2021). These tables show the increased investments made in vegetation management since fiscal 2021.

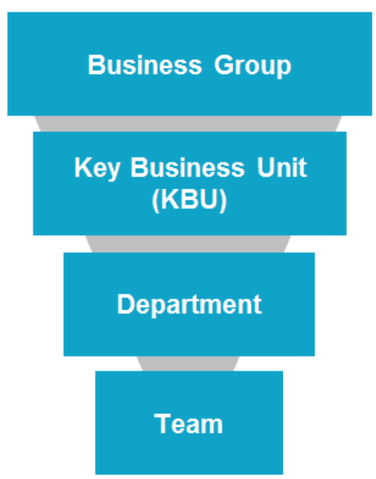
5.3 BC Hydro Has Maintained the Same Organizational Structure

BC Hydro has six Business Groups, made up of 37 KBUs. We continue to be organized based on a centralized organizational structure that aligns with the work functions that we perform. We refer to this structure as our Plan-Build-Operate-Support model. The centralized organizational structure aligns our Business Groups to the lifecycle of our work delivery, which encourages consistent adoption of best practices used across the company and facilitates stronger collaboration and cooperation in similar functions across our business. This model is continuing to drive benefits throughout the organization. We have maintained the model but, as described below, have introduced some changes within it to improve our compliance efforts and meet evolving business needs.

5.3.1 Organizational Nomenclature

Figure 5-3 below provides a simplified diagram of our organizational structure, for the purpose of clarifying nomenclature used in this application. The nomenclature is the same as in the previous two applications.

Figure 5-3 Organizational Nomenclature



5.3.2 There Have Been Limited Organizational Changes

Our Business Groups and their respective KBUs are summarized in Table 5-2 below.

Table 5-2 Business Groups and KBUs[160]

	Business Group	Key Business Unit
Plan	Integrated Planning	Energy Planning and Analytics
		Dam Safety
		Asset Planning
		Interconnections and Shared Assets
		Engineering Design
		Engineering Services
Build	Capital Infrastructure Project Delivery	Project Delivery
		Indigenous Relations
		Environment
		Properties
Operate	Operations	Program and Contract Management
		Line Field Operations
		Stations Field Operations
		Distribution Design and Customer Connections
		Construction Services
		Generation System Operations
		Transmission and Distribution System Operations
Support	Safety and Compliance	Safety
		Learning and Development
		Security and Emergency Management
		Reliability Standards Assurance
	Finance, Technology, Supply Chain	Finance
		Technology
		Supply Chain
	Customer and Corporate Affairs	Customer Service
		Conservation and Energy Management
		Communications and Community Engagement
		Regulatory and Rates
	Other	Human Resources
		Office of the General Counsel
		Office of the President and Chief Executive Officer

160 Each of the six Business Groups ("Other" is not a business group) also include a Business Unit Support KBU, which brings the total KBUs to 37. These KBUs are relatively small and primarily include funding for BC Hydro's Executive Team members and their support staff.

Since the Previous Application, there have been limited organizational changes. They are:

- The Stations Asset Planning KBU and Line Asset Planning KBU have been consolidated into the Asset Planning KBU in the Integrated Planning Business Group. Combining these teams into a single KBU supports consistency with respect to planning and asset management and promotes further collaboration. The change will also enable the teams to focus more on the core work for the power system, regulatory requirements, and build a more robust and resilient MRS program for Integrated Planning;
- The functions of the former Safety System and Assurance KBU and the Field Safety Services KBU have been combined to form the Safety KBU. This integration was completed to improve efficiency and effectiveness by aligning BC Hydro's safety functions with our Safety Framework, further discussed in Chapter 5D, and its documented responsibilities; and
- Since the Previous Application, the Human Resource KBU has been transferred to the Other group from the Customer and Corporate Affairs Business Group (previously the People, Customer and Corporate Affairs Business Group). This was done to reflect the Chief Human Resources Officer reporting directly to the President and Chief Executive Officer, effective November 1, 2021. This shift reflects the significance of the human resources function in managing the programs that support, develop and shape our people and corporate culture. The Human Resources KBU is, among other things, leading company-wide inclusion and diversity efforts.

  In addition, the functions of the Ethics and Merit Office have been added to the Human Resources KBU. This move allows for greater alignment between the two groups as the Ethics Officer frequently collaborates with Human Resources on investigations, employee complaints and other conflict resolution situations.

5.4 Fiscal 2023 to Fiscal 2025 Budgeting Process Was Consistent with Prior Years

BC Hydro's budgeting process for the Test Period was consistent with the approach we have used in prior years, which the BCUC has found to be reasonable.[161]

The budgeting process incorporated both top-down and bottom-up elements. The Executive Team provided the necessary governance and oversight. The budgeting process incorporated expenditure reprioritization and trade-off decisions to respond to emerging cost pressures facing BC Hydro.

- From a **bottom-up** perspective, each KBU conducts an in-depth review of their operating costs, considering current operational and project related needs based on forecast work plans, resourcing requirements and legislative and compliance requirements. Through this process, cost pressures and savings opportunities are identified and consolidated at a Business Group level. Following initial reviews at the Business Group level, the Executive Team engages in an iterative review process.
- From a **top-down** perspective, BC Hydro's Executive Team reviews the identified cost pressures and savings opportunities and considers the goals and targets set out in documents including the Service Plan and the Five-Year Strategy to inform an overall top down target. The Executive Team then prioritizes the cost pressures and cost savings to be undertaken to arrive at the final budget.

The result of the top-down and bottom-up process was the approval of the planned operating costs proposed in this application.

[161] BCUC Decision and Order No. G-187-21, Fiscal 2022 Revenue Requirements Application (June 17, 2021), page 27: "The Panel considers BC Hydro's budgeting process involving top-down and bottom-up elements goes beyond the examination of incremental changes from the prior year and continues to be reasonable for forecasting operating costs. Therefore, for these reasons, the Panel finds the fiscal 2022 operating costs requested for recovery to be reasonable."

As the BCUC has recognized, our top-down and bottom-up budgeting process "goes beyond the examination of incremental changes from the prior year".[162] It also "provides insight into the cost pressures and savings opportunities for BC Hydro."[163]

We continue to have appropriate financial oversight processes [164,165] in place, consistent with prior years, with the objective of remaining within operating cost budgets determined through the budgeting process.

5.5 Fiscal 2023 to Fiscal 2025 Operating Cost Increases

This section outlines the fiscal 2023 to fiscal 2025 forecast operating cost increases. BC Hydro's base operating costs are increasing by 2.4 per cent in fiscal 2023, 2.2 per cent in fiscal 2024, and 3.4 per cent in fiscal 2025. The average annual increases in base operating costs from fiscal 2023 through fiscal 2025 is 2.6 per cent per year. While we have identified six drivers of the base operating cost increase, over three-quarters (81.3 per cent) of the increase is associated with uncontrollable costs and reliability investments.

5.5.1 Most of the Change in Base Operating Costs is Associated with Uncontrollable Factors and Reliability Investments

Figure 5-4 below shows the six drivers of the change in base operating costs.

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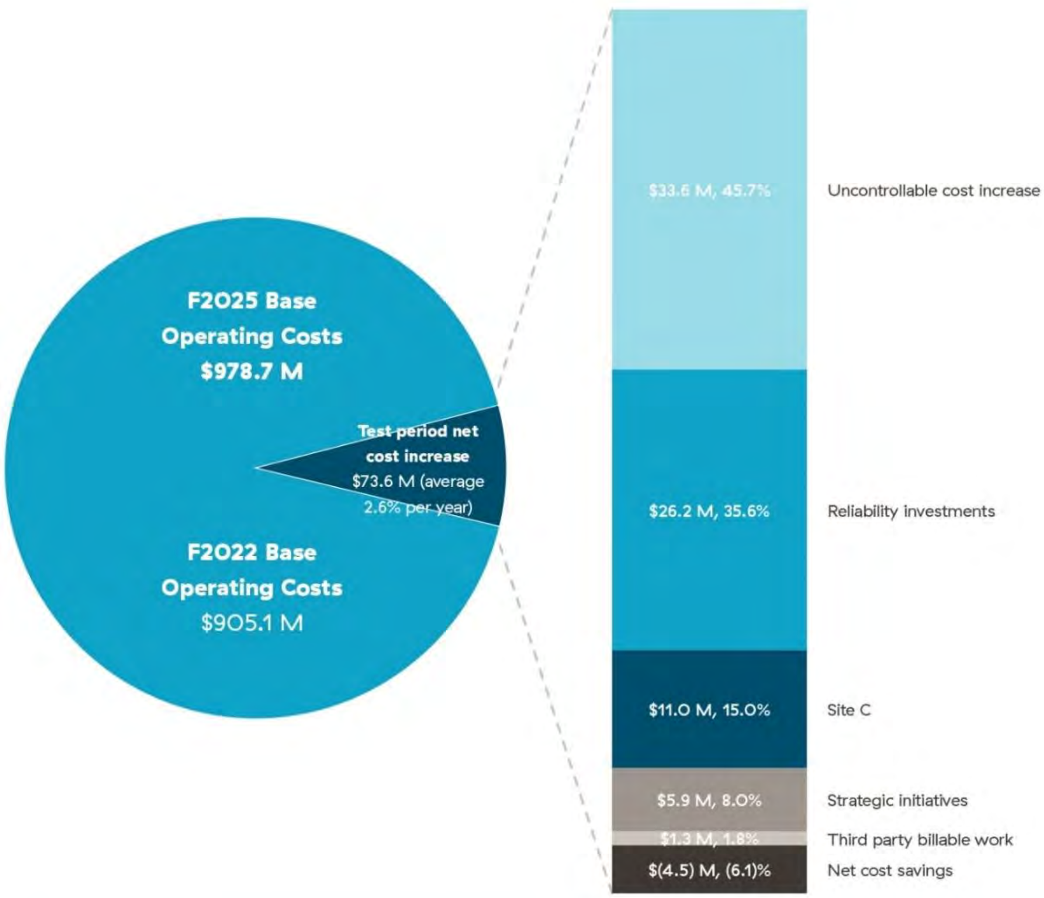
[162] BCUC Decision and Order No. G-187-21, Fiscal 2022 Revenue Requirements Application (June 17, 2021), page 27.

[163] BCUC Decision and Order No. G-246-20, Fiscal 2020 to Fiscal 2021 Revenue Requirements Application (October 2, 2020), page 58, "The Panel accepts BC Hydro's approach to leveraging a top down to bottom up budgeting to forecast its base operating costs for the Test Period, which provides insight into the cost pressures and savings opportunities for BC Hydro."

[164] The Executive Team reviews summary monthly and year-to-date financial results including operating costs and variances to ensure that KBUs and Business Groups are on track with their budgets. Emerging cost pressures are reviewed, and the team works together to ensure BC Hydro can achieve its year-end targets through collective action.

[165] Managers receive monthly reporting outlining their monthly and year-to-date costs to ensure that they are on track with their budgets. Variances are quantified and explained, working with finance and business group leadership. Year-end forecasts also identify any expected challenges in meeting annual targets, and actions to remain on-track are implemented.

Figure 5-4 Summary of Test Period Base Operating Costs Increases



Base Operating Costs—$ million[1]	Starting point	Current fiscal year	$ increase	% increase	Average % increase per year
F2023	905.1	926.6	21.5	2.4%	
F2024	926.6	947.0	20.4	2.2%	
F2025	947.0	978.7	31.7	3.4%	
Test period total	**905.1**	**978.7**	**73.6**	**8.1%**	**2.6%**
[1] Appendix A, Schedule 5.0, line 14	a	b	c=b−a	d=c/a	

May not add due to rounding

As shown in Figure 5-4 above, the net increase in base operating costs over the Test Period can be separated into six categories:

1. Uncontrollable cost increases of $33.6 million (or 45.7 per cent of the Test Period net increase), as further described in section 5.5.3.1 and Table 5-6, include:

    i. Labour costs partially offset by a reduction in current service pension[166] costs due to a favourable change in the discount rate in fiscal 2023;

    ii. BCUC and Canada Energy Regulator Cost Recovery Levies;

    iii. Insurance costs;

    iv. Water Use Plan Order Review Program costs; and,

    v. Technology licensing and application costs.

2. Reliability investments of $26.2 million (or 35.6 per cent of the Test Period net increase), as further described in section 5.5.3.2 and Table 5-6, include

    i. Costs to strengthen our MRS program and implement and sustain new Standards and functions;

    ii. Costs for vegetation management to support reliability, compliance, access and employee and public safety; and,

    iii. Costs to enhance cybersecurity programs.

3. Site C operating costs of $11.0 million (or 15 per cent of the Test Period net increase). The Site C Generating Station is expected to transition to partial operations by December 2024 in anticipation of the in-service of the first generating unit, with expectation of full operations by end of fiscal 2026. The planned operating costs in the Test Period represent the costs associated with partial operations, further described in section 5.5.3.3 and Table 5-6;

[166] Current Service Costs are for future pension benefits earned by employees in the current year and are determined by BC Hydro's external actuary. The present value of future pension benefits earned by employees in the current year are determined using the market discount rate determined at the date of the forecast. The market discount rate is based on AA Canadian Corporate bond yields. Current service costs are sensitive to changes in the market discount rate. A decrease in the market discount rate will increase current service costs, and vice versa. Current service costs are shown in section 5.12.4.2, including Table 5-42, which shows changes in discount rates and current service costs in recent years.

4. Strategic Initiatives of $5.9 million (or 8 per cent of the Test Period increase), as further described in section 5.5.3.4 and Table 5-6, include:
    i. Increased costs to support the implementation of the Electrification Plan, as further described in Chapter 10, section 10.4.2.3;
    ii. Increased costs to support and develop a strategy to pursue new renewable generation opportunities to reduce diesel use in remote communities; and,
    iii. Increased costs to support the development and implementation of BC Hydro's UNDRIP plan.
5. Third-party billable work of $1.3 million (or 1.8 per cent of the Test Period net increase) as further discussed in section 5.5.3.5, and Table 5-6. Costs associated with the increase in work volumes in these areas are offset by an increase in miscellaneous revenues;
6. Net cost savings of $(4.5) million (or 6.1 per cent decrease over the Test Period), further described in section 5.5.3.6, and Table 5-6, is comprised of the following:
    iv. Other cost increases of $8.4 million [167] which include:
        - Apprentice and trainee funding to address increasing resource planning forecasts and to account for attrition;
        - Work program resourcing requirements to ensure adequate resources and support are in place for the Operations Business Group workplan, as further described in section 5.11;
        - Routine trouble work increases primarily caused by vegetation growth, electricity system expansion and climate change impacts;

[167] Refer to rows 27 to 32 in Table 5-6.

- Enterprise compliance resource requirements to provide centralized compliance assurance across the organization for regulatory obligations; and,
- Expenditures related to electric vehicle charging infrastructure which are prescribed undertakings under the Greenhouse Gas Reduction (Clean Energy) Regulation (**GGRR**).

The above cost increases are offset by:

(i) Savings of $12.9 million[168] primarily due to:

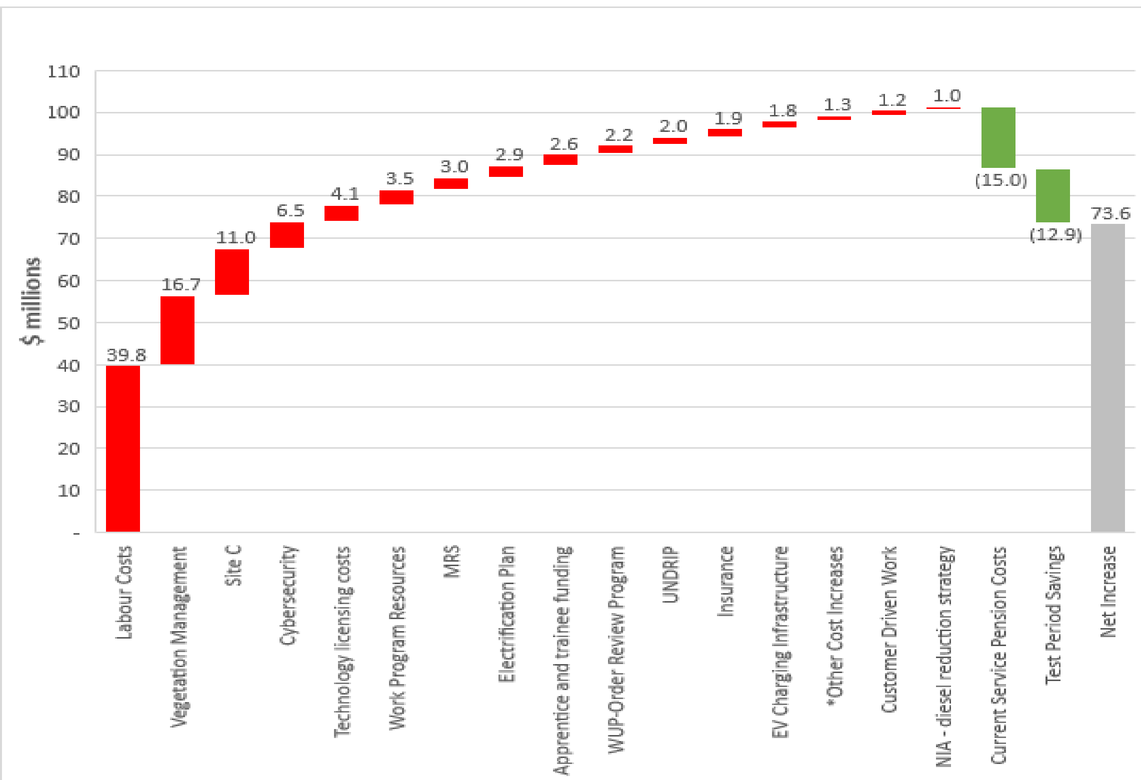
- The funding approved in the Previous Application to complete significant catch-up on frontline technical and leadership training no longer being required in future years;
- Storm restoration cost reduction due to lower costs in recent years which has resulted in a decrease in the rolling five-year average of storm restoration costs;
- The realization of benefits from the implementation of the Supply Chain Applications Project;
- Permanent travel reductions due to changes utilized during the COVID-19 pandemic that will be carried forward (e.g., more virtual meetings instead of in-person meetings);
- The transition from the implementation phase for safety initiatives to a phase of sustainment and continuous improvement; and
- Capital overhead savings as result of increased costs eligible for capitalization.

[168] Refer to rows 33 to 39 in Table 5-6.

5.5.2 Further Overview of the Change in Base Operating Costs

Figure 5-5 below provides a further breakdown of cumulative Test Period cost increases and savings that were presented in Figure 5-4 above. The red bars show the factors that are increasing costs. The green bars show offsetting savings, culminating in the net change of $73.6 million (the grey bar) representing the change in base operating costs from the fiscal 2022 Decision amounts to the fiscal 2025 plan.

Figure 5-5 Summary of Changes to BC Hydro's Test Period Base Operating Costs[169]



169 Other Cost Increases include:

BCUC and Canada Energy Regulator	$0.6 million
Damage to Plant	$0.5 million
Routine Trouble Work	$0.4 million
Enterprise Compliance Resource	$0.2 million
Interconnection Study & Project costs	$(0.4) million
Total	$1.3 million

Table 5-3 below provides a continuity table by Business Group that summarizes the changes to base operating costs in fiscal 2023 compared to fiscal 2022.

Table 5-3 Summary of Changes to Fiscal 2023 Base Operating Costs by Business Group[170,171]

	F2023 Plan ($ million)	Ref	BC Hydro	Integrated Planning	Capital Infrastructure Project Delivery	Operations	Safety & Compliance	Finance, Technology, Supply Chain	Customer, Corporate Affairs	Other
1	**F2022 Revenue Requirement Application Plan**	a	**1,126.5**	**352.2**	**84.3**	**261.4**	**68.3**	**299.1**	**122.3**	**(61.1)**
2	**Compliance Filing Adjustment**	b	**(0.0)**	**0.8**					**(0.8)**	
3	Reorganizational Impact	c	-						(24.4)	24.4
4	**F2022 Decision (Schedule 5.0, line 19)**	d = Σ a to c	**1,126.5**	**353.0**	**84.3**	**261.4**	**68.3**	**299.1**	**97.1**	**(36.7)**
5	Budget Transfers Between Business Groups	e	**0.0**	0.9	(0.6)	1.4	(2.1)	0.9	0.4	(0.9)
6	**Less:**									
7	IFRS Ineligible Capital Overhead	f	(214.9)	-	-	-	-	-	-	(214.9)
8	Waneta 2/3rd Operating Costs	g	(6.1)	(6.1)	-	-	-	-	-	-
9	Customer Crisis Fund Operating Costs	h	(0.5)	-	-	-	-	-	(0.5)	-
10		i = Σ f to h	**(221.4)**	**(6.1)**	-	-	-	-	**(0.5)**	**(214.9)**
11	**F2022 Base Operating Costs (Schedule 5.0, line 14)**	j=e+i	**905.1**	**347.8**	**83.7**	**262.8**	**66.2**	**300.0**	**97.0**	**(252.4)**
12	**Current Year Budget Transfers**	k	-	-	0.7	(0.5)	-	-	(0.5)	0.3
13	**Test Period Net Cost Increase/Decrease**									
14	**1. Uncontrollable Cost Increases**									
15	Current Service Pension Costs		(21.7)							
16	Other Labour Costs		10.7							
17	Current Service Costs and Other Labour Costs		(11.0)	(2.7)	(0.9)	(2.8)	(0.7)	(2.5)	(0.9)	(0.6)
18	Technology Licensing & Application Support Costs		4.1	-	-	-	-	4.1	-	-
19	Water Use Plan Order Review Program		2.2	-	-	2.2	-	-	-	-
20	Insurance		0.9	-	-	-	-	0.9	-	-
21	BCUC and CER Cost Recovery Levies		0.2	-	-	-	-	-	0.2	-
22		l	**(3.6)**	(2.7)	(0.9)	(0.6)	(0.7)	2.5	(0.7)	(0.6)
23	**2. Reliability Investments**									
24	Vegetation Management		8.2	8.1	-	0.1	-	-	-	-
25	Mandatory Reliability Standards		5.5	0.2	-	1.5	1.7	2.0	-	0.1
26	Cyber Security		4.2	-	-	-	-	4.2	-	-
27		m	**17.9**	8.3	-	1.6	1.7	6.2	-	0.1
28	**3. Site C**	n	**0.4**	0.3	-	0.1	-	-	-	-
29	**4. Strategic Initiatives**									
30	UNDRIP		1.6	-	1.6	-	-	-	-	-
31	Electrification Plan		1.2	0.4	0.0	0.6	-	-	0.2	-
32	Non-Integrated Area (NIA) - diesel reduction strategy		0.7	0.7	-	-	-	-	-	-
33		o	**3.5**	1.1	1.6	0.6	-	-	0.2	-
34	**5. Third Party Billable Work**									
35	Interconnection study and project work		1.8	1.8	-	-	-	-	-	-
36	Customer Driven Work		1.2	-	-	1.2	-	-	-	-
37	Damage to Plant		0.5	-	-	0.5	-	-	-	-
38		p	**3.5**	1.8	-	1.7	-	-	-	-
39	**6. Net Cost Savings**									
40	Work Program Resources		3.3	0.5	-	2.9	-	-	-	-
41	Routine Trouble Work		3.2	-	-	3.2	-	-	-	-
42	Electric Vehicle Charging Infrastructure Costs		1.8	1.0	-	-	-	-	0.8	-
43	Apprentice and trainee funding		0.5	-	-	-	0.5	-	-	-
44	IRP Funding		0.3	0.3	-	-	-	-	-	-
45	Enterprise Compliance Resource		0.2	-	-	-	0.2	-	-	-
46	Test Period Savings		(9.7)	(0.9)	(0.3)	(5.1)	(2.3)	(0.4)	(0.2)	(0.6)
47		q	**(0.4)**	0.9	(0.3)	1.0	(1.6)	(0.4)	0.6	(0.6)
48	**Total Test Period Net Increase/(Decrease)**	r = Σ l to q	**21.5**	**9.7**	**0.5**	**4.4**	**(0.6)**	**8.3**	**0.1**	**(1.1)**
49	**F2023 Base Operating Costs (Current Year) (Schedule 5.0, line 14)**	s = j+k+r	**926.6**	**357.6**	**84.8**	**266.8**	**65.6**	**308.4**	**96.6**	**(253.2)**
50	**Total Percentage Increase**	(s-j)/j	2.4%	2.8%	1.4%	1.5%	-0.9%	2.8%	-0.4%	0.3%

Table may not add due to rounding

170 Other includes Office of the President and Chief Executive Officer, Office of the General Counsel, Human Resources, Corporate Costs and Capitalized Costs.

171 Further breakdown of the Test Period Savings, line 46, is provided in section 5.5.3.6.

Similarly, Table 5-4 and Table 5-5 below provide a continuity table by Business Group that summarize the changes in base operating costs in fiscal 2024 and fiscal 2025 compared to fiscal 2023 and fiscal 2024, respectively. Operating costs for each Business Group and Key Business Unit are provided in Schedule 5.1 to Schedule 5.7 of Appendix A – Financial Schedules.

Table 5-4 Summary of Changes to Fiscal 2024 Base Operating Costs by Business Group[172,173]

	F2024 Plan ($ million)	Ref	BC Hydro	Integrated Planning	Capital Infrastructure Project Delivery	Operations	Safety & Compliance	Finance, Technology, Supply Chain	Customer, Corporate Affairs	Other
1	**F2023 Base Operating Costs Carryforward**	a=ln 49 Table 5-4	**926.6**	357.6	84.8	266.8	65.6	308.4	96.6	(253.2)
2	**Test Period Net Cost Increase/Decrease**									
3	**1. Uncontrollable Cost Increases**									
4	Current Service Pension Costs		3.3							-
5	Other Labour Costs		13.4							-
6	Current Service Costs and Other Labour Costs		16.7	4.3	1.0	4.6	1.1	3.4	1.6	0.7
7	Insurance		0.5	-	-	-	-	0.5	-	-
8	BCUC and CER Cost Recovery Levies		0.2	-	-	-	-	-	0.2	-
9		b	**17.4**	4.3	1.0	4.6	1.1	3.9	1.8	0.7
10	**2. Reliability Investments**									
11	Vegetation Management		3.9	3.9	-	-	-	-	-	-
12	Cyber Security		1.9	-	-	-	-	1.9	-	-
13	Mandatory Reliability Standards		(0.9)	(0.7)	-	-	(1.6)	1.6	-	(0.3)
14		c	**4.9**	3.2	-	-	(1.6)	3.5	-	(0.3)
15	**3. Site C**	d	**0.8**	0.8	-	(0.0)	-	-	-	-
16	**4. Strategic Initiatives**									
17	Electrification Plan		0.9	0.6	-	0.2	-	-	0.1	-
18	UNDRIP		0.4	-	0.4	-	-	-	-	-
19	Non-Integrated Area (NIA) - diesel reduction strategy		0.3	0.3	-	-	-	-	-	-
20		e	**1.6**	0.9	0.4	0.2	-	-	0.1	-
21	**5. Third Party Billable Work**									
22	Interconnection study and project work		(1.5)	(1.5)	-	-	-	-	-	-
23		f	**(1.5)**	(1.5)	-	-	-	-	-	-
24	**6. Net Cost Savings**									
25	Apprentice and trainee funding		1.0	-	-	-	1.0	-	-	-
26	Work Program Resources		0.1	0.0	-	0.0	-	-	-	-
27	IRP Funding		(0.6)	(0.6)	-	-	-	-	-	-
28	Routine Trouble Work		(1.4)	-	-	(1.4)	-	-	-	-
29	Test Period Savings		(1.8)	-	-	(1.0)	-	(0.8)	-	-
30		g	**(2.8)**	(0.6)	-	(2.4)	1.0	(0.8)	-	-
31	**Total Test Period Net Increase/(Decrease)**	h = ∑ b to g	**20.4**	**7.0**	**1.4**	**2.4**	**0.5**	**6.6**	**1.9**	**0.4**
32	**F2024 Base Operating Costs (Current Year) (Schedule 5.0, line 14)**	i =a+h	**947.0**	**364.6**	**86.3**	**269.2**	**66.1**	**314.9**	**98.6**	**(252.8)**
33	**Total Percentage Increase**	(i-a)/a	2.2%	2.0%	1.7%	0.9%	0.8%	2.1%	2.0%	-0.2%

Table may not add due to rounding

172 Other includes Office of the President and Chief Executive Officer, Office of the General Counsel, Human Resources, Corporate Costs and Capitalized Costs.

173 Further breakdown of the Test Period Savings, line 29, is provided in section 5.5.3.6.

Table 5-5 Summary of Changes to Fiscal 2025 Base Operating Costs by Business Group[174,175]

	F2025 Plan ($ million)	Ref	BC Hydro	Integrated Planning	Capital Infrastructure Project Delivery	Operations	Safety & Compliance	Finance, Technology, Supply Chain	Customer, Corporate Affairs	Other
1	**F2024 Base Operating Costs Carryforward**	a=ln 32 Table 5-5	**947.0**	364.6	86.3	269.2	66.1	314.9	98.6	(252.8)
2	**Test Period Net Cost Increase/Decrease**									
3	**1. Uncontrollable Cost Increases**									
4	Current Service Pension Costs		3.4							-
5	Other Labour Costs		15.7							-
6	Current Service Costs and Other Labour Costs		19.1	4.8	1.2	5.2	1.2	4.0	1.9	0.8
7	Insurance		0.5	-	-	-	-	0.5	-	-
8	BCUC and CER Cost Recovery Levies		0.2	-	-	-	-	-	0.2	-
9		b	**19.8**	4.8	1.2	5.2	1.2	4.5	2.1	0.8
10	**2. Reliability Investments**									
11	Vegetation Management		4.6	4.6	-	-	-	-	-	-
12	Cyber Security		0.4	-	-	-	-	0.4	-	-
13	Mandatory Reliability Standards		(1.6)	(1.1)	-	-	(0.3)	-	-	(0.3)
14		c	**3.4**	3.5	-	-	(0.3)	0.4	-	(0.3)
15	**3. Site C**	d	**9.8**	7.3	0.1	2.1	0.1	0.2	-	-
16	**4. Strategic Initiatives**									
17	Electrification Plan		0.7	0.5	-	0.1	-	-	0.1	-
18		e	**0.7**	0.5	-	0.1	-	-	0.1	-
19	**5. Third Party Billable Work**									
20	Interconnection study and project work		(0.7)	(0.7)	-	-	-	-	-	-
21		f	**(0.7)**	(0.7)	-	-	-	-	-	-
22	**6. Net Cost Savings**									
23	Apprentice and trainee funding		1.1	-	-	-	1.1	-	-	-
24	Work Program Resources		0.1	0.0	-	0.1	-	-	-	-
25	IRP Funding		0.3	0.3	-	-	-	-	-	-
26	Test Period Savings		(1.3)	-	-	-	(0.3)	(0.8)	-	(0.2)
27	Routine Trouble Work		(1.4)	-	-	(1.4)	-	-	-	-
28		g	**(1.3)**	0.3	-	(1.3)	0.8	(0.8)	-	(0.2)
29	**Total Test Period Net Increase/(Decrease)**	h = ∑ b to g	**31.7**	**15.8**	**1.3**	**6.1**	**1.9**	**4.2**	**2.2**	**0.3**
30	**F2025 Base Operating Costs (Current Year) (Schedule 5.0, line 14)**	i =a+h	**978.7**	**380.4**	**87.6**	**275.3**	**68.0**	**319.1**	**100.8**	**(252.5)**
31	**Total Percentage Increase**	(i-a)/a	3.4%	4.3%	1.5%	2.3%	2.8%	1.3%	2.2%	-0.1%

Table may not add due to rounding

5.5.3 Explanation of the Six Cost Drivers of the Change in Base Operating Costs

This section provides more information about the six cost drivers which are driving the increase in base operating expenses. We continue to look for improvements and efficiencies to reduce costs; however, after several years of rigorous fiscal discipline, the opportunity to realize further savings in the Test Period was limited.

174 Other includes Office of the President and Chief Executive Officer, Office of the General Counsel, Human Resources, Corporate Costs and Capitalized Costs.

175 Further breakdown of the Test Period Savings, line 26, is provided in section 5.5.3.6.

A detailed description for each identified driver item is provided in the subsections following Table 5-6 below.

Table 5-6 also includes FTEs. It shows that the increase in FTEs is primarily as result of resourcing requirements to address key initiatives included in these six cost drivers (e.g., MRS, Site C, Electrification Plan, and the work program resourcing requirements to support the operations workplan and to address increased compliance requirements). FTEs are further discussed in section 5.12.1.

Table 5-6 Six Cost Drivers Driving the Increase in Base Operating Costs and FTEs

	Ref	Item	F2023	F2024	F2025	Test Period Total	F2023	F2024	F2025	Test Period Total
			($ million)				FTEs			
	Six Cost Drivers									
1	1	**Uncontrollable Cost Increases, Section** 5.5.3.1								
2	1	Current Service Costs	(21.7)	3.3	3.4	(15.0)	-	-	-	-
3	2	Labour	10.7	13.4	15.7	39.8	-	-	-	-
4	3	BCUC and Canada Energy Regulator (**CER**) Cost Recovery Levies	0.2	0.2	0.2	0.6	-	-	-	-
5	4	Property, General Liability, and Directors and Officers liability Insurance	0.9	0.5	0.5	1.9	-	-	-	-
6	5	Water Use Plan Order Review Program	2.2	-	-	2.2	-	-	-	-
7	6	Technology Licensing and Application Support Costs	4.1	-	-	4.1	-	-	-	-
8		**Uncontrollable Cost Increases Total**	**(3.6)**	**17.4**	**19.8**	**33.6**	**-**	**-**	**-**	**-**
9	2	**Reliability Investments,** Section 5.5.3.2								
10	1	Mandatory Reliability Standards[176]	5.5	(0.9)	(1.6)	3.0	29	18	1	48
11	2	Vegetation Management	8.2	3.9	4.6	16.7	8	-	-	8
12	3	Cybersecurity	4.2	1.9	0.4	6.5	5	10	-	14
13		**Reliability Investments Total**	**17.9**	**4.9**	**3.4**	**26.2**	**42**	**28**	**1**	**70**

176 As discussed in section 5.7, the MRS operating cost increase of $5.5 million in fiscal 2023 represents incremental funding of $22.5 million in fiscal 2023, less the fiscal 2022 one-time time costs of $17.0 million.

Ref	Item	F2023	F2024	F2025	Test Period Total	F2023	F2024	F2025	Test Period Total
3	**Site C, Section** 5.5.3.3	0.4	0.8	9.8	11.0	2	2	23	27
	Site C Total	**0.4**	**0.8**	**9.8**	**11.0**	**2**	**2**	**23**	**27**
4	**Strategic Initiatives, Section** 5.5.3.4								
1	Electrification Plan	1.2	0.9	0.7	2.9	44	6	4	53
2	NIA Diesel Reduction Strategy	0.7	0.3	-	1.0	3	-	-	3
3	UNDRIP	1.6	0.4	-	2.0	5	-	-	5
	Strategic Initiatives Total	**3.5**	**1.6**	**0.7**	**5.9**	**52**	**6**	**4**	**61**
5	**Third-Party Billable Work, Section** 5.5.3.5								
1	Damage to Plant	0.5	-	-	0.5	-	-	-	-
2	Customer Driven Work	1.2	-	-	1.2	-	-	-	-
0	Interconnection Study and Project Work	1.8	(1.5)	(0.7)	(0.4)	-	-	-	-
	Third Party Billable Work Total	**3.5**	**(1.5)**	**(0.7)**	**1.3**	**-**	**-**	**-**	**-**

Ref	Item	F2023	F2024	F2025	Test Period Total	F2023	F2024	F2025	Test Period Total
6	**Net Cost Savings, Section 5.5.3.6**								
1	Apprentice and Trainee Funding	0.5	1.0	1.1	2.6	(2)	14	15	27
2	Integrated Resource Plan Funding	0.3	(0.6)	0.3	-	-	-	-	-
3	Work Program Resources	3.3	0.1	0.1	3.5	28	-	-	28
4	Routine Trouble Work	3.2	(1.4)	(1.4)	0.4	-	-	-	-
5	Enterprise Compliance Resource	0.2	-	-	0.2	1	-	-	1
6	Electric Vehicle Charging Infrastructure Costs	1.8	-	-	1.8	-	-	-	-
1	Employee Training	(2.3)	(1.0)	-	(3.3)	-	-	-	-
2	Storm Restoration	(2.3)	-	-	(2.3)	-	-	-	-
3	Supply Chain Applications Project Benefit	(0.5)	(0.8)	(0.8)	(2.2)	(1)	(9)	(8)	(18)
4	Travel Savings	(2.1)	-	-	(2.1)	-	-	-	-
5	Safety Initiative Funding Reduction	(1.7)	-	(0.3)	(2.0)	-	-	-	-
6	Eligible Capital Overhead	(0.5)	-	(0.2)	(0.7)	-	-	-	-
7	Labour Savings	(0.3)	-	-	(0.3)	-	-	-	-
	Total Net Cost Savings	**(0.4)**	**(2.8)**	**(1.3)**	**(4.5)**	**(1)**	**(9)**	**(8)**	**(18)**
Total Test Period Net Cost Increase		**21.5**	**20.4**	**31.8**	**73.6**	**121**	**40**	**35**	**196**[177]
Table may not add due to rounding									

177 Represents regular hour FTEs. Total Test Period FTE increase equals 204 FTEs (195.9 regular hour FTEs plus 8.5 overtime hour FTEs), further discussed in section 5.12.1)

A detailed description for each incremental cost increase and decrease as categorized by the six drivers in Table 5-6 is provided in the following sections.

5.5.3.1 Uncontrollable Cost Increases

Uncontrollable cost increases of $33.6 million (or 45.7 per cent of the Test Period net cost increase)[178] include:

1. **Current Service Costs** of $(15.0) million over the Test Period. Current Service Costs[179] relate to BC Hydro's pension plan and are decreasing in fiscal 2023 primarily due to the 81 basis points increase in the discount rate from 2.59 per cent to 3.40 per cent. As in prior applications, the discount rate has been provided by our external actuary. Changes in the discount rate are market driven and outside of BC Hydro's control. The incremental increase in fiscal 2024 and fiscal 2025 is due to increasing labour costs, which are discussed in the next subsection. Current service costs are further discussed in section 5.12.4.2;

2. **Labour costs** of $39.8 million over the Test Period. Labour costs are increasing due to salary and benefit cost increases. Salaries are planned to increase by 2.0 per cent for both Union as well as Management and Professional staff in each year of the Test Period.

   Union collective agreements expire March 31, 2022 and wage increases for the Test Period are still to be negotiated. This planned increase aligns with forecast market salary increases.

[178] Test Period net cost increase $73.6 million (Table 5-6, row 41).

[179] Current Service Costs are for future pension benefits earned by employees in the current year and are determined by BC Hydro's external actuary. The present value of future pension benefits earned by employees in the current year are determined using the market discount rate determined at the date of the forecast. The market discount rate is based on AA Canadian Corporate bond yields. Current service costs are sensitive to changes in the market discount rate. A decrease in the market discount rate will increase current service costs, and vice versa. Current service costs are shown in section 5.12.4.2, including Table 5-42, which shows changes in discount rates and current service costs in recent years.

BC Hydro considers management and professional compensation increases, which are essentially cost of living increases, to be a priority akin to non-controllable costs given how BC Hydro's employee compensation compares to median market. There were no salary increases for Management and Professional staff in fiscal 2022. According to a Compensation Planning Outlook 2021 report by the Conference Board of Canada, the forecast median market salary increases in 2021 is 2.1 per cent for non-unionized employees. Negotiated increases for unionized employees will be consistent with the Public Sector Employers' Council bargaining mandate, which is not expected to be released until the fall of 2021. Benefit costs increase annually due to prescribed increases to statutory benefits and increases to health benefit costs (e.g., Employment Insurance premiums, Canada Pension Plan premiums, and health and dental fees). Labour costs are further discussed in section 5.12.2;

3. **BCUC and CER Cost Recovery Levies** of $0.6 million over the Test Period. Cost recovery levies represent the amounts billed to BC Hydro by the BCUC and the CER to cover a portion of the regulators' budgets. The increases for fiscal 2023 to fiscal 2025 are based on historical trends and information received from the regulators. Future cost recovery levies are uncertain and are expected to continue to increase resulting in an upward pressure on costs. The fiscal 2023 budget represents a 2.8 per cent increase from expected fiscal 2022 costs. Fiscal 2024 and fiscal 2025 each assume a 2.6 per cent increase in levies;

4. **Insurance** costs of $1.9 million over the Test Period. Insurance costs (specifically, in relation to property, general liability, cyber liability and directors and officers liability) are expected to continue to increase in fiscal 2023 as global insurance market capacity remains constrained and upward pressure on premiums persists. BC Hydro has forecast modest increases for fiscal 2024 and fiscal 2025 as, while insurance market conditions are currently highly

uncertain, we do not expect the recent substantial premium increases to continue indefinitely;

5. **Water Use Plan Order Review Program** costs of $2.2 million over the Test Period. The operating cost increase is related to BC Hydro's obligation to fulfill Water Use Plan order review requirements under the Provincial Water Use Planning Guidelines issued by the province. Reviews of the orders are becoming increasingly complex due to changes in environmental legislation and the implementation of UNDRIP. Over the Test Period, there will be a significant increase in the number of Water Use Plan order reviews that are to be completed. The outcome of each Water Use Plan order review sets the foundation for BC Hydro's generating facilities to be authorized under the *Fisheries Act*. Authorization is required to maintain compliance under the *Fisheries Act*. The incremental cost increase primarily relates to capacity funding for Indigenous groups as part of our duty to consult and engage, as well as third-party facilitation and decision-making support; and

6. **Technology Licensing and Application Support Costs** of $4.1 million over the Test Period. The operating cost increases in software licensing and outsourced application and infrastructure support costs are driven by rising contractual costs, changes in licensing models and the increased use of (and investment in) digital technology to support business operations. Technology licensing and application support costs are further discussed in Chapter 5E, section 5E.5.2.

5.5.3.2 Reliability Investments

Reliability Investments of $26.2 million (or 35.6 per cent of the Test Period net cost increase)[180] include:

[180] Test Period net cost increase $73.6 million (Table 5-6, row 41).

1. **Mandatory Reliability Standards** costs of $3.0 million over the Test Period. The operating cost increase is required to strengthen our MRS program and to implement and sustain new Standards and functions as further discussed in section 5.7;
2. **Vegetation Management** costs of $16.7 million over the Test Period**.** The operating cost increase is required to address the increase in vegetation work under the new Vegetation Management Strategy adopted by BC Hydro, as further discussed in section 5.8. The strategy sets out an increase in overall vegetation management funding to support reliability, maintaining compliance with regulatory requirements, access and employee and public safety. Benchmarking confirms that BC Hydro's total vegetation management budgets, including the increase in the Test Period, are within industry benchmarks.[181] BC Hydro expects this increased investment will produce a material improvement in program outcomes for the reasons described in section 5.8; and
3. **Cybersecurity** costs of $6.5 million over the Test Period. The operating cost increases are driven by heightened global cybersecurity risk from the growing complexity and volume of cyber attacks and the need to address recommendations from cybersecurity capability self-assessments and audits. Cybersecurity is further discussed in section 5.9.

5.5.3.3 Site C Operating Costs

Site C operating costs of $11.0 million (or 15 per cent of the Test Period net cost increase).[182] Assets in the Site C Generating Station are expected to transition from the construction phase to the operating phase starting in fiscal 2023 in advance of the generating units forecast to be placed in-service during fiscal 2025 and

[181] Refer to section 9 of BC Hydro's Vegetation Management Strategy included in Appendix G for additional information on vegetation management benchmarking.

[182] Test Period net cost increase $73.6 million (Table 5-6, row 41).

fiscal 2026. During this transition period, operating costs and operating FTEs will ramp-up to transition these assets to the operating phase. The $11.0 million of operating costs is comprised of:

- $5.2 million for additional FTEs (i.e., electricians, mechanics, field managers, etc.) to operate the assets, to manage the reservoir intake debris removal program, and to execute maintenance work; and
- $5.8 million for operating costs related to contract commitments in fiscal 2025, including the Peace River Regional District.

Site C's transition to partial operations is discussed further in section 5.10.

5.5.3.4 Strategic Initiatives

Strategic Initiatives of $5.9 million (or 8 per cent of the Test Period net cost increase)[183] include:

1. **Electrification Plan** costs of $2.9 million over the Test Period which is comprised of a portion of the incremental 53 FTEs time for activities such as training which are allocated to operating costs, and the operations of the public electric vehicle charging station infrastructure. The operating cost increase and FTE increase is required to deliver the Electrification Plan. The Electrification Plan will reduce rate increases for customers, lower greenhouse gas emissions and provide economic benefits for British Columbia and is discussed further in Chapter 10, section 10.2;
2. **Non-Integrated Areas – Diesel Reduction Strategy** costs of $1.0 million over the Test Period. Increased costs to support and develop a strategy to pursue new renewable generation opportunities to reduce diesel use in remote communities. There has been substantial interest in reducing diesel generation in remote B.C. communities, resulting from a combination of improvements in

[183] Test period net cost increase $73.6 million (Table 5-6, row 41).

renewable generation and storage technology, concerns regarding climate change and an increase in the availability of government grants to communities in support of clean energy investments. The Government of B.C.'s CleanBC plan sets out objectives for the Government of B.C. and BC Hydro to reduce diesel use in remote communities. BC Hydro is developing a strategy to pursue new renewable generation opportunities in remote communities. We are working with governments, clean energy industry partners and with Indigenous Communities to identify and pursue projects that are mutually beneficial and to advance reconciliation; and

3. **UNDRIP** costs of $2.0 million over the Test Period. UNDRIP is a declaration which establishes an international framework of minimum standards for the "survival, dignity, and well-being" of Indigenous peoples and recognizes Indigenous peoples' basic human rights. In 2019 the Government of B.C. passed the Declaration on the *Rights of Indigenous Peoples Act* to adopt UNDRIP and has mandated BC Hydro to implement UNDRIP as it relates to our specific work and context. We have been working to implement UNDRIP and advance reconciliation for some time. This work will now be formalized through the development of an UNDRIP implementation plan. BC Hydro will be co-developing the UNDRIP implementation plan with Indigenous Nations in B.C. The plan will outline the actions we will be taking as a company to implement UNDRIP and will be a living document which will be updated with Indigenous Nations in the years ahead to reflect changes to relevant government policy and BC Hydro's context. The actions included in the final version of the UNDRIP implementation plan are likely to impact all areas of the business and require work by all Business Groups. The plan is expected to build on efforts already underway across the company and will also add new actions not previously explored by BC Hydro. Implementing the actions outlined in the plan will require an increased level of support and resourcing.

5.5.3.5 Third-Party Billable Work

Third-Party Billable Work of $1.3 million (or 1.8 per cent of the Test Period net cost increase)[184] include:

1. **Damage to Plant** costs of $0.5 million over the Test Period. The operating cost increase is primarily a result of higher costs associated with damage to BC Hydro assets such as motor vehicle accidents. Costs associated with the increase are offset by a corresponding increase in miscellaneous revenues, as further discussed in Chapter 8, section 8.8;

2. **Customer Driven Work** costs $1.2 million over the Test Period. The operating cost increase is primarily due to increased customer-driven project activities (e.g., temporary re-locations and installing flag lines and/or equipment barriers for overhead lines at house moves and active construction sites). Costs associated with the increase are offset by a corresponding increase in miscellaneous revenues, as further discussed in Chapter 8, section 8.8; and

Interconnection Study and Project Work net reduction of $(0.4) million over the Test Period. Based on historical trending and expected future customer interconnection study and project work, BC Hydro is reducing planned operating costs to complete interconnection study and project work in the Test Period. Associated costs are offset by a change in miscellaneous revenues, as further discussed in Chapter 8, section 8.8. Interconnection study and project work expenditures related to the Electrification Plan, further discussed in Chapter 10, section 10.4.1.6, are separate and are deferred expenditures.

5.5.3.6 Net Cost Savings

Net cost savings of $4.5 million (or (6.1) per cent of the Test Period net cost increase) consist of Other Cost Increases of $8.4 million[185] (or 11.4 per cent of the

[184] Test Period net cost increase $73.6 million (Table 5-6, row 41).
[185] Table 5-6, sum of rows 27 to 32.

Test Period net cost increase[186]) offset by cost savings and reductions of $12.9 million[187] (or (17.5) per cent of the Test Period net cost increase).[188] A detailed breakdown of Other Cost increases and Cost Savings and Reductions is provided below.

Other Cost Increases consist of:

1. **Apprentice and Trainee Funding** increase of $2.6 million over the Test Period. The Learning and Development KBU's operating costs will increase during the Test Period. Apprentice and trainee FTEs will decline by two in fiscal 2023 but will increase by 14 FTEs in fiscal 2024 and 15 FTEs in fiscal 2025. The changes are the result of the resource planning forecasting process which takes into consideration factors such as maintenance and capital project plans, and the retirement and age risks within the different trades areas. The volume of intakes is adjusted to accommodate the forecast work requirements and attrition;

2. **Integrated Resource Plan,** net zero impact over the Test Period. BC Hydro will file the 2021 Integrated Resource Plan in December 2021. The operating cost increase in fiscal 2023 is required to fund additional resources for the regulatory proceeding. That funding is eliminated in fiscal 2024, but additional funding is also required in fiscal 2025 for preliminary work on the next Integrated Resource Plan;

3. **Work Program Resource Requirement** costs of $3.5 million over the Test Period which includes 28 additional FTEs starting in fiscal 2023 and $0.9 million in contractor funding. The operating cost increase and FTE increase during the Test Period is required to ensure adequate resources and support are in place

186 Test Period net cost increase $73.6 million (Table 5-6, row 41).
187 Table 5-6, sum of rows 33 to 39.
188 Test Period net cost increase $73.6 million (Table 5-6, row 41).

for the Operations Business Group to deliver its workplan and address increased compliance requirements, as further discussed in section 5.11;

4. **Routine Trouble Work** costs of $0.4 million over the Test Period. The operating cost increase of $3.2 million in fiscal 2023 is due to increases in routine trouble work primarily caused by vegetation growth near BC Hydro's transmission and distribution overhead circuits, expansion of the electrical system and climate change impacts to the growth rate and health of vegetation across the province. The operating cost decrease of $1.4 million in each of fiscal 2024 and 2025 is a result of the execution of the Vegetation Management Strategy, further discussed in Appendix G;

5. **Enterprise Compliance Resource** costs of $0.2 million over the Test Period. Regulatory, legislative and other compliance obligations continue to increase. To increase consistency and reduce risks in achieving, sustaining and demonstrating compliance with regulatory, legislative and other obligations across the organization it is important for BC Hydro to achieve and sustain an enterprise compliance approach that outlines expectations and to conduct assurance activities to ensure controls are effective. This funding will support a dedicated resource to carry out this work; and

6. **Electric Vehicle Charging Infrastructure** costs of $1.8 million over the Test Period. This operating cost increase is due to expenditures related to electric vehicle charging infrastructure which are prescribed undertakings under the GGRR. Electric Vehicle charging infrastructure costs are further described in Chapter 10, section 10.4.3.2.

Cost Savings and Reductions consist of:

1. **Employee Training** reduction of $3.3 million over the Test Period. In fiscal 2022, BC Hydro included an increase of $3.3 million to provide IBEW employees with additional required technical and leadership training. In the Previous Application, BC Hydro committed to monitor these training plans and

adjust as necessary. During fiscal 2022, BC Hydro will complete significant catch-up on technical training as well as develop and pilot crew leadership training, which will be delivered in fiscal 2023 for $1.0 million (i.e., a reduction of $2.3 million relative to fiscal 2022). The training is required because BC Hydro identified that IBEW employees have fallen behind on technical training due to the need to dedicate existing training to meet growing safety and compliance training requirements. This training will allow IBEW employees to complete both the mandatory safety and regulatory training, as well as the technical and leadership training to maintain their current skills required to work safely and efficiently and maintain system reliability. Therefore, there is a $2.3 million reduction in IBEW employee training in fiscal 2023 and the remaining $1.0 million is eliminated in fiscal 2024 such that BC Hydro will revert to IBEW employee training funding levels prior to fiscal 2022;

2. **Storm Restoration** reduction of $2.3 million over the Test Period. BC Hydro continues to budget for storm restoration operating costs using the BCUC-approved approach of a rolling five-year average of normal weather years. In fiscal 2021, we experienced below average storm related damage, which has caused the rolling five-year average of storm restoration operating costs to decrease.[189] As previously approved by the BCUC, variances between planned and actual storm restoration operating costs are deferred to the Storm Restoration Costs Regulatory Account, which is discussed in Appendix R, section 3.2;

[189] Five year-rolling average for Storm Restoration costs:

Storm Restoration Costs ($ million)	F2014 Actual	F2015 Actual	F2016 Actual	F2017 Actual	F2018 Actual	F2019 Actual	F2020 Actual	F2021 Actual	Rolling 5-Year Average	Change
Fiscal 2020 - Fiscal 2021 RRA	4.6	12.9	23.5	25.3	22.9				**17.8**	
Fiscal 2020 - Fiscal 2021 RRA Decision, Directive #19		12.9	23.5	25.3	22.9	25.6			**22.0**	**4.2**
Fiscal 2022 Decision			23.5	25.3	22.9	25.6	10.1		**21.5**	**(0.5)**
Fiscal 2023 - Fiscal 2025 RRA				25.3	22.9	25.6	10.1	12.1	**19.2**	**(2.3)**

3. **Supply Chain Applications Project Benefit Realization** of $2.2 million over the Test Period. Implementation of the Supply Chain Applications Project reduces operating costs as a result of effort benefits (headcount reduction), reduced cost from Active Contract and Supplier Management, reduced inventory obsolescence and improved excess project material visibility. The incremental savings and headcount reductions over the Test Period reflect the expectation of when the benefits will be realized. The benefits are further described in Appendix H of the BC Hydro Supply Chain Applications Phase Two filing;[190]

4. **Travel Savings** of $2.1 million across all Business Groups, over the Test Period, represents an approximate 13 per cent reduction from the fiscal 2022 Decision amounts. Travel includes transportation, accommodation, meal-related costs, and other related travel expenses for events such as training sessions, conferences, and meetings with internal and external stakeholders. Although travel requirements associated with field work have returned to pre-pandemic levels, BC Hydro increased the use of technology solutions such as video conferencing and collaboration tools during the COVID-19 pandemic. As a result, there is a planned, permanent reduction in some travel related to training, conferences, and meetings due to plans to continue to adopt and shift towards these remote work tools even as travel restrictions are lifted;

5. **Safety Initiative Funding** reduction of $2.0 million over the Test Period. BC Hydro first provided safety initiatives funding in the Fiscal 2017 to Fiscal 2019 Revenue Requirements Application and has made concerted efforts over successive test periods (i.e., fiscal 2020 to fiscal 2021, and fiscal 2022) to improve worker safety through a variety of initiatives. In order to sustain progress realized from these initiatives and further improve safety

[190] BC Hydro Supply Chain Applications Phase Two Verification - Errata (January 2019), Appendix H.

performance, we are transitioning to a phase of sustainment and continuous improvement supported by base work. This means that some of the amounts previously required to advance and implement new initiatives are no longer required. BC Hydro's Safety Framework will support this approach with its established governance structure and systematic risk management processes that facilitate targeted investments in our safety programs. As a result, BC Hydro is reducing its plan by $1.7 million in fiscal 2023 and additional $0.3 million in fiscal 2025;

6. **Eligible Capital Overhead** of $0.7 million over the Test Period. The reduction in operating costs is due to increased capital overhead transfers (credits) as a result of increased costs eligible for capitalization. These increased costs are primarily due to changes to Standard Labour Rates; and

7. **Labour Savings** of $0.3 million over the Test Period. We have been able to reduce the Trades Training Instructor actual overtime spend due to efficiencies in scheduling Trades Training Instructors to support field workers onsite and classroom courses.

5.5.4 Overview of the Change in Net Operating Costs and Reconciliation

We use various terminologies when describing BC Hydro's operating costs. Table 5-7 below helps to explain the various operating cost views, which are unchanged from prior applications. While the base operating costs are the appropriate focus when assessing BC Hydro's cost control, we have provided in this section a continuity of net operating costs from the fiscal 2022 Decision to fiscal 2023, fiscal 2024 and fiscal 2025, as shown in Table 5-8, Table 5-9, and Table 5-10 respectively.

Table 5-7 Explanation of Operating Cost Views

Cost Components	Base Operating Costs	Net Operating Costs	Gross Operating Costs	Current Operating Costs
Normal day to day operations of BC Hydro including costs such as Labour, Materials and Services.	√	√	√	√
Recoveries Capitalized Costs Re-Classification Adjustment	√	√	√	√
Capital overhead that can no longer be capitalized under IFRS[191] Cost related to BC Hydro's purchase of Teck's two-third interest in Waneta Customer Crisis Fund		√	√	√
Costs incurred in the current period but recovered in rates in future years consistent with the recovery mechanisms established for each regulatory account.			√	
Costs incurred in prior periods to be recovered in the current period consistent with the recovery mechanisms established for each regulatory account.				√

Base operating costs, which are the primary focus of this Chapter, are defined as personnel, materials and external services expenses included in income that are incurred in the day-to-day operating of BC Hydro’s electric utility, net of recoveries, capitalized costs and reclassification adjustments.

Base operating costs are a component of net operating costs. Net operating costs also include capital overhead that can no longer be capitalized under International Financial Reporting Standards (**IFRS**), costs related to the 2017 Waneta Transaction and the Customer Crisis Fund. Net operating costs are a component of two operating cost views, gross operating costs and current operating costs, as follows:

[191] Represents IFRS ineligible capital overhead costs that have been phased-in to operating costs over a 10-year period (the final year being fiscal 2022).

- Net operating costs, combined with costs incurred in the current period that are to be recovered in rates in future years through the recovery mechanisms established for each regulatory account, represent BC Hydro’s total gross operating costs; and
- Net operating costs, combined with costs incurred in prior periods to be recovered in the current period through the recovery mechanisms established for each regulatory account, represent BC Hydro’s total current operating costs.

5.5.4.1 *Base Operating Costs Should Be the Focus When Assessing BC Hydro’s Cost Management*

Base operating costs are, in BC Hydro’s view, the relevant measure for the assessment of our efforts to control operating costs because they exclude costs that, among other things, vary according to changes in accounting rules and the mechanisms in place to recover regulatory account balances. BC Hydro reports its base operating costs as part of its Annual Service Plan.

5.5.4.2 *Net Operating Costs for the Test Period*

Table 5-8, Table 5-9, and Table 5-10 below provide continuity tables that summarize the changes to BC Hydro’s net operating costs for fiscal 2023, fiscal 2024, and fiscal 2025 respectively. Operating costs for each Business Group and Key Business Unit are provided in Schedule 5.1 to Schedule 5.7 of Appendix A – Financial Schedules.

Table 5-8 Summary of BC Hydro's Fiscal 2023 Net Operating Costs[192,193]

	F2023 Plan ($ million)	Ref	BC Hydro	Integrated Planning	Capital Infrastructure Project Delivery	Operations	Safety & Compliance	Finance, Technology, Supply Chain	Customer, Corporate Affairs	Other
1	**F2022 Revenue Requirement Application Plan**	a	**1,126.5**	**352.2**	**84.3**	**261.4**	**68.3**	**299.1**	**122.266**	**(61.1)**
2	**Compliance Filing Adjustment**	b	**(0.0)**	**0.8**	-	-	-	-	**(0.8)**	-
3	Reorganizational Impact	c	-						(24.4)	24.4
4	**F2022 Decision (Schedule 5.0, line 19)**	d=Σ a to c	**1,126.5**	**353.0**	**84.3**	**261.4**	**68.3**	**299.1**	**97.1**	**(36.7)**
5	Budget Transfers Between Business Groups	e	0.0	0.9	(0.6)	1.4	(2.1)	0.9	0.4	(0.9)
6	**F2022 Forecast (Schedule 5.0, line 19)**	f=d+e	**1,126.5**	**353.9**	**83.7**	**262.8**	**66.2**	**300.0**	**97.5**	**(37.6)**
7	Current Year Budget Transfers Between Business Groups	g	-	-	0.7	(0.5)	-	-	(0.5)	0.3
8	**Current Year Incremental Adjustments:**									
9	Waneta 2/3rd Operating Costs	h	(0.1)	(0.1)	-	-	-	-	-	-
10	Customer Crisis Fund Operating Costs	i	(0.5)	-	-	-	-	-	(0.5)	-
11		j = h+oi	**(0.6)**	**(0.1)**	-	-	-	-	**(0.5)**	-
12	**Test Period Net Cost Increase/Decrease**									
13	**1. Uncontrollable Cost Increases**									
14	Current Service Pension Costs		(21.7)							-
15	Other Labour Costs		10.7							-
16	Current Service Costs and Other Labour Costs		(11.0)	(2.7)	(0.8)	(2.8)	(0.7)	(2.5)	(0.9)	(0.6)
17	Technology Licensing & Application Support Costs		4.1	-	-	-	-	4.1	-	-
18	Water Use Plan Order Review Program		2.2	-	-	2.2	-	-	-	-
19	Insurance		0.9	-	-	-	-	0.9	-	-
20	BCUC and CER Cost Recovery Levies		0.2	-	-	-	-	-	0.2	-
21		k	**(3.6)**	(2.7)	(0.8)	(0.6)	(0.7)	2.5	(0.7)	(0.6)
22	**2. Reliability Investments**									
23	Vegetation Management		8.2	8.1	-	0.1	-	-	-	-
24	Mandatory Reliability Standards		5.5	0.2	-	1.5	1.7	2.0	-	0.1
25	Cyber Security		4.2	-	-	-	-	4.2	-	-
26		l	**17.9**	8.3	-	1.6	1.7	6.2	-	0.1
27	**3. Site C**	m	**0.4**	0.3	-	0.1	-	-	-	-
28	**4. Strategic Initiatives**									
29	UNDRIP		1.6	-	1.6	-	-	-	-	-
30	Electrification Plan		1.2	0.4	0.0	0.6	-	-	0.2	-
31	Non-Integrated Area (NIA) - diesel reduction strategy		0.7	0.7	-	-	-	-	-	-
32		n	**3.5**	1.1	1.6	0.6	-	-	0.2	-
33	**5. Third Party Billable Work**									
34	Interconnection study and project work		1.8	1.8	-	-	-	-	-	-
35	Customer Driven Work		1.2	-	-	1.2	-	-	-	-
36	Damage to Plant		0.5	-	-	0.5	-	-	-	-
37		o	**3.5**	1.8	-	1.7	-	-	-	-
38	**6. Net Cost Savings**									
39	Work Program Resources		3.3	0.5	-	2.9	-	-	-	-
40	Routine Trouble Work		3.2	-	-	3.2	-	-	-	-
41	Electric Vehicle Charging Infrastructure Costs		1.8	1.0	-	-	-	-	0.8	-
42	Apprentice and trainee funding		0.5	-	-	-	0.5	-	-	-
43	IRP Funding		0.3	0.3	-	-	-	-	-	-
44	Enterprise Compliance Resource		0.2	-	-	-	0.2	-	-	-
45	Test Period Savings		(9.7)	(0.9)	(0.3)	(5.1)	(2.3)	(0.4)	(0.2)	(0.6)
46		p	**(0.4)**	0.9	(0.3)	1.0	(1.6)	(0.4)	0.6	(0.6)
47	**Total Test Period Net Increase/(Decrease)**	r=Σ k to p	**21.5**	**9.7**	**0.5**	**4.4**	**(0.6)**	**8.3**	**0.1**	**(1.1)**
48	**F2023 Net Operating Costs (Schedule 5.0, line 19)**	s=f+g+j+r	**1,147.4**	**363.5**	**84.8**	**266.8**	**65.6**	**308.4**	**96.6**	**(38.3)**

Table may not add due to rounding

192 Row 2 relates to Directive 22 of the BCUC's Decision on the Previous Application, which directed BC Hydro to amend its forecast for interconnection revenue in fiscal 2022 to $4.6 million and adjust forecast costs required to generate this revenue; and Directive 24 which directed BC Hydro to remove all fiscal 2022 costs related to Electric Vehicle charging stations and defer these costs to the Electric Vehicle Costs Regulatory Account;

Rows 3, 5 and 7 relate to restructuring impacts and budget transfers between Business Groups. On a consolidated basis they net to zero;

Row 9 relates to costs related to BC Hydro's purchase of Teck's two-thirds interest in Waneta, per BCUC Order No. G-130-18;

Row 10 relates to the Customer Crisis Fund operating costs (administrative costs to run the program and grants) which are offset in miscellaneous revenues, approved by BCUC Order No. G-166-17; and,

Other includes Office of the President and Chief Executive Officer, Office of the General Counsel, Human Resources, Corporate Costs and Capitalized Costs.

193 Further breakdown of the Test Period Savings, line 46, is provided in section 5.5.3.6.

Table 5-9 Summary of BC Hydro's Fiscal 2024 Net Operating Costs[194,195]

	F2024 Plan ($ million)	Ref	BC Hydro	Integrated Planning	Capital Infrastructure Project Delivery	Operations	Safety & Compliance	Finance, Technology, Supply Chain	Customer, Corporate Affairs	Other
1	**F2023 Revenue Requirement Application Plan Carryforward**	a=Ln 48 Table 5-8	**1,147.4**	**363.5**	**84.8**	**266.8**	**65.6**	**308.4**	**96.6**	**(38.3)**
2	**Current Year Incremental Adjustments:**									
3	Waneta 2/3rd Operating Costs	b	**0.2**	0.2	-	-	-	-	-	-
4	**Test Period Net Cost Increase/Decrease**									
5	**1. Uncontrollable Cost Increases**									
6	Current Service Pension Costs		3.3							-
7	Other Labour Costs		13.4							-
8	Current Service Costs and Other Labour Costs		16.7	4.3	1.0	4.6	1.1	3.4	1.6	0.7
9	Insurance		0.5	-	-	-	-	0.5	-	-
10	BCUC and CER Cost Recovery Levies		0.2	-	-	-	-	-	0.2	-
11		c	**17.4**	4.3	1.0	4.6	1.1	3.9	1.8	0.7
12	**2. Reliability Investments**									
13	Vegetation Management		3.9	3.9	-	-	-	-	-	-
14	Cyber Security		1.9	-	-	-	-	1.9	-	-
15	Mandatory Reliability Standards		(0.9)	(0.7)	-	-	(1.6)	1.6	-	(0.3)
16		d	**4.9**	3.2	-	-	(1.6)	3.5	-	(0.3)
17	**3. Site C**	e	**0.8**	0.8	-	(0.0)	-	-	-	-
18	**4. Strategic Initiatives**									
19	Electrification Plan		0.9	0.6	-	0.2	-	-	0.1	-
20	UNDRIP		0.4	-	0.4	-	-	-	-	-
21	Non-Integrated Area (NIA) - diesel reduction strategy		0.3	0.3	-	-	-	-	-	-
22		f	**1.6**	0.9	0.4	0.2	-	-	0.1	-
23	**5. Third Party Billable Work**									
24	Interconnection study and project work		(1.5)	(1.5)	-	-	-	-	-	-
25		g	**(1.5)**	(1.5)	-	-	-	-	-	-
26	**6. Net Cost Savings**									
27	Apprentice and trainee funding		1.0	-	-	-	1.0	-	-	-
28	Work Program Resources		0.1	0.0	-	0.0	-	-	-	-
29	IRP Funding		(0.6)	(0.6)	-	-	-	-	-	-
30	Routine Trouble Work		(1.4)	-	-	(1.4)	-	-	-	-
31	Test Period Savings		(1.8)	-	-	(1.0)	-	(0.8)	-	-
32		h	**(2.8)**	(0.6)	-	(2.4)	1.0	(0.8)	-	-
33	**Total Test Period Net Increase/(Decrease)**	i=Σ c to h	**20.4**	**7.0**	**1.4**	**2.4**	**0.5**	**6.6**	**1.9**	**0.4**
34	**F2024 Net Operating Costs (Schedule 5.0, line 19)**	j = a+b+i	**1,167.9**	**370.7**	**86.3**	**269.2**	**66.1**	**314.9**	**98.6**	**(37.9)**

Table may not add due to rounding

194 Row 3 relates to costs related to BC Hydro's purchase of Teck's two-thirds interest in Waneta, per BCUC Order No. G-130-18; and

Other includes Office of the President and Chief Executive Officer, Office of the General Counsel, Human Resources, Corporate Costs and Capitalized Costs.

195 Further breakdown of the Test Period Savings, line 29 is provided in section 5.5.3.6.

Table 5-10 Summary of BC Hydro's Fiscal 2025 Net Operating Costs[196,197]

	F2025 Plan ($ million)	Ref	BC Hydro	Integrated Planning	Capital Infrastructure Project Delivery	Operations	Safety & Compliance	Finance, Technology, Supply Chain	Customer, Corporate Affairs	Other
1	**F2024 Revenue Requirement Application Plan Carryforward**	a=Ln 34 Table 5-9	**1,167.9**	**370.7**	**86.3**	**269.2**	**66.1**	**314.9**	**98.6**	**(37.9)**
2	**Current Year Incremental Adjustments:**									
3	Waneta 2/3rd Operating Costs	b	**0.2**	**0.2**	**-**	**-**	**-**	**-**	**-**	**-**
4	**Test Period Net Cost Increase/Decrease**									
5	**1. Uncontrollable Cost Increases**									
6	Current Service Pension Costs		3.4							-
7	Other Labour Costs		15.7							-
8	Current Service Costs and Other Labour Costs		19.1	4.8	1.2	5.2	1.2	4.0	1.9	0.8
9	Insurance		0.5	-	-	-	-	0.5	-	-
10	BCUC and CER Cost Recovery Levies		0.2	-	-	-	-	-	0.2	-
11		d	**19.8**	4.8	1.2	5.2	1.2	4.5	2.1	0.8
12	**2. Reliability Investments**									
13	Vegetation Management		4.6	4.6	-	-	-	-	-	-
14	Cyber Security		0.4	-	-	-	-	0.4	-	-
15	Mandatory Reliability Standards		(1.6)	(1.1)	-	-	(0.3)	-	-	(0.3)
16		e	**3.4**	3.5	-	-	(0.3)	0.4	-	(0.3)
17	**3. Site C**	f	**9.8**	7.3	0.1	2.1	0.1	0.2	-	-
18	**4. Strategic Initiatives**									
19	Electrification Plan		0.7	0.5	-	0.1	-	-	0.1	-
20		g	**0.7**	0.5	-	0.1	-	-	0.1	-
21	**5. Third Party Billable Work**									
22	Interconnection study and project work		(0.7)	(0.7)	-	-	-	-	-	-
23		h	**(0.7)**	(0.7)	-	-	-	-	-	-
24	**6. Net Cost Savings**									
25	Apprentice and trainee funding		1.1	-	-	-	1.1	-	-	-
26	IRP Funding		0.3	0.3	-	-	-	-	-	-
27	Work Program Resources		0.1	0.0	-	0.1	-	-	-	-
28	Test Period Savings		(1.3)	-	-	-	(0.3)	(0.8)	-	(0.2)
29	Routine Trouble Work		(1.4)	-	-	(1.4)	-	-	-	-
30		i	**(1.3)**	0.3	-	(1.3)	0.8	(0.8)	-	(0.2)
31	**Total Test Period Net Increase/(Decrease)**	j=Σ d to i	**31.7**	**15.8**	**1.3**	**6.1**	**1.9**	**4.2**	**2.2**	**0.3**
32	**F2025 Net Operating Costs (Schedule 5.0, line 19)**	m = a+c+l	**1,199.8**	**386.7**	**87.6**	**275.3**	**68.0**	**319.1**	**100.7**	**(37.6)**

Table may not add due to rounding

Table 5-11 below shows the reconciliation of base operating costs to the net operating costs as shown in Appendix A.

[196] Row 8 relates to costs related to BC Hydro's purchase of Teck's two-thirds interest in Waneta, per BCUC Order No. G-130-18; and,

Other includes Office of the President and Chief Executive Officer, Office of the General Counsel, Human Resources, Corporate Costs and Capitalized Costs.

[197] Further breakdown of the Test Period Savings, line 26, is provided in section 5.5.3.6.

Table 5-11 Reconciliation of Base Operating Costs to Net Operating Costs

($ million)	F2023 Plan	F2024 Plan	F2025 Plan
Base Operating Costs (Schedule 5.0, line 14)	**926.6**	**947.0**	**978.7**
IFRS Ineligible Capital Overhead (Schedule 5.0, line 15)	214.9	214.9	214.9
Waneta 2/3rd Operating Costs (Schedule 5.0, line 16)	5.9	6.1	6.3
Customer Crisis Fund Operating Costs (Schedule 5.0, line 17)	-	-	-
Net Operating Costs (Schedule 5.0, line 19)	**1,147.4**	**1,167.9**	**1,199.9**

5.6 BC Hydro Has Performance Metrics for Increased Reliability Investments and Strategic Initiatives in the Test Period

BC Hydro has been working to develop new performance metrics, including metrics to monitor our effectiveness in areas where there is increased investment related to reliability and BC Hydro's strategic initiatives for the Test Period.

Table 5-12 below provides a consolidated view of performance metrics associated with measuring outcomes and effectiveness of specific areas of investment in the Test Period (e.g., MRS, Cyber Security, Vegetation Management, Electrification, NIA Diesel, UNDRIP), and also includes references to where these investments are discussed in further detail in Chapter 5. The metrics shown in Table 5-12 below are subsets of BC Hydro's Business Group performance metrics and targets provided in Appendix E of the Application, and BC Hydro's Five-Year Strategy metrics and targets provided in Appendix D of the Application.

The format provided in Table 5-12 below reflects feedback received through informal discussions with the Commercial Energy Consumers Association. A key insight from these discussions for BC Hydro was the benefit of providing performance metrics that allow inputs, outputs and outcomes to be quantified. In other words, using performance metrics to measure the amount of resources being invested and the relative efficiency of that investment, the outputs achieved from that investment and the improved outcomes for customers realized as a result.

Table 5-12 Performance Metrics for Reliability Investments and Strategic Initiatives over the Test Period

	Area of Investment	Incremental Investment Previous Application and Current Test Period ($ million)	Desired Outcome	Supporting Metric	Target	Chapter 5 Reference
Reliability Investments	Mandatory Reliability Standards	F2022 Decision $21.7 F2023 to F2025 Plan $3.0	Increased compliance and system resilience and reliability	MRS Reported Non-Compliance Reduction Against F2021 (%)	F2023 –60% F2024 –70% F2025 –80%	Section 5.7
				Mitigation Plan Actions Completed on Time (%)	F2023 – 96% F2024 – 97% F2025 – 98%	
	Vegetation Management	F2022 Decision $25.0 F2023 to F2025 Plan $16.7	Increase system reliability by decreasing vegetation originated outages	Distribution Forced Outages – Vegetation Originated (%)	F2023 – 37% F2024 – 35% F2025 – 30%	Section 5.8
				Transmission Right of Way Maintained (%)	F2023 – 20% F2024 – 20% F2025 – 20%	
	Cybersecurity	F2022 Decision $3.0 F2023 to F2025 Plan $6.5	Increase system resilience and reliability	BitSight Security Rating (Basic / Intermediate / Advanced)	F2023 – Advanced F2024 – Advanced F2025 – Advanced	Section 5.9
				BitSight Security Ranking Amongst Canadian Peers	F2023 – Upper Quartile F2024 – Upper Quartile F2025 – Upper Quartile	

	Area of Investment	Incremental Investment Previous Application and Current Test Period ($ million)	Desired Outcome	Supporting Metric	Target	Chapter 5 Reference
Strategic Initiatives	Electrification Plan	F2023 to F2025 Plan $2.9[198]	Increase electricity use	Load Growth Supporting CleanBC (GWh, F2020 baseline)	4,700 GWh by end of F2026	Section 5.5.3, Table 5-6, line 17 Chapter 10
				New Connected Commercial and Industrial Load (MW, F2020 baseline)	750 MW by end of F2026	
				GHG Emissions Reduction Electrification (tonnes CO2/year, F2020 baseline)	2.5 million tonnes/year by end of F2026	
	Non-Integrated Areas	F2023 to F2025 Plan $1.0	Reduce diesel generation and GHG emissions	Non-Integrated Areas Diesel Reduction	TBD[199]	Section 5.5.3, Table 5-6, line 18
	UNDRIP	F2023 to F2025 Plan $2.0	Strengthen relationships with Indigenous Communities	Indigenous Employment at BC Hydro (% increase, F2021 baseline)	25% increase by end of F2026	Section 5.5.3, Table 5-6, line 19
				Indigenous Awareness Training at BC Hydro (% complete)	80% by end of F2026	

198 The outcomes shown in the table are the result of the combined operating, capital and deferred expenditures related to the Electrification Plan, which is further discussed in Chapter 10.

199 Specific reduction targets are currently under development and will be confirmed in conjunction with Government.

	Area of Investment	Incremental Investment Previous Application and Current Test Period ($ million)	Desired Outcome	Supporting Metric	Target	Chapter 5 Reference
				Indigenous Procurement (cumulative since 2015)	$1 billion by the end of F2026	

5.7 Mandatory Reliability Standards

BC Hydro is subject to Mandatory Reliability Standards (**MRS** or **Standards**) that are in place to ensure the reliable operation of the Bulk Electric System[200] throughout North America. BC Hydro's ongoing compliance with the Standards is mandatory.

In the Previous Application, BC Hydro indicated that we expected additional costs with respect to MRS compliance to continue. We also stated our expectation that the MRS program and investments will expand in future years as new standards and new versions of existing standards are implemented.[201] In its Decision on the Previous Application, the BCUC found our planned $21.7 million increase for MRS-related expenditures in fiscal 2022 to be reasonable and stated that "the investments are not only warranted but required to safeguard the BES [Bulk Electric System]." [202]

The fiscal 2022 Decision amount of $21.7 million related to MRS operating costs included $4.7 million of ongoing costs (the remaining $17.0 million were one-time costs in fiscal 2022).[203] The investment of $21.7 million in fiscal 2022 laid a strong foundation for repeatable compliance (through improved processes, documentation, systems and training). The $4.7 million of ongoing costs includes $3.6 million for 21.5 FTEs required for sustainment including the completion of routine monthly, quarterly and annual controls and activities necessary to maintain compliance; and $1.1 million for ongoing MRS consulting and contractor services to obtain subject matter expertise on industry best practices and compliance assurance support where specialized expertise is required, as well as application and vendor support for technologies.

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200 The Bulk Electric System is defined as the electrical generation resources, transmission lines, interconnections with neighbouring systems and associated equipment, generally operated at voltages of 100 kV or higher.

201 BC Hydro Fiscal 2022 Revenue Requirements Application, Exhibit B-2, section 5.6, p. 5-25 and p. 5-33.

202 See BCUC Decision and Order No. G-187-21, page 30.

203 See BC Hydro's response to BCUC IR 1.23.1 (Exhibit B-4) in the proceeding regarding the Previous Application.

Relative to the $4.7 million in ongoing costs, BC Hydro's planned operating cost increases for MRS over the Test Period are $22.5 million in fiscal 2023 (plan of $27.2 million), followed by a decrease of $0.9 million in fiscal 2024 (plan of $26.3 million) and a further decrease of $1.6 million in fiscal 2025 (plan of $24.7 million). The total plan costs for the Test Period is $78.2 million, meaning the total incremental cost increase in the Test Period is $64.1 million ($78.2 million total plan costs less ongoing baseline costs in each year of $4.7 million). Of the total increase of $64.1 million, $16.3 million is confidential and is discussed in confidential Appendix JJ and the remaining $47.8 million is discussed below. In addition, FTEs are planned to increase by 48 over the Test Period compared to the fiscal 2022 Decision amounts.

Table 5-1 below provides a continuity table which summarizes the changes to MRS operating costs from the Previous Application.

Table 5-13 MRS Operating Costs Continuity Schedule

	($ million)		
1	F2022 Decision	a	21.7
2	Less: F2022 One-time Costs[204]	b	(17.0)
3	F2022 Decision Ongoing Costs	c=a+b	4.7
4	F2023 Incremental[205]	d	22.5
5	F2023 Plan	e=c+d	27.2
6	F2024 Incremental	f	(0.9)
7	F2024 Plan	g=e+f	26.3
8	F2025 Incremental	h	(1.6)
9	F2025 Plan	i=g+h	24.7
10	Total Plan for the Test Period	j=e+g+i	78.2
11	Total Incremental Costs for the Test Period	k=j-(3*c)	64.1

Table 5-15 below provides a continuity table which summarizes the changes to MRS FTEs from the Previous Application.

Table 5-14 MRS FTE Continuity Schedule

1	F2022 Decision	a	21.5
4	F2023 Incremental	b	29
5	F2024 Incremental	c	18
6	F2025 Incremental	d	1
7	**Test Period Incremental FTEs**	e=b+c+d	**48**
8	Total F2025	f=a+e	69.5

These planned incremental operating costs and FTEs build on the foundation we are laying in fiscal 2022, which will continue to improve the sustainability and effectiveness of our MRS program. They will advance BC Hydro's ability to strengthen our MRS program and successfully implement future versions of

[204] In BC Hydro's response to BCUC IR 1.23.1 in the Previous Application Proceeding, BC Hydro explains that the incremental MRS investments for fiscal 2022 include both one-time expenses and recurring operating costs. Of the $21.7 million total cost, $17.0 million is one-time costs.

[205] Table 5-6 in section 5.5.3 describes a cost pressure of $5.5 million in fiscal 2023 for MRS Costs. This amount represents the incremental funding of $22.5 million in fiscal 2023, less the fiscal 2022 one-time time costs of $17.0 million.

Standards. We also describe in section 5.7.5.1 below how we propose to address any unanticipated MRS costs arising during the Test Period due to, for example, the adoption of future Standards not currently under consideration.

5.7.1 Public Section Includes Information Unless it is Security-Sensitive or Subject to BCUC Confidentiality Requirements

As in the Previous Application, we have split the content of the discussion on MRS between this section, intended for public viewing, and a confidential appendix (Appendix JJ) that is being made available to the BCUC only. We have endeavoured to include as much information as possible within this public section, while (a) maintaining security, and (b) respecting the BCUC's MRS Rules of Procedure.

As noted in Chapter 5, section 5.6.1 of the Previous Application, there are two related reasons for maintaining confidentiality over the information in Appendix JJ:

- First, information related to the protection of cyber infrastructure is highly security-sensitive. The release of that information to the public could compromise the safety and reliability of the Bulk Electric System[206] by exposing it to physical attacks by malicious actors or cyberattacks; and
- Second, the BCUC's MRS Rules of Procedure, including the Compliance Monitoring Program Rules and Penalty Guidelines, make the framework and processes for reporting, auditing and oversight of MRS compliance confidential.[207] While certain information about an entity's violations, if

[206] The Bulk Electric System is defined as the electrical generation resources, transmission lines, interconnections with neighbouring systems and associated equipment, generally operated at voltages of 100 kV or higher.

[207] Specifically, information produced for, or created in the course of, any compliance monitoring process is considered confidential information pursuant to the BCUC's MRS Rules of Procedure (see section 2.2, definition of "confidential information"). Further, and with respect to information that is submitted to the BCUC for the purposes of a Hearing, the Rules of Procedure provide that "[a]ll information…will be held in confidence pursuant to the BCUC's Rules of Practice and Procedure." (See section 6.2 of the BCUC MRS Rules of Procedure). Finally, where applicable, notices of alleged violations are also treated as confidential unless and until the BCUC confirms the alleged violation and the BCUC considers that disclosure would not identify a cyber-security incident or otherwise jeopardize the security of the Buk Electric System (see section 4.3.1 of the Compliance Monitoring Program for BC Mandatory Reliability Standards).

> confirmed, may become public after the fact, there remains a presumption of confidentiality. The presumption of confidentiality is especially important where the subject-matter relates to a cybersecurity incident or may otherwise jeopardize the security of the Bulk Electric System.

In its Decision on the Previous Application, the BCUC indicated that "in general ratepayers should be able to review and understand why proposed operating and capital investments are required to maintain compliance with MRS."[208] However, the BCUC acknowledged that:

> "…BC Hydro is particularly sensitive and vulnerable to external threats if security risks are exposed, such as if information about violations were to be published prior to the mitigation of these violations. Information from these incidents could potentially expose a path of entry for those who may wish to do harm to the system."[209]

Further, the BCUC agreed "that it is appropriate that certain CIP[210] and cybersecurity information be kept confidential to safeguard the BES" and "that certain sensitive cybersecurity information ought to remain confidential due to the risk of inadvertent disclosure and potential harm to BC Hydro, its ratepayers, and the public."[211]

As a result, BC Hydro is limiting circulation of such information to the BCUC only. We understand that this presents a challenge for interveners. However, we believe very strongly that it is in the public interest to impose strict limitations on the circulation of security-sensitive information to reduce the potential for inadvertent disclosure, as well as to respect the compliance processes and rules that the BCUC has put in place for MRS.

208 See BCUC Decision and Order No. G-187-21, page 34.
209 See BCUC Decision and Order No. G-187-21, page 35.
210 Critical Infrastructure Protection (**CIP**) a set of MRS. Refer to Table 5-15 below for definitions of all MRS.
211 See BCUC Decision and Order No. G-187-21, page 35.

5.7.2 MRS Background

This section provides important context for our planned incremental MRS investments during the Test Period. It focusses on the MRS program in B.C. and the importance of MRS for the reliable operation of the Bulk Electric System.

5.7.2.1 *Standards Specify Requirements for Reliable Operation and Protection of Bulk Electric System*

As discussed in our Previous Application, MRS define the reliability requirements for planning and operating the Bulk Electric System. There are currently 13 MRS standard domains with reliability standards approved in British Columbia which apply to BC Hydro’s operations.

Each standard domain will typically include multiple Standards, and each Standard will include a number of specific requirements. For example, the CIP standard domain includes 11 currently effective Standards with 39 requirements. Each requirement includes a number of elements for which BC Hydro must develop operating processes in order to achieve the requirement. Chapter 5D, section 5.D.8.1 provides a description of the Mandatory Reliability Standard lifecycle.

Table 5-15 below provides a list of standard domains and the number of Standards that are applicable to BC Hydro[212] within those domains of coverage.

[212] As of June 30, 2021.

Table 5-15 Mandatory Reliability Standards by Area

Domain Name	Domain Area	Summary of Domain	Standards	Requirements
BAL	Resource and Demand Balancing	Real Power Balancing Control Performance to Automatic Time Error Correction and Automatic Generation Control.	6	28
CIP	Critical Infrastructure Protection	Sabotage Reporting to Cyber Security standards in the areas of Critical Asset Identification, Security Management Controls and Electronic and Physical Security of Cyber Assets.	11	39
COM	Communications	Telecommunications /Communications and Coordination.	2	20
EOP	Emergency Preparedness and Operations	Emergency Operations Planning and Load Shedding Plans, to System Restoration Coordination and Restoration from Blackstart Resources.	7	51
FAC	Facilities Design, Connections and Maintenance	Facility Connection Requirements and Transmission Vegetation Management, to System Operating Limits Methodologies and Transmission Maintenance.	9	41
INT	Interchange Scheduling and Coordination	Interchange Transaction Implementation to Interchange Coordination Exemptions.	5	15
IRO	Interconnection Reliability Operations and Coordination	Reliability Coordination – Responsibilities and Authorities, to Operations Planning and Transfer Path Unscheduled Flow Relief.	13	50
MOD	Modeling, Data, and Analysis	Development of Steady-State and Dynamics System Models of the interconnected transmission system and Transmission Reliability Margin Calculation Methodologies, to the development and documentation of transfer capability calculations in the support of system operations.	13	79
PER	Personnel Performance, Training, and Qualifications	Operating Personnel Training and Certification procedures and requirements.	2	9
PRC	Protection and Control	System Protection Coordination among operating entities and Disturbance Monitoring, to the Development and Documentation of Under Frequency/Voltage Load Shedding Programs and associated Maintenance and Testing programs.	20	73
TOP	Transmission Operations	Normal Operations Planning to Planned Outage Coordination and System Operating Limits along Major WECC Transfer Paths.	10	77
TPL	Transmission Planning	Transmission System Planning Performance Requirements under normal conditions to System Performance Planning Following Loss of Single/Multiple Bulk Electric System Element(s).	1	7
VAR	Voltage and Reactive	Voltage and Reactive Control in real time to protect equipment, to Power System	3	22

As of June 30, 2021, there are 102 Standards effective and applicable to BC Hydro, comprised of a total of 511 requirements, including both CIP and Operations & Planning Standards and requirements.

Across North America, the electrical grid is becoming more complex and therefore more challenging to manage. There is more intermittent generation, increased frequency and severity of weather events impacting the grid, digital technologies are replacing mechanical equipment, and attempts to access and disrupt systems are becoming more sophisticated. As a result of this changing environment, the Standards have increased over time in both number and complexity which has correspondingly expanded the scope of compliance activities.

A number of different entities are involved in the development, approval, adoption, administration, and monitoring of MRS in British Columbia. The process, at a high level, unfolds as follows:

- The North American Electric Reliability Corporation (**NERC**)[213] and the six Regional Reliability Organizations are responsible for developing Standards;
- The Federal Energy Regulatory Commission (**FERC**) is responsible for adopting Standards in the United States;
- BC Hydro assesses FERC-adopted MRS for adoption, administration and operation in British Columbia in accordance with section 125.2 of the *Utilities Commission Act* and the Mandatory Reliability Standards Regulation (B.C. Reg. 32/2009);
- The BCUC is responsible for the adoption and administration of the Standards in British Columbia, which includes monitoring compliance;

[213] NERC is a not-for-profit international regulatory authority whose mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid. NERC develops and enforces reliability standards; annually assesses seasonal and long-term reliability; monitors the Bulk Electric System through system awareness; and educates, trains, and certifies industry personnel. NERC's area of responsibility spans the continental US, Canada and the northern portion of Baja California, Mexico.

- The Western Electricity Coordinating Council (**WECC**) is one of the six Regional Reliability Organizations in North America tasked with MRS oversight responsibility of certain aspects of the North American Bulk Electric System. WECC is the regional entity for the geographic area known as the Western Interconnection which extends from Canada to Mexico and includes the provinces of British Columbia and Alberta, the northern portion of Baja California, Mexico and all or portions of the 14 Western U.S. states between. WECC is also the administrator for and appointed by the BCUC in the administration of the approved MRS program in British Columbia and, in that capacity, assists the BCUC in carrying out the registration of parties and compliance monitoring.

Standards adopted by the BCUC apply to every registered owner, operator and user of various components of the Bulk Electric System. Entities that perform these functions are required to register and comply with Standards adopted by the BCUC. BC Hydro is the largest and most complex of these entities to which the Standards apply.

5.7.3 Fiscal 2023 to Fiscal 2025 Budget Strengthens our MRS Program and Addresses New Standards and Functions

BC Hydro's incremental operating costs during the Test Period are broadly focused on two key drivers: (1) Strengthening our MRS Program (refer to section 5.7.4), and (2) Implementing and Sustaining New Standards and Functions (refer to section 5.7.5).

Table 5-16 below summarizes the planned incremental MRS related operating costs for the Test Period.

Table 5-16 Fiscal 2023 to Fiscal 2025 Incremental MRS Operating Costs

	F2022 Decision	F2023 Increase	F2023 Plan	F2024 Increase	F2024 Decrease	F2024 Plan	F2025 Increase	F2025 Decrease	F2025 Plan
Strengthening Our MRS Program									
Implement Mitigation Plans	-	2.3	2.3	-	(1.8)	0.6	-	(0.3)	0.3
Investments in Program Sustainment	4.7	11.6	16.3	2.9	(3.3)	15.8	-	-	15.8
Program Assurance	-	1.1	1.1	0.8	-	1.9	-	(0.8)	1.1
Sub-Total Strengthen Our MRS Program	4.7	15.0	19.7	3.7	(5.1)	18.3	-	(1.0)	17.3
New Standards and Functions									
Implement New Standards	-	0.7	0.7	-	(0.7)	-	-	-	0.0
Sustain New Standards	-	4.6	4.6	1.1	-	5.7	0.5	-	6.2
Implement New Functions	-	1.6	1.6	0.1	-	1.7	-	(1.1)	0.6
Sustain New Functions	-	0.7	0.7	-	-	0.7	-	-	0.7
Sub-Total New Standards and Functions	-	7.5	7.5	1.2	(0.7)	8.1	0.5	(1.1)	7.5
Total	**4.7**	**22.5**	**27.2**	**4.9**	**(5.8)**	**26.3**	**0.5**	**(2.1)**	**24.7**

Table 5-17 below summarizes the planned incremental MRS FTEs for the Test Period.

Table 5-17 Fiscal 2023 to Fiscal 2025 Incremental MRS FTEs

	F2022 Decision	F2023 Increase	F2023 Plan	F2024 Increase	F2024 Plan	F2025 Increase	F2025 Plan	F2023-F2025 Incremental
Strengthening Our MRS Program								
Implement Mitigation Plans	-	-	-	-	-	-	-	-
Investments in Program Sustainment	21.5	17.5	39.0	11.5	50.5	-	50.5	29.0
Program Assurance	-	4.0	4.0	2.0	6.0	-	6.0	6.0
Sub-Total Strengthening Our MRS Program	21.5	21.5	43.0	13.5	56.5	-	56.5	35.0
New Standards and Functions								
Implement New Standards	-	-	-	-	-	-	-	-
Sustain New Standards	-	3.5	3.5	4.5	8.0	1.0	9.0	9.0
Implement New Functions	-	-	-	-	-	-	-	-
Sustain New Functions	-	4.0	4.0	-	4.0	-	4.0	4.0
Sub-Total New Standards and Functions	-	7.5	7.5	4.5	12.0	1.0	13.0	13.0
Total	**21.5**	**29.0**	**50.5**	**18.0**	**68.5**	**1.0**	**69.5**	**48.0**

5.7.4 Strengthening Our MRS Program

The first key driver for the incremental operating costs and FTEs over the Test Period is focused on strengthening our MRS program in a number of important areas.

Over the last decade, the approach we took to implement and sustain MRS investments was discrete in nature with a capital project implementation mindset. We focused on specific tasks in specific areas of the business as and where the program required it. We also did not separately budget or track MRS sustainment; rather, those costs were embedded within the work across the organization.

As discussed in section 5.7.2 the electrical grid has become more complex and accordingly MRS compliance has become increasingly more complex – both with respect to the number of Standards we must be compliant with and the scope of the requirements associated with those Standards. Where we could previously manage our compliance requirements within each business group, this increased scope and complexity now impacts most (if not all) business groups across BC Hydro. As a result, and as described in the Previous Application, this has necessitated a transition to a more programmatic approach and specifically, one that reflects increased investment in the overall MRS program structure to better facilitate sustainment of the current and future program. This approach was reflected in the Previous Application and the funding approved represented a significant step forward in our MRS program. Specifically, the investments in people, processes and procedures built a strong foundation that we are now able to expand on and further strengthen.

The investments we are making in MRS over the Test Period reflect our continued commitment to strengthening our MRS program. As described below, we will: complete mitigation plan activities to ensure compliance with all applicable Standards, we will further improve our processes in key areas, we will make sure we have the right systems in place to support our people and functions, we will expand our IT infrastructure to ensure more efficient and effective program delivery, and, we will enhance our training program to facilitate continued understanding of the Standards and requirements.

All of these actions require significant resources. That is why we are adding 35 FTEs and investing an incremental $41.1 million[214] over the Test Period which will help to strengthen our MRS program. We believe these investments are necessary and prudent to mature the MRS program and will continue to enable a strong compliance program going forward.

Strengthening our MRS program is focused on three important areas: implementing our mitigation plans, investing in our program, and undertaking program assurance. Each of these areas is discussed further in the sections below.

5.7.4.1 *Implement Mitigation Plans*

Over the course of fiscal 2021 to date we have had a number of Mitigation Plans in place to address non-compliance with MRS. As a result, a key driver of our planned fiscal 2022 spend was focused on compliance-related activities, many of which activities are either completed or close to completion.

Over the Test Period, we are still working to achieve compliance in certain areas where necessary mitigation measures have been identified in either BCUC-approved or WECC-recommended Mitigation Plans. Details on the incremental $3.2 million[215] of expenditures for implementing those Mitigation Plans is outlined in confidential Appendix JJ.

Further, MRS will continue to evolve, and we expect that there will continue to be unplanned costs to implement and maintain compliance with MRS requirements for

[214] $41.1 million is the sum of the fiscal 2023 to 2025 plan amounts to Strengthen our MRS Program ($55.2 million) less ongoing costs in each year from the fiscal 2022 Decision ongoing costs ($4.7 million multiplied by three years = $14.1 million).

[215] $3.2 million is the sum of the fiscal 2023 to fiscal 2025 plan amounts to Implement Mitigation Plans.

the foreseeable future. Therefore, as discussed in Chapter 7, section 7.3.2.1, BC Hydro is seeking BCUC approval in this application for the continued use of the MRS Costs Regulatory Account for fiscal 2023 and future years. Effective starting in fiscal 2023, BC Hydro proposes that the scope of the MRS Costs Regulatory Account include costs associated with the following items, as required:

- Unplanned costs related to the implementation of new or revised MRS adopted as a result of a future Assessment Report filed with the BCUC where the BCUC's adoption of such new or changed MRS occurred too late to be reflected in our forecast for the test period; and
- Unplanned costs incurred in a test period to address possible non-compliances with MRS, if and as required, where the work related to such possible non-compliances was identified too late to be reflected in our forecast for the test period. BC Hydro notes that this does not include any penalties assessed against BC Hydro, which are to the account of the shareholder.

5.7.4.2 *Investments in Program Sustainment*

To systematically reduce the risk of non-compliance across the MRS program, BC Hydro is also strengthening the program beyond the specific MRS requirements where we experienced non-compliances. This has required us to more broadly review our program needs and make enhancements where necessary. Key investments we are making to strengthen the sustainment of the MRS program during the Test Period include:

- Strengthening oversight of the MRS program, for example by continuing to develop a CIP Program Office to drive consistent implementation and sustainment of CIP Standards;
- Improving policies, processes and controls in areas of higher risk within the MRS program;

- Implementing and sustaining technology, such as the enterprise compliance management system (refer to Chapter 6, section 6.5.1), to improve sustainability of the MRS program;
- Adding resources to coordinate and execute compliance work, for example Operations resources to implement patches and Technology resources to maintain compliance related systems; and
- Training for employees and contractors so that they are aware of and equipped to meet the MRS compliance expectations.

Total incremental operating costs required over the Test Period for program sustainment is $33.8 million[216] and is discussed in the respective business group sub-sections in section 5.7.6. The fiscal 2025 plan amount of $15.8 million is ongoing.

5.7.4.3 *Program Assurance*

Providing assurance is a critical element of a management system to ensure the effectiveness of the system is verified and continuous improvement opportunities are identified and implemented. To provide reasonable assurance that internal controls to meet MRS requirements are effective, BC Hydro has recently introduced a risk-based assurance component to its MRS program, which aligns with a similar component that BC Hydro has in its Safety Framework as outlined in Chapter 5D, section 5D.2.1.7. Each reliability standard will have, at a minimum, one assurance activity in a three-year cycle to align with the triennial WECC audit cycle; however, different risks warrant different levels of assurance. For example, for higher risk areas within the MRS program, more in-depth or frequent assurance activities will be performed, such as a walkthrough of existing controls, spot checks and/or full-scale audits with control evaluation and testing. For lower risk areas, less in-depth and

[216] $33.8 million is the sum of the fiscal 2023 to 2025 plan amounts for Investments in Program Sustainment ($47.9 million) less ongoing costs in each year from the fiscal 2022 Decision ongoing costs ($4.7 million multiplied by three years = $14.1 million).

less frequent assurance activities will be performed, such as our review of compliance declarations from business groups and supporting evidence to demonstrate compliance. This ensures our resources are focused on the highest risk areas of the MRS program.

During the Test Period, assurance work is planned for: (a) new or revised Standards coming into effect to ensure we are compliant prior to Standards becoming effective (e.g., CIP Version 7 that expands the CIP scope to 131[217] stations), (b) the implementation of new capital projects to make sure that MRS requirements have been met for new and decommissioned assets, including Site C, (c) Standards currently in effect that have been identified as higher risk of non-compliance and could impact the reliability of the Bulk Electric System, and, (d) preparation for the WECC triennial audit expected to be conducted in fiscal 2024.

Incremental funding required over the Test Period for program assurance is $4.1 million,[218] which is discussed in the respective business group sub-sections in section 5.7.6. The fiscal 2025 plan amount of $1.1 million is ongoing.

5.7.5 New Standards and Functions

The other key driver for the incremental operating costs over the Test Period is with respect to implementing and sustaining new Standards and functions as they are approved and become effective.

As described below, the industry continues to develop new and revised Standards, expand the scope of requirements within certain Standards and introduce functions as needed to improve reliability of the Bulk Electric System across North America. These new and revised Standards are drivers for implementation and sustainment costs during the Test Period. More specifically, we must make an incremental

[217] There are a further two sites that are not yet in service and are therefore not included in the project but will be addressed as they are put into service.

[218] $4.1 million is the sum of the fiscal 2023 to fiscal 2025 plan amounts for Program Assurance.

investment of $23.1 million,[219] including an increase of nine FTEs, to become compliant with and sustain these new and revised Standards over the Test Period. Implementation costs are one-time and sustainment costs are ongoing; specifically, $6.9 million of the $7.5 million fiscal 2025 plan amount is ongoing and for sustainment.

5.7.5.1 *Implement New Standards*

The BCUC has adopted eight new/revised Standards and 25 requirements that will become effective (and are applicable to BC Hydro) during the Test Period.

In addition, BC Hydro filed Assessment Report No. 14 in April 2021 and the Planning Coordinator Assessment Report in May 2021. As a result of these assessment reports, BC Hydro expects that the BCUC will adopt another nine new or revised Standards (consisting of 59 requirements)[220] that would also become effective at different points during the Test Period.

Table 5-18 below summarizes the number of new and revised Standards and requirements that we are aware will become effective (and are applicable to BC Hydro) during the Test Period. The implementation of the new and revised Standards is reflected in the planned expenditures for the Test Period and we discuss two key areas with respect to changes to the CIP standards that are driving increased costs, below.

219 $23.1 million is the sum of the fiscal 2022 to fiscal 2025 plan amounts for New Standards and Functions.

220 Revised Standards/Requirements may supersede existing ones.

Table 5-18 Fiscal 2023 to Fiscal 2025 Upcoming Standards and Requirements[221]

Adoption Status	Number of Standards	Number of Requirements
BCUC Approved with Effective Date During Test Period[222]	8	25
Recommended by BC Hydro for Adoption (Assessment Report No. 14)[223]	2	5
Recommended by BC Hydro for Adoption (Planning Coordinator Assessment Report) [224]	7	54
Total	**17**	**84**

Although the new and revised Standards set out above (up to and including those assessed in Assessment Report No. 14 and Planning Coordinator Assessment Report) are reflected in the planned expenditures for the Test Period, the BCUC considers the adoption of new or revised Standards on an annual basis. We expect that the BCUC will adopt additional new or revised Standards during the Test Period as a result of a future Assessment Report. As new standards are adopted or revised, additional funding may be required to implement and achieve compliance with those Standards in the future. As noted above, and as described further in Chapter 7, section 7.3.2.1, BC Hydro is seeking BCUC approval in this application for the continued use of the MRS Costs Regulatory Account for fiscal 2023 and future years in respect of associated costs that arise.

221 Revised Standards/Requirements may supersede existing ones.
222 Three standards (PER-006, PRC-012, PRC-027) with effective date October 1, 2021 also coming into effect; outside of table scope.
223 Assessment 14 also included five standards (BAL-003-2, FAC-002-3, IRO-010-3, MOD-031-3, TOP-003-4) with effective dates between now and the start of the Test Period; outside of table scope.
224 PC Assessment also included three standards (PRC-010-2, PRC-012-2, TPL-001-4) with effective dates between now and the start of the Test Period. Additionally, TPL-001-5.1 has a recommended effective date 36 months after full implementation of MOD-032-1, meaning an effective date of October 1, 2026. Both scenarios are outside of table scope.

5.7.5.2 *Increasing Scope and Complexity of CIP Standards Is Driving Costs in the Test Period*

Changes to CIP Standards in two areas are significantly expanding the scope and complexity of the compliance obligations on BC Hydro, and are driving additional costs.

First, a new version of CIP-003-8 (referred to as CIP Version 7) has been adopted and will be effective in October 2023 with some requirements coming into effect in October 2021. As a result of this change, BC Hydro will be required to expand CIP compliance to 18 generating stations, 115 transmission substations and thousands of additional cyber assets.

As of June 30, 2021, BC Hydro has approximately 3,850 CIP cyber assets. As a result of the changes required to comply with CIP-003-8, we expect that number to increase 300 per cent to 400 per cent and that most compliance functions within BC Hydro will need to scale up their services to support the stations and CIP cyber assets in scope.

Secondly, a new standard, CIP-013 has been adopted and will be effective April 1, 2023. CIP-013 covers the cybersecurity supply chain. This Standard takes cybersecurity beyond the border of the individual registered entity and requires that processes and controls be established to identify and manage cybersecurity risk for suppliers that provide products and services to BC Hydro's Bulk Electric System Cyber Systems.

Incremental operating costs required over the Test Period to implement new Standards is $0.7 million,[225] which is discussed in the respective business group sub-sections in section 5.7.6. Additionally, incremental capital expenditures are required over the Test Period to implement new Standards. Refer to Chapter 6 for

[225] $0.7 million is the sum of the fiscal 2023 to fiscal 2025 plan amounts to Implement New Standards.

more information, specifically section 6.4.2.2 for CIP-003-8 (CIP Version 7) and section 6.5.1.5 for CIP-013.

5.7.5.3 *Sustain New Standards*

Once a new Standard has been implemented and effective, BC Hydro is required to comply with it. As such, and similar to its compliance with all Standards, BC Hydro incurs sustainment costs associated with newly implemented Standards.

Following the example provided above, to sustain compliance with the new CIP version 7 standard additional maintenance work is required for 131 stations coming in scope. This includes activities for physical security monitoring and investigations, management of switches and firewalls, system licensing, support for the expansion of our compliance management and physical access management systems, change management and evidence management related to the networks, and the expansion of the Transient Cyber Asset program to all the low impact stations. Furthermore, sustainment of the new CIP-013 Standard will require performing additional processes and procedures, for example performing supplier risk management assessments and maintaining the associated technology to support those processes.

Incremental funding required over the Test Period for sustaining new Standards is $16.5 million,[226] which is discussed in the respective business group sub-sections in section 5.7.6.

5.7.5.4 *Implement New Functions*

Over the Test Period, we are also implementing a new MRS function – the Planning Coordinator. At the present time, there are no registered Planning Coordinators in the B.C. MRS program. However, there are a number of Standards and requirements already in effect in B.C. which relate to the Planning Coordinator

226 $16.5 million is the sum of the fiscal 2023 to fiscal 2025 plan amounts to Sustain New Standards.

function and, as a result of BC Hydro filing the Planning Coordinator Assessment Report with the BCUC in May 2021, the BCUC is considering adopting a number of additional Planning Coordinator related Standards.

The Planning Coordinator function serves to coordinate, facilitate, integrate and evaluate transmission facility and service plans and resource plans within a Planning Coordinator area and coordinate those plans with adjoining Planning Coordinator areas. WECC is working to establish registered Planning Coordinators across the WECC region to support the reliability of the Bulk Electric System.

BC Hydro currently expects to register as the Planning Coordinator for its Bulk Electric System assets by no later than February 1, 2022. Upon registration, BC Hydro will need to comply with any Standards and requirements that relate to the Planning Coordinator function already in effect. As of May 31, 2021, this includes 12 Standards and 40 requirements.

BC Hydro plans to assume the accountability for the Planning Coordinator function in stages,[227] which for existing Standards already in effect will begin when BC Hydro registers for the Planning Coordinator function and will extend beyond fiscal 2025 (following the implementation timelines of the Assessment Reports). However, in anticipation of BC Hydro's Planning Coordinator registration, there are a number of activities required to ensure compliance with the applicable Standards and establish and support BC Hydro's Planning Coordinator function prior to registration. This includes:

- Continuing to develop the Planning Coordinator team within the Integrated Planning Business Group during the Test Period so that it can "coordinate, facilitate, integrate and evaluate transmission facility and service plans and

[227] In the first phase, BC Hydro would become the Planning Coordinator for its own Bulk Electric System assets. In the second phase, BC Hydro would offer Planning Coordinator services to IPP and TVC entities interconnected to BC Hydro's system who are registered for certain functions under the BCUC MRS program. In the third phase, BC Hydro would consider offering PC services to unrelated entities who are registered as Transmission Planners under the BCUC MRS program, namely, FortisBC Inc.

resource plans within [BC Hydro's] Planning Coordinator area and coordinate those plans with adjoining Planning Coordinator areas";[228]

- Performing the activities required of a Planning Coordinator;
- Confirming how the introduction of the Planning Coordinator function in B.C. will impact BC Hydro's MRS functions and responsibilities as additional Standards are adopted and BC Hydro's accountability as a Planning Coordinator changes over time during the staged approach; developing or modifying processes; procedures and associated documentation (to substantiate compliance) to reflect the Planning Coordinator function; and, on an ongoing basis, improving and revising processes and procedures as Planning Coordinator related Standards are revised and/or new Planning Coordinator related Standards are adopted; and
- Developing training and change management processes to support deployment of the Planning Coordinator function and the related changes to processes and procedures.

Work is required in the Test Period to ensure compliance with the Planning Coordinator related standards and requirements that the BCUC determines will become effective during the Test Period, and to prepare for compliance with Planning Coordinator related standards that will become effective after fiscal 2025.

Incremental funding required over the Test Period for the implementing of the Planning Coordinator function is $3.9 million,[229] which is discussed in the respective business group sub-section in section 5.7.6.

[228] Methodology for Defining Planning Coordinator Areas in WECC Region. Planning Coordinator Function Task Force (**PCFTF**). September 14, 2015. https://www.wecc.org/Reliability/PCFTF%20White%20Paper_final_9-14-15.pdf. Accessed on July 14, 2021.

[229] $3.9 million is the sum of the fiscal 2023 to fiscal 2025 plan amounts to Implement New Functions.

5.7.5.5 *Sustain New Functions*

The Planning Coordinator associated Standards will come into effect over the Test Period; therefore, in parallel to implementing the new Standards sustainment activities will start once BC Hydro registers for the Planning Coordinator function. To sustain the new Planning Coordinator function, incremental operating costs are required in each year of the Test Period.

The Planning Coordinator role will be performed by a dedicated team to coordinate, facilitate, integrate and evaluate transmission plans and resource plans within BC Hydro's Planning Coordinator area and coordinate those plans with adjoining Planning Coordinator areas. Among others, these activities include coordinating transmission adequacy and security studies with Transmission Planners and affected adjacent entities, maintaining simulation models of the power system, participating in WECC programs to mitigate the effects of low voltage or low power system frequency conditions, and developing corrective action plans where required. There are four additional FTEs required starting in fiscal 2023. In addition, work will be required to support ongoing program improvements with respect to BC Hydro's Planning Coordinator compliance obligations.

Incremental funding required over the Test Period for sustaining the Planning Coordinator function is $2.1 million,[230] which is discussed in the respective business group sub-sections in section 5.7.6.

5.7.6 Overview of Funding Requirements in Test Period

The fiscal 2022 Decision amount of $21.7 million related to MRS operating costs included $4.7 million of ongoing costs (the remaining $17.0 million were one-time costs in fiscal 2022).[231] The investment of $21.7 million in fiscal 2022 laid a strong foundation for repeatable compliance (through improved processes, documentation,

230 $2.1 million is the sum of the fiscal 2023 to fiscal 2025 plan amounts to Sustain New Functions.
231 See BC Hydro's response to BCUC IR 1.23.1 (Exhibit B-4) in the proceeding regarding the Previous Application.

systems and training). The $4.7 million of ongoing costs includes $3.6 million for 21.5 FTEs required for sustainment including the completion of routine monthly, quarterly and annual controls and activities necessary to maintain compliance; and $1.1 million for ongoing MRS consulting and contractor services to obtain subject matter expertise on industry best practices and compliance assurance support where specialized expertise is required, as well as application and vendor support for technologies.

Relative to the $4.7 million in ongoing costs, BC Hydro's planned operating cost increases for MRS over the Test Period are $22.5 million in fiscal 2023 (plan of $27.2 million), followed by a decrease of $0.9 million in fiscal 2024 (plan of $26.3 million) and a further decrease of $1.6 million in fiscal 2025 (plan of $24.7 million). The total plan costs for the Test Period is $78.2 million, meaning the total incremental cost increase in the Test Period is $64.1 million ($78.2 million total fiscal 2023 to fiscal 2025 plan amounts less ongoing baseline costs in each year of $4.7 million). Of the total increase of $64.1 million, $16.3 million is confidential and is discussed in the confidential Appendix JJ and the remaining $47.8 million is discussed below. In addition, FTEs are planned to increase by 48 over the Test Period compared to the fiscal 2022 Decision amounts.

This section will discuss the funding requirements by business group, driver category, and key activity.

5.7.6.1 *Integrated Planning Business Group*

Table 5-19 below summarizes the planned incremental MRS related operating costs for the Test Period for the Integrated Planning Business Group.

Table 5-19 Fiscal 2023 to Fiscal 2025 Incremental MRS Operating Costs for Integrated Planning

	F2022 Decision	F2023 Increase	F2023 Plan	F2024 Increase	F2024 Decrease	F2024 Plan	F2025 Increase	F2025 Decrease	F2025 Plan
Strengthening Our MRS Program									
Implement Mitigation Plans	-	1.0	1.0	-	(1.0)	-	-	-	-
Investments in Program Sustainment	1.0	2.6	3.6	1.0	(0.3)	4.3	-	-	4.3
Program Assurance	-	-	-	-	-	-	-	-	-
Sub-Total Strengthen Our MRS Program	1.0	3.6	4.6	1.0	(1.3)	4.3	-	-	4.3
New Standards and Functions									
Implement New Standards	-	0.7	0.7	-	(0.7)	-	-	-	-
Sustain New Standards	-	3.7	3.7	0.2	-	3.8	-	-	3.8
Implement New Functions	-	1.6	1.6	0.1	-	1.7	-	(1.1)	0.6
Sustain New Functions	-	0.7	0.7	-	-	0.7	-	-	0.7
Sub-Total New Standards and Functions	-	6.6	6.6	0.3	(0.7)	6.2	-	(1.1)	5.1
Total	1.0	10.2	11.2	1.3	(2.0)	10.5	-	(1.1)	9.4

As shown in the table above, relative to the $1.0 million in ongoing costs from the Previous Application, BC Hydro's planned operating cost increases over the Test Period are $10.2 million in fiscal 2023 (plan of $11.2 million), followed by a net decrease of $0.7 million in fiscal 2024 (plan of $10.5 million) and a further decrease of $1.1 million in fiscal 2025 (plan of $9.4 million). The total planned costs for the Test Period are $31.1 million, meaning the total incremental cost increase in the Test Period is $28.1 million ($31.1 million total plan costs less ongoing costs in each of the three years of $1.0 million). Of the total increase of $28.1 million, $7.5 million is confidential and is discussed in the confidential Appendix JJ and the remaining $20.6 million is discussed below. Of the total plan amount of $31.1 million, $13.2 million is for Strengthening our MRS Program and $17.9 million is for new Standards and Functions.

Table 5-20 below summarizes the planned incremental MRS related FTEs for the Test Period for the Integrated Planning Business Group.

Table 5-20 Fiscal 2023 to Fiscal 2025 Incremental MRS FTEs for Integrated Planning

	F2022 Decision	F2023 Increase	F2023 Plan	F2024 Increase	F2024 Plan	F2025 Increase	F2025 Plan	F2023-F2025 Incremental
Strengthening Our MRS Program								
Implement Mitigation Plans	-	-	-	-	-	-	-	-
Investments in Program Sustainment	5.0	0.5	5.5	0.5	6.0	-	6.0	1.0
Program Assurance	-	-	-			-	-	-
Sub-Total Strengthening Our MRS Program	5.0	0.5	5.5	0.5	6.0	-	6.0	1.0
New Standards and Functions								
Implement New Standards	-	-	-	-	-	-	-	-
Sustain New Standards	-	-	-	-	-	-	-	-
Implement New Functions	-	-	-	-	-	-	-	-
Sustain New Functions	-	4.0	4.0	-	4.0	-	4.0	4.0
Sub-Total New Standards and Functions	-	4.0	4.0	-	4.0	-	4.0	4.0
Total	5.0	4.5	9.5	0.5	10.0	-	10.0	5.0

Strengthening our MRS Program

Strengthening our MRS program is focused on three areas: implementing our Mitigation Plans, investing in program sustainment, and undertaking program assurance.

Implementing Mitigation Plans

- $1.0 million of one-time, incremental operating costs is required in fiscal 2023 to implement Mitigation Plans as discussed in the confidential Appendix JJ.

Investments in Program Sustainment

- $1.1 million of incremental operating costs is required in fiscal 2023 for sustainment activities related to the Protection and Control (**PRC**) Standards that come into effect in fiscal 2022, and additional program support. This funding decreases by $0.3 million to $0.8 million for fiscal 2024 and fiscal 2025. Across the Test Period, this funding will support activities such as protection coordination studies, additional Remedial Action Scheme studies and sustaining our process for developing new and revised protection system settings. One FTE is planned to be added midway through fiscal 2023 resulting in an FTE increase of 0.5 in fiscal 2023 and 0.5 in fiscal 2024.
- $1.0 million of incremental operating costs is required for sustainment activities related to the CIP Standards for each year of the Test Period to sustain confidential compliance activities as discussed in the confidential Appendix JJ.
- $0.5 million in incremental operating costs is required in fiscal 2023 to sustain confidential compliance activities as detailed in confidential Appendix JJ. This funding increases by $1.0 million to $1.5 million for fiscal 2024 and fiscal 2025.

Program Assurance

- No planned incremental operating costs in the Test Period.

New Standards and Functions

New Standards and Functions is focused on four areas: implementing new Standards, sustaining new Standards, implementing new functions and sustaining new functions.

Implement New Standards

- $0.5 million of one-time, incremental operating costs is required in fiscal 2023 to implement CIP Version 7. This funding will be used for asset change management and training.
- $0.2 million of one-time, incremental operating costs is required in fiscal 2023 to implement CIP-013.

Sustain New Standards

- $3.5 million of incremental operating costs is required each year of the Test Period to sustain CIP Version 7. This funding will support activities such as annual reviews of corporate compliance processes, policies, and procedures, maintaining electronic access controls, and managing station network changes. $0.2 million of incremental operating costs is required in fiscal 2023 to sustain CIP-013 and an additional $0.2m million in fiscal 2024 and fiscal 2025.

Implement New Functions

- $1.6 million of incremental operating costs is required in fiscal 2023 to establish a new Planning Coordinator function. $1.7 million is required in fiscal 2024 ($0.1 million increase) and $0.6 million is required in fiscal 2024 ($1.1 million decrease). Refer to section 5.7.5.4 for additional information.

Sustain New Functions

- $0.7 million of incremental operating costs is required each year of the Test Period to sustain the new Planning Coordinator function. This includes the addition of four FTEs in fiscal 2023. Refer to section 5.7.5.5 for additional information.

Refer to Chapter 5A for additional details about this Business Group.

5.7.6.2 *Finance, Technology, Supply Chain Business Group*

Table 5-21 below summarizes the planned incremental MRS related operating costs for the Test Period for the Finance, Technology, Supply Chain Business Group.

Table 5-21 Fiscal 2023 to Fiscal 2025 Incremental MRS Operating Costs for Finance, Technology, Supply Chain

	F2022 Decision	F2023 Increase	F2023 Plan	F2024 Increase	F2024 Decrease	F2024 Plan	F2025 Increase	F2025 Decrease	F2025 Plan
Strengthening Our MRS Program									
Implement Mitigation Plans	-	-	-	-	-	-	-	-	-
Investments in Program Sustainment	1.8	1.9	3.7	1.2	-	4.9	-	-	4.9
Program Assurance	-	-	-	-	-	-	-	-	-
Sub-Total Strengthen Our MRS Program	1.8	1.9	3.7	1.2	-	4.9	-	-	4.9
New Standards and Functions									
Implement New Standards	-	-	-	-	-	-	-	-	-
Sustain New Standards	-	0.7	0.7	0.4	-	1.1	-	-	1.1
Implement New Functions	-	-	-	-	-	-	-	-	-
Sustain New Functions	-	-	-	-	-	-	-	-	-
Sub-Total New Standards and Functions	-	0.7	0.7	0.4	-	1..1	-	-	1.1
Total	1.8	2.6	4.4	1.6	-	6.0	-	-	6.0

As shown in the table above, relative to the $1.8 million in ongoing costs from the Previous Application, BC Hydro's planned operating cost increases over the Test Period are $2.6 million in fiscal 2023 (plan of $4.4 million), followed by a net increase of $1.6 million in fiscal 2024 (plan of $6.0 million) and no change in fiscal 2025 (plan of $6.0 million). The total plan costs for the Test Period are $16.4 million, meaning the total incremental cost increase in the Test Period is $11.0 million ($16.4 million total plan costs less ongoing costs in each year of $1.8 million). Of the total plan amount of $16.4 million, $13.5 million is for Strengthening our MRS Program and $2.9 million is for new Standards and Functions.

Table 5-22 below summarizes the planned incremental MRS related FTEs for the Test Period for the Finance, Technology, Supply Chain Business Group.

Table 5-22 Fiscal 2023 to Fiscal 2025 Incremental MRS FTEs for Finance, Technology, Supply Chain

	F2022 Decision	F2023 Increase	F2023 Plan	F2024 Increase	F2024 Plan	F2025 Increase	F2025 Plan	F2023-F2025 Incremental
Strengthening Our MRS Program								
Implement Mitigation Plans	-	-	-	-	-	-	-	-
Investments in Program Sustainment	8	4.5	12.5	7.5	20	-	20	12
Program Assurance	-	-	-			-	-	-
Sub-Total Strengthening Our MRS Program	8	4.5	12.5	7.5	20	-	20	12
New Standards and Functions								
Implement New Standards	-	-	-		-	-	-	-
Sustain New Standards	-	2.5	2.5	2.5	5	-	5	5
Implement New Functions	-	-	-	-	-	-	-	-
Sustain New Functions	-	-	-	-	-	-	-	-
Sub-Total New Standards and Functions	-	2.5	2.5	2.5	5	-	5	5
Total	8	7	15	10	25	-	25	17

Strengthening our MRS Program

Strengthening our MRS program is focused on three areas: implementing our mitigation plans, investing in program sustainment, and undertaking program assurance.

Implement Mitigation Plans

- No planned incremental operating costs in the Test Period.

Investments in Program Sustainment

- $1.5 million of incremental operating costs for the CIP Program Office in fiscal 2023, which supports the CIP Senior Manager in managing the CIP program across BC Hydro. The CIP Program Office will drive consistent implementation and sustainment of CIP standards; provide CIP compliance subject matter expertise, program management and coordination support; and provide a centralized view of CIP compliance performance and risk mitigation opportunities. This funding increases by $0.7 million to $2.2 million for fiscal 2024 and 2025. Included in the incremental operating costs is the addition of four FTEs in fiscal 2023 and another four FTEs in fiscal 2024.
- $0.4 million of incremental operating costs in fiscal 2023 for system licensing, maintenance, and support for sustainment of the expansion of our compliance management workflow and asset repository system, presently used for CIP and to be used to support all of MRS. This funding increases by $0.5 million to $0.9 million for fiscal 2024 and 2025. Included in the incremental operating costs is one FTE that will be added midway through fiscal 2023 resulting in an FTE increase of 0.5 in fiscal 2023 and 0.5 in fiscal 2024; and the addition of three FTEs in fiscal 2024.

Program Assurance

- No planned incremental operating costs in the Test Period.

New Standards and Functions

New Standards and Functions is focused on four areas: implementing new Standards, sustaining new Standards, implementing new functions and sustaining new functions.

Implement New Standards

- No planned incremental operating costs in the Test Period.

Sustain New Standards

- $0.4 million of incremental operating costs is required in fiscal 2023 for system licensing, maintenance, and support following the implementation of CIP-013. This funding increases by $0.3 million to $0.7 million for fiscal 2024 and fiscal 2025. Included in the incremental operating costs are three FTEs that will be added midway through fiscal 2023 resulting in an FTE increase of 1.5 in fiscal 2023 and 1.5 in fiscal 2024. These three FTEs will manage the systems, risk assessments and procedures associated with meeting the CIP-013 requirements.
- $0.3 million of incremental operating costs is required in fiscal 2023 for system licensing, maintenance, and support for the expansion of our compliance management and physical access management systems to sustain CIP Version 7 (an incremental 131 stations in scope). This funding increases by $0.1 million to $0.4 million for fiscal 2024 and fiscal 2025. This includes two FTEs that will be added midway through fiscal 2023 resulting in an FTE increase of one in fiscal 2023 and one in fiscal 2024. These two FTEs will provide systems support for our compliance management and physical access management systems.

Implement New Functions

- No planned operating costs in the Test Period.

Sustain New Functions

- No planned operating costs in the Test Period

Refer to Chapter 5E, section 5E.5 for additional details on the Technology KBU.

5.7.6.3 *Safety and Compliance Business Group*

Table 5-23 below summarizes the planned incremental MRS related operating costs for the Test Period for the Safety and Compliance Business Group.

Table 5-23 Fiscal 2023 to Fiscal 2025 Incremental MRS Operating Costs for Safety and Compliance

	F2022 Decision	F2023 Increase	F2023 Plan	F2024 Increase	F2024 Decrease	F2024 Plan	F2025 Increase	F2025 Decrease	F2025 Plan
Strengthening Our MRS Program									
Implement Mitigation Plans	-	0.5	0.5	-	(0.5)	-	-	-	-
Investments in Program Sustainment	1.3	3.7	5.0	0.7	(3.0)	2.7	-	-	2.7
Program Assurance	-	0.8	0.8	0.8	-	1.6	-	(0.8)	0.8
Sub-Total Strengthening Our MRS Program	1.3	5.0	6.3	1.5	(3.5)	4.3	-	(0.8)	3.5
New Standards and Functions									
Implement New Standards	-	-	-	-	-	-	-	-	-
Sustain New Standards	-	0.2	0.2	0.6	-	0.8	0.5	-	1.3
Implement New Functions	-	-	-	-	-	-	-	-	-
Sustain New Functions	-	-	-	-	-	-	-	-	-
Sub-Total New Standards and Functions	-	0.2	0.2	0.6	-	0.8	0.5	-	1.3
Total	1.3	5.2	6.5	2.1	(3.5)	5.1	0.5	(0.8)	4.8

As shown in the table above, relative to the $1.3 million in ongoing costs from the Previous Application, BC Hydro’s planned operating cost increases over the Test Period are $5.2 million in fiscal 2023 (plan of $6.5 million), followed by a net decrease of $1.4 million in fiscal 2024 (plan of $5.1 million) and a further decrease of $0.3 million in fiscal 2025 (plan of $4.8 million). The total plan costs for the Test Period are $16.4 million, meaning the total incremental cost increase in the Test Period is $12.5 million ($16.4 million total plan costs less ongoing costs in each year of $1.3 million). Of the total increase of $12.5 million, $0.5 million is confidential and the remaining $12.0 million is discussed below. Of the total plan amount of $16.4 million, $14.1 million is for Strengthening our MRS Program and $2.3 million is for new Standards and Functions.

Table 5-24 below summarizes the planned incremental MRS related FTEs for the Test Period for the Safety and Compliance Business Group.

Table 5-24 Fiscal 2023 to Fiscal 2025 Incremental MRS FTEs for Safety and Compliance

	F2022 Decision	F2023 Increase	F2023 Plan	F2024 Increase	F2024 Plan	F2025 Increase	F2025 Plan	F2023-F2025 Incremental
Strengthening Our MRS Program								
Implement Mitigation Plans	-	-	-	-	-	-	-	-
Investments in Program Sustainment	4.5	1.5	6.0	3.5	9.5	-	9.5	5.0
Program Assurance		2.0	2.0	2.0	4.0	-	4.0	4.0
Sub-Total Strengthening Our MRS Program	4.5	3.5	8.0	5.5	13.5	-	13.5	9.0
New Standards and Functions								
Implement New Standards	-	-	-	-	-	-	-	-
Sustain New Standards		1.0	1.0	2.0	3.0	1.0	4.0	4.0
Implement New Functions	-	-	-	-	-	-	-	-
Sustain New Functions	-	-	-	-	-	-	-	-
Sub-Total New Standards and Functions	-	1.0	1.0	2.0	3.0	1.0	4.0	4.0
Total	4.5	4.5	9.0	7.5	16.5	1.0	17.5	13.0

Strengthening our MRS Program

Strengthening our MRS program is focused on three areas: implementing our mitigation plans, investing in program sustainment, and undertaking program assurance.

Implementing Mitigation Plans

- $0.5 million of one-time, incremental operating costs is required in fiscal 2023 to implement Mitigation Plans as discussed in the confidential Appendix JJ.

Investments in Program Sustainment

- $3.0 million of one-time, incremental operating costs is required in fiscal 2023 for external support regarding Operations & Planning Standards program improvements. This work improves the policies, procedures and controls for BC Hydro's compliance with the approximate 91 Operations & Planning Standards. The Operations & Planning Standards will be enhanced to mature the program to meet industry practice.
- $0.2 million of incremental operating costs is required in fiscal 2023 for Security Command Centre contractors to strengthen our program and to also accommodate monitoring of additional physical access control systems. This funding increases by $0.1 million to $0.3 million in fiscal 2024 and fiscal 2025.
- $0.4 million of incremental operating costs is required in fiscal 2024 and fiscal 2025 for physical security including investigations, audits, and other compliance activities, and the design of physical security structures. Two FTEs are added fiscal 2024.
- $0.3 million of incremental operating costs is required each year of the Test Period for the development and sustainment of MRS training in the Learning & Development KBU.

- $0.2 million of incremental operating costs is required in fiscal 2023 for three FTEs: one MRS Program Analyst, and two compliance management system analysts. The three FTEs are planned to be added midway through fiscal 2023 resulting in an FTE increase of 1.5 in fiscal 2023 and 1.5 in fiscal 2024. This funding increases by $0.2 million to $0.4 million in fiscal 2024 and fiscal 2025.

Program Assurance

- As discussed in section 5.7.4.3 above, BC Hydro has recently introduced a risk-based assurance component to its MRS program. $0.4 million of incremental operating costs is required in fiscal 2023 to hire four FTEs midyear to support ongoing CIP, Operations & Planning, and project compliance assurance work. Also, an additional $0.4 million of incremental operating costs is required in fiscal 2023 (one-time funding that continues in fiscal 2024) for contracted resources to provide control assurance on higher risk areas. This funding increases by $0.8 million in fiscal 2024 (plan of $1.6 million) to fully fund the aforementioned FTEs and a one-time expenditure to prepare for the triennial WECC audit. Subsequently it decreases by $0.8 million in fiscal 2025 (plan of $0.8 million) as the one-time funding is no longer required.

New Standards and Functions

New Standards and Functions is focused on four areas: implementing new Standards, sustaining new Standards, implementing new functions and sustaining new functions.

Implement New Standards

- No planned incremental operating costs in the Test Period.

Sustain New Standards

- $0.2 million of incremental operating costs is required in fiscal 2023 for physical security including investigations, audits, and other compliance activities, and the design of physical security structures to accommodate the increasing number of locations requiring protection under CIP Version 7. This funding increases by $0.4 million to $0.6 million in fiscal 2024 and increases by another $0.2 million to $0.8 million in fiscal 2025. Four FTEs are planned to be added: one in fiscal 2023, two in fiscal 2024, and one in fiscal 2025.

- $0.2 million of incremental operating costs is required in fiscal 2024 for Security Command Centre contractors to accommodate the increasing number of locations requiring monitoring under CIP Version 7. This funding increases by $0.3 million to $0.5 million in fiscal 2025.

Implement New Functions

- No planned operating costs in the Test Period.

Sustain New Functions

- No planned operating costs in the Test Period.

Refer to Chapter 5D, sections 5D.6 to 5D.8 for additional details.

5.7.6.4 *Operations Business Group*

Table 5-25 below summarizes the planned incremental MRS related operating costs for the Test Period for the Operations Business Group.

Table 5-25 Fiscal 2023 to Fiscal 2025 Incremental MRS Operating Costs for Operations

	F2022 Decision	F2023 Increase	F2023 Plan	F2024 Increase	F2024 Decrease	F2024 Plan	F2025 Increase	F2025 Decrease	F2025 Plan
Strengthening Our MRS Program									
Implement Mitigation Plans	-	-	-	-	-	-	-	-	-
Investments in Program Sustainment	0.6	3.4	4.0	-	-	4.0	-	-	4.0
Program Assurance	-	0.3	0.3	-	-	0.3	-	-	0.3
Sub-Total Strengthening Our MRS Program	0.6	3.7	4.3	-	-	4.3	-	-	4.3
New Standards and Functions									
Implement New Standards	-	-	-	-	-	-	-	-	-
Sustain New Standards	-	-	-	-	-	-	-	-	-
Implement New Functions	-	-	-	-	-	-	-	-	-
Sustain New Functions	-	-	-	-	-	-	-	-	-
Sub-Total New Standards and Functions	-	-	-	-	-	-	-	-	-
Total	0.6	3.7	4.3	-	-	4.3	-	-	4.3

As shown in the table above, relative to the $0.6 million in ongoing costs from the Previous Application, BC Hydro's planned operating cost increases over the Test Period are $3.7 million in fiscal 2023 (plan of $4.3 million) and no change in fiscal 2024 or fiscal 2025 (plan of $4.3 million in each year). The total plan costs for the Test Period are $12.9 million, meaning the total incremental cost increase in the Test Period is $11.1 million ($12.9 million total plan costs less ongoing costs in each year of $0.6 million). Of the total increase of $11.1 million, $6.6 million is confidential and the remaining $4.5 million is discussed below. The total plan amount of $12.9 million is for Strengthening our MRS Program.

Table 5-26 below summarizes the planned incremental MRS related FTEs for the Test Period for the Operations Business Group.

Table 5-26 Fiscal 2023 to Fiscal 2025 Incremental MRS FTEs for Operations

	F2022 Decision	F2023 Increase	F2023 Plan	F2024 Increase	F2024 Plan	F2025 Increase	F2025 Plan	F2023-F2025 Incremental
Strengthening Our MRS Program								
Implement Mitigation Plans	-	-	-	-	-	-	-	-
Investments in Program Sustainment	4.0	11.0	15.0	-	15.0	-	15.0	11.0
Program Assurance	-	2.0	2.0		2.0	-	2.0	2.0
Sub-Total Strengthening Our MRS Program	4.0	13.0	17.0	-	17.0	-	17.0	13.0
New Standards and Functions								
Implement New Standards	-	-	-	-	-	-	-	-
Sustain New Standards	-	-	-	-	-	-	-	-
Implement New Functions	-	-	-	-	-	-	-	-
Sustain New Functions	-	-	-	-	-	-	-	-
Sub-Total New Standards and Functions	-	-	-	-	-	-	-	-
Total	4.0	13.0	17.0	-	17.0	-	17.0	13.0

Strengthening our MRS Program

Strengthening our MRS program is focused on three areas: implementing our mitigation plans, investing in program sustainment, and undertaking program assurance.

Implement Mitigation Plans

- No planned incremental operating costs in the Test Period.

Investments in Program Sustainment

- $2.2 million of incremental operating costs is required each year of the Test Period to sustain confidential compliance activities as discussed in the confidential Appendix JJ.
- $1.2 million of incremental operating costs for 11 FTEs (all to be added in fiscal 2023) to support strengthening our compliance program within the Operations Business Group for each year of the Test Period as follows:
  - Eight FTEs in the Station Field Operations KBU for: compliance management (one FTE); technical support and training for operations and maintenance personnel (two FTEs); and additional Communication Protection and Controls Technologists to perform additional industrial control and monitoring device maintenance and cybersecurity tasks required for compliance (five FTEs);
  - One FTE in the Program Contract Management KBU for compliance management; and
  - Two FTEs in the Transmission Distribution & Systems Operation KBU to support CIP related patching.

Program Assurance

- $0.3 million of incremental operating costs is required each year of the Test Period for program assurances activities. This includes the addition of two FTEs in fiscal 2023 for field compliance and assurance.

New Standards and Functions

New Standards and Functions is focused on four areas: implementing new Standards, sustaining new Standards, implementing new functions and sustaining new functions.

Implement New Standards

- No planned incremental operating costs in the Test Period.

Sustain New Standards

- No planned incremental operating costs in the Test Period.

Implement New Functions

- No planned operating costs in the Test Period.

Sustain New Functions

- No planned operating costs in the Test Period.

Please refer to Chapter 5C, sections 5C.4, 5C.6 and 5C.10 for additional details about each KBU.

5.1.6.5 General Counsel

The total plan costs for the Test Period for General Counsel are $1.7 million, which is discussed in confidential Appendix JJ. $0.8 million of incremental operating costs is required for activities associated with Mitigation Plans in fiscal 2023. This funding decreases by $0.3 million to $0.6 million for fiscal 2024 and decreases further by $0.3 million to $0.3 million for fiscal 2025.

5.8 Vegetation Management

This section describes BC Hydro's planned vegetation management activities during the Test Period, which are informed by BC Hydro's Vegetation Management Strategy, provided as Appendix G.

Table 5-27 below shows the planned vegetation management expenditures for the Test Period. Compared to fiscal 2022 Decision amounts, BC Hydro is increasing funding for vegetation management by $8.1 million in fiscal 2023, $4.0 million in fiscal 2024 and $4.8 million in fiscal 2025.[232] In addition, FTEs are planned to increase by eight over the Test Period.

Table 5-27 Summary of Test Period Vegetation Management Funding[233,234]

($ million)	F2022 Decision	LiDAR	Incremental Funding	F2023 Plan	Incremental Funding	F2024 Plan	Incremental Funding	F2025 Plan
Transmission Vegetation Maintenance	33.3	3.9	1.7	38.9	1.1	40.0	2.0	41.9
Distribution Vegetation Maintenance	36.1		3.9	40.1	3.3	43.3	3.6	46.9
Access Maintenance	1.0		2.7	3.7	0.2	3.9	-	3.9
Total Gross	**70.5**	**3.9**	**8.4**	**82.7**	**4.5**	**87.2**	**5.6**	**92.8**
Distribution Vegetation Recoveries (TELUS)	(6.9)		(0.3)	(7.2)	(0.5)	(7.7)	(0.8)	(8.5)
Total Net of Recoveries	**63.5**	**3.9**	**8.1**	**75.5**	**4.0**	**79.5**	**4.8**	**84.3**

As described below, BC Hydro has developed a new Vegetation Management Strategy, which forms the basis of the planned expenditures during the Test Period. The funding will support the required annual work volumes for a Stable Annual Vegetation Maintenance Approach to vegetation management (further discussed in section 5.8.2.2 below), with an average system-wide cycle of five years for both the

232 Includes Standard Labour Rate changes of ($0.1) million in fiscal 2023, $0.1 million in fiscal 2024, and $0.2 million in fiscal 2025.

233 Incremental Funding column Includes Standard Labour Rate changes of ($0.1) million in fiscal 2023, $0.1 million in fiscal 2024, and $0.2 million in fiscal 2025.

234 In the Previous Application, LiDAR was considered a planning operational cost as it was newly added to the vegetation management program. It has since been classified as Transmission maintenance, similar to all inspection expenditures, with the change having no impact on the overall O&M budget.

transmission and distribution systems. The approach that BC Hydro is taking under the Vegetation Management Strategy is consistent with industry practices and the planned expenditures for the Test Period are in line with industry, as further discussed in section 5.8.4 below. The planned approach is expected to deliver improved outcomes.

5.8.1 Previous Application Demonstrated Need for Additional Investment in Vegetation Management

The planned vegetation management expenditures for the Test Period are part of an ongoing topic that was discussed in the two previous revenue requirements applications.

5.8.1.1 *Previous Application Identified Four Drivers of Additional Funding*

In the proceeding for BC Hydro's F2020-F2021 RRA, BC Hydro identified vegetation management as an area that would require additional investment going forward.[235] The BCUC, in its Decision on the F2020-F2021 RRA, also directed BC Hydro to address the adequacy of its vegetation management funding in the next application (i.e., the Previous Application).[236]

In the Previous Application, we explained that additional funding was required because:

- Vegetation that had been cleared during a period of heightened activity over a decade ago had regrown and was now reaching maturity size that posed a risk to the system;
- Cost pressures have increased with electrical system expansion, new regulatory requirements and general cost inflation associated with vegetation

[235] BC Hydro Fiscal 2020 to Fiscal 2021 Revenue Requirements Proceeding, Transcript Volume 5, January 20, 2020, O'Riley, page 358, line 21 to page 359, line 8.
[236] Directive 22; BCUC Decision and Order No. G-246-20, BC Hydro Fiscal 2020 to Fiscal 2021 Revenue Requirements Application (October 2, 2020), page 73.

maintenance activities, and these costs pressures can no longer be absorbed in existing budgets; and

- Climate change is impacting the growth rate and health of vegetation across the province.

As BC Hydro explained in the Previous Application, the fiscal 2022 vegetation management budget reflected the maximum amount of work that we believed we could manage in response to these drivers; greater effort could result in inefficiencies and market challenges. We also explained that fiscal 2022 was a transitional year for BC Hydro's vegetation management program while a new Vegetation Management Strategy was developed to inform budgets in future years.

In its Decision, the BCUC approved additional funding for vegetation management stating:

> "The Panel acknowledges that BC Hydro's proposed F2022 budget responds clearly to the BCUC's directive in the Previous RRA decision to ensure it addresses the adequacy of its vegetation management funding. An approximate 50 percent increase in the vegetation management budget is a sizeable increase. However, the reliability risk posed by continued accumulation on the transmission system and the potential resulting impact on the distribution system, as described by BC Hydro, is of high significance."[237]

5.8.1.2 *We Have Addressed BCUC Directives Regarding Vegetation Management*

The BCUC's Decision on the Previous Application included several directives or comments regarding vegetation management, which we have addressed.

The BCUC directed BC Hydro to file the new Vegetation Management Strategy with this application (Directive 10), stating:

[237] BCUC Decision and Order No. G-187-21, BC Hydro Fiscal 2022 Revenue Requirements Application (June 17, 2021), page 40.

> "The Panel supports BC Hydro's commitment to reducing vegetation risk and improving reliability on its transmission and distribution systems and looks forward to receiving BC Hydro's new VMS which will assist in moving it to a sustainable clearing program."[238]

We have filed the Vegetation Management Strategy as Appendix G.[239]

Directive 11 directed BC Hydro to provide a breakdown of the planned vegetation management budget in a format similar to that provided in Table 5-11 of the Previous Application, expanded to include historical costs for the most recent five years. This is provided in section 5.8.3 below.

The BCUC also highlighted key considerations, which BC Hydro has addressed through the Vegetation Management Strategy and the planned vegetation management budgets for fiscal 2023 to fiscal 2025. Specifically:

- The BCUC asked BC Hydro to elaborate on its long-term plan to address vegetation risk and reliability on the distribution system and provided feedback on the allocation of spending between transmission and distribution vegetation management.[240] BC Hydro is increasing spending on distribution vegetation management in the Application. We also plan to increase annual pruning volumes on the distribution system by approximately 25 per cent compared to fiscal 2022 amounts and remove approximately 40,000 hazard trees in fiscal 2023 so that the documented inventory is fully cleared. Distribution vegetation maintenance is also moving to an average five year cycle, increasing frequency from the status quo. Further information is provided in section 5.8.2.5 below; and

238 BCUC Decision and Order No. G-187-21, BC Hydro Fiscal 2022 Revenue Requirements Application (June 17, 2021), page 42.

239 Directive 10 also directed BC Hydro to file any revisions to the Vegetation Management Strategy with the BCUC. Section 2 of Appendix G sets out what constitutes a revision to the strategy.

240 BCUC Decision and Order No. G-187-21, BC Hydro Fiscal 2022 Revenue Requirements Application (June 17, 2021), page 41.

- The BCUC also expressed a desire to better understand how BC Hydro plans to clear accumulation on the transmission system in a timely fashion.[241] BC Hydro had increased transmission maintenance volumes in fiscal 2021 and fiscal 2022 to begin to address the highest risk accumulation. This approach is expected to continue during the Test Period and the system will experience a full maintenance cycle during these five years. This will address the accumulation and support a shift to a stable approach in the years following. Further information is provided in section 5.8.2.4 below.

5.8.2 Vegetation Management Strategy Establishes the Approach Underlying the Planned Test Period Expenditures

The new Vegetation Management Strategy establishes the approach to vegetation management that underlies the planned vegetation management expenditures during the Test Period. As described below, the new Vegetation Management Strategy was the outcome of a broad and structured review of potential approaches.

5.8.2.1 *Investment in Vegetation Management Supports Safety, Reliability, Compliance, Access and Stewardship*

When developing the Vegetation Management Strategy, BC Hydro set the following goals to define the desired outcomes from the delivery of vegetation management activities.

- **Safety:** Manage the ongoing and persistent risks posed from growing vegetation to the electric system to support both employee and public safety, with an additional focus on fire ignition prevention and mitigation.

- **Reliability:** Ensure appropriate system reliability through the reduction of vegetation related contacts with utility assets.

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[241] BCUC Decision and Order No. G-187-21, BC Hydro Fiscal 2022 Revenue Requirements Application (June 17, 2021), page 41.

- **Compliance:** Manage ongoing compliance with all regulatory, statutory and legal requirements.
- **Access:** Secure appropriate and safe access to assets and rights-of-way.
- **Stewardship:** Act as responsible stewards of vast areas of vegetation within rights-of-way and across public and private property and continue to ensure social, environmental, financial and cultural perspectives are respected while balanced with vegetation management needs of the electrical system.

5.8.2.2 *BC Hydro Assessed Different Approaches and Determined that Stable Annual Vegetation Maintenance Is Best*

The Vegetation Management Strategy considers the best mix of vegetation management approaches going forward. As described below, we assessed four different approaches to vegetation management, and determined that the Stable Annual Vegetation Maintenance is the best approach.

As we described during the Previous Application proceeding, BC Hydro has always used a combination of area clearing and targeted removals to address vegetation. The relative mix varies over time based on the type of vegetation and its proximity to power lines.[242] More specifically, for the transmission system, vegetation management is conducted through a combination of full clearing, hot-spotting and edge tree management.

- **Full clearing** is when an area of a right-of-way is cleared to the ground through various vegetation management techniques such as mowing, brushing and falling.
- **Hot-spotting** is when selective stands of trees or individual large trees are removed while the surrounding area is left untreated. Hot-spotting is used when a small number of faster and larger species begin to emerge within an area that

[242] Fiscal 2022 Revenue Requirements Application, Transcript Volume 1, Ms. Daschuk, page 24, line 15 to page 25, line 9.

does not yet need full clearing to maintain clearances between power lines and the vegetation canopy.

- **Edge tree removal** is when hazard trees at the edge of the right-of-way are removed because they are at risk of falling into the right-of-way and power system assets.

For the distribution system, vegetation management is conducted through a combination of pruning and hazard tree removal.

- **Pruning** is the practice of cutting vegetation adjacent to the distribution system back and away from power lines as well as clearing of vegetation below the distribution lines that has the potential to grow up and into the lines over time.
- **Hazard tree removal** targets trees that pose a potential risk to power lines such as large trees that are dead, dying or showing signs of instability.

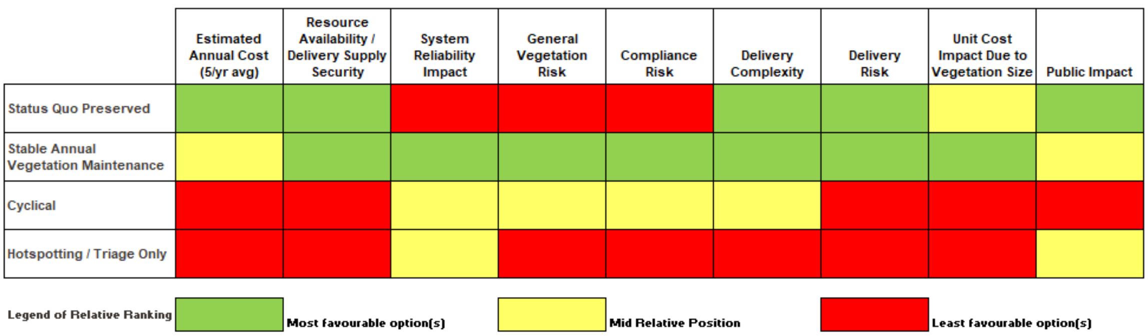
When developing the Vegetation Management Strategy, BC Hydro analyzed four different potential combinations of these approaches:

- **Status Quo** – continuing at the fiscal 2021 level of investment which represented some clearing and pruning, with a focus on hot-spotting, hazard tree removal and edge tree removal.
- **Stable Annual Vegetation Maintenance** – a constant rate of maintenance activities (more clearing and pruning) each year, matched to the vegetation growth rate.
- **Cyclical** – similar to BC Hydro's historical approach, periods of heightened clearing and pruning activity followed by periods focused on hot-spotting, hazard tree removal and edge tree removal.
- **Hot-spotting and Triage Only** – a targeted focus on removing vegetation two growing seasons before it is expected to pose a risk to power lines.

BC Hydro evaluated each of these potential approaches against the following criteria: estimated annual cost over the next five year period, the stability and expected availability of required resources, the impact on system reliability, the level of vegetation risk assumed, the level of compliance risk assumed, the operational complexity required to deliver the annual program, the level of delivery risk, the cost per unit of work, and the resulting public impact.[243]

Figure 5-6 below provides the results of our evaluation. Stable Annual Vegetation Maintenance emerged as the best approach among the four options considered.

Figure 5-6 Evaluation of Vegetation Management Approaches



5.8.2.3 *BC Hydro Identified Specific Actionable Objectives and the Required Work Volumes Under a Stable Annual Vegetation Maintenance Approach*

Once we established the overall goals and approach to inform the Vegetation Management Strategy, we identified specific actionable objectives and work volumes required to achieve these objectives. This aligned to the goals of the program described in section 5.8.2.1.

The actionable objectives are:

- Plan and implement an effective vegetation management program across the province that ensures sustainable mitigation of the risk posed by regular annual

[243] Further information on these criteria is provided in Appendix G, section 6.

growth, notable events (infestations, droughts, climate impacts, etc.) and storms;

- Improve visibility of vegetation across the system and adopt a more dynamic approach of assessing annual workplans that take into account variable growth rates, system conditions and climate impacts;
- Strengthen compliance assurance within vegetation program delivery and processes;
- Manage climate change impacts and risks (e.g., wildfires, storm resiliency, tree health from drought, flooding, disease and other impacts);
- Secure vegetation management resources and ensure supply;
- Maximize efficacy of vegetation investment (e.g., treatment longevity, vegetation and access inspections combined, etc.); and
- Optimize vegetation management delivery.

BC Hydro then determined the specific work volumes required to achieve these objectives under the Stable Annual Vegetation Maintenance Approach. BC Hydro's target is to achieve these required work volumes by fiscal 2025. Each annual workplan in the meantime will fully utilize the available resources to plan, complete and provide quality assurance for the work required until a regular stable program can be achieved by fiscal 2025. Over the course of the Test Period, we will address key areas of focus (e.g., hazard tree inventory removal) through heightened work amounts in specific areas for set durations.

The work volumes are summarized in Table 5-28 below and explained further in the sub-sections that follow. Further information is provided in the Vegetation Management Strategy filed as Appendix G. The Stable Annual Vegetation Maintenance Approach will be achieved when all of the criteria in the table are achieved or exceeded for each particular category of the system.

Table 5-28 Minimum and Optimal Work Levels

Category	Activity	Minimum Annual Work Level	Optimal Annual Work Level
Transmission Vegetation Maintenance	ROW Clearing (hectares)	**6,700**	**8,600** (adjusted to achieve VMS goals and address climate change uncertainty)
	Hotspotted Trees Removed (trees)	**40,000**	**30,000** (only optimal w hen clearing at optimal level)
	Edge Trees Removed (trees)	**25,000**	**30,000**
	LiDAR Scanned and Modelled (% of system)	**20%**	**20%**
	System Patrolled & Inspected (% of system)	**100%**	**100%**
Distribution Vegetation Maintenance	Vegetation Pruned (meters)	**3,100,000**	**3,300,000**
	Hazard Trees Removed (trees)	**26,000**	**30,000**
	System Patrolled & Inspected (% of system)	**33%**	**50%**
Access, Facilities and Properties	Access Patrolled & Inspected (% of system)	**33%**	**50%**
	Facilities Vegetation Assessment	**100%**	**100%**
	Priority Sites Maintained Post Assessment	**100% High Priority 50% Medium Priority**	**100% High and Medium**

5.8.2.4 *Transmission Work Volumes Will Maintain a Five-Year Average System Wide Cycle*

For transmission vegetation management, BC Hydro calculated the minimum work level required to maintain an average system-wide maintenance cycle of five years. This average includes areas with high vegetation growth, which require shorter cycles (i.e., three to four years) as well as areas with slower vegetation growth, requiring less frequent cycles (i.e., between five and 10 years).

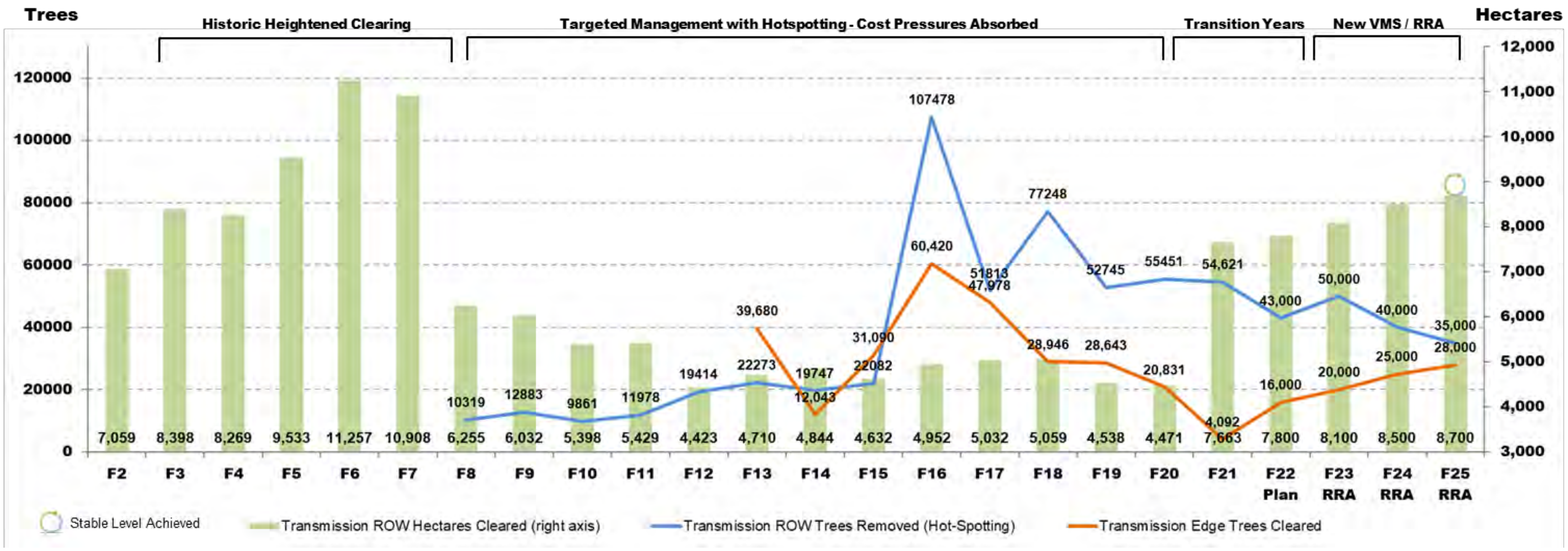
When averaging all of the required maintenance across the various regions (with differing species and growth rates), the system wide average is roughly five seasons of growth before maintained vegetation can begin to once again represent a risk to the system. Maintaining a five-year average cycle will address the risks in advance of a potential problem.

In its Decision on the Previous Application, the BCUC also expressed a desire to better understand how BC Hydro plans to clear accumulation on the transmission system in a timely fashion.[244] BC Hydro had increased transmission maintenance volumes in fiscal 2021 and fiscal 2022 to begin to address the highest risk accumulation. This approach is expected to continue during the Test Period and the system will experience a full maintenance cycle during these five years. This will address the accumulation and support a shift to a stable approach in the years following.

Figure 5-7 below shows the planned annual work volumes for the Test Period compared to historical work volumes. The combination of clearing, hot-spotting and edge tree removal volumes reflects the Stable Annual Vegetation Maintenance Approach.

244 BCUC Decision and Order No. G-187-21, BC Hydro Fiscal 2022 Revenue Requirements Application (June 17, 2021), page 41.

Figure 5-7 Transmission Historic Vegetation Management Levels



Across all regions, ground inspections will be conducted annually and will be augmented by enhanced modelling through a LiDAR program that will cover a minimum of 20 per cent of the system each year. LiDAR models provide a dynamic view of the power system under variable loading and environmental conditions (e.g., line sag and sway) in addition to modelling future vegetation growth. This, combined with the point in time ground inspection, provides a holistic view of the system in both the present state and accounts for variables not visible at the moment of inspection.

5.8.2.5 *Distribution Work Volumes Will Maintain a Five-Year Average System Wide Cycle*

For distribution vegetation management, BC Hydro also calculated the minimum work level required to maintain an average system-wide maintenance cycle of five years, with more frequent cycles in areas with higher growth (i.e., two to three years) and less frequent cycles in areas with slower growth (i.e., four to six years).

In its Decision on the Previous Application, the BCUC asked BC Hydro to elaborate on its long-term plan to address vegetation risk and reliability on the distribution system and provided feedback on the allocation of spending between transmission and distribution vegetation management.[245]

Over the Test Period, BC Hydro plans to increase annual pruning volumes on the distribution system by approximately 25 per cent compared to fiscal 2022 amounts. In addition, BC Hydro is planning to remove approximately 40,000 hazard trees in fiscal 2023 so that the documented inventory is fully cleared, and a stable, ongoing maintenance level can be established. This is shown in Figure 5-8 below.

[245] BCUC Decision and Order No. G-187-21, BC Hydro Fiscal 2022 Revenue Requirements Application (June 17, 2021), page 41.

Figure 5-8 Distribution Hazard Tree Inventory

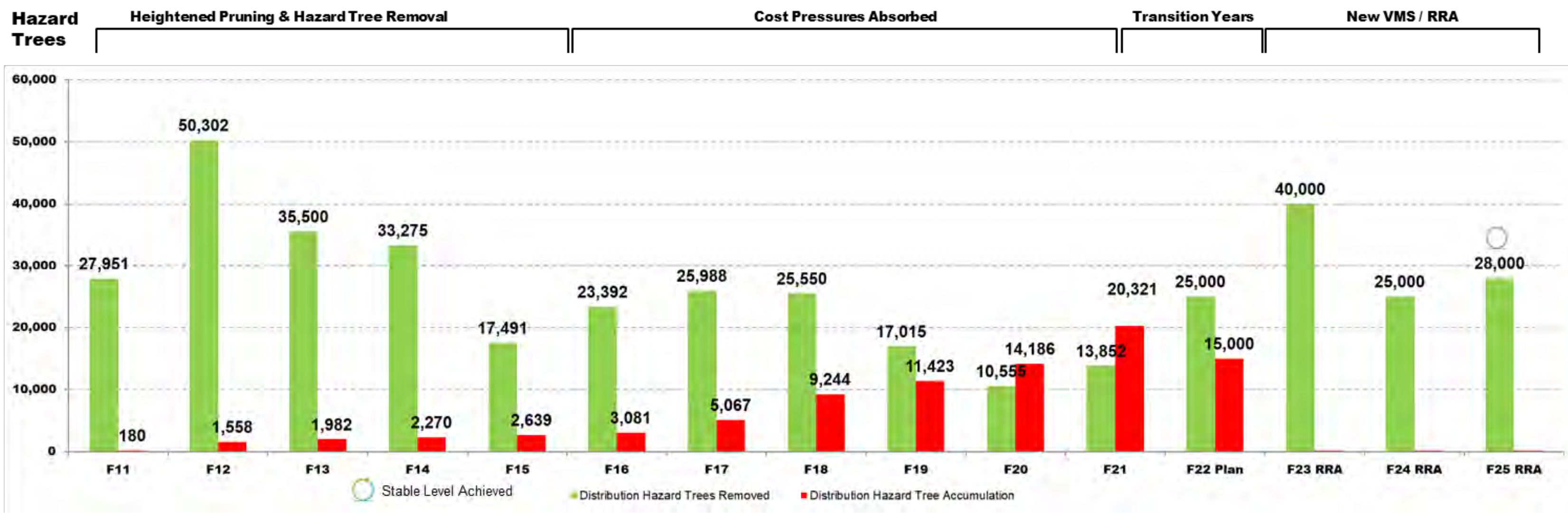
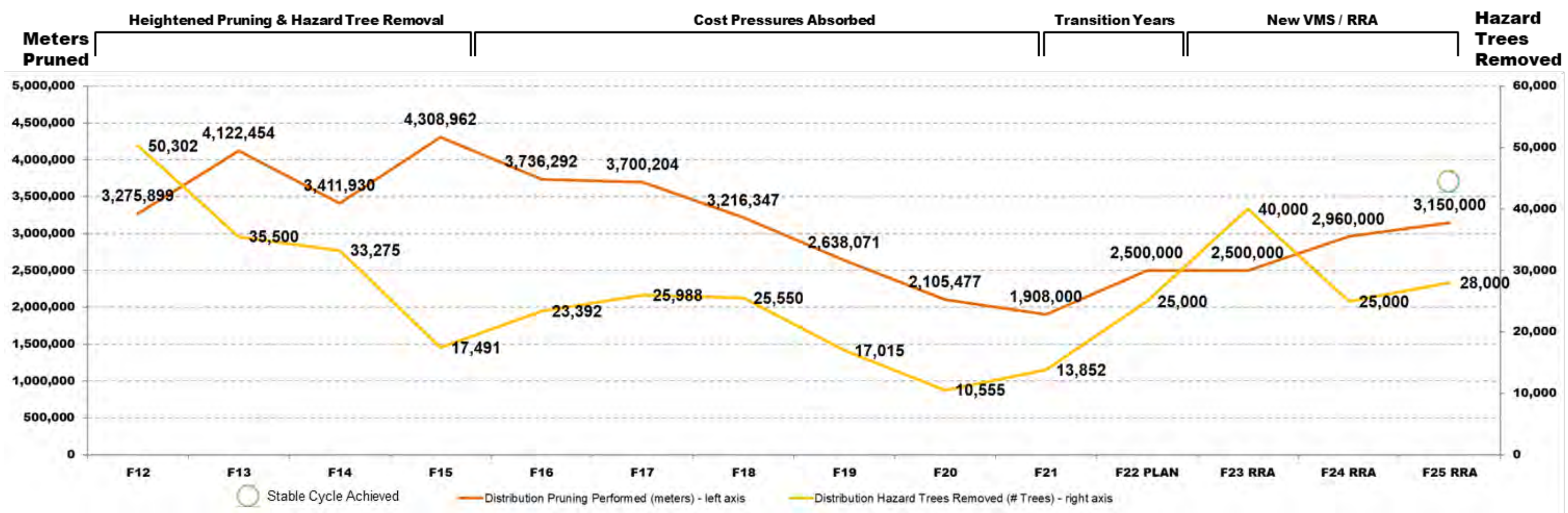


Figure 5-9 below provides a summary of planned pruning and hazard tree removal activity over the Test Period, which reflects the Stable Annual Vegetation Maintenance Approach. As set out in section 5.8.3 below, funding for distribution vegetation management is planned to increase to support these higher work volumes.

1 **Figure 5-9 Distribution Vegetation Maintenance Levels**



Over the Test Period, starting fiscal 2023, BC Hydro will also increase the frequency of its manual visual inspections of vegetation on the distribution system to a minimum level of once every three years and move towards the optimal level of once every two years by fiscal 2025. This level of inspection will be greater than the annual clearing capability; however, it will enable the most effective targeting of the annual program. This frequency is intended to allow for proactive identification of potential risks that would impact reliability and safety on the distribution system.

5.8.2.6 *Access, Facilities and Properties Work Is Also Increasing*

Over the Test Period, access, facilities and properties vegetation management will also increase in terms of inspection frequency and maintenance conducted.

Inspections for access areas (roads, bridges, culverts, helipads, etc.) will begin on a three-year cycle, starting in fiscal 2023, and move towards the optimal level of once every two years by fiscal 2025. Facilities and properties will continue with the established annual inspections. The inspections will result in work requirements that will be addressed based on priority. High priority elements will be addressed within the same annual workplan, whereas medium priority elements will be addressed within the current or following annual workplan. Low priority elements will be monitored and addressed as capacity is available.

5.8.3 Increased Test Period Funding Delivers the Stable Annual Approach in the Vegetation Management Strategy

The planned Test Period funding is calculated based on the work volumes required to achieve the vegetation management objectives under the Stable Annual Vegetation Maintenance Approach.

Compared to fiscal 2022 Decision amounts, BC Hydro is increasing funding for vegetation management by $8.1 million in fiscal 2023, $4.0 million in fiscal 2024 and

$4.8 million in fiscal 2025.[246] The costs were calculated based on the required work volumes multiplied by the contract rates we have for the units needed. Our existing contracts cover the Test Period, which affords us a degree of certainty on the rates.

This includes $0.9 million for an additional six vegetation coordinators and an additional two vegetation specialists/foresters to support increased activity levels and to strengthen important capabilities, such as site prescriptions (i.e., treatment plan for a specific site). We require internal resources to support the site level planning of vegetation work, create unit based work orders (inclusive of mapping and tree markers), complete quality assurance checks once contractors complete work and to support ancillary requirements (public engagement, permitting, documentation, reporting, etc.). Due to the expected increase in work volumes, these operational resources are needed to deliver the vegetation management program effectively.

The annual investment is planned to incrementally increase each year so that additional internal and external resources have sufficient time to be on-boarded, build up their delivery capabilities and complete the required training. The fiscal 2025 level of investment represents the ongoing work required to support the Stable Annual Vegetation Maintenance Approach. This level of investment is expected to continue beyond fiscal 2025, with adjustments as required to account for future cost pressures, inflation and market rate fluctuations, so that the annual volume of work can be maintained.

With this increased funding, BC Hydro's total planned vegetation management expenditure in fiscal 2025 is $92.8 million (before recoveries from TELUS for shared assets). Approximately 75 per cent of the total vegetation management budget is for external contractors to perform the required work in the field. These contracts are competitively sourced and represent current market rates. Approximately 18 per cent

[246] Includes Standard Labour Rate changes of ($0.1) million in fiscal 2023, $0.1 million in fiscal 2024, and $0.2 million in fiscal 2025.

of the total budget is for internal resources to perform inspections, quality assurance, site planning and patrols. The remaining seven percent is for planning, program management and administration. These ratios are consistent with historical norms for the program.

Directive 11 directed BC Hydro to provide a breakdown of the planned vegetation management budget in a format similar to that provided in Table 5-11 of the Previous Application, expanded to include historical costs for the most recent five years. Table 5-29 below provides the historical costs for the most recent ten years (i.e., fiscal 2012 to fiscal 2021). Table 5-30 below provides a breakdown of the fiscal 2022 Decision amounts to fiscal 2025 plan in a format similar to that provided in Table 5-11 of the Previous Application.

Table 5-29 Historic Vegetation Management Costs[247]

($ million)	F2012 Actual	F2013 Actual	F2014 Actual	F2015 Actual	F2016 Actual	F2017 Actual	F2018 Actual	F2019 Actual	F2020 Actual	F2021 Actual
Transmission Vegetation Maintenance	19.8	21.6	19.9	21.7	18.4	18.9	19.0	18.7	21.5	27.1
Distribution Vegetation Maintenance	35.5	34.8	30.1	32.2	32.7	32.4	31.2	31.8	28.4	31.9
Access Maintenance	1.0	1.2	1.1	1.3	1.0	1.0	1.0	1.2	1.0	0.9
Total Gross	**56.3**	**57.6**	**51.1**	**55.2**	**52.1**	**52.4**	**51.2**	**51.7**	**50.9**	**59.9**
Distribution Vegetation Recoveries (TELUS)	(10.3)	(8.2)	(7.0)	(5.5)	(6.2)	(6.7)	(6.5)	(6.4)	(5.5)	(6.4)
Total Net of Recoveries	**46.0**	**49.5**	**44.2**	**49.7**	**45.9**	**45.7**	**44.7**	**45.3**	**45.3**	**53.5**

247 F2012 to F2020 actuals are represented in real dollars that were adjusted using the B.C. Consumer Price Index with fiscal 2021 as the base year.

Table 5-30 Fiscal 2022 to Fiscal 2025 Vegetation Management Plan[248,249]

($ million)	F2022 Decision	LiDAR	Incremental Funding	F2023 Plan	Incremental Funding	F2024 Plan	Incremental Funding	F2025 Plan
Transmission Vegetation Maintenance	33.3	3.9	1.7	38.9	1.1	40.0	2.0	41.9
Distribution Vegetation Maintenance	36.1		3.9	40.1	3.3	43.3	3.6	46.9
Access Maintenance	1.0		2.7	3.7	0.2	3.9	-	3.9
Total Gross	**70.5**	**3.9**	**8.4**	**82.7**	**4.5**	**87.2**	**5.6**	**92.8**
Distribution Vegetation Recoveries (TELUS)	(6.9)		(0.3)	(7.2)	(0.5)	(7.7)	(0.8)	(8.5)
Total Net of Recoveries	**63.5**	**3.9**	**8.1**	**75.5**	**4.0**	**79.5**	**4.8**	**84.3**

5.8.4 BC Hydro Has Validated the Vegetation Management Strategy and Planned Expenditures

As we describe below, BC Hydro's Vegetation Management Strategy and the corresponding activities and funding levels during the Test Period have been validated in a variety of ways, including:

- Benchmarking data provided by First Quartile;
- External review of the Vegetation Management Strategy by Guidehouse;
- The Canadian Electricity Association 2021 Vegetation Maintenance Report;
- Competitive procurement processes for external vegetation work delivery services;
- Publicly accessible utility regulatory filings; and
- Internal analysis of BC Hydro's current and historical vegetation performance and expenditures.

5.8.4.1 *First Quartile Data: Test Period Vegetation Management Expenditures Are in Line with Industry Benchmarks*

BC Hydro's planned expenditures for the Test Period are aligned with industry benchmarks provided by First Quartile.

[248] Includes Standard Labour Rate changes of ($0.1) million in fiscal 2023, $0.1 million in fiscal 2024, and $0.2 million in fiscal 2025.

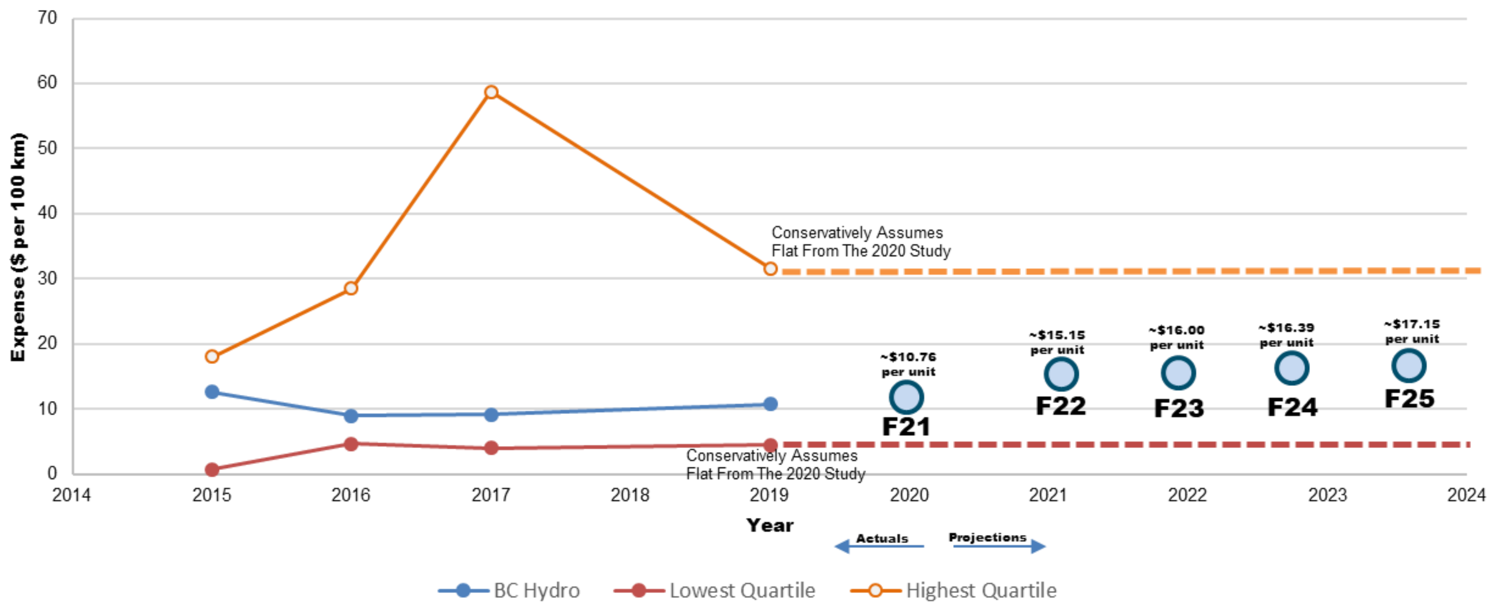
[249] In the Previous Application, LiDAR was considered a planning operational cost as it was newly added to the vegetation management program. It has since been classified as Transmission maintenance, similar to all inspection expenditures, with the change having no impact on the overall O&M budget.

First Quartile is a professional consulting firm that performs work in the energy sector. It conducts surveys to provide utilities with comparative analysis in various operational areas, including vegetation management. First Quartile's benchmarking is among those benchmarking reports that BC Hydro is proposing to continue as part of its overall approach to cost benchmarking as discussed in Chapter 1 and in Appendix Y.

First Quartile's survey with regard to vegetation management includes approximately 40 utilities across North America as well as a small number of international utilities. While each utility is different (geography, climate, vegetation species, etc.), the relatively large sample size, combined with normalizing adjustments by First Quartile, provides useful insight and relative comparisons. First Quartile Benchmarking was used by BC Hydro as a resource to establish a relative industry view and support context for decision making within the new Vegetation Management Strategy. As BC Hydro moves through the implementation of the new Vegetation Management Strategy, we will continue to monitor our performance against our industry peers and may conduct additional reviews to understand any significant differences that may emerge.

With regard to the transmission system, Figure 5-10 below shows that the planned vegetation management funding amounts equate to approximately $17 per 100 km of overhead circuits by fiscal 2025, which is within the industry range and below the industry average of approximately $20 per 100 km.

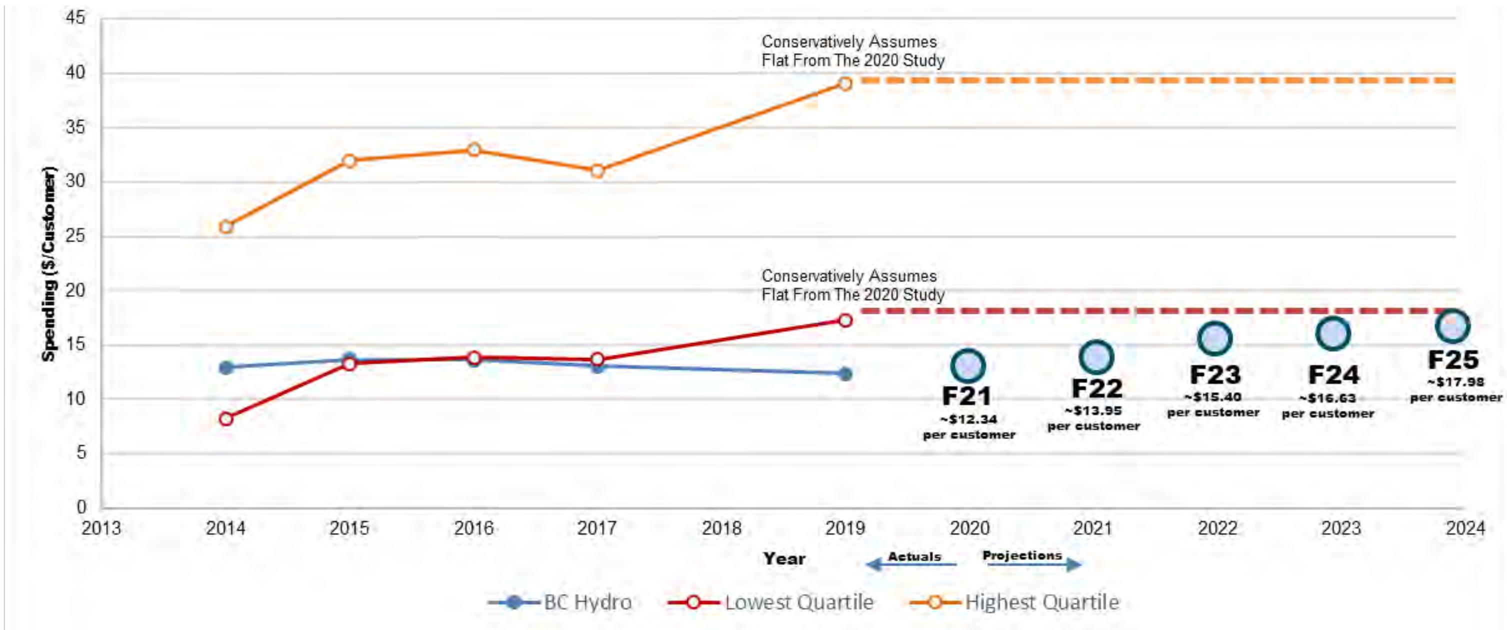
Figure 5-10 Transmission Line Right of Way Vegetation Expense per 100 Overhead Circuit Kilometres



Source: First Quartile Benchmarking Utilities (n) = ~40 per year (fluctuates +/- 5 pear year based on study participants.

With regard to the distribution system, Figure 5-11 below shows that the planned vegetation management funding amounts increase to approximately $18 per customer, which is more in line with the industry range compared to previous expenditure levels.

Figure 5-11 Distribution Vegetation Expenditures Per Customer Per Year



Source: First Quartile Benchmarking Utilities (n) = ~40 per year (fluctuates +/- 5 pear year based on study participants)

5.8.4.2 *Guidehouse Review: Vegetation Management Strategy Is Consistent with Industry Practices*

BC Hydro engaged Guidehouse to perform an external review of the Vegetation Management Strategy and BC Hydro's planned vegetation management capabilities and practices. Overall, Guidehouse concluded that BC Hydro's Vegetation Management Strategy and plans were consistent with (or, in some cases, slightly exceeded) industry practices.

Guidehouse is an experienced consulting firm used by a number of utilities across North America. Their practice extends to vegetation management and this expertise was leveraged to provide an external review of the Vegetation Management Strategy.

To conduct the review, Guidehouse interviewed staff members, conducted a peer review and assessed differences between BC Hydro and other utilities. The review included an evaluation of compliance requirements, trim cycles, hazard and edge tree removal, technology (i.e., LiDAR) and internal staff expertise.

5.8.4.3 *Other Validation*

Other inputs used to inform the strategy and the Test Period values were a report produced by the CEA and our recent market procurement for vegetation services. The CEA report demonstrated that BC Hydro's overall approach to vegetation management is consistent in terms of approach other Canadian utilities engage (e.g., means of inspection, cutting techniques, compliance elements).

The recent market procurement ensured BC Hydro's contractor rates for vegetation maintenance reflect fair market values and were secured using a competitive process.

Further information on these external reviews is provided in the Vegetation Management Strategy.[250]

5.8.5 Performance Metrics and Targets: Increased Work Volumes and Funding Will Improve Outcomes for Customers

As summarized in Table 5-31 below, BC Hydro has identified performance metrics and targets to monitor and evaluate the future outputs and outcomes achieved as a result of the Vegetation Management Strategy and the associated activities and investment.[251]

Table 5-31 Vegetation Management Performance Metrics and Targets

	Inputs (i.e., Planned Investment)	Outputs (i.e., Target)	Outcomes
Transmission	$38.9 million in F2023 $40.0 million in F2024 $41.9 million in F2025	6700-8600 hectares cleared / year 30,000-40,000 trees addressed / year 100% annual inspections 20% LiDAR / year	Compliance with required standards. Reliable and safe operation of the transmission system.

250 Refer to Appendix G, section 9.

251 The Commercial Energy Consumers Association of BC provided helpful feedback on their views on the purpose and application of performance metrics. A key insight from these discussions for BC Hydro was the benefit of providing performance metrics that allow inputs, outputs and outcomes to be quantified. In other words, using performance metrics to measure the amount of resources being invested and the relative efficiency of that investment, the outputs achieved from that investment and the improved outcomes for customers realized as a result. BC Hydro has applied this approach to its presentation of vegetation management performance metrics information.

	Inputs (i.e., Planned Investment)	Outputs (i.e., Target)	Outcomes
Distribution	$40.1 million in F2023 $43.3 million in F2024 $46.9 million in F2025	3.1 to 3.3 million meters pruned each year by fiscal 2025; 26,000 to 30,000 hazard trees removed each year (higher level in F2023 for addressing inventory) Remaining trees in the distribution hazard tree inventory reduced to zero by the end of fiscal 2023	30% reduction in outages caused by vegetation by fiscal 2025
Access	$3.7 million in F2023 $3.9 million in F2024 $3.9 million in F2025	All access areas, facilities and properties inspected by fiscal 2025. A priority based workplan developed with high priority items addressed in the same year.	Improved access to assets and easier movement of resources to maintenance areas Reduced risk of access impairment Properties and facilities in compliance with required regulations

In terms of the transmission system, BC Hydro's planned investment in vegetation management over the Test Period is expected to produce the following outputs:

- Clear between 6,700 and 8,600 hectares of vegetation each year;
- Address 30,000 to 40,000 trees through hot-spotting each year;
- Remove 25,000 to 30,000 edge trees each year;
- Inspect 100 per cent of the system each year; and
- Scan and model 20 per cent of the system through LiDAR each year.

BC Hydro expects that achieving these outputs will maintain compliance with required standards (notably Mandatory Reliability Standards) and promote ongoing safe and reliable operation of the transmission system.

In terms of the distribution system, BC Hydro's planned investment in vegetation management over the Test Period is expected to produce the following outputs:

- Prune between 3.1 million and 3.3 million meters each year by fiscal 2025;
- Remove 26,000 to 30,000 hazard trees each year by fiscal 2025; and
- Reduce the remaining trees in the distribution hazard tree inventory to zero by the end of fiscal 2023.

BC Hydro expects that achieving these outputs will reduce outages caused by vegetation by approximately 30 per cent by fiscal 2025.

5.9 Cybersecurity

BC Hydro has a strong record in managing cybersecurity risk and adapting to a cybersecurity threat landscape that is constantly changing and growing in sophistication. Over the past five years, we have grown and enhanced our cybersecurity program to meet the needs of the organization and pro-actively manage the risk. While BC Hydro has established a strong base to actively prevent, detect and respond to cyber threats, we must continue to enhance our overall cybersecurity capacity and capability to secure our digital systems against potential cyber attacks.

In fiscal 2022, we increased our investment in cybersecurity by $3.0 million, and indicated a need for further investment in future years. Consistent with those expectations, we plan to make a significant investment in the Test Period. As shown in Table 5-32 below, BC Hydro is planning to increase funding for cybersecurity by a further $6.5 million for fiscal 2023 through fiscal 2025 resulting in a total cybersecurity operating budget of $14.5 million by fiscal 2025. The additional funding will be directed towards our expanding digital footprint, continuous improvement following industry best practices, and areas that have emerged as a result of the changing threat landscape.

Table 5-32 Cybersecurity Operating Budget

$ million	F2022 Decision	F2023 Increase	F2024 Increase	F2025 Increase	F2025 Plan
Operating budget	$8.0	$4.2	$1.9	$0.4	$14.5
FTEs	25	4.5	9.5	0	39

Cybersecurity has been a topic of interest for the BCUC in the last two revenue requirements proceedings, and has been the subject of BCUC directives.[252] In the interest of providing a complete picture of our program, we have included below some background information that was also in the Previous Application. We have also identified work we have done since then and provided additional information on our plans going forward.

5.9.1 Defining Cybersecurity and How it Differs from MRS Critical Infrastructure Protection (CIP) Compliance

Cybersecurity is the practice of securing our digital systems against unauthorized access and potential loss of data or disruption to our business. It is becoming an increasingly important aspect of our business.

As our dependency on digital systems (e.g., the internet and digital communications) increases, so does our cybersecurity risk. As new technologies emerge, opportunities for innovation are created but the landscape of cyber threats is also expanded. A successful cyber attack on BC Hydro could have serious consequences including the release of sensitive information, disruption of data or systems needed to run our day-to-day business operations, disruption of our grid operations or even the security of our employees or the public.

Managing cybersecurity risk involves a multilayer approach that includes the technical capabilities to:

[252] Directive 21 of the BCUC's Decision on the F2020-F2021 RRA directed BC Hydro to address the adequacy of its cybersecurity programs. Directives 8 and 9 of BCUC's Decision on the Previous Application are also specific to cybersecurity.

- Identify potential threats;
- Protect our information and systems;
- Detect attacks and breaches of our defences;
- Respond to cyber incidents efficiently and effectively; and
- Recover from any incident by restoring our information and systems.

Successful cyber risk management requires skilled cybersecurity teams, well-architected Information Technology and Operational Technology environments, specialized hardware and software to detect threats and protect our environment, and strong response and recovery plans. In addition, employees, contractors, vendors, and customers must be well-trained to identify and respond to evolving cyber threats.

Although enterprise cybersecurity must be managed across our entire digital landscape, some digital systems, if disrupted, could impact the operation of the Bulk Electric System. These digital systems must be protected in a manner that is compliant with the CIP Standards, which are part of MRS.[253] The majority of these systems are Operational Technology systems, residing in our control centres and our most critical generating and transmission stations. The Operational Technology environment is inclusive of Industrial Control Systems, a term used to describe those systems that directly control and operate physical devices. For those Operational Technology assets that have the potential to impact our Bulk Electric System, BC Hydro has implemented a number of protections to meet current CIP requirements and continues to implement additional measures to both strengthen our security posture and to meet emerging CIP requirements. This also requires investment in Information Technology systems such as those for managing and monitoring the digital networks as well as those that track and manage the business

253 Mandatory Reliability Standards are discussed further in section 5.7.

processes to support compliance. BC Hydro plans to extend this implementation to those Industrial Control Systems and facilities that do not fall under CIP Standards and are not considered critical to the operation of the Bulk Electric System.

Achieving and strengthening our compliance with the CIP Standards is mandatory and challenging as both cyber threats and the CIP Standards themselves evolve over time. New standards will typically encompass more of our digital systems and/or introduce new protection requirements so achieving and strengthening compliance takes considerable on-going efforts. Compliance with CIP requires specialized people, processes, and technologies to be in place to meet the necessary requirements of the standards. FTE and funding requirements related to CIP compliance are identified in section 5.7.

5.9.2 BC Hydro Is Pro-Actively Managing Cybersecurity Risk

BC Hydro has a large and complex technology landscape with multiple sophisticated enterprise and business applications, broad networks to geographically dispersed locations, critical power systems management technologies and thousands of end-point devices. As described below, our proactive approach to cybersecurity risk management includes following the National Institute of Standards and Technology (**NIST**)[254] framework, seeking out intelligence on threats, and employing an appropriate complement of internal and external experts.

5.9.2.1 *We Use an Industry Standard Risk Management Framework - NIST*

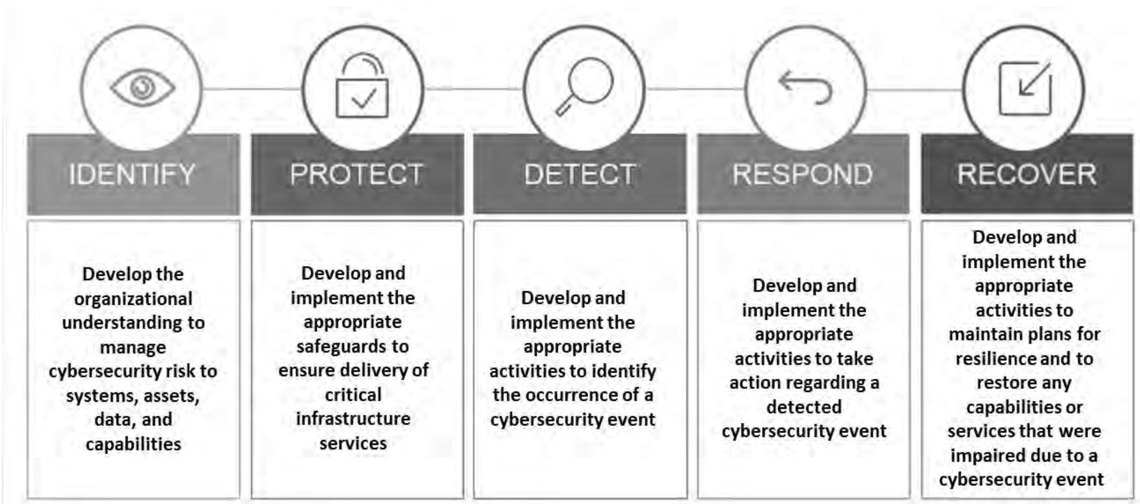
BC Hydro follows the NIST framework, a well established risk-based approach to managing cybersecurity risk, to help ensure we are taking appropriate measures to protect our environment.

The NIST Framework serves three main functions:

[254] The NIST is a federal, non-regulatory agency of the U.S. government.

- Helps organizations proactively identify, manage, and assess cybersecurity risks;
- Provides an approach to prioritize cybersecurity resources, make risk decisions, and take action to reduce risk; and
- Enhances cybersecurity communication within an organization and with other organizations (such as subsidiaries, partners, suppliers, regulators, and auditors).

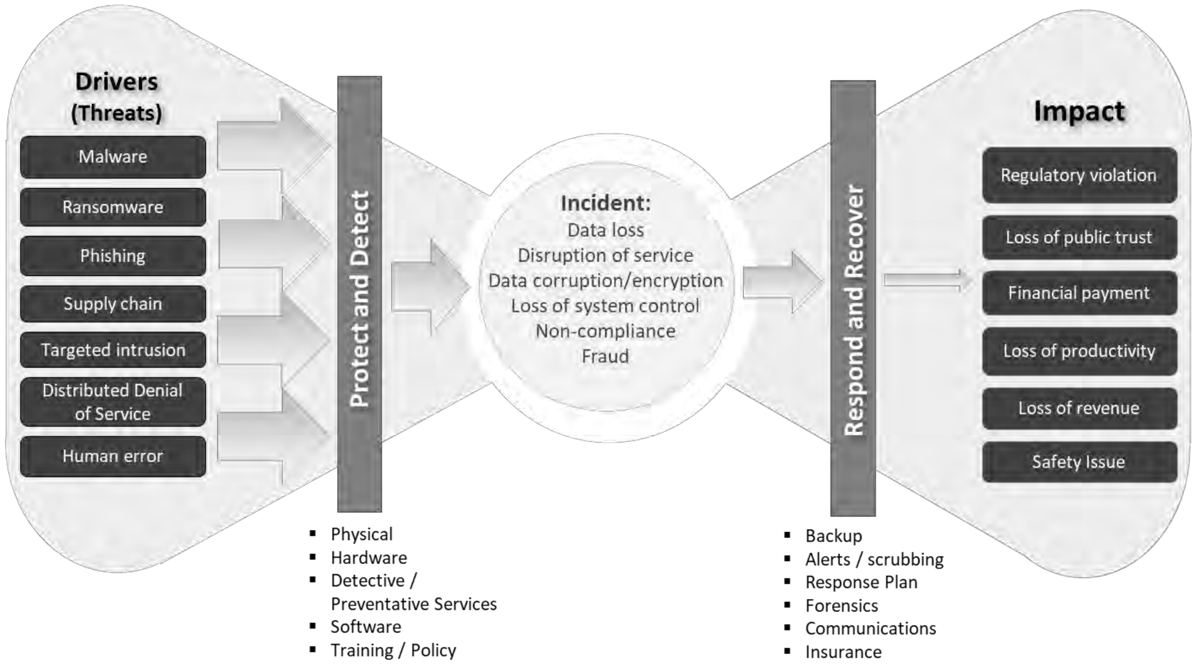
Figure 5-12 The NIST Cybersecurity Framework



BC Hydro has effectively used this framework to ensure our cybersecurity program includes all of the functional components defined as best practice for cybersecurity including risk management.

BC Hydro’s risk management approach identifies threats, implements layers of protection and detection controls, and prepares and deploys further layers of response and recovery strategies to manage the likelihood of an incident occurring and any potential impact. The bowtie representation is a common method of representing risk management and is shown in Figure 5-13 below.

Figure 5-13 Bowtie Representation of Cybersecurity Risk Management



Our top cybersecurity risks can be classified into three broad categories:

- Data encryption, ransom, or loss;
- Loss of control/performance of systems; and
- Compliance violations.

We use industry experience and expert judgement to assess the likelihood and impact of cyber incidents. Due to the complex and continually changing nature of cyber threats, risk assessments are not precise and need to be conducted often to keep pace with the evolving environment. Judgement is used to determine if the level of risk is acceptable from an enterprise perspective, or if actions are required to mitigate it. In general, investments in improved protections can help reduce the likelihood of events, and investments in improved response and recovery can help reduce the impact of events.

A risk management approach calls for continuous adaptation as the cybersecurity threats evolve and change. Our protection and detection controls must be continually updated, and our response and recovery plans must be tested and updated as threats emerge and evolve. It is important to have several layers of controls so that any one failure does not result in a breach. Some controls are stronger than others and our most important control is our people. Creating a culture of cybersecurity at BC Hydro through training and awareness, feedback loops, campaigns and programs is a foundation to our approach.

5.9.2.2 *We Seek Out Intelligence on Threats*

BC Hydro uses a mix of resources to gain intelligence of the evolving threat landscape. Our cybersecurity teams and organization leaders are in regular contact with our peers in utilities across Canada and the USA, we participate in industry forums and cybersecurity groups such as Canadian Energy Association (**CEA**), Electricity Information Sharing and Analysis Center and Canadian Centre for Cyber Security as well as maintaining open lines of communication with other government organizations in BC. Our vendors and service providers are also very good sources of information.

5.9.2.3 *We Use an Appropriate Mix of Internal and External Expertise*

BC Hydro employs a broad mix of resources for its cybersecurity program. Our approach is to use internal resources where inside business knowledge and communication is necessary. We use external resources for commodity type functions such as patching and identity management. We use specialist resources for specific roles that are difficult to fill. We have also retained professional resources to assist in our response in the event of a major cybersecurity incident.

5.9.3 BC Hydro Has a Good Track Record and Has Responded Effectively to Threats

As we described in the Previous Application proceeding, BC Hydro's cybersecurity controls and staff have been effective in keeping our systems secure. We use several tools for assessing our maturity and readiness, which show favourable results. Our planned investment is intended to sustain, and build upon, the positive track record to date.

5.9.3.1 *We Have Mitigated Recent Threats*

Since 2016, BC Hydro has not itself experienced any notable impacts from cybersecurity incidents beyond those resulting from lost laptops or limited-impact phishing attempts. However, more significant threats have emerged, and BC Hydro has mitigated these risks.

Since the Previous Application, there have been three incidents that demonstrate the present threat and BC Hydro's ability to respond:

- **SolarWinds:** BC Hydro was made aware of this threat in December 2020 through its participation in the Electricity Information Sharing and Analysis Center and Canadian Centre for Cyber Security. In this incident the SolarWinds company was breached and malware hidden in their software upgrade patches. BC Hydro, together with our subsidiaries Powertech Labs (**Powertech**) and Powerex, responded quickly to the threat and it was successfully mitigated with no impact to BC Hydro operations;
- **Powertech Labs:** In February 2021, Powertech, a wholly owned subsidiary of BC Hydro, experienced a ransomware attack. Some of Powertech's systems were encrypted and some data copied to a location outside of Powertech. A generic ransomware note was left but the attackers did not follow up with a specific request. BC Hydro, Powertech and Powerex teams immediately activated our Incident Response Plans and took several measures to ensure the protection of BC Hydro and Powerex systems. BC Hydro used our external cybersecurity service provider (FireEye/Mandiant) to support efforts to identify any indications of system compromise. None were found and there was no impact to BC Hydro or Powerex system or operations. BC Hydro has since reviewed all data related to BC Hydro interests that was copied outside of

Powertech's environment. All risks related to the released data have been mitigated. BC Hydro has since extended our cybersecurity detection and monitoring to include Powertech's perimeter; and

- **Microsoft Exchange** (e-mail): In March 2021, Microsoft released an advisory related to a vulnerability in Microsoft Exchange, the application that provides BC Hydro's email service. BC Hydro picked up the advisory through its regular intelligence monitoring and responded by ensuring all patches were applied and all steps taken to ensure that BC Hydro's systems had not been compromised. The threat was successfully mitigated with no impact to BC Hydro operations.

These attacks highlight the importance of continued vigilance and reinvestment in cybersecurity specifically with respect to vulnerability management and staying current with software products.

5.9.3.2 *We Use Various Means to Assess Cybersecurity Health, Breadth and Maturity*

We use several means for tracking our cybersecurity health, breadth and maturity. In this context, "maturity" refers to the level to which cybersecurity risk management capability is practiced within BC Hydro. In referring to the "breadth" of our cybersecurity practices, we are referring to the extent to which these practices are implemented across BC Hydro's digital environments.

BC Hydro tracks our daily BitSight Security Rating[255] to assess BC Hydro's security health from an external perspective. BC Hydro's Security Rating has been consistently rated as "Advanced" over the past 18 months. However, cybersecurity threats are constantly evolving, and our expanding footprint of digital technologies

[255] To generate the ratings, BitSight gathers and evaluates publicly available data on security behaviors from collection points across the globe. BitSight's algorithms analyze the data for severity, frequency, duration, and confidence to create an overall rating of that organization's current security health. Ratings are between 250 and 900 (a higher score is better) and are described as Basic, Intermediate and Advanced. All of the data used to derive a BitSight Security Rating is externally available and collected without any intrusive testing on an organization.

means we must continuously improve the maturity and breadth of our cybersecurity practices to appropriately manage the risk.

As described in the Previous Application, BC Hydro has used two frameworks to assess the maturity and breadth of its capability:

- The National Institute of Standards and Technology (**NIST**) Cybersecurity Risk Management Implementation Framework; and
- the U.S. Department of Energy, Electricity Subsector Cybersecurity Capability Maturity Model (**C2M2**).

Both the NIST framework and the C2M2 model are well-established within the industry and across the cybersecurity domain as a means to guide and measure the implementation of cybersecurity practices within an organization.

BC Hydro's self-assessment using the NIST framework showed a reasonable[256] level of practice implementation across the Information Technology environment and those Operational Technology environments that fall under the CIP requirements. The self-assessment identified a general lack of uniformity in practice implementation across the full BC Hydro landscape.

BC Hydro's self-assessment using the C2M2 model shows the opportunity for practice enhancements in the areas of Risk Management, Threat and Vulnerability Management, Situational Awareness, Program Management and Supply Chain and External Dependencies Management.

Since the Previous Application, BC Hydro has also trialed the Canadian Cyber Security Tool (**CCST**)[257] made available by Public Safety Canada in collaboration with the Canadian Centre for Cyber Security. The CCST provides a report on

[256] Reasonable is gauged as an average "level 2 – performed" using the implementation maturity levels defined for the C2M2 model. Practices are documented, stakeholders are involved, adequate resources are provided, standards and guidelines are in place.

[257] For additional information on the CCST, or to obtain access to the tool, please contact Public Safety Canada at: ps.cyberengagements-engagementscybernetiques.sp@canada.ca.

BC Hydro's Cyber Security Technical and Program Resilience, as well as comparative results of how BC Hydro performs against other critical infrastructure stakeholders across Canada. Using this tool, BC Hydro achieved a Level 4: Mature ranking in both Technical Resilience and Program Resilience. There are five possible levels with Level 5: Advanced being the highest. For Technical Resilience, a mature ranking indicates an organization has "an approach to cyber security that is both extensive and comprehensive". However, "additional opportunities exist to reduce the risk of cyber security incidents and data breaches". For Program Resilience, the ranking relates to the "degree of formality and optimization of processes". A mature ranking indicates that processes are "quantitatively managed in accordance with agreed upon metrics". Overall, BC Hydro ranked in the top quartile based on all organizations that have used the CCST.

Continuous improvement in BC Hydro's cybersecurity practices are required to strengthen the security of our Information Technology and Operational Technology environments. Threat intelligence, risk assessments, maturity self-assessments, performance during incidents, audits and CIP compliance requirements all play into identifying areas for BC Hydro to improve our practices. The following sections describe how BC Hydro has identified the need for additional FTEs and funding within the Test Period. These additional FTEs and funding are required to grow the Cybersecurity team and extend and enhance our capability and maturity to fulfill BC Hydro's evolving responsibilities in managing cybersecurity risk.

5.9.4 We Have Accomplished Important Steps Since Filing the Previous Application

We have improved BC Hydro's cybersecurity capability in several ways since filing the Previous Application. Specifically, we have:

- Created a new Director of Cybersecurity and Compliance role overseeing a combined Cybersecurity and Compliance Department, as shown in Figure 5-14 below. This new organizational structure is designed to provide more senior management for cybersecurity and adds new functions for Cybersecurity Governance, Risk and Compliance as well as a new CIP Program Office. The function of the Department is described in Chapter 5E, section 5E.5.2.5 of this application;

Figure 5-14 Cybersecurity and Compliance Department Organizational Structure

- Engaged our external cybersecurity service provider, Mandiant, to complete a ransomware risk assessment for our environment, implemented the immediate recommendations and updated our plans to include the longer-term recommendations;
- Expanded our monitoring and detection capability through additional internal resources, extensions to our monitoring systems and use of Mandiant services to provide additional tools and resource capacity;
- Created a dedicated vulnerability management role to address increasing threats related to exploitation of product vulnerabilities;
- Completed an assessment using the CCST described in the previous section and received specific advice and guidance for BC Hydro's Technical and Program Resilience. Guidance focused on continuous improvement to areas

including vulnerability management and external supplier risk management; and

- Engaged an Operational Technology security architect to oversee architectural designs and standards related to security and monitoring of Operational Technology networks, Industrial Control Systems and devices. These designs and standards are used in the implementation of the CIP v7 Project and will also be used for the work to address the Office of the Auditor General audit recommendations regarding security of BC Hydro’s remaining Industrial Control Systems.

5.9.5 BC Hydro’s Resource Strategy for Cybersecurity

Prior to 2016, BC Hydro had a largely outsourced cybersecurity operations team. In 2016, the Technology KBU established an internal Cybersecurity Operations team to supplement existing planning and compliance resources. This Operations team was funded through a repatriation of the outsourced function in August 2017.

Since 2016, BC Hydro has increased its focus on cybersecurity, and this is reflected in the growth of the Cybersecurity team. In fiscal 2021, BC Hydro formed a new, consolidated Cybersecurity Department, which:

- Brought together Cybersecurity Planning and Cybersecurity Operations; and
- Created a separate CIP Compliance team.

The Cybersecurity Department included 19 FTEs, with an additional two FTEs in the Technology Project Delivery team dedicated to implementing cybersecurity investments, as well as an additional cybersecurity architect in the Enterprise Architecture team.

In the Previous Application, we planned an additional $3.4 million in funding for fiscal 2022, which included six FTEs (two of which were reallocated internally). These FTEs and funds were required to enhance program and risk management, expand cybersecurity practices into the Operational Technology environment and address the complexity and growing volume of cyber attacks that BC Hydro is experiencing. The roles of all current employees in the department are described in Chapter 5E, section 5E.5.2.5 of the Application.

In this application, we are planning for an additional $6.5 million in funding including 14 FTEs in order to extend and expand our practices in the areas of cybersecurity training and awareness, vulnerability management, risk assessments, cybersecurity assurance, monitoring and detection as well as response and recovery. The expected functions for these employees are described in section 5.9.6.2 below.

5.9.6 Planned Test Period Investments Target Priority Areas

This section describes how we have determined BC Hydro's requirement for additional FTEs and funding in the Test Period with reference to on-going threat intelligence, continuous improvement through self-assessments and pro-active third-party risk assessments. The outcomes of the work contemplated in Directives 8[258] and 9[259] of BCUC's Decision on the Previous Application will provide future input to BC Hydro's cybersecurity planning.

5.9.6.1 *Industry Standard Maturity Self-Assessments Identify Areas of Focus*

As noted in the Previous Application and above, the assessments performed using the NIST Framework, C2M2 and CCST have identified areas of focus, which we have been acting on.

[258] Directive 8; BCUC Decision and Order No. G-187-21, BC Hydro Fiscal 2022 Revenue Requirements Application (June 17, 2021), page 33. Directive 8 directed BC Hydro to undertake a Cyber Risk Assessment of all its cyber assets within 3 months, file it with the BCUC and notify the BCUC of any required actions in response to immediate or time-sensitive concerns.

[259] Directive 9; BCUC Decision and Order No. G-187-21, BC Hydro Fiscal 2022 Revenue Requirements Application (June 17, 2021), page 33. Directive 9 directed BC Hydro to develop a company-wide Cyber Security Plan that encompasses BC Hydro, its subsidiaries and third-parties that interface with BC Hydro and file the plan with the BCUC within one year.

Findings from these assessments indicate opportunities to enhance our practices in the areas of Risk Management, Threat and Vulnerability Management, Situational Awareness, Program Management and Supply Chain and External Dependencies Management.

- The areas of **Risk Management** and **Program Management** require more senior and experienced resources to provide expert judgement and make decisions with implications for enterprise level risk management. Two FTEs were reallocated to the Cybersecurity Department from within the Technology KBU in fiscal 2022 to provide experience and seniority. Additional funding is required in the Test Period to expand operational activities such as identity and access management, enterprise training and awareness programs as well as product and project risk assessments.
- In the area of **Threat and Vulnerability Management**, the Cybersecurity Operations team uses cybersecurity detection tools to regularly scan for vulnerabilities across the Information Technology environment. In fiscal 2022, BC Hydro added one FTE to establish a vulnerability management practice. In the Test Period, additional capacity is required to thoroughly assess and respond to the results of these scans and to extend this practice across the Operational Technology environment.
- **Situational Awareness** for the Operational Technology environment requires the extension of systems, currently used for detection of attacks in the Information Technology environment, into the Operational Technology environment. Expanding this function also requires additional licensing and FTEs to monitor the systems and respond to alerts. BC Hydro expanded monitoring and detection in fiscal 2022. In the Test Period, BC Hydro will continue to expand on this function.
- **Supply Chain and External Dependencies Management** requires additional process and systems development so that all Information Technology and

Operational Technology supplier and customer dependencies are identified, and cybersecurity risks are addressed. This capability will be advanced through the work required to achieve compliance with MRS CIP-013[260] by April 2023. BC Hydro requires additional funds and FTEs to sustain and strengthen the processes and systems developed to manage supply chain cybersecurity risk.

5.9.6.2 *BC Hydro Requires Additional Cybersecurity Resources and Funding to Enhance our Practices*

Incremental funding and FTEs budgeted for the Test Period will enhance our cybersecurity practices, such as:

- Continue to enhance and expand identity and access management processes, practices and tools to improve cybersecurity controls for electronic and physical access;
- Enhance and expand our vulnerability management program to assure timely identification and patch management practices to prevent threat actors from exploiting known product vulnerabilities;
- Continue to enhance and extend monitoring and detection to address the evolving cyber threat landscape. The growing digitization of the utility requires BC Hydro to extend cybersecurity monitoring across our Information Technology and Operational Technology environments;
- Continue to develop and improve training and awareness programs for employees and contractors to strengthen the security of our systems as our people are the first line of defence for cybersecurity;
- Continue to extend regular risk assessments and penetration testing across expanding digital and cloud environments. As new systems and tools are

[260] The CIP-013 project is to implement standards to mitigate cyber security risks to the reliable operation of the Bulk Electric System by implementing security controls for supply chain risk management of Bulk Electric System Cyber Systems.

deployed, they must be assessed for possible vulnerabilities to attack. We must develop expertise in managing cybersecurity risks associated with cloud deployments and services and as threats evolve, we must continually test our defences against new methods of attack;

- Enhance information protection and recovery plans to focus on specific ransomware and supply chain attack scenarios so that our response and recovery plans continue to evolve in line with newly evolving threats; and
- Enhance practices to address increasing risk from vendors and suppliers. Recent attacks have been the result of attackers infiltrating software development supply chains and taking advantage of vulnerabilities in packaged software.

Table 5-33 below shows how the additional 14 FTEs and $6.5 million in operating costs for the Test Period are aligned to these focus areas.

Table 5-33 Additional Resources Required for Cybersecurity Function in Fiscal 2023 to Fiscal 2025

Practices	F2023 incremental				F2024 incremental				F2025 incremental			
	FTE	Funding ($ million)			FTE	Funding ($ million)			FTE	Funding ($ million)		
		Labour	Other	Total		Labour	Other	Total		Labour	Other	Total
Enhance identity and access management	1.0	0.2		0.2				-				-
Enhance vulnerability management	2.0	0.3		0.3				-				-
Extend cybersecurity monitoring and detection	0.5	0.1	2.9	3.0	2.5	0.4	0.1	0.5			0.2	0.2
Enhanced training and awareness	1.0	0.1	0.3	0.4	2.0	0.4	0.1	0.5				-
Extend risk assessments and penetration testing			0.3	0.3	2.0	0.4		0.4			0.1	0.1
Enhance information protection and recovery plans				-	2.0	0.3		0.3				-
Enhance supply chain risk management				-	1.0	0.2		0.2		0.1*		0.1
Total	**4.5**	**0.7**	**3.5**	**4.2**	**9.5**	**1.7**	**0.2**	**1.9**	**-**	**0.1**	**0.3**	**0.4**

* Reflects the fiscal 2025 SLR increase for all FTEs added in fiscal 2023 and fiscal 2024.

5.9.7 2019 Internal Audit and External Assessment Echoed Results of Maturity Self-Assessments

As described in the Previous Application, BC Hydro's internal audit team, using external subject matter experts, conducted an audit of our cybersecurity practice in early 2019. The audit identified opportunities for improvement in areas similar to those identified through our maturity self-assessments:

- Governance;
- Threat and Vulnerability Management;
- Incident Response; and
- Vendor Risk Management.

In March 2019, the Office of the Auditor General (**OAG**) submitted an audit report on BC Hydro's cybersecurity practices and controls related to its Industrial Control Systems. The OAG audit was specific to Industrial Control Systems located at our generation, transmission and distribution facilities that do not fall under the CIP Standards and are not considered critical to the operation of the Bulk Electric System.

As recommended by the OAG audit, BC Hydro initiated a third-party risk assessment of the Industry Control Systems environment that identified general areas for improvement similar to the internal audit as well as some specific technical recommendations. BC Hydro addressed the highest risk recommendations associated with our Industrial Control Systems environments immediately following the results of the external assessment. The remaining audit recommendations are aligned with activities we are undertaking in order to mitigate cybersecurity risk to our Bulk Electric System and comply with CIP requirements for low-impact assets (CIP v7 Project).

In December 2020, in response to increasing ransomware threat activity, BC Hydro engaged an external specialist company to assess our ability to protect, respond and recover from a ransomware attack. BC Hydro has implemented the immediately required recommendations of this assessment and included the remainder into our capital investment planning.

In its Decision on the Previous Application, the BCUC expressed concern that the remaining areas covered by the recommendations may provide potential cybersecurity vulnerabilities and suggested that BC Hydro should afford the same or similar level of protection across all cyber assets.[261] BC Hydro is addressing the audit recommendations as they relate to the remainder of these Industrial Control Systems facilities:

- Identified risks at 131 Industrial Control Systems sites will be addressed by October 1, 2023 through the completion of the CIP v7 Project. There are a further two sites that are not yet in service and thus not included in the project but will be addressed as they are put into service; and
- BC Hydro plans to then complete activities at the remaining 150 sites, on a prioritized basis, by March 31, 2027. These sites are not considered critical to the operation of the Bulk Electric System and represent much lower cybersecurity risks. Many of the sites are smaller distribution substations that are not connected to the internet and have systems that can only be accessed if someone actually gains physical access into the facility.

Figure 5-15 below categorizes Information Technology and Operational Technology between those that are, and are not, subject to MRS and specifically the CIP Standards.

[261] BCUC Decision and Order No. G-187-21, BC Hydro Fiscal 2022 Revenue Requirements Application (June 17, 2021), page 32.

Figure 5-15 Information Technology and Operational Technology Subject to MRS and Not Subject to MRS

	Information Technology *Systems used for business purposes*	**Operational Technology** *Systems that provide operational monitoring and/or controls of assets in the electric network*
Subject to MRS	Critical MRS controls	Critical MRS controls *(54 high/medium impact facilities; plus 133 low impact facilities once NERC CIP v7 implemented and 2 new sites put into service)*
Not Subject to MRS	Critical controls	150 lower priority facilities

Appendix EE provides further information on BC Hydro's plan to address the OAG audit findings with respect to cybersecurity controls for Industrial Control Systems at sites not covered by CIP requirements. While we believe that the sequencing and timing of our work to address the audit recommendations is appropriate, we recognize the BCUC's concerns and have sought independent validation of our approach.

Specifically, the Cyber Risk Assessment and Cyber Security Plan that we are undertaking pursuant to the BCUC's Directives 8[262] and 9[263] from the Previous Application provide an opportunity to confirm previous assessments and work with regard to the OAG audit recommendations. BC Hydro has included this work within the scope of the assessment and plan, directed by the BCUC, and will inform the BCUC of the results.

262 Directive 8; BCUC Decision and Order No. G-187-21, BC Hydro Fiscal 2022 Revenue Requirements Application (June 17, 2021), page 33. Directive 8 directed BC Hydro to undertake a Cyber Risk Assessment of all its cyber assets within three months, file it with the BCUC and notify the BCUC of any required actions in response to immediate or time-sensitive concerns.

263 Directive 9; BCUC Decision and Order No. G-187-21, BC Hydro Fiscal 2022 Revenue Requirements Application (June 17, 2021), page 33. Directive 9 directed BC Hydro to develop a company-wide Cyber Security Plan that encompasses BC Hydro, its subsidiaries and third-parties that interface with BC Hydro and file the plan with the BCUC within one year.

5.10 Site C is Starting the Transition to Operating Phase

The Site C Project is constructing a third dam and hydroelectric generating station on the Peace River in northeast B.C. to provide 1,100 megawatts of capacity and produce about 5,100 gigawatt hours of electricity per year. Construction of the Site C Project started in summer 2015. Assets in the Site C Generating Station are expected to transition from the construction phase to the operating phase starting in fiscal 2023 in advance of the generating units forecasted to be placed in-service during fiscal 2025 and fiscal 2026. During this transition period, operating costs and operating FTEs will ramp-up. As described below, the vast majority (almost 90 per cent) of the incremental operating costs and FTEs planned for the Test Period occur in fiscal 2025.

During the Test Period, the first generating unit is expected to be placed in-service in December 2024 and will begin to produce power to help meet forecasted customer load, which generates revenue for BC Hydro.

5.10.1 Overview: Costs Comprised of Staffing, Maintenance Work, and Contract Commitments

Over the Test Period, an incremental total of $11.0 million of operating costs and 26.8 FTEs are required during the transition to the operating phase. The $11.0 million of operating costs is comprised of:

- $5.2 million for additional FTEs (i.e., electricians, mechanics, field managers, etc.) to operate the assets, to manage the reservoir intake debris removal program, and to execute maintenance work; and
- $5.8 million for operating costs related to contract commitments in fiscal 2025, including the Peace River Regional District.

Table 5-34 below summarizes the incremental operating costs, FTEs, and key schedule assumptions by fiscal year as the Site C Project transitions various assets from the construction phase to the operating phase:

Table 5-34 Site C Operating Phase Fiscal 2023 to Fiscal 2025 Plan Operating Costs and FTEs

Fiscal Year	Incremental Operating Costs ($ million)	Incremental FTEs	Key Schedule Assumptions[1]
Fiscal 2023 Plan	0.4	2.0	50 per cent of the auxiliary assets[2] transitioned to the operating phase
Fiscal 2024 Plan	0.8	1.5	Spillway and an additional 12.5 per cent of the auxiliary assets[2] transitioned to the operating phase
Fiscal 2025 Plan	9.8	23.3	Two generating units and an additional 12.5 per cent of the auxiliary assets[2] transitioned to the operating phase
Total	**11.0**	**26.8**	

Note 1: The timing of the incremental costs and FTEs are based on key Site C Project schedule assumptions. In the case that the Site C Project is ahead or behind schedule, incremental costs may be incurred differently than planned.

Note 2: Examples of auxiliary assets are station service equipment, battery banks, heating, ventilation, air conditioning (**HVAC**), water treatment equipment, etc.

The Site C incremental operating costs for the transition to the operating phase are comprised of two categories:

1. **Operating Costs** – These costs are to fund the staff required to support and operate the Site C Generating Station and the site substation – Southbank. The staffing was determined by assessing resource requirements at other comparable BC Hydro generating stations and conducting interviews in the areas that will be impacted by the Site C operating phase. The staffing also incorporates the timing and ramp-up of these resources based on Site C Project schedule assumptions. In addition, these costs are for managing the reservoir intake debris removal program and for planned contract commitments. The plant is expected to be staffed by October 2024 in anticipation of the first generating unit planned to be in-service in December 2024; and
2. **Maintenance Costs** – These costs are to fund the maintenance work on the Site C Generating Station and the site substation – Southbank. A large portion of these costs were determined by assessing the historical maintenance

expenditures from fiscal 2016 to fiscal 2020 incurred at other comparable BC Hydro generating stations. The annual average of maintenance expenditures from fiscal 2016 to fiscal 2020 at these comparable generating stations were then adjusted for differentiating factors, such as the number of generating units and spillway comparisons. The result for each generating station was then averaged to provide an approximation of the Site C annual maintenance costs.

The following sections describe the key Site C operating phase schedule assumptions and the ramping up of incremental costs and FTEs by fiscal year.

5.10.2 Fiscal 2023 Site C Operating Costs and FTEs

The incremental operating costs and FTEs for fiscal 2023 plan are $0.4 million and two FTEs, respectively. These increases are required to support about 50 per cent of the total Site C auxiliary assets (i.e., station service equipment, battery banks, HVAC, water treatment equipment, etc.) that will transition from the construction phase to the operating phase by the end of fiscal 2023. Table 5-35 below provides a summary for fiscal 2023:

Table 5-35 Site C Operating Phase Fiscal 2023 Plan Operating Costs and FTEs

Description	Incremental Operating Costs ($ million)	Incremental FTEs
Operating	0.1	
Maintenance	0.3	
Total	**0.4**	**2.0**

5.10.2.1 *Fiscal 2023 Operating Costs*

The fiscal 2023 plan incremental operating costs is $0.1 million. These costs are mostly to fund an electrician to provide operational support to the Site C Southbank Substation.

5.10.2.2 *Fiscal 2023 Maintenance Costs*

The fiscal 2023 plan incremental maintenance costs are $0.3 million, which reflect maintaining the assets that are planned to be operational during the fiscal year. The assets planned to be operational during fiscal 2023 represent approximately 50 per cent of the total auxiliary assets. These costs also include funding for two FTE field maintenance engineers who will begin providing technical maintenance engineering expertise at the Site C Generating Station starting in October 2022.

5.10.2.3 *Fiscal 2023 FTEs*

The two incremental FTEs are:

- One FTE field maintenance engineer. As mentioned above, two FTE field maintenance engineers will begin supporting the Site C Generating Station starting in October 2022. Since October 2022 is halfway through fiscal 2023, these two field maintenance engineers are equivalent to one FTE field maintenance engineer for fiscal 2023; and
- One FTE electrician who will provide operational support to the Site C Southbank Substation.

Table 5-38 below shows the ramp up of resources, as measured in FTEs, from fiscal 2023 to fiscal 2026. The FTEs shown in fiscal 2026 represents an entire fiscal year of these resources fully on-boarded and allocated to Site C (i.e., there is no pro-rating of positions, as measured in FTEs).

5.10.3 Fiscal 2024 Site C Operating Costs and FTEs

The incremental operating costs and FTEs for fiscal 2024 are $0.8 million and 1.5 FTEs, respectively. These increases are required to support the spillway and an additional 12.5 per cent of the total auxiliary assets that will transition from the construction phase to the operating phase by the end of fiscal 2024. Table 5-36 below provides a summary for fiscal 2024 plan:

Table 5-36 Site C Operating Phase Fiscal 2024 Plan Operating Costs and FTEs

Description	Incremental Operating Costs ($ million)	Incremental FTEs
Operating	-	
Maintenance	0.8	
Total	**0.8**	**1.5**

5.10.3.1 *Fiscal 2024 Maintenance Costs*

The fiscal 2024 incremental maintenance cost is $0.8 million, which reflects maintaining the additional assets that are planned on being operational during the fiscal year, such as the spillway and an additional 12.5 per cent of the total auxiliary assets.

In addition, incremental FTEs related to field maintenance engineers and an area planner / scheduler, who is responsible for planning and scheduling maintenance work for the operations trade staff, are also reflected in the incremental maintenance costs.

5.10.3.2 *Fiscal 2024 FTEs*

The 1.5 incremental FTEs are:

- One FTE field maintenance engineer. As mentioned above, the two FTE field maintenance engineers who will begin supporting the Site C Generating Station halfway through fiscal 2023 are expected to support the Site C Generating Station full-time in fiscal 2024. This additional field maintenance engineer FTE in fiscal 2024 reflects their full-time allocation to the Site C Generating Station; and
- 0.5 FTE area planner / scheduler responsible for planning and scheduling maintenance work for the Site C Generating Station trade staff. The area planner / scheduler will begin supporting Site C in fiscal 2024 at 50 per cent capacity.

Table 5-38 below shows the ramp up of resources, as measured in FTEs, from fiscal 2023 to fiscal 2026. The FTEs shown in fiscal 2026 represents an entire fiscal year of these resources fully on-boarded and allocated to Site C (i.e., there is no pro-rating of positions, as measured in FTEs).

5.10.4 Fiscal 2025 Site C Operating Costs and FTEs

As indicated above, approximately 90 per cent of the incremental Site C related operating expenses in the Test Period are associated with fiscal 2025.

The incremental operating costs and FTEs for fiscal 2025 plan are $9.8 million and 23.3 FTEs, respectively. These increases are required to support two generating units placed in-service and an additional 12.5 per cent of the total auxiliary assets that will transition from the construction phase to the operating phase by the end of fiscal 2025. In addition, there will be $5.8 million of operating costs related to planned contract commitments in fiscal 2025. Table 5-37 below provides a summary for fiscal 2025:

Table 5-37 Site C Operating Phase Fiscal 2025 Plan Operating Costs and FTEs

Description	Incremental Operating Costs ($ million)	Incremental FTEs
Operating	8.7	
Maintenance	1.1	
Total	**9.8**	**23.3**

5.10.4.1 *Fiscal 2025 Operating Costs*

The fiscal 2025 plan incremental operating costs is $8.7 million, which includes:

- $1.7 million related to 23.3 incremental FTEs to achieve the required complement of staff to operate, maintain, and support the Site C Generating Station, service contracts for fish and aquatic monitoring programs, and physical security guards to satisfy security and MRS requirements for the station;

- $1.2 million to manage the reservoir intake debris removal program to keep debris out of the penstock, turbine, and water passages; and
- $5.8 million related to contract commitments in fiscal 2025, including the Peace River Regional District.

5.10.4.2 *Fiscal 2025 Maintenance Costs*

The fiscal 2025 plan incremental maintenance cost is $1.1 million, which reflects maintaining the additional assets that are planned on being operational during the fiscal year, such as two generating units and an additional 12.5 per cent of the total auxiliary assets.

5.10.4.3 *Fiscal 2025 FTEs*

There are 23.3 incremental FTEs in fiscal 2025. For the following 14.3 FTEs of the 23.3 FTEs, there will be an on-boarding, training, and ramp-up period between April 1, 2024 and September 30, 2024, which is reflected by the following partial FTEs:

- 3.5 FTE electricians, 3.5 FTE general tradespeople and driver/helpers, 3.1 FTE mechanics, and 2.1 FTE communication protection and control technologists to achieve full crew complement to perform maintenance, operations and future capital projects/programs support;
- 1.4 FTE field managers to manage the trade crews; and
- 0.7 FTE office administrator to provide administrative support to the local field managers and trade crews.

For the remaining nine FTEs of the 23.3 FTEs, they are fully allocated to Site C starting April 1, 2024 (i.e., fiscal 2025):

- Two FTE dam safety civil technologists to carry out monitoring and data collection on the Site C dam and reservoir slopes;

- Two FTE material storekeepers to perform material management duties for the Site C Generating Station and Southbank Substation such as planning inventory levels / coordinating material availability and ordering, receiving, storing, monitoring, controlling, shipping, delivering and disposal of material;
- One FTE senior field manager responsible for the Site C Generating Station, the site substation – Southbank, and other substations within the region;
- One additional FTE maintenance engineer to provide technical maintenance engineering expertise to Southbank Substation and other substations within the region;
- One FTE equipment specialist to provide equipment testing and capital asset expertise to the Site C Generating Station, Southbank Substation and other substations within the region;
- One FTE system analyst to provide business support for the Site C Generating Station, Southbank Substation, and other stations related asset and work management data and ensure the maintenance data stored within the Enterprise Asset Management system is current;
- 0.5 FTE area planner / scheduler to plan and schedule maintenance work for the Site C Generating Station trade staff. Note that the area planner / scheduler, who began supporting the Site C Generating Station at 50 per cent capacity in fiscal 2024, will now support Site C full-time in fiscal 2025. This additional 0.5 FTE in fiscal 2025 reflects their full-time allocation to Site C Generating Station; and
- 0.5 FTE Occupational Safety and Health Specialist who will provide expertise and technical support, advice and guidance for Site C staff on all manners related to occupational safety and health including design and development of hazard specific programs and leading or supporting safety incident investigations.

Table 5-38 below shows the ramp up of resources, as measured in FTEs, from fiscal 2023 to fiscal 2026. The FTEs shown in fiscal 2026 represents an entire fiscal year of these resources fully on-boarded and allocated to Site C (i.e., there is no pro-rating of positions, as measured in FTEs).

5.10.5 Transition to Operating Phase Will Continue After Test Period

Assets in the Site C Generating Station will finish transitioning from the construction phase to the operating phase after the Test Period, by the end of fiscal 2026.

For the planned FTEs on-boarding during the Test Period, Table 5-38 below shows the ramp up of resources, as measured in FTEs, from fiscal 2023 to fiscal 2026. Although fiscal 2026 is outside the Test Period, the FTEs shown in fiscal 2026 represents an entire fiscal year of these resources fully on-boarded and allocated to Site C (i.e., there is no pro-rating of positions, as measured in FTEs). This reflects the currently anticipated on-going FTE requirements for these roles to support the Site C Generating Station.

In addition to the 33 FTEs in fiscal 2026 shown in Table 5-38 below, there are approximately six additional FTEs that are planned to be on-boarded in fiscal 2026. These additional six FTEs are not shown in Table 5-38 below as they are not planned to be on-boarded during the Test Period.

Table 5-38 Site C Operating Phase FTEs – Fiscal 2023 to Fiscal 2026

Role	Total FTEs			
	Fiscal 2023	Fiscal 2024	Fiscal 2025	Fiscal 2026
Electrician	1.0	1.0	4.5	6.0
Field Maintenance Engineer	1.0	2.0	3.0	3.0
Area Planner / Scheduler	-	0.5	1.0	1.0
General Tradespeople	-	-	3.5	5.0
Mechanic	-	-	3.1	4.5
Communication Protection & Control Technologist	-	-	2.1	3.0
Field Manager	-	-	1.4	2.0
Office Administrator	-	-	0.7	1.0
Dam Safety Civil Technologist	-	-	2.0	2.0
Material Storekeepers	-	-	2.0	2.0
Senior Field Manager	-	-	1.0	1.0
Equipment Specialist	-	-	1.0	1.0
System Analyst	-	-	1.0	1.0
Occupational Safety and Health Specialist	-	-	0.5	0.5
Total FTEs	**2.0**	**3.5**	**26.8**	**33.0**
Year-Over-Year Incremental FTE Increase	**2.0**	**1.5**	**23.3**	**6.2**

5.11 Operations Work Program Delivery Resource Requirements

The Operations Business Group is responsible for operating BC Hydro's generating, transmission and distribution facilities and assets, and for executing work across multiple work programs. A work program is a program of repeatable standard units of work that utilizes simplified workflows. Work programs are typically set-up for one fiscal year at a time in an annual workplan and can be for maintenance or capital work. Examples of work programs include wood pole replacement, asbestos abatement and stations maintenance.

The operating cost increase of $3.5 million for an increase of 28 FTEs and $0.9 million of contractor funding, as described in section 5.5.3.6 and Table 5-6, is required so that adequate project and field resources and support are in place for the Operations Business Group to deliver the annual workplan and to address increased compliance requirements across most work categories. Meeting evolving regulatory standards and permitting requirements on projects and programs during the planning, design and construction phases translates to additional work effort by Operations field personnel. The planned investment will also fund our ability to deliver on shifting workload demands of customer, critical or emergent work.

5.11.1 Overview

The $3.5 million cost increase over the Test Period is mainly comprised of:

- $2.5 million of operating costs primarily related to labour. Due to the nature of the work activities, 11 of the 28 FTEs are fully allocated as operating costs, such as the Field Managers in the Stations Field Operations KBU and a trainer for Real Time Operations training requirements in the Transmission and Distribution System Operations KBU, as discussed further below. The remaining 17 of the 28 FTEs have planned utilization rates charged to capital and work programs. A portion of their time (for activities such as training) are allocated to operating costs; and
- $0.9 million of contractor funding to ensure resources are available to deliver on shifting workload demands, such as customer, critical or emergent work.

The additional FTEs are being added to three KBUs as further discussed below:

5.11.2 Program and Contract Management KBU

The Program and Contract Management KBU in the Operations Business Group requires 16 incremental FTEs as a result of increases in workload. The Program and

Contract Management KBU has been assigned additional priority work with significant compliance elements, including overall accountability for delivering high volume regulatory programs like asbestos and Polychlorinated Biphenyls (**PCB**) equipment removal programs.

The asbestos program has increased expenditures from $8 million in fiscal 2017 to $22 million in fiscal 2022 Decision amounts as shown in Schedule 2.2 of Appendix A. This is a result of increased effort to identify, label, inventory and abate asbestos containing materials across BC Hydro Generation, Transmission and Distribution facilities to protect workers and comply with WorkSafe regulations.

The PCB equipment removal program has increased in expenditures from $14 million in fiscal 2017 to $39 million in fiscal 2022 Decision amounts as shown in Schedule 2.2 of Appendix A. This is a result of accelerating the PCB equipment phase out schedule to comply with Environment Canada PCB Regulations requiring removal and disposal of equipment by December 31, 2025.

Additionally, the Program and Contract Management KBU has been assigned the LED Streetlight Project and Electric Vehicle Charging Stations Projects.

Resources are also required to manage the increases in capital expenditures of programs and projects assigned to the Program and Contract Management KBU. Examples include increases in Transmission capital expenditures from $384 million in fiscal 2020 Plan (Table 6-11 in the Previous Application) to $494 million in fiscal 2025 (Chapter 6, Table 6-12) and increases in Customer Driven capital expenditures from $232 million in fiscal 2020 Plan (Table 6-31 in the Previous Application) to $263 million in fiscal 2025 Plan (Chapter 6, Table 6-30).

Given this growth in base work, the Program and Contract Management KBU has added the following 16 FTEs in the Test Period:

- Five Project Managers to support capital projects work and complex maintenance work that require technical oversight, outage planning and coordination of trades work and to manage the additional Generation and Dam Safety project work and Generation civil maintenance work;

- Four Program Managers to oversee and deliver larger scope portfolios for Distribution Line, Transmission Line, the PCB program and the Electric Vehicle portfolio;
- Three Civil Inspectors and one Civil Manager to manage increasing volumes of civil underground construction and support Field Review and Quality Control management of the construction work particularly for customer driven work;
- Two Program Leads responsible for Asbestos and PCB respectively to address increased work scope and regulatory schedule changes; and
- One Distribution Maintenance Analyst to address increase in Distribution Line workload.

5.11.3 Stations Field Operations KBU

The Stations Field Operations KBU in the Operations Business Group requires 11 incremental FTEs. This KBU is under resource pressure to execute on maintenance and equipment operations work and provide operational support to capital projects within the workplan, while regulatory requirements related to MRS, asbestos management, PCB containing equipment removals and lifting device certification have imposed higher workloads.

Stations maintenance and equipment operations work, which accounts for approximately 70 to 80 per cent of the total hours worked by the Stations Operations department each year, has increased in expenditures from $116.3 million in fiscal 2017 to $146.9 million in fiscal 2022 Decision due to increasing workplans and regulatory work. The remaining approximate 20 to 30 per cent of total hours each year is spent supporting capital projects, a portion of which is described in section 5.11.1 as capital programs and projects that are assigned by the Programs and Contract Management KBU to Stations Field Operations for execution.

The increases in BC Hydro's capital project expenditures drives an increased need for resources in the Stations Field Operations KBU to execute or support the capital project work.

Given this growth in base work, the Stations Field Operations KBU is planning to add the following 11 FTEs in the Test Period:

- Three Field Managers to provide sufficient supervision for safety, compliance and work delivery in high workload areas for the completion of maintenance work and multi-year capital projects;
- One Planning Manager at Non-Integrated Areas to convert the existing contracted position to an internal FTE position. This role supports work planning, contractor coordination and logistics required to get trade workers and materials to these remote facilities. Contractor costs were reduced by an equivalent amount. This allows for consistency and alignment of the NIA Planning Manager role with the six other internal FTE Planning Managers for rest of the province;
- Six Trade Workers (Electricians, Mechanic, Thermal Plant Operations Technician) to address high workloads and assist with capital projects implementation; and
- One Field Services Administrator at Revelstoke Generating Station. This role is in addition to one existing Field Services Coordinator and will ensure appropriate backup and support for the 28 FTEs at Revelstoke Generating Station.

5.11.4 Transmission and Distribution System Operations KBU

The Transmission and Distribution System Operations KBU in the Operations Business Group requires one incremental FTE for Real Time Operations safety and compliance training requirements. Control room operators require years of training in their specialized roles and a full-time trainer is required to ensure all operators are meeting their technical and safety training requirements. Changes related to regulatory standards and compliance, along with upgrades to operational technology and system technologies, mean that this work is more complex and on-going training requirements are significant and increasing, even for experienced Operators.

5.12 FTE and Labour Costs

This section reviews BC Hydro's FTEs[264] and operating labour costs.

Excluding the Site C Project capital FTEs, BC Hydro's FTEs are higher by 125[265] FTEs in fiscal 2023, a further 42[266] FTEs in fiscal 2024 and a further 38[267] FTEs in fiscal 2025 from the fiscal 2022 Decision FTEs, for a total Test Period increase of 204[268] FTEs and a total workforce at the end of the Test Period of 7,201[269] FTEs.

In this section, we make the following points:

- The Test Period FTE change over the fiscal 2022 Decision FTEs is primarily a result of increased resources relating to the investments in MRS, vegetation management and cybersecurity, the Electrification Plan and the transition of the Site C Project to operations in anticipation of the December 2024 in-service date of the first generating unit, partially offset by a reduction due to the Supply Chain Application benefits realization (headcount reduction), further discussed in section 5.12.1;

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264 FTEs are calculated by taking the total number of hours (regular and overtime) worked in a given year, divided by the average number of hours a full-time employee would work per year. These averages differ by affiliation. Consistent with the Previous Application, for the fiscal 2023 to fiscal 2025 Test Period, these averages are 1,621 hours for Management and Professional employees (including Executive), 1,535 hours for MoveUp employees and 1,461 hours for International Brotherhood of Electrical Workers employees.

265 Refer to Figure 5-16 row 9 fiscal 2023 total 7,121 FTEs minus fiscal 2022 total 6,996 FTEs.

266 Refer to Figure 5-16 row 9 total fiscal 2024 7,163 FTEs minus total fiscal 2023 7,121 FTEs.

267 Refer to Figure 5-16 row 9 total fiscal 2025 7,201 FTEs minus total fiscal 2023 7,163 FTEs.

268 May not add due to rounding.

269 Total fiscal 2025 FTEs of 7,654 (Figure 5-16) less Site C FTEs of 453.

- In the Test Period, Standard Labour Rates are increasing due to a 2.0 per cent salary increase and cost increases to employee benefits, partially offset by a decrease in current service pension costs due to discount rate changes, further discussed in section 5.12.2;
- The results of our vacancy factor analysis reinforced the reasonableness of the amount included in the Previous Application and the appropriateness of using the same forecast savings in the Test Period, further discussed in section 5.12.3; and
- Current service costs relate to BC Hydro's pension program and represent the cost of the future benefits earned by the employees in the current year. The decrease in current service costs is driven by a higher discount rate. Current service costs are further discussed in section 5.12.4.2.

5.12.1 BC Hydro's Operating FTEs Have Remained Relatively Flat Since Fiscal 2012

BC Hydro's operating FTEs have remained relatively flat since fiscal 2012, with changes during that period occurring within a relatively tight band. Over this time, the increase in overall FTEs has been primarily driven by an increase in capital FTEs. During the Test Period:

- Operating FTEs (depicted in the top blue line in Figure 5-16) are planned to increase due to investments in MRS,[270] vegetation management[271] and cybersecurity,[272] work program resources[273] to deliver the operations workplan and to address increased compliance requirements across work categories, the

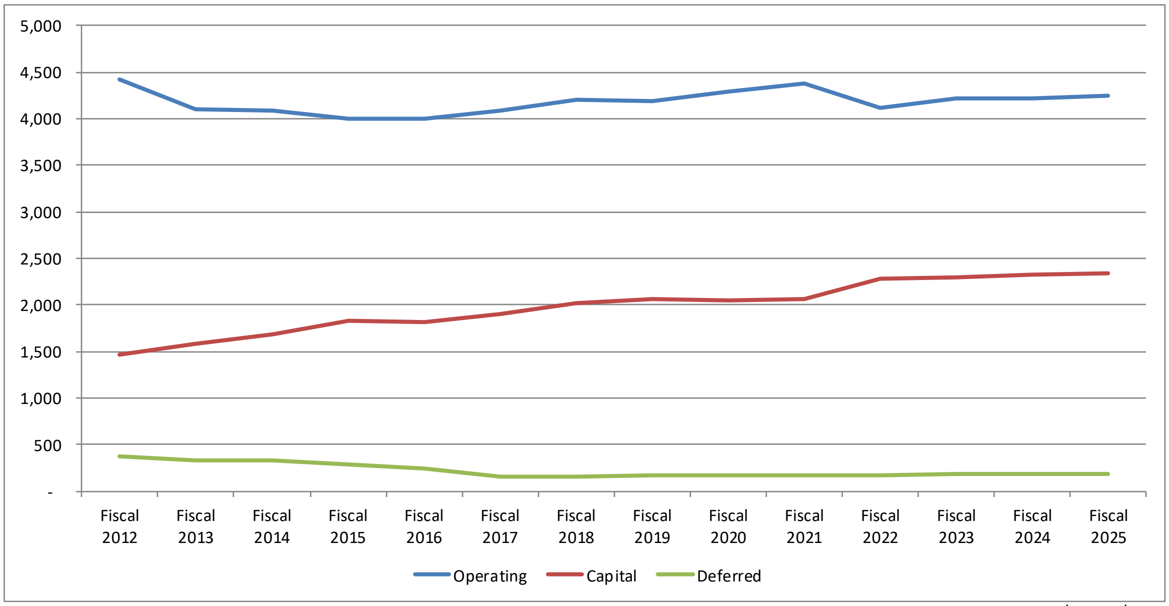
[270] Further described in section 5.7.
[271] Further described in section 5.8.
[272] Further described in section 5.9.
[273] Further described in section 5.11

transition of the Site C Project[274] to operations, and to support and deliver the Electrification Plan;[275]

- The increase in capital FTEs (depicted in the middle red line in Figure 5-16), is primarily due to increasing the apprentice and trainee program intakes[276] to support current and future work requirements, and utilization changes resulting in a shift between operating and capital and to support and deliver the Electrification Plan;[277] and
- The increase in deferred FTEs (depicted in the bottom green line in Figure 5-16), is primarily to support the Electrification Plan.[278]

[274] Further described in section 5.10.
[275] Further described in Chapter 10, section 10.4.
[276] Further described in section 5.5.3.6, line 1.
[277] Further described in Chapter 10, section 10.4.
[278] Further described in Chapter 10, section 10.4.

Figure 5-16 FTEs (Excluding Site C Project, Smart Metering Infrastructure Project, Accenture Repatriation)[279] (Fiscal 2012 to Fiscal 2025)



											a			b	b-a
	FTEs Including Regular and Overtime Hours	Fiscal 2012 Actual	Fiscal 2013 Actual	Fiscal 2014 Actual	Fiscal 2015 Actual	Fiscal 2016 Actual	Fiscal 2017 Actual	Fiscal 2018 Actual	Fiscal 2019 Actual	Fiscal 2020 Actual	Fiscal 2021 Actual	Fiscal 2022 Decision	Fiscal 2023 Plan	Fiscal 2024 Plan	Fiscal 2025 Plan	Change F2022 - F2025
1	Operating	4,415	4,096	4,089	4,003	3,997	4,082	4,209	4,185	4,287	4,374	4,121	4,214	4,224	4,243	122
2	Capital	1,460	1,582	1,686	1,835	1,811	1,905	2,013	2,061	2,043	2,058	2,286	2,295	2,327	2,345	59
3	Deferred	377	330	325	293	250	161	162	171	170	170	166	189	189	190	23
4	**Sub-total**	**6,252**	**6,008**	**6,101**	**6,131**	**6,058**	**6,148**	**6,385**	**6,416**	**6,501**	**6,603**	**6,573**	**6,698**	**6,740**	**6,778**	**204**
5	SMI	80	118	111	85	69	-	-	-	-	-	-				
6	Site C Project	56	82	92	97	107	167	226	322	445	479	504	721	651	453	(51)
7	Accenture Repatriation	-	-	-	-	-	-	-	423	423	423	423	423	423	423	-
8	**Total FTEs, Appendix A, Schedule 16 Line 48**	**6,388**	**6,208**	**6,303**	**6,312**	**6,234**	**6,315**	**6,611**	**7,161**	**7,369**	**7,505**	**7,500**	**7,842**	**7,814**	**7,654**	**154**
9	Total FTEs, Excluding Site C Project	6,332	6,126	6,211	6,215	6,127	6,148	6,385	6,839	6,924	7,026	6,996	7,121	7,163	7,201	204

May not add due to rounding

As shown in the table above, excluding Site C Project[280] FTEs, total fiscal 2025 plan FTEs of 7,201 are higher by 204 compared to the fiscal 2022 Decision FTEs of 6,996. The following points further explain the net increase of 204 FTEs:

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279 "Deferred" FTEs refers to FTEs whose work is charged to regulatory accounts. Almost all of BC Hydro's current deferred FTEs are charged to the DSM Regulatory Account.

280 The Site C Project fiscal 2023 to fiscal 2025 FTE Plan amounts are based on the updated project budget of $16 billion. The fiscal 2022 Decision FTE amount was based on the previous project budget of $10.7 billion

- Row 1 shows an increase of 122 operating FTEs compared to fiscal 2022 Decision and is primarily due to:
  - 70 FTE[281] increase relating to Reliability Investments, including MRS (48 FTEs), further described in section 5.7, Vegetation Management (8 FTEs), further described in section 5.8, and Cybersecurity (14 FTEs), further described in section 5.9;
  - 28 FTE[282] increase relating to work program resource requirements to deliver the operations workplan and to address increased compliance requirements across most work categories, further described in section 5.11;
  - 24 FTE[283] increase relating to transition of the Site C Project to operations in anticipation of the December 2024 in-service date of the first generating unit, further described in section 5.10;
  - 23 FTE[284] increase relating to the increase in apprentice and trainee intakes to address increasing resource planning forecasts and to account for attrition, further described in section 5.5.3.6 and Table 5-6;
  - Eight FTE increase comprised of:
    - Three FTE[285] increase related to Non-Integrated Areas (NIA) diesel reduction strategy, further described in section 5.5.3.4 and Table 5-6;
    - Two FTE[286] increase related to UNDRIP, further described in section 5.5.3.4, and Table 5-6;

[281] Refer to Table 5-39, rows 8, 9, and 10 for fiscal 2023, rows 24, 25 for fiscal 2024 and row 36 for fiscal 2025, for increase by Business Group.
[282] Refer to Table 5-39 row 15 fiscal 2023 for the increase by Business Group.
[283] Refer to Table 5-39 rows 11, 26, and 37 for fiscal 2023, fiscal 2024 and fiscal 2025 respectively, for increase by Business Group. Site C resource requirement consist of operating and capital FTEs.
[284] Refer to Table 5-39, rows 14, 29, and 40 for fiscal 2023, fiscal 2024 and fiscal 2025 respectively, for increase by Business Group. Apprentice and Trainee resource requirement consist of operating and capital FTEs.
[285] Refer to Table 5-39, row 5 for fiscal 2023 increase by Business Group.
[286] Refer to Table 5-39,row 6 for fiscal 2023 increase by Business Group.

- Two FTE increase related to the reallocation of resources within the Customer and Corporate Affairs Business Group due to the increase in the number of regulatory filings and complexity of applications; offset by a corresponding decrease in deferred FTEs; and,
- One FTE[287] required to focus on compliance in high-priority areas across the organization; further described in section 5.5.3.6, and Table 5-6.

▶ Seven FTE[288] increase to support and deliver the Electrification Plan, further described in Chapter 10;

▶ Six FTE[289] increase relating to overtime FTEs, offset by,

▶ 18 FTE[290] decrease relating to the Supply Chain Applications benefit realization, further described in section 5.5.3.6, and Table 5-6;

▶ 20 FTE decrease relating to utilization changes, offset by a corresponding increase in capital FTEs; and,

▶ Six FTE decrease relating to other miscellaneous changes.

- Row 2 shows an increase of 59 capital FTEs compared to fiscal 2022 Decision FTEs and is primarily due to:

▶ 21 FTE[291] increase to support and deliver the Electrification Plan, further described in Chapter 10;

▶ 20 FTE increase relating to utilization and other changes, offset by a corresponding decrease in operating FTEs;

287 Refer to Table 5-39, row 16 for fiscal 2023 increase by Business Group.

288 Refer to Table 5-39, rows 4, 22, and 34 for fiscal 2023, fiscal 2024 and fiscal 2025 respectively, for increase by Business Group.

289 Refer to Table 5-39, rows 17, 30, and 41 for fiscal 2023, fiscal 2024, and fiscal 2025 respectively, for the increase by Business Group.

290 Refer to Table 5-39, rows 2, 20, and 32 for fiscal 2023, fiscal 2024, and fiscal 2025 respectively, for the increase by Business Group.

291 Refer to Table 5-39, rows 4, 22, and 34 for fiscal 2023, fiscal 2024 and fiscal 2025 respectively, for increase by Business Group.

  - Four FTE[292] increase relating to increasing the apprentice and trainee intakes to address increasing resource planning forecasts and to account for attrition, further described in section 5.5.3.6, and Table 5-6;
  - Three FTE[293] increase related to UNDRIP work, further described in section 5.5.3.4, and Table 5-6;
  - Three FTE[294] increase relating to resource requirements to support capital work subsequent to the transition of the Site C Project to operations, further described in section 5.10; and,
  - Two FTE[295] increase relating to overtime FTEs, and,
  - Six FTE increase relating to other miscellaneous changes.
- Row 3 shows an increase of 23 deferred FTEs compared to the fiscal 2022 Decision FTEs and is primarily due to:
  - 25 FTE[296] increase to support and deliver the Electrification Plan, further described in Chapter 10, section 10.4; offset by,
  - Two FTE decrease related to the reallocation of resources within the Customer and Corporate Affairs Business Group due to the increase in the number of regulatory filings and complexity of applications; offset by a corresponding increase in operating FTEs.

Table 5-39 below provides an FTE continuity schedule which highlights the key drivers for the net new change from the fiscal 2022 Decision FTEs by Business Group.

[292] Refer to Table 5-39 rows 14, 29, and 40 for fiscal 2023, fiscal 2024 and fiscal 2025 respectively, for increase by Business Group.
[293] Refer to Table 5-39, row 6 for fiscal 2023 increase by Business Group.
[294] Refer to Table 5-39 rows 11, 26, and 37 for fiscal 2023, fiscal 2024 and fiscal 2025 respectively, for increase by Business Group.
[295] Refer to Table 5-39 rows 17, 30, and 41 for fiscal 2023, fiscal 2024, and fiscal 2025 respectively, for the increase by Business Group.
[296] Refer to Table 5-39 rows 4, 22, and 34 for fiscal 2023, fiscal 2024 and fiscal 2025 respectively, for increase by Business Group.

FTEs for each Business Group and Key Business Unit are provided in Schedule 16.0 of Appendix A – Financial Schedules.

Table 5-39 Continuity Schedule of Planned FTEs (Fiscal 2022 Decision to Fiscal 2025 RRA Plan)

	FTEs Including Regular and Overtime Hours	Integrated Planning	Capital Infrastructure Project Delivery	Operations	Safety & Compliance	Finance, Technology, Supply Chain	Customer, Corporate Affairs	Other	Total	Site C	Total
1	**F2022 Decision (Schedule 16.0, line 48)**	980	726	2,985	416	972	742	175	**6,996**	504	**7,500**
2	Reduction in FTEs due to SCA benefits	-	-	-	-	(1)	-	-	**(1)**	-	**(1)**
3	Strategic Initiatives:										
4	Electrification Plan	9	2	12	-	-	21	-	**44**	-	**44**
5	NIA Diesel Reduction Strategy	3	-	-	-	-	-	-	**3**	-	**3**
6	UNDRIP	-	5	-	-	-	-	-	**5**	-	**5**
7	Reliability Investments:										
8	Mandatory Reliability Standards	5	-	13	5	7	-	-	**29**	-	**29**
9	Cybersecurity	-	-	-	-	5	-	-	**5**	-	**5**
10	Vegetation Management	-	-	8	-	-	-	-	**8**	-	**8**
11	Site C operational resource requirements	1	-	1	-	-	-	-	**2**	-	**2**
12	Site C project resource requirements	-	-	-	-	-	-	-	**-**	179	**179**
13	Other:										
14	Apprentice and trainees	-	-	-	(2)	-	-	-	**(2)**	-	**(2)**
15	Work Program Resources	-	-	28	-	-	-	-	**28**	-	**28**
16	Enterprise Compliance Resource	-	-	-	1	-	-	-	**1**	-	**1**
17	Miscellaneous changes for overtime hour FTEs	(0)	(0)	3	(2)	(0)	3	-	**4**	38	**42**
18	Miscellaneous changes for regular hour FTEs	6	1	6	(12)	2	(1)	(2)	**-**	-	**-**
19	**F2023 RRA Plan (Schedule 16, line 48)**	**1,004**	**733**	**3,057**	**405**	**985**	**765**	**173**	**7,121**	**721**	**7,842**
20	Reduction in FTEs due to SCA benefits	-	-	-	-	(9)	-	-	**(9)**	-	**(9)**
21	Strategic Initiatives:										
22	Electrification Plan	-	-	6	-	-	-	-	**6**	-	**6**
23	Reliability Investments:										
24	Mandatory Reliability Standards	1	-	-	8	10	-	-	**18**	-	**18**
25	Cybersecurity	-	-	-	-	10	-	-	**10**	-	**10**
26	Site C operational resource requirements	1	-	1	-	-	-	-	**2**	-	**2**
27	Site C project resource requirements	-	-	-	-	-	-	-	**-**	(62)	**(62)**
28	Other:										
29	Apprentice and trainees	-	-	-	14	-	-	-	**14**	-	**14**
30	Miscellaneous changes for overtime hour FTEs	0	-	(0)	2	0	(0)	-	**1.78**	(8)	**(6)**
31	**F2024 RRA Plan (Schedule 16, line 48)**	**1,005**	**733**	**3,063**	**428**	**995**	**765**	**173**	**7,163**	**651**	**7,814**
32	Reduction in FTEs due to SCA benefits	-	-	-	-	(8)	-	-	**(8)**	-	**(8)**
33	Strategic Initiatives:										
34	Electrification Plan	-	-	3	-	-	1	-	**4**	-	**4**
35	Reliability Investments:										
36	Mandatory Reliability Standards	-	-	-	1	-	-	-	**1**	-	**1**
37	Site C operational resource requirements	5	-	16	1	2	-	-	**23**	-	**23**
38	Site C project resource requirements	-	-	-	-	-	-	-	**-**	(170)	**(170)**
39	Other:										
40	Apprentice and trainees	-	-	-	15	-	-	-	**15**	-	**15**
41	Miscellaneous changes for overtime hour FTEs	(0)	-	0	3	(0)	0	-	**2.79**	(28)	**(25)**
42	**F2025 RRA Plan (Schedule 16, line 48)**	**1,010**	**733**	**3,082**	**447**	**989**	**765**	**173**	**7,201**	**453**	**7,654**

May not add due to rounding

5.12.2 Standard Labour Rates in the Test Period Are Impacted by Salary and Benefit Increases and Current Service Costs

As in the Previous Application, the Test Period revenue requirements reflect Standard Labour Rates and Standard Labour Hours calculated by BC Hydro. BC Hydro uses these to assign payroll, benefits, and current service costs to departments, work activities, projects, and work orders. The methodology for calculating the Standard Labour Rates and Standard Labour Hours remains unchanged from the Previous Application.

Table 5-40 below provides the weighted average Standard Labour Rate and the Standard Labour Hours for each affiliation.

The decrease to the Standard Labour Rates in fiscal 2023 reflects the following:

- Operating cost decrease of $21.7 million for current service costs, which (as described in section 5.12.4.2) is driven by a higher discount rate; and
- Operating cost increase of $10.7 million primarily due to an average 2.0 per cent general wage increase for Union and Management and Professional staff and benefit cost increases which are primarily due to prescribed increases to statutory benefits and increases to health benefit costs in the Test Period.

The increase to the Standard Labour Rates in fiscal 2024 and fiscal 2025 reflects the following:

- $13.4 million in fiscal 2024 and $15.7 million in fiscal 2025 primarily due to an average 2.0 per cent general wage and salary increase and benefit increases described above; and
- Operating cost increases of $3.3 million in fiscal 2024 and $3.4 million in fiscal 2025 for current service costs, which (as described in section 5.12.4.2) are driven by salary increases in the actuarial projection.

The Standard Labour Hours which are calculated using historical average actual hours worked by affiliation remain unchanged from the Previous Application.

Table 5-40 Standard Labour Rates by Affiliation

Affiliation	Standard Labour Hours	F2022 RRA Plan ($)	F2023 Plan ($)	F2024 Plan ($)	F2025 Plan ($)
MoveUp	1,535	68.25	68.46	70.19	71.73
International Brotherhood of Electrical Workers	1,461	90.99	90.42	92.71	95.32
Management and Professionals	1,621	111.59	108.95	112.03	115.69

5.12.3 Vacancy Factor Savings Analysis Supports Maintaining Same Savings (Directive 20)

This sub-section responds to Directive 20 of the BCUC's Decision on the F2020-F2021 RRA. Directive 20 required BC Hydro to begin tracking, measuring and reporting on the annual vacancy factor savings and to provide a rationale for any significant differences from the forecast savings. The results of our analysis reinforce the reasonableness of the amount included in the F2020-F2021 RRA and the appropriateness of using the same forecast savings in the Test Period.

In preparing this analysis, BC Hydro employed the same methodology that was used in the Previous Application. The methodology includes the following steps:

1. Tabulate the 12-month average vacancies which occurred in each KBU in the fiscal year;
2. Apply the average standard labour rate per FTE in each KBU to estimate the total cost savings associated with those vacancies; and
3. Deduct the average amount of time FTEs in each KBU charge to work programs (capital, deferred, maintenance) to calculate the operating cost portion of vacancy factor savings achieved.

The forecast savings include labour budget reductions that some Business Groups had made prior to the F2020-F2021 RRA to recognize that positions will not remain filled 100 per cent of the time, as well as the $5.6 million in vacancy factor savings included in the F2020-F2021 RRA.[297]

Table 5-41 below provides by Business Group, the vacancy-related savings included in previous budgets (referred to as 'Baseline'), the incremental $5.6 million vacancy factor savings included in the F2020-F2021 RRA, and the estimated actual vacancy factor savings realized in fiscal 2021.

Table 5-41 Fiscal 2021 Vacancy Factor Savings Results

	Budget				
Business Group ($ million)	**Baseline**	**F20-F21 RRA**	**Total**	**Actual F21**	**Variance**
Capital Infrastructure Project Delivery	0.7	1.6	2.3	2.3	0.0
Integrated Planning	1.2	1.1	2.3	0.8	(1.5)
Operations	0.7	0.5	1.2	0.2	(0.9)
Safety and Compliance	0.3	0.2	0.5	0.9	0.4
People, Customer & Corporate Affairs	0.2	0.5	0.7	2.6	1.9
Finance, Technology, Supply Chain	0.3	1.4	1.7	4.3	2.6
Other	0.1	0.3	0.4	0.8	0.4
Total	3.5	5.6	9.0	12.0	3.0

The table shows that estimated operating cost vacancy factor savings (calculated using the methodology described above) in fiscal 2021 is $12.0 million versus a plan of $9.0 million. The largest driver of the higher than planned savings is the temporary pause put on filling vacancies during the COVID-19 pandemic. This was one of the cost reduction strategies implemented by BC Hydro to help mitigate the cost pressures faced in fiscal 2021 resulting from the COVID-19 pandemic. As this was a temporary cost reduction strategy, it is not expected to continue, and vacancy

[297] This is discussed further in BC Hydro's response to BCUC IR 2.230.4 from the F2020-F2021 RRA proceeding.

factor savings are expected to return to budgeted levels in fiscal 2022 and the Test Period.

This analysis reinforced the reasonableness of the amount included for fiscal 2021 in the F2020-F2021 RRA. As a result, BC Hydro has used the same amount of vacancy factor savings in the operating expense forecast for the Test Period. BC Hydro will continue to carry out its analysis annually as each fiscal year completes and will report on the results in the next application.

5.12.4 Post Employment Benefit Costs

Post employment benefit costs in the Test Period are based on a forecast methodology that is consistent with the methodology used in previous revenue requirement applications.

5.12.4.1 Overview: Consistent Methodology as in Previous Applications

Post employment benefit costs are comprised of a number of components that are categorized as either current service costs or non-current service costs:

- **Current service costs** are the annual costs of accruing employees' post employment benefits. These costs recognize the cost of the future benefits earned by the employees in the current year. Current service costs are included in the Standard Labour Rates and charged to current work (capital and operating). Therefore, these costs are reflected in the costs presented throughout this application; and
- **Non-current service costs** are comprised of plan income on pension plan assets and interest expense on post employment benefit liabilities. While non- current service costs are included in finance charges, the discussion on non-current service costs is included below so that current and non-current service costs are discussed together in one section within this application.

This section has been prepared under International Accounting Standard 19, Employee Benefits (**IAS 19**), with the exception of the return (investment income) on pension plan assets. The latter is determined and based on the expected long-term rate of return rather than the liability discount rate as specified by IAS 19. The expected long-term rate of return reflects BC Hydro's expected earnings on pension plan assets; therefore, it is a more appropriate rate to use for rate setting purposes. This forecast methodology is consistent with the methodology used in previous revenue requirement applications.

BC Hydro's independent external actuary performs an actuarial valuation of its post retirement benefit plans for accounting purposes using the actuarial cost method prescribed by IAS 19. An actuarial valuation estimates the plans' funded status (assets less liabilities) at a specific point in time. In addition, an actuarial valuation also estimates the annual current service costs. At each actuarial valuation, the plan membership is updated, and all economic and demographic assumptions are reviewed and updated as required. An actuarial valuation is required to be performed at least every three years and actuarial projections are performed in between actuarial valuation years. The last actuarial valuation was performed as at December 31, 2018, and the next actuarial valuation will be performed as at December 31, 2021 and the results will be available in September 2022.

In accordance with BCUC Order No. G-47-18 to the Fiscal 2017 to Fiscal 2019 Revenue Requirements Application, the discount rate used to forecast post employment benefit plan costs is based on the market discount rate in effect at the time the forecast was prepared. The discount rate is calculated in accordance with IAS 19 by BC Hydro's external actuary. It is based on a hypothetical basket of high quality Canadian corporate debt (AA) that has the same cash flow as the BC Hydro post employment benefit plan benefit payments, in terms of both timing and amount. The discount rate for the pension plans in effect at the time the fiscal 2023 to fiscal 2025 forecast was prepared (as at March 31, 2021), was 3.40 per cent.

5.12.4.2 Current Service Costs

Current service costs are the annual costs of accruing employees' post employment benefits. These costs recognize the cost of the future benefits earned by the employees in the current year.

Current service costs are sensitive to changes in the discount rate. A decrease in the discount rate will increase current service costs while an increase in the discount rate will decrease current service costs.

Current service costs are shown in Table 5-42 below.

Table 5-42 Current Service Pension Costs

	A	B	C	D	E	F	G	H	I	J	H
($ million)	F2020 RRA	F2020 Actual	F2021 RRA	F2021 Actual	F2022 RRA	F2023 Plan	Change from F2022 RRA	F2024 Plan	Change from F2023 Plan	F2025 Plan	Change from F2024 Plan
Current Service Costs	130.0	128.5	132.5	122.8	188.5	152.4	(36.1)	157.9	5.5	163.5	5.6
Discount Rate - %	3.33	3.33	3.33	3.83	2.59	3.40	0.81	3.40	NA	3.40	NA
Discount Rate as at:	March 31, 2019	March 31, 2019	March 31, 2019	March 31, 2020	July 31, 2020	March 31, 2021		March 31, 2021		March 31, 2021	

The decrease in current service costs from fiscal 2022 Decision amount to fiscal 2023 plan of $36.1 million, column G in Table 5-42 above, is primarily due to the 81 basis points increase in the discount rate from 2.59 per cent (based on discount rates at July 31, 2020) in fiscal 2022 to 3.40 per cent (based on discount rates at March 31, 2021) in fiscal 2023. The discount rate has been increasing due to rising Government of Canada Bond yields. The decrease in current service cost is partially offset by a slight increase in the fiscal 2024 to fiscal 2025 plan due to salary increases in the actuarial projection.

The operating cost portion of the total decrease is $21.7 million in fiscal 2023 (i.e., $36.1 million total decrease multiplied by 60 per cent). The remaining portion is charged to capital.

5.12.4.3 *Non-Current Pension Costs*

Non-current service costs are comprised of plan income on pension plan assets and interest expense on post employment benefit liabilities:

- Plan income (i.e., investment income on pension plan assets) is calculated by multiplying the expected long-term rate of return by the market value of the plan assets at the beginning of the fiscal year, adjusted for expected contributions and benefit payments during the year.

  The expected long-term rate of return on the pension plan assets is determined based on the actual asset allocation of the BC Hydro registered pension plan. A decrease in the expected long-term rate of return on pension plan assets will decrease the amount of plan income recognized, while an increase in the expected long-term rate of return on pension plan assets will increase the amount of plan income recognized. The market value of the plan assets is provided by the British Columbia Investment Management Corporation; and

- Interest expense, also known as interest accretion, relates to the expected increase in the discounted pension benefit obligation to recognize the passage of time.

Interest expense is calculated by multiplying the discount rate by the amount of the pension obligation at the beginning of the fiscal year adjusted for the accrual of current service costs and expected benefit payments during the year. A decrease in the discount rate will result in a decrease in interest expense, while an increase in the discount rate will result in an increase in interest expense. As discussed above, the discount rate is increasing, thus increasing interest expense in the Test Period.

Non-current service costs are shown below in Table 5-43.

Table 5-43 Non-Current Pension Costs

($ million)	F2020 RRA	F2020 Actual[1]	F2021 RRA	F2021 Actual[1]	F2022 RRA	F2023 Plan	F2024 Plan	F2025 Plan
Plan Income	(255.4)	(61.0)	(266.7)	(749.0)	(263.9)	(303.3)	(317.4)	(332.4)
Interest Expense	218.9	184.0	224.5	358.0	211.9	250.0	260.1	270.8
Total	(36.5)	123.0	(42.2)	(391.0)	(52.0)	(53.3)	(57.3)	(61.6)
Interest Rate on Liability - %	3.33	3.33	3.33	3.83	2.59	3.40	3.40	3.40
Rate of Return on plan assets - %	6.90	1.20	6.90	20.49	6.90	6.70	6.70	6.70

1. Includes the actuarial gain or loss on pension plan assets to reflect total Plan Income.

Non-current service costs are included in finance charges, as shown in Appendix A, Schedule 8.0, line 28.

5.13 COVID-19 Impacts Were Temporary (Directive 65)

This section addresses the impacts of the COVID-19 pandemic on BC Hydro's operating costs, responding to Directive 65 from the BCUC's Decision on the F2020-F2021 RRA. The operating cost pressures and savings caused by the COVID-19 pandemic and the cost reduction strategies implemented by BC Hydro to further mitigate these cost pressures were temporary in nature. Over the past number of months, spending in most areas has returned to budgeted levels.

Most of the operating cost pressures experienced, such as the pause on field and project work while safe working practices were developed, and most of the cost savings realized, such as reduced fuel and transportation costs, have declined significantly as most of BC Hydro's KBUs have returned to normal work activities. Other cost reduction strategies such as not catching up the line and stations maintenance work that was temporarily paused in fiscal 2021 in response to the onset of the COVID-19 pandemic were temporary in nature and are not expected to continue beyond fiscal 2021.

While most operating cost pressures and savings and cost reduction strategies are not expected to continue in fiscal 2022 or the Test Period, BC Hydro has implemented a number of processes and tools during the COVID-19 pandemic (e.g., video conferencing for meetings and training sessions) which will enable a permanent travel cost reduction. Accordingly, BC Hydro has included an annual travel cost reduction of $2.1 million in the Test Period, further described in section 5.5.3.6.

Although future costs and savings associated with the COVID-19 pandemic remain uncertain (e.g., impacts of potential future variants of the virus), there is cautious optimism that normal work activities will persist for the foreseeable future. Accordingly, BC Hydro has not forecast any additional operating cost pressures or savings related to the COVID-19 pandemic in the Test Period.

5.14 Cost Pressures in Fiscal 2020 to F2021 Test Period (Directive 18)

This section responds to Directive 18 of the BCUC's Decision on the F2020-F2021 RRA. Directive 18 required BC Hydro to: summarize the operating cost pressures it experienced during the fiscal 2020 to fiscal 2021 test period and how it alleviated those cost pressures; and, where it was unable to alleviate the cost pressure, describe the activities BC Hydro had to forego and the risks resulting from not doing the activity.

As described in the F2020-F2021 RRA [298] proceeding, BC Hydro's approach to managing operating cost pressures is to take many small corrective actions to remain on track throughout a fiscal year. Examples include the management of overtime and travel costs. Cost pressures that cannot be absorbed within a KBU are raised to the Executive Team as part of the monthly review process for discussion of corrective action options such as advancing or delaying work. The review may result in target adjustments for a KBU, while keeping BC Hydro's overall budget the same.

Below is a summary of the operating cost pressures BC Hydro experienced during fiscal 2020 and fiscal 2021, the actions taken to alleviate the pressures faced, and the risks associated with foregoing activities to do so.

Fiscal 2020

A number of operating cost pressures arose during fiscal 2020 prior to the onset of the COVID-19 pandemic including routine distribution emergency response (routine trouble), BCUC and National Energy Board fees and levies, and insurance premiums. These cost pressures were largely alleviated through one-time, unplanned savings such as a third-party settlement related to the joint use pole cost sharing agreement, as well as some small corrective actions (e.g., management of travel costs). As these cost pressures were largely offset by one-time, unplanned savings and small corrective actions, there was no material risk associated with activities BC Hydro had to forego.

In addition, there were operating cost pressures for higher than planned damage to plant, customer work and interconnection studies expenditures. These pressures

[298] This is discussed further in BC Hydro's response to BCUC IR 1.36.3 from the F2020-F2021 RRA proceeding.

were fully offset with higher than planned miscellaneous revenue associated with this billable work and therefore did not require BC Hydro to forego any activities.

BC Hydro's operating costs were on track to be on plan leading into the final month of fiscal 2020; however, in mid-March of 2020, BC Hydro had to implement a number of measures in response to the onset of the COVID-19 pandemic which resulted in additional cost pressures (e.g., temporary pause on field and project work while safe working practices were developed). Given that this unforeseen event occurred in the last month of fiscal 2020, there was insufficient time to alleviate these pressures through corrective actions, resulting in BC Hydro exceeding the operating cost plan for fiscal 2020.

Fiscal 2021

Similar to fiscal 2020, BC Hydro faced a number of cost pressures throughout fiscal 2021. At the start of fiscal 2021, it was recognized that the COVID-19 pandemic would result in significant operating cost pressures (e.g., continuation of the temporary pause on field and project work while safe working practices were developed, the procurement and distribution of personal protective equipment). In response, BC Hydro implemented a number of cost reduction strategies to mitigate these pressures. These included reducing the line and stations maintenance work plan to recognize the challenges faced by the field crews to perform work while adhering to COVID-19 safety protocols. In addition, a temporary hold was placed on non-field work travel and many job vacancies were not immediately filled.

Generally, reducing planned maintenance work represented some risk; however, the relatively short nature of the delays, and the opportunity to re-prioritize more critical activities in fiscal 2022 meant that BC Hydro considered the risk to be manageable.

The total cost pressures associated with the COVID-19 pandemic were significant; however, the savings and cost reduction strategies implemented early in the fiscal year to mitigate these cost pressures exceeded the cost pressures, resulting in a net savings. While it is challenging to isolate cost pressures and savings specifically related to COVID-19, BC Hydro estimates the net savings associated with the COVID-19 pandemic to be approximately $15 million.

These savings helped mitigate additional operating cost pressures including transmission right of way work on Bulk Electric System circuits, support for Mandatory Reliability Standards and routine distribution emergency response (routine trouble). Given that BC Hydro had already implemented a number of cost reduction strategies early in the year to offset the COVID-19 pandemic cost pressures, these additional operating cost pressures could not be further mitigated without significantly impacting BC Hydro's operations. Accordingly, BC Hydro exceeded its operating cost plan for the year.

5.15 BC Hydro's Power System Maintenance

Ongoing maintenance of the Power System is necessary for assets to achieve their expected performance throughout their lifecycle. As described below:

- The maintenance budgeting processes used to develop the fiscal 2023 to fiscal 2025 budgets accounts for three categories of maintenance, considers various factors to determine the levels of funding required and seeks out opportunities to control costs; and
- The Power System Maintenance budget is to increase from $267.2 million in fiscal 2022 to $281.6 million for fiscal 2023 plan, $287.2 million for fiscal 2024 plan, and $294.1 million for fiscal 2025 plan. The increases are primarily driven by vegetation management and Site C powerhouse maintenance.

The Integrated Planning Business Group, discussed in Chapter 5A, holds the Power System maintenance budget and is responsible for maintenance investment decisions. The Operations Business Group, discussed in Chapter 5C, is responsible for executing maintenance work.

5.15.1 Maintenance Budgeting Processes Includes Three Categories of Maintenance and Considers Various Factors and Opportunities for Cost Control

The maintenance budgeting processes used to develop the fiscal 2023 to fiscal 2025 budgets accounts for three categories of maintenance, considers various factors to determine the levels of funding required and seeks out opportunities to control costs.

We address maintenance cost pressures where feasible through a number of improvements to grid intelligence and control, system automation, replacing older assets with new assets with lower maintenance requirements and business processes as well as through strategic asset management and capital investment planning.

When developing a budget for maintenance work, we must account for three broad categories of maintenance, which are summarized in Figure 5-17 below. All of these activities are essential for the Power System to function safely and reliably.

Figure 5-17 Maintenance Work Types

Preventative	Condition-Based	Corrective
• Inspections, testing, calibration, and condition assessments • This is Planned Work	• Prioritized work based on current condition • Repair or replace in-service assets • This is Planned Work	• In-service asset damage or failure • This is Emergent Work

The Power System asset maintenance programs also include two additional work categories which are required for safe and reliable asset operation:

- **Facility Maintenance:** work required to maintain the facilities and properties associated with the Power System. This includes items such as roofs, roads, fences, landscaping and snow removal; and
- **Engineering Services:** engineering support required for equipment maintenance. This includes activities such as developing and updating

maintenance standards as well as performing failure investigations or specialized inspections or testing.

5.15.1.1 *Determining the Appropriate Maintenance Investment Level Requires Consideration of Many Factors*

While the trigger for spending on corrective maintenance - a failure or an emergent issue – is generally clear, a number of factors must be considered to determine the timing and prioritization of preventative and condition-based maintenance.

- **Timing of preventative maintenance:** The frequency and timing of preventative maintenance activities are determined by factors such as asset criticality, component age and current condition, component failure modes, failure costs, and the duration required for repairs in the case of failure. Preventive maintenance programs are also influenced by manufacturers' recommendations, regulatory requirements, failure rates, engineering judgement, field experience, historical reviews, and industry practices. As a result, preventative maintenance requirements and frequencies are cyclical and can vary by asset, which means that preventative maintenance work is not uniform year over year.
- **Timing and prioritization of condition-based maintenance:** The majority of condition-based maintenance work consists of annually planned repairs or replacements of defective or damaged components of the system and occurs before equipment fails. Condition-based maintenance is triggered by the condition of equipment as determined by preventative maintenance inspections, tests, maintenance standards, manufacturer notices and/or operational readings or alarms. Condition-based maintenance is prioritized based on risk, considering factors such as asset criticality, component age and condition, and the consequence of failure. These considerations are analysed to determine when work should be undertaken or if the component condition should continue to be monitored.

5.15.2 Increase in Power System Maintenance Driven by Vegetation Management and Site C Powerhouse Maintenance

The Power System Maintenance budget is planned to increase over the Test Period compared to the fiscal 2022 Decision amounts, primarily due to two drivers: vegetation management and Site C powerhouse maintenance.

For fiscal 2022, maintenance was budgeted at $267.2 million. The budget for the Test Period is $281.6 million for fiscal 2023 plan, $287.2 million for fiscal 2024 plan, and $294.1 million for fiscal 2025 plan. Table 5-44 below shows actual and planned maintenance costs by category. These costs are included in the KBU budgets in the Integrated Planning Business Group, discussed in Chapter 5A, and in the Operations Business Group, discussed in Chapter 5C, but are consolidated below to provide an aggregate view.

Table 5-44 Maintenance Cost by Category-Fiscal 2021 Actual to Fiscal 2025 Plan

	($ million)	F2021 Actuals	F2022 Decision	F2023 Plan	F2024 Plan	F2025 Plan
1	Maintenance					
2	Line Asset Maintenance	112.4	127.7	140.2	144.9	150.4
3	Stations Asset Maintenance	81.5	91.1	91.6	93.6	96.0
4	Distribution Emergency Response	59.9	48.4	49.7	48.7	47.7
5	Total Maintenance	253.7	267.2	281.6	287.2	294.1

Note: Distribution Emergency Response actuals include storm deferral entries.

Table 5-45 below shows the drivers of the budget increase from fiscal 2022 Decision amounts for each fiscal year in the Test Period. The primary drivers are additional funding for vegetation management and an increase in Stations Asset Maintenance to maintain the increase in assets as the result of Site C. Section 5.8 provides the details of the incremental vegetation management budget in the Test Period, which is required to support BC Hydro's Vegetation Management Strategy. Section 5.10 provides information on the maintenance budget increases for Site C Dam and Powerhouse assets as they transition from the construction phase to the operating phase.

Table 5-45 Maintenance Cost Increases – Fiscal 2022 Decision to Fiscal 2025 Plan[299]

	($ million)	Line Asset Maintenance	Stations Asset Maintenance	Distribution Emergency Response	Total
1	**Fiscal 2022 RRA Decision**	**127.7**	**91.1**	**48.4**	**267.2**
2	Storm Restoration Five Year Average	-	-	(2.3)	(2.3)
3	Standard Labour Rate	(0.3)	(0.5)	(0.1)	(0.8)
4	Vegetation & Access Management	8.1	-	-	8.1
5	Reclass of LiDAR from Operating to Maintenance	3.9	-	-	3.9
6	Site C Maintenance	-	0.3	-	0.3
7	Other	0.8	0.7	3.7	5.2
8	**Total Incremental Change**	**12.5**	**0.6**	**1.3**	**14.3**
9	**Fiscal 2023 Plan**	**140.2**	**91.6**	**49.7**	**281.6**
10	Standard Labour Rate	0.8	1.2	0.4	2.4
11	Vegetation & Access Management	3.9	-	-	3.9
12	Site C Maintenance	-	0.7	-	0.7
13	Other	-	0.0	(1.4)	(1.4)
14	**Total Incremental Change**	**4.7**	**1.9**	**(1.0)**	**5.6**
15	**Fiscal 2024 Plan**	**144.9**	**93.6**	**48.7**	**287.2**
16	Standard Labour Rate	0.9	1.3	0.4	2.6
17	Vegetation & Access Management	4.6	-	-	4.6
18	Site C Maintenance	-	1.1	-	1.1
19	Other	-	0.0	(1.4)	(1.4)
20	**Total Incremental Change**	**5.5**	**2.4**	**(1.0)**	**6.9**
21	**Fiscal 2025 Plan**	**150.4**	**96.0**	**47.7**	**294.1**

BC Hydro's maintenance activities are categorized into line asset maintenance, stations asset maintenance and distribution emergency response. The following sub-sections provide a summary of maintenance expenditure by category.

[299] Storm Restoration cost savings are included in Table 5-3, line 46 under the Operations Business Group and further discussed in section 5.5.3.6 line 2 Storm Restoration.

The vegetation management cost increase is included in Table 5-3, line 24 under the Integrated Planning Business Group and further discussed in section 5.8.

In the Previous Application, LiDAR was considered a planning operational cost as it was newly added to the vegetation management program. It has since been classified as Transmission maintenance, similar to all inspection expenditures, with the change having no impact on the overall O&M budget.

5.15.2.1 *Line Asset Maintenance Expenditures*

Table 5-46 Line Asset Maintenance Expenditures

	($ million)	F2021 Actuals	F2022 Decision	F2023 Plan	F2024 Plan	F2025 Plan
1	Transmission Maintenance	47.2	53.6	62.0	63.5	65.7
2	Distribution Maintenance	46.6	53.4	56.8	59.9	63.0
3	Telecom P&C Maintenance	18.6	20.7	21.4	21.6	21.7
4	Total Line Asset Maintenance	112.4	127.7	140.2	144.9	150.4

- **Transmission Maintenance:** includes transmission line and vegetation maintenance. Annual expenditures include:
  - Approximately 33,000 transmission system inspections, test and treat inspections of wood poles as well as performing planned and unplanned repairs; and
  - Vegetation patrols of approximately 18,500 km of transmission circuits, and planned vegetation maintenance for reliable and safe operation of the transmission system.
- **Distribution Maintenance:** includes distribution line, vegetation and meter maintenance. Annual expenditures include:
  - Approximately 83,000 inspections and 13,000 repairs of the overhead and underground system on assets such as maintenance holes, cables, reclosers and voltage regulators and switches;
  - Approximately 94,000 pole top and test and treat inspections and 4,400 repairs on wood pole structures;
  - Vegetation patrols of approximately 25 per cent of overhead distribution circuits based on growth rates and maintenance cycles, and routine maintenance to manage vegetation in proximity to distribution lines to reduce outages and damage caused by falling trees; and

- ▶ Programs to sample and test on average approximately 6,900 meters (sample test orders and time-expired orders) and exchange failed and time-expired meters, so that BC Hydro is in compliance with the requirements of the *Electricity and Gas Inspection Act* and with Measurement Canada's sampling regulations.

- **Telecommunications Protection and Control Maintenance:** annual expenditures include approximately 5,400 Telecom and Protection and Control preventative maintenance inspections, as well as corrective repairs of Protection, Automation/Control, and Telecom assets (including Microwave and Very High Frequency repeater facilities) to ensure continuous reliable power system operations as well as compliance with MRS and other mandatory standards and regulations. The category also includes support for conducting system disturbance tracking and reporting (**SDR**) and expenditures for radio licenses, telecom leases and vendor technical support.

5.15.2.2 *Stations Asset Maintenance Expenditures*

Table 5-47 Stations Asset Maintenance Expenditures

	($ million)	F2021 Actuals	F2022 Decision	F2023 Plan	F2024 Plan	F2025 Plan
1	Generation Maintenance	53.6	61.8	62.3	63.9	65.9
2	Stations Maintenance	22.3	23.9	23.9	24.2	24.6
3	Non-Integrated Area Maintenance	5.6	5.4	5.4	5.5	5.6
4	Total Stations Asset Maintenance	81.5	91.1	91.6	93.6	96.0

- **Generation Maintenance:** annual expenditures, from approximately 16,000 completed work orders, include inspection, compliance with regulatory requirements, testing and repairs at generating station and storage dam assets, including generators, turbines, spillways, civil infrastructure and dams and their supporting systems.

- **Substations Maintenance:** annual expenditures, from approximately 20,000 completed work orders, include inspections and repairs of transmission and distribution substations, addressing assets such as power transformers, circuit breakers, disconnects, capacitors, reactors, synchronous condensers, control buildings, fences and other associated devices.
- **Non-Integrated Area Maintenance:** annual expenditures, from approximately 51 scheduled and 20 unscheduled maintenance trips, include routine, scheduled and corrective work at non-integrated diesel generating stations and one run of the river hydro generating station.

5.15.2.3 *Distribution Emergency Response Maintenance Expenditures*

Table 5-48 Distribution Emergency Response Maintenance Expenditures

	($ million)	F2021 Actuals	F2022 Decision	F2023 Plan	F2024 Plan	F2025 Plan
1	Routine Trouble	29.2	24.1	27.2	26.2	25.2
2	Storm	26.2	21.5	19.2	19.2	19.2
3	Damage to Plant	4.5	2.8	3.3	3.3	3.3
4	Total Distribution Emergency Response	59.9	48.4	49.7	48.7	47.7

Note: Storm Actuals include deferral entries.

- **Routine Trouble:** refers to maintenance expenditures for day-to-day restoration of power outages.
- **Storm:** refers to maintenance expenditures for events causing outages over a large geographic area, affecting a large number of customers or of extended duration.
- **Damage to Plant:** refers to events where a third-party may be liable for the cost of system repairs. These costs are partially offset by miscellaneous revenues.

5.15.3 BC Hydro Benchmarks Well on Maintenance Costs

Maintenance costs are well suited to benchmarking between companies, since cost data can be compared relative to common industry performance indicators. This section includes First Quartile's fiscal 2020 benchmarking results for substations, transmission and distribution lines, and Guidehouse's (formerly known as Navigant) fiscal 2013 to 2018 results for generation. Benchmarking results for vegetation management are discussed in section 5.8 and the Vegetation Management Strategy in Appendix G. These reports form part of our proposed terms of reference for future statistical cost benchmarking, discussed further in section 1.3.8.3 of Chapter 1 and in Appendix Y. These recent benchmarking results have shown that BC Hydro's maintenance and operating cost performance is either consistent with or lower than our utility peers. Benchmarking studies represent one point of data in comparing the organization's performance to peers, and on their own are not used to make specific management decisions or draw definitive conclusions. In cases where BC Hydro's performance is different than the industry peers, additional review may be undertaken to understand why this is the case.

5.15.3.1 *Maintenance Benchmarking is Completed Regularly by Independent Experts*

BC Hydro retains two independent experts in utility benchmarking, First Quartile and Guidehouse, to provide maintenance benchmarking services:

- **First Quartile (transmission and distribution):** First Quartile Consulting offers benchmarking services to help utilities compare performance and identify areas of opportunity in comparison to industry peers. First Quartile provides normalized comparisons between companies across various maintenance categories including distribution, transmission, vegetation and stations. For fiscal 2020, 34 operating companies participated in the benchmarking study.
- **Guidehouse (generation):** Guidehouse's GSK Hydro Benchmarking program is focused on generation. BC Hydro has been participating in this program for

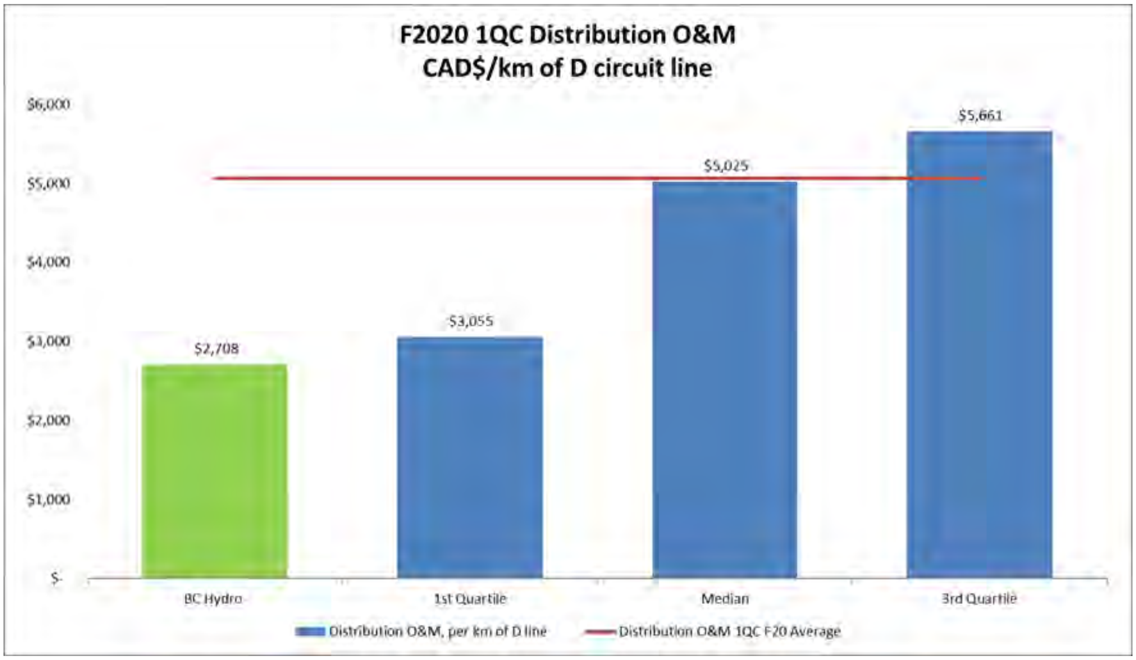
20 years. The benchmarking peer group includes over 500 generation stations, comprised of about 1,900 units that represent approximately 112,000 MW of installed capacity. Participants in the program are predominately from the United States and Canada, but also include companies from around the globe including Europe, New Zealand and South America. The stations included are diverse in size, type of facility and age, and include a mix of run-of-river, reservoir, pumped storage and pumping stations. Accordingly, the stations are grouped into approximately 325 station groups and study results are presented on a group basis for comparability.

5.15.3.2 *Our Transmission and Distribution Lines Costs Are Below Peer Group Average*

First Quartile compared the transmission and distribution line maintenance costs of approximately 20 utilities.

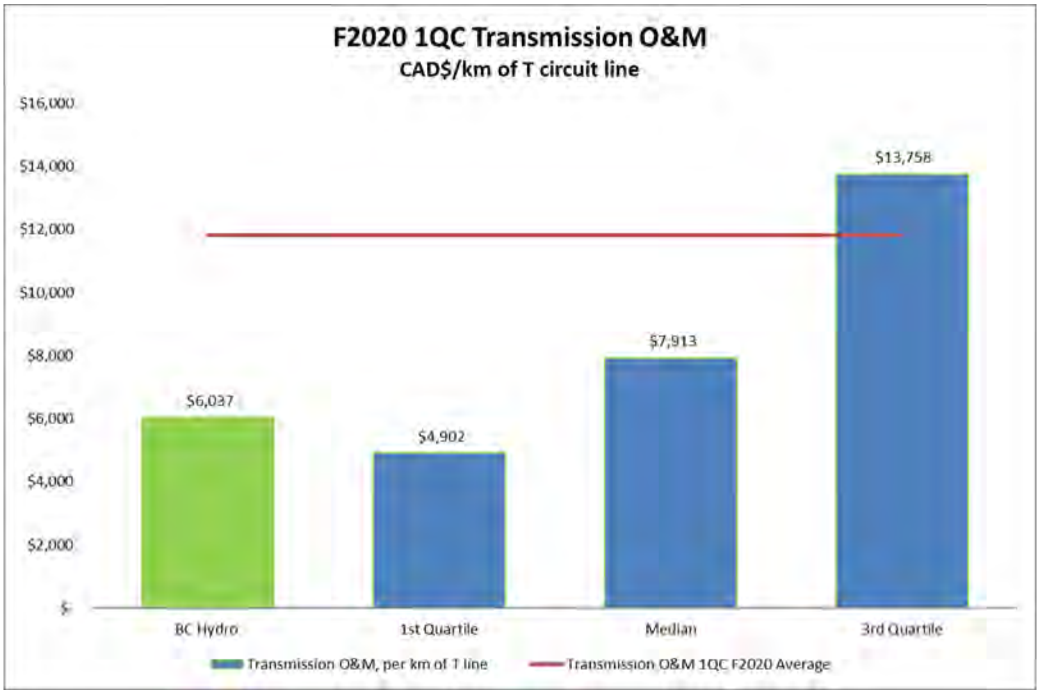
As shown in Figure 5-18 below, First Quartile has found that BC Hydro’s operations and maintenance costs were below the average for the utilities included in the distribution category.

1 **Figure 5-18 Distribution Line Operations and**
2 **Maintenance Costs**



3 Similarly, as shown in Figure 5-19 below, BC Hydro's operations and maintenance
4 costs were below the average for utilities included in the transmission category.

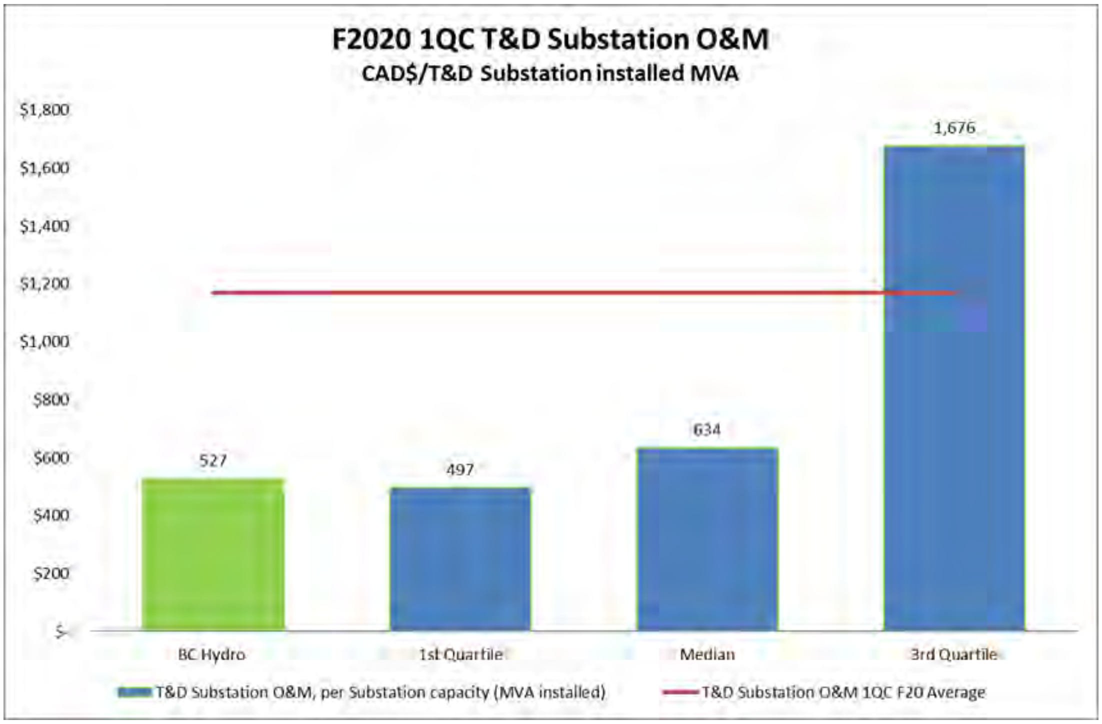
Figure 5-19 Transmission Line Operations and Maintenance Costs



5.15.3.3 *Our Transmission and Distribution Stations Costs are Below Peer Group Average*

The fiscal 2020 First Quartile benchmarking results also showed that BC Hydro's operations and maintenance costs were below average (i.e., favourable) for Transmission and Distribution Stations. In fact, as shown in Figure 5-20 below, BC Hydro is only slightly above the first (i.e., best) quartile of the peer group.

Figure 5-20 Transmission and Distribution Stations Operations and Maintenance Costs



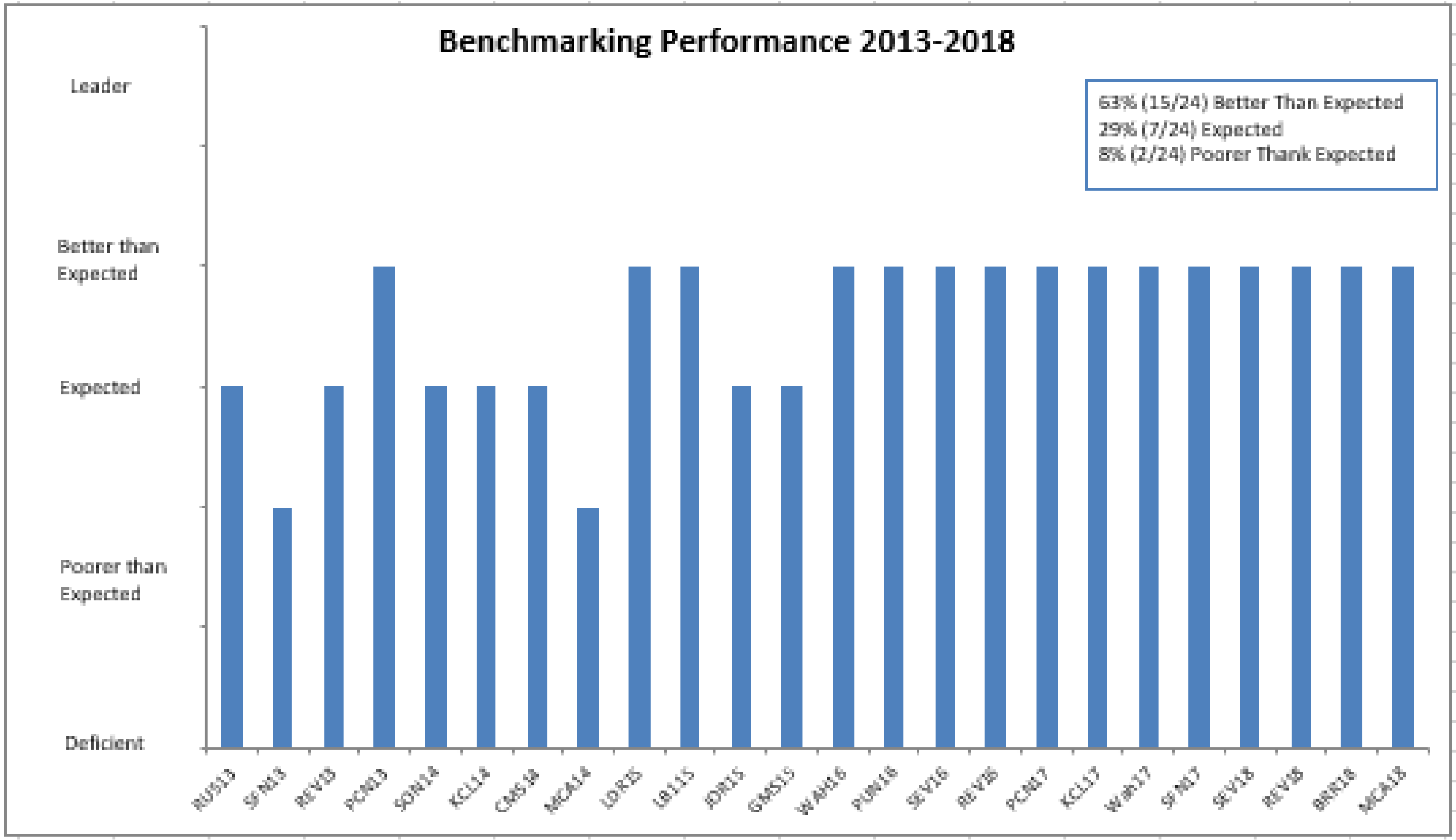
5.15.3.4 *Our Generation Station Maintenance Costs Compare Favourably*

Benchmarking of generation station maintenance costs reveals a similar pattern, with BC Hydro being low cost relative to other hydroelectric stations of a similar age and size.

BC Hydro participates in Guidehouse Consulting's GSK Hydro Benchmarking program each year, using three or four generation stations to compare maintenance and operating costs against a designated peer group of hydroelectric generating stations. The stations selected change from year to year and are periodically re-examined to provide historical cost progression comparisons. Guidehouse performs an in-depth cost review on each station, and produces a report comparing BC Hydro's stations to other hydroelectric stations within the designated peer group. In order to provide the BCUC with a representative sample of BC Hydro's generation station performance, we have assembled the results of the 24 most recent Guidehouse reviews in Figure 5-21 below.

Guidehouse's reviews showed that 92 per cent of BC Hydro's stations sampled were performing as expected or better in maintenance and operations costs, where "better" represents lower costs than expected.

1 **Figure 5-21 Generation Stations Benchmarking Performance – 2013 to 2018 [300,301]**



300 The lower cost performance for Stave Falls (**SFN**) and Mica (**MCA**) previous to 2017 were related to sizeable capital investments in the benchmark year including spillway projects at Stave Falls and the Mica Unit 5 and Unit 6 project. Both facilities were reviewed in the last two years and reflective of sustaining investments.

301 The results from benchmarking against fiscal 2020 data is not yet available, so the results from benchmarking against fiscal 2019 data has been provided.

These results confirm that BC Hydro's generation station maintenance costs are favourable when compared to our utility peers. Guidehouse studies control for type, size and age of generation facilities which mitigates the influence of the inherent economies of scale associated with our large hydroelectric generation.

5.15.4 Sustaining Capital Deferrals Did Not Increase Maintenance (Directive 24)

This sub-section responds to Directive 24 of the BCUC's Decision on the F2020-F2021 RRA. Directive 24 required BC Hydro to report on any additional maintenance spending that has occurred as a result of the reduced sustaining capital expenditures during the fiscal 2020 to fiscal 2021 test period. The directive also required BC Hydro to present a trend analysis of maintenance spending on capital for the ten most recently completed fiscal years. As described below, the analysis shows the following:

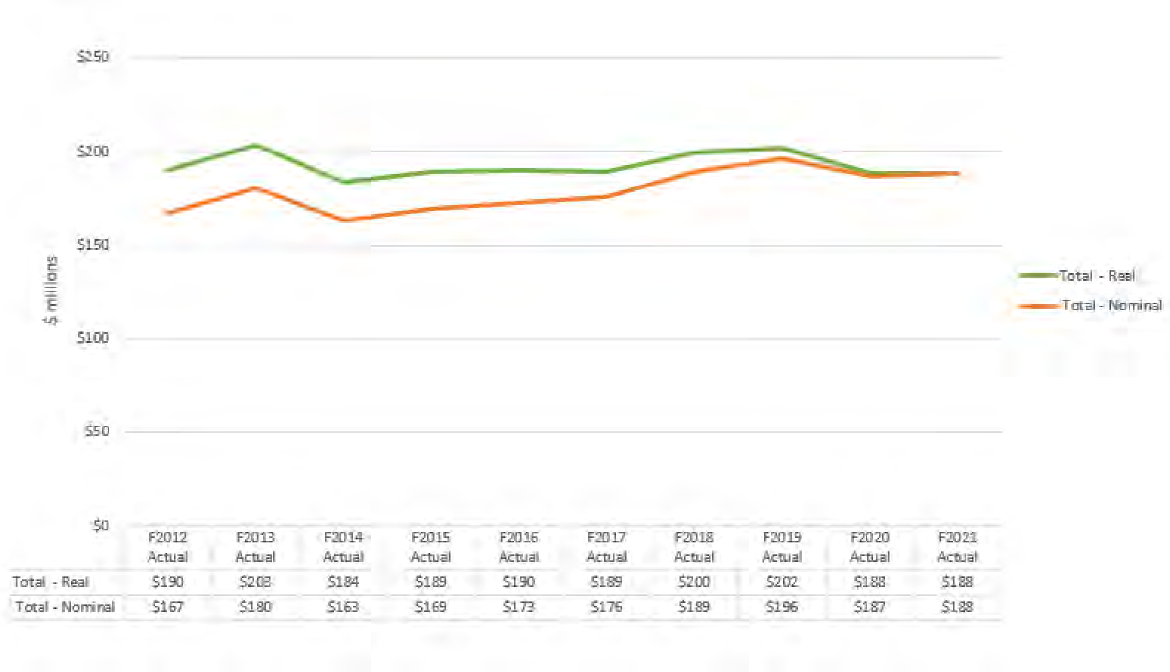
- Sustaining capital project deferrals in the fiscal 2020 to fiscal 2021 test period provided depreciation savings to BC Hydro's customers and did not result in any notable increases to maintenance spending.
- It is difficult to draw any firm conclusions on the correlation between maintenance and capital expenditures as the relationship between them is complex; one is generally not a substitute for the other and both are required to achieve the expected performance of an asset through its lifecycle.

We believe that we continue to plan maintenance appropriately and that the requested budget will allow us to do that in the Test Period.

5.15.4.1 *Trend Analysis Reflects the Complexity of Inter-relationship*

BC Hydro has interpreted Directive 24 to be requesting an analysis of the trend between maintenance expenditures and sustaining capital expenditures. Figure 5-22 below shows the BC Hydro's power system infrastructure maintenance expenditures from fiscal 2012 to fiscal 2021, represented as nominal and real adjusted to fiscal 2021 dollars using the B.C. Consumer Price Index.

Figure 5-22 Power System Infrastructure Maintenance Fiscal 2012 to Fiscal 2021 Actuals[302]



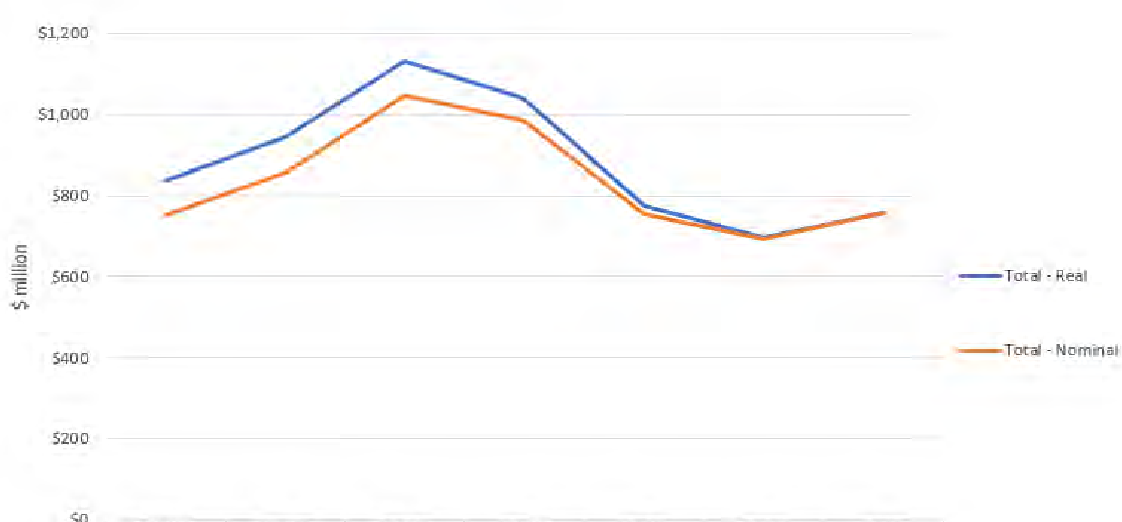
When considering the total power system infrastructure maintenance in real dollars, the fluctuation in spend ranges from 9 per cent decrease to 7 per cent increase. Given that BC Hydro's power system infrastructure maintenance activities are varied and cover a broad range of assets, this fluctuation is considered reasonable. With the exception of recent increased maintenance expenditures related to vegetation management and MRS, the drivers for increases in the Test Period are similar to those experienced in past fiscal years. Some of the main drivers for the changes in the historical maintenance spend included standard labour rate changes, inflation of materials and services costs, increased condition-based work driven by class

[302] The following notes apply to the actual amounts shown in Figure 5-22 above: Nominal and real dollars are shown. Real dollars were adjusted using the B.C. Consumer Price Index with fiscal 2021 as the base year. Supporting numbers exclude deferral and vegetation management.

defects (i.e., overhead line automatic splice replacements on the Distribution system) and increases in corrective work.

Figure 5-23 below shows the sustaining capital expenditures from fiscal 2015 to fiscal 2021 represented as nominal and real dollars adjusted to fiscal 2021 dollars using the B.C. Consumer Price Index.

Figure 5-23 Sustaining Capital Expenditures Fiscal 2015 to Fiscal 2021 Actuals[303,304]



	F2015 Actuals	F2016 Actuals	F2017 Actuals	F2018 Actuals	F2019 Actuals	F2020 Actuals	F2021 Actuals
Total - Real	$837	$944	$1,130	$1,040	$776	$697	$758
Total - Nominal	$751	$858	$1,047	$984	$754	$693	$758

When considering the sustaining capital expenditures in real dollars, the fluctuation in the spend ranges from 25 per cent decrease to 20 per cent increase. Similar to the maintenance expenditures, this fluctuation is considered reasonable. The trend in capital expenditures is heavily influenced by large projects as they progress through the project life cycle. For example, the increase in fiscal 2017 and

[303] Growth capital expenditures and the expenditures associated with the Waneta 2/3's interest purchase are not included. Sustaining capital expenditures are shown net of contribution in aid. Real sustaining capital expenditures are inflated to fiscal 2021 dollars using the B.C. Consumer Price Index.

[304] For pre fiscal 2015 capital expenditures, BC Hydro is not able to provide a growth/sustaining capital breakdown due to organizational structure and reporting changes.

fiscal 2018 sustaining capital expenditures is attributed to the re-development project for the John Hart Generating Station.[305]

It is difficult to draw any firm conclusions on the correlation between maintenance and capital expenditures as the relationship between them is complex; one is generally not a substitute for the other and both are required to achieve the expected performance of an asset through its lifecycle. For many power system assets, an initial capital investment is needed to install an asset at the start of its lifecycle. Power system assets can have very long lives (50 to 100 years) and on-going maintenance expenditures are required to monitor and preserve the functionality and performance of an asset over its life. For the larger power system assets, the up-front costs can be very high, while the on-going (annual) maintenance costs can be considerably lower. Increasing maintenance spending beyond a certain point will not necessarily extend the life of an asset further, however a lack of maintenance may shorten the life of an asset, reducing the performance and requiring a premature replacement or refurbishment.

For large high value power system assets, the decision to replace or refurbish through capital investment is driven by factors that extend beyond trends in the asset's maintenance costs. This is because the on-going maintenance costs are typically an order of magnitude lower than the capital cost of a replacement or refurbishment. Factors such as increased safety risks, reliability performance trends, levels of system redundancy, risk of in-service failure, increased total financial costs, environmental implications and regulatory requirements must be considered when making the decision to initiate a capital investment and are more likely to determine the need for and timing of a capital investment. BC Hydro's risk framework is used to guide asset management decisions which will impact the required capital investments and maintenance expenditures.

[305] Refer to F2020-F2021 RRA, Appendix I, Page 1, line 2.

5.15.4.2 *Fiscal 2020 to Fiscal 2021 Capital Project Deferrals Have Not Increased Maintenance Expenditures*

The capital deferrals during fiscal 2020 and fiscal 2021 have not resulted in an increase to maintenance expenditures.

In section 6.3.2 of the F2020-F2021 RRA, BC Hydro stated that growth and sustaining capital expenditures were decreased in that test period after factoring in the moderation in system load growth and strong historical system performance. As shown in BC Hydro's response to BCUC IR 1.108.1.1 in that proceeding, the reduction in capital additions over fiscal 2020 to fiscal 2021 was $137 million as the result of the decision to defer investments based on the factors noted above. Further, in BC Hydro's response to BCUC IR 1.108.1.2 in that proceeding, a list of the projects deferred or cancelled in the fiscal 2020 to fiscal 2024 period was provided. This table is provided below for ease of reference.

Table 5-49 List of Capital Projects Deferred or Cancelled – Fiscal 2020 to Fiscal 2021[306]

Project Name	Reason for Deferral / Cancellation	Operational Impact
Fraser Valley West Area Reinforcement: Phase 2 (formerly Fraser Valley West Substation Expansion)	Expected Change in Load Forecast	None anticipated
Metro North Transmission (**MNT**)	Expected Change in Load Forecast	None anticipated
Yaletown (**DGR**) Property Purchase	Expected Change in Load Forecast	None anticipated
Hundred Mile House – Spences Bridge	Expected Change in Load Forecast	None anticipated
Capilano Substation 25 kV Conversion	Expected Change in Load Forecast	None anticipated
VI-GUL-005 SAL 25F61 Submarine Cable Extension to North Pender Island	Review of the cost-benefit and further study of the system risks is required to justify the timing of the project scope	None anticipated

[306] Table originally provided in BC Hydro's response to BCUC IR 1.108.1.2, F2020-F2021 RRA (Exhibit B-5).

Project Name	Reason for Deferral / Cancellation	Operational Impact
LM-VAN-088 DV - West End Voltage Conversion Preparation for DGR 12F86 and 87	Extension of schedules for all Downtown Vancouver/West End voltage conversions to align with changes in the timing of new substations	None anticipated
LaJoie - Governor/Pressure Regulating Valve Replacement	Adjusted project timing based on the balance of system performance, risk and affordability	Accepted potential for increased maintenance and requirement to man the station during line outages due to control issues of the governor
MCA - Replace Units 1 to 4 Cooling Water Piping	Adjusted project timing based on the balance of system performance, risk and affordability	Accepted potential for additional maintenance to repair pipe leaks until risks addressed
PCN - Flood Discharge Gates Reliability Improvement	Project cancelled at conclusion of Definition Phase due to insufficient risk reductions to justify costs. Review of the delivery and procurement models for project scope is required. Need is expected to be addressed under future projects later in the planning horizon.	None anticipated. Project initiation was advanced in efforts to gain synergies with a similar project at WAC Bennett Dam, which were not realized
Revelstoke - U1 - U4 Service Water Piping Replacement	Highest risk items addressed through targeted small capital investments. Deferred pending condition assessment update of remaining items.	Accepted potential for additional maintenance to repair pipe leaks until risks addressed

Of the 11 projects listed above, three identified the potential for additional maintenance due to the deferral of the capital investment. One deferred investment has resulted in maintenance expenditures associated with assets to be addressed as part of the Revelstoke – U1 – U4 Service Water Piping Replacement project, that may have been avoided if the project had proceeded as originally planned. This includes a total of $48 thousand in corrective work and approximately $18 thousand in additional system testing. This project is included in the Fiscal 2022 to Fiscal 2031

Capital Plan, which was used to support this application, but is not planned to start within the Test Period. The additional maintenance spend was not significant enough to warrant a re-assessment of the investment's priority within the Capital Plan.

5.16 Chapters 5A to 5G Provide "Full Cost" View of Operating Costs by Business Group and KBU

In Chapters 5A through 5G, BC Hydro provides detailed support for the forecast operating costs, by Business Group.

In its Decision on the Previous Application, the BCUC acknowledged that the Previous Application was designed for an expedited review and may not have allowed for a thorough investigation into the historically approved level of expenditures, unlike BC Hydro's F2020-F2021 RRA. The BCUC noted that the Fiscal 2023 to Fiscal 2025 Revenue Requirements Application would be a more appropriate proceeding to fully test the baseline level of operating costs including any incremental changes. Accordingly, these chapters provide significantly more information than the Previous Application on the operating costs and FTEs for each of BC Hydro's six business groups and 37 KBUs. They provide the full cost picture rather than focusing only on incremental changes, in a format and level of detail consistent with Chapters 5A to 5G in the F2020-F2021 RRA.

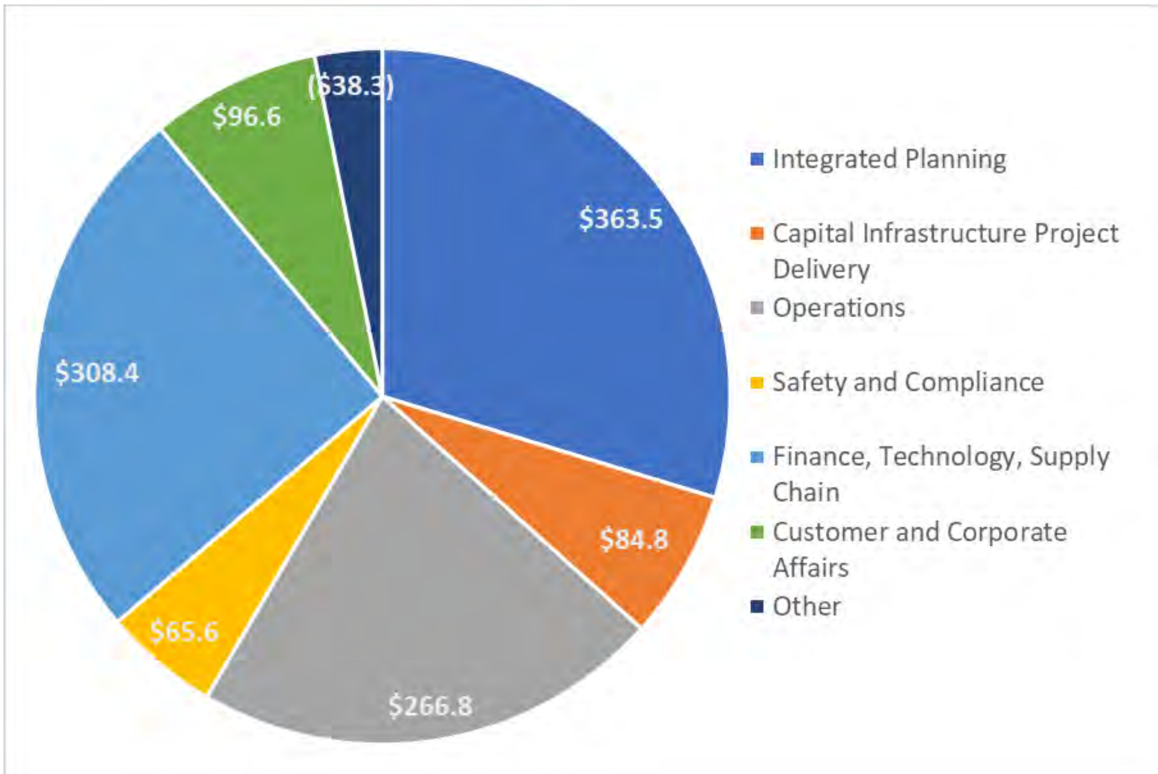
Figure 5-24 and Figure 5-25 below provide a summary of operating costs and FTEs by Business Group. Additional details are provided in Table 5-50 and Table 5-51.

When reviewing the summaries provided below, it is important to note the following:

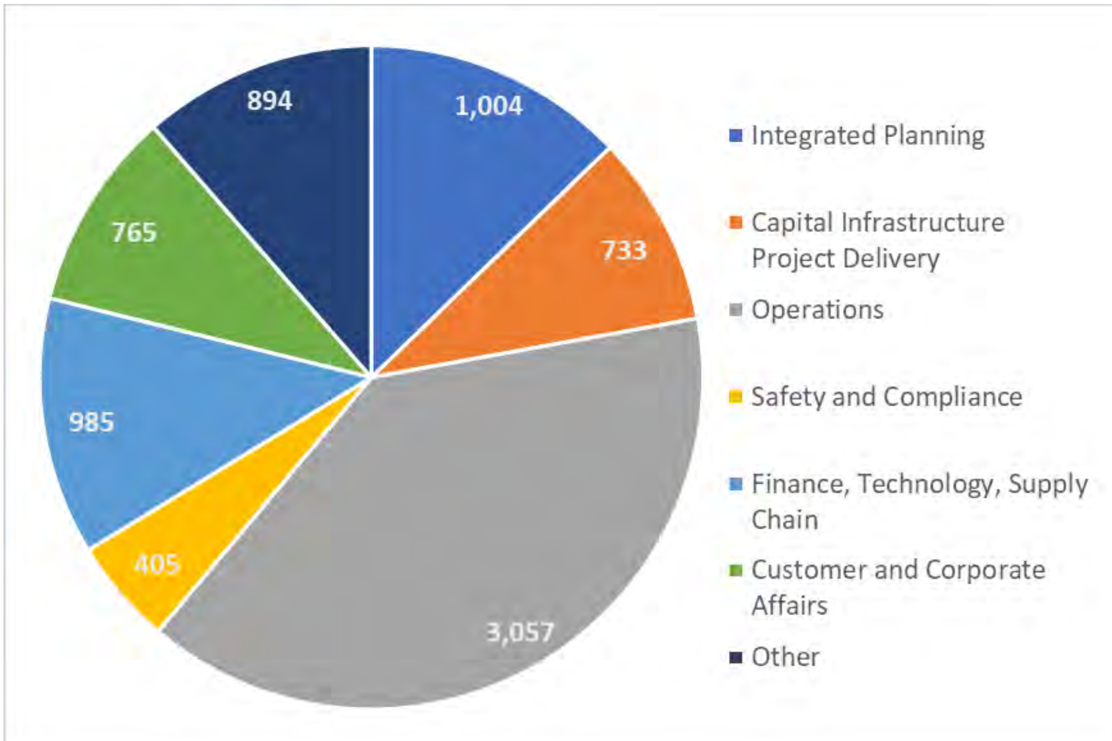
- The Integrated Planning Business Group holds the budget for all maintenance work while the Operations Business Group holds the FTEs associated with all maintenance work and is responsible for executing this work;

- The Safety and Compliance Business Group includes the Learning and Development KBU, which includes the FTEs related to apprentices and trainees, which perform work throughout the organization; and
- The Site C Project has been included in the Other category. The project has FTEs, as shown below; however, all project costs are charged to capital and to the Site C Regulatory Account.

Figure 5-24 Net Operating Costs by Business Group ($ million) (Fiscal 2023)



1 **Figure 5-25 FTEs by Business Group (Fiscal 2023)**[307]



307 Other category includes 721 Site C Project FTEs.

Table 5-50 Net Operating Costs by Business Group and KBU

	($ million)	Schedule Reference	F2021 Actual	F2022 Decision	F2023 Plan	F2024 Plan	F2025 Plan
			1	2	3	4	5
	Integrated Planning						
1	Energy Planning and Analytics	5.1 L1	8.8	9.0	9.1	8.7	9.4
2	Dam Safety	5.1 L2	10.4	11.4	11.2	11.4	11.9
3	Asset Planning	5.1 L3	236.8	270.4	278.9	286.3	294.1
4	Interconnections and Shared Assets	5.1 L4	15.4	13.1	14.7	14.1	14.2
5	Engineering Design	5.1 L5	17.3	18.2	18.3	18.4	18.9
6	Engineering Services	5.1 L6	7.2	9.0	9.0	9.3	9.5
7	Business Unit Support	5.1 L7+L10	21.8	21.9	22.2	22.6	28.8
8	Total Integrated Planning	5.1 L13	317.7	353.0	363.5	370.7	386.7
	Capital Infrastructure Project Delivery						
9	Project Delivery	5.2 L1	13.2	15.4	15.2	15.5	15.9
10	Indigenous Relations	5.2 L2	7.4	6.7	8.1	8.6	8.8
11	Environment	5.2 L3	28.9	31.0	30.7	31.0	31.4
12	Properties	5.2 L4	30.5	30.3	30.0	30.3	30.5
13	Business Unit Support	5.2 L5	0.8	0.9	0.9	0.9	0.9
14	Total Capital Infrastructure Project Delivery	5.2 L11	80.8	84.3	84.8	86.3	87.6
	Operations						
15	Program and Contract Management	5.3 L1	14.4	17.3	19.2	19.7	20.2
16	Line Field Operations	5.3 L2	103.1	92.3	92.2	91.8	92.1
17	Stations Field Operations	5.3 L3	57.7	55.8	56.0	56.5	59.7
18	Distribution Design and Customer Connect	5.3 L4	14.6	16.4	17.4	17.9	18.4
19	Construction Services	5.3 L5	14.8	14.9	13.9	14.0	14.3
20	Generation System Operations	5.3 L6	19.4	19.8	22.5	22.9	23.3
21	Transmission and Distribution System Operations	5.3 L7	40.3	41.6	41.8	42.6	43.5
22	Business Unit Support	5.3 L8	0.6	3.3	3.7	3.7	3.8
23	Total Operations	5.3 L14	265.0	261.4	266.8	269.2	275.3
	Safety & Compliance						
24	Safety	5.4 L1	19.4	22.5	20.1	20.5	20.7
25	Learning and Development	5.4 L2	19.2	24.5	23.9	25.3	27.0
26	Security and Emergency Management	5.4 L3	16.4	12.5	12.6	13.8	14.4
27	Reliability Standards Assurance	5.4 L4	8.0	8.1	8.3	5.9	5.2
28	Business Unit Support	5.4 L5	0.7	0.8	0.6	0.7	0.7
29	Total Safety & Compliance	5.4 L11	63.7	68.3	65.6	66.1	68.0
	Finance, Technology, Supply Chain						
30	Finance	5.5 L1	46.0	51.0	51.1	52.5	54.0
31	Technology	5.5 L2	137.8	146.3	157.9	162.4	164.0
32	Supply Chain	5.5 L3	92.7	101.0	98.6	99.2	100.2
33	Business Unit Support	5.5 L4	0.8	0.9	0.8	0.9	0.9
34	Total Finance, Technology, Supply Chain	5.5 L10	277.3	299.1	308.4	314.9	319.1
	Customer & Corporate Affairs						
35	Customer Service	5.6 L1+L9	64.5	68.3	67.8	69.2	70.7
36	Conservation and Energy Management	5.6 L2	0.5	0.7	0.6	0.7	0.7
37	Communications and Community Engagement	5.6 L3	12.9	14.2	13.9	14.2	14.5
38	Regulatory and Rates	5.6 L4	13.7	13.1	13.4	13.7	14.0
39	Business Unit Support	5.6 L5	0.8	0.9	0.8	0.9	0.9
40	Total Customer and Corporate Affairs	5.6 L11	92.4	97.1	96.6	98.6	100.8
	Other						
41	Human Resources	5.7 L1	21.0	24.4	23.6	24.1	24.6
42	Office of the General Counsel	5.7 L2	15.5	13.0	12.9	12.9	12.8
43	Office of the President and Chief Executive Officer	5.7 L3	0.8	0.9	0.9	0.9	0.9
44	Site C Project	5.7 L4	(0.0)	0.0	0.0	0.0	0.0
45	Corporate Costs	5.7 L5	(3.3)	0.5	0.5	0.5	0.5
46	Capitalized Costs	5.7 L6+L8	(93.9)	(75.5)	(76.2)	(76.2)	(76.4)
47	Total Other	5.7 L12	(59.9)	(36.7)	(38.3)	(37.9)	(37.6)
48	Total BC Hydro Net Operating Costs	5.0 L19	1,037.0	1,126.5	1,147.4	1,167.9	1,199.9

Table may not add due to rounding

Table 5-51 FTEs by Business Group and KBU

		Schedule Reference	F2021 Actual	F2022 Decision	F2023 Plan	F2024 Plan	F2025 Plan
			1	2	3	4	5
	Integrated Planning						
1	Energy Planning and Analytics	16.0 L1	45	44	44	44	45
2	Dam Safety	16.0 L2	36	39	39	39	41
3	Asset Planning	16.0 L3	198	200	211	211	211
4	Interconnections and Shared Assets	16.0 L4	48	46	47	47	47
5	Engineering Design	16.0 L5	432	408	413	414	415
6	Engineering Services	16.0 L6	224	239	246	247	248
7	Business Unit Support	16.0 L7	3	3	3	3	3
8	Total Integrated Planning	16.0 L8	986	980	1,004	1,005	1,010
	Capital Infrastructure Project Delivery						
9	Project Delivery	16.0 L9	434	431	434	439	439
10	Indigenous Relations	16.0 L10	60	74	79	74	74
11	Environment	16.0 L11	93	95	95	95	95
12	Properties	16.0 L12	116	123	123	123	123
13	Business Unit Support	16.0 L13	3	3	3	3	3
14	Total Capital Infrastructure Project Delivery	16.0 L14	706	726	733	733	733
	Operations						
15	Program and Contract Management	16.0 L15	272	280	317	318	318
16	Line Field Operations	16.0 L16	907	924	925	925	925
17	Stations Field Operations	16.0 L17	710	724	745	745	760
18	Distribution Design and Customer Connect	16.0 L18	370	379	385	391	394
19	Construction Services	16.0 L19	416	397	396	396	396
20	Generation System Operations	16.0 L20	89	81	82	82	82
21	Transmission and Distribution System Operations	16.0 L21	204	197	201	201	201
22	Business Unit Support	16.0 L22	5	4	6	6	6
23	Total Operations	16.0 L23	2,972	2,985	3,057	3,063	3,082
	Safety & Compliance						
24	Safety	16.0 L24	117	112	110	110	111
25	Learning and Development	16.0 L25	290	246	240	256	274
26	Security and Emergency Management	16.0 L26	29	33	34	38	39
27	Reliability Standards Assurance	16.0 L27	9	22	19	22	22
28	Business Unit Support	16.0 L28	3	3	2	2	2
29	Total Safety & Compliance	16.0 L29	448	416	405	428	447
	Finance, Technology, Supply Chain						
30	Finance	16.0 L30	209	211	211	211	211
31	Technology	16.0 L31	271	283	297	316	316
32	Supply Chain	16.0 L32	513	475	474	465	459
33	Business Unit Support	16.0 L33	3	3	3	3	3
34	Total Finance, Technology, Supply Chain	16.0 L34	996	972	985	995	989
	Customer & Corporate Affairs						
35	Customer Service	16.0 L35	507	492	504	504	504
36	Conservation and Energy Management	16.0 L36	119	116	122	122	123
37	Communications and Community Engagement	16.0 L37	97	108	110	110	110
38	Regulatory and Rates	16.0 L38	23	23	26	26	26
39	Business Unit Support	16.0 L39	3	3	3	3	3
40	Total Customer and Corporate Affairs	16.0 L40	749	742	765	765	766
	Other						
41	Human Resources	16.0 L41	126	131	129	129	129
42	Office of the General Counsel	16.0 L42	39	41	41	41	41
43	Office of the President and Chief Executive Officer	16.0 L43	3	3	3	3	3
44	Site C Project	16.0 L44	479	504	721	651	453
45	Corporate Costs	16.0 L45	0	0	0	0	0
46	Capitalized Costs	16.0 L46	0	0	0	0	0
47	Total Other	16.0 L47	648	679	894	824	626
48	Total BC Hydro FTEs	16.0 L59	7,505	7,500	7,842	7,814	7,654

Table may not add due to rounding

BC Hydro
Power smart

BC Hydro Fiscal 2023 to Fiscal 2025
Revenue Requirements Application

Chapter 5A

Operating Costs
Integrated Planning
Business Group

PLAN

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5A.1 Introduction – Integrated Planning Business Group

Chapter 5A provides and explains in detail the composition of, and rationale for, the operating costs of the Integrated Planning Business Group.

The Integrated Planning Business Group is one of six business groups in the organization and is responsible for planning BC Hydro's Power System. It serves as the Plan function of the Plan-Build-Operate-Support model. Since the Previous Application, there have been a number of organizational changes within the Integrated Planning Business Group, which are descripted in this Chapter; however, the overall responsibilities of this Business Group remain consistent with the Previous Application.

The Integrated Planning Business Group budget was developed as part of the budgeting process outlined in Chapter 5, section 5.4, which the BCUC found to be reasonable in its decision on the Previous Application.[308] The budgeting approach includes both bottom-up and top-down elements and examines more than just incremental costs.

The information provided in Chapter 5A demonstrates the basis for the entirety of the Business Group and KBU budgets, rather than focussing only on incremental cost requirements. This information is provided in a format and level of detail consistent to that presented in the equivalent chapter in the F2020-F2021 RRA. Specifically, Chapter 5A is organized as follows:

- Section 5A.2 provides an overview of the organization and responsibilities of the Integrated Planning Business Group;

[308] BCUC Decision and Order No. G-187-21, Fiscal 2022 Revenue Requirements Application (June 17, 2021), p. 27: "The Panel considers BC Hydro's budgeting process involving top-down and bottom-up elements goes beyond the examination of incremental changes from the prior year and continues to be reasonable for forecasting operating costs. Therefore, for these reasons, the Panel finds the fiscal 2022 operating costs requested for recovery to be reasonable."

- Section 5A.3 provides the operating costs and FTE information for the Integrated Planning Business Group as a whole;[309] and
- Sections 5A.4 to 5A.10 provide more detailed information on the responsibilities, cost and FTEs for each KBU within the Integrated Planning Business Group. The operating costs and FTE information for each KBU is broken out into two sections:[309]
  - Overview of Operating Costs and FTEs – This section explains the starting operating costs and FTEs for the KBU based on the fiscal 2022 Decision amounts; and
  - Fiscal 2023 to Fiscal 2025 Plan Operating Costs and FTEs – This section explains any incremental changes in the KBU between fiscal 2022 Decision amounts and fiscal 2023 to fiscal 2025 plan.

5A.2 Overview of Integrated Planning Business Group Organization and Responsibilities

The Integrated Planning Business Group brings together our main planning, asset management and engineering functions to plan and design a safe, efficient and reliable system that drives the most value from our investments and meet the needs of our customers.

More specifically, the Integrated Planning Business Group is responsible for:

- Developing the load forecast and the Integrated Resource Plan;
- Determining when and where to invest in our system;
- Governing the safe management of reservoir containment and water conveyance;
- Producing the Capital Plan and fulfilling the role of project initiator;

[309] Please note the amounts presented in the tables in these sections may not add due to rounding.

- Managing requests to interconnect, supply, or receive electrical services from our system; and
- Providing engineering services to the organization.

The Integrated Planning Business Group consists of the following KBUs:

Business Group	Key Business Unit
Integrated Planning	Energy Planning and Analytics Dam Safety Asset Planning Interconnections and Shared Assets Engineering Design Engineering Services Business Unit Support

Since the Previous Application, there has been one change to the organization of this Business Group: Stations Asset Planning and Line Asset Planning have been consolidated into a single KBU called Asset Planning. While the Line Asset Planning and Stations Asset Planning department structures will remain intact, bringing the two KBUs together, reporting to the Vice President of Asset Planning will continue to drive consistency with respect to planning and asset management. Further information can be found in Chapter 5, section 5.3.2. The organizational change does not alter the overall functions undertaken by the Business Group.

5A.3 Fiscal 2023 to Fiscal 2025 Plan Operating Cost and FTE Summaries

This section addresses planned operating costs and FTEs for the Integrated Planning Business Group. The following are some key points of note with respect to the information provided in Figure 5A-1, Table 5A-1 and Figure 5A-2, Table 5A-2 and Table 5A-3:

- Approximately $232 million or 64 per cent of the operating costs for the Integrated Planning Business Group are directly attributable to power system maintenance programs;

- Over 65 per cent of the FTEs in this Business Group are represented by the Engineering Design and Engineering Services KBUs. Over 76 per cent of the labour costs for these FTEs are not included in the operating costs budget as these costs are charged primarily to capital projects; and
- Operating costs are increasing in the Integrated Planning Business Group, primarily due to Standard Labour Rates (as discussed further in Chapter 5, section 5.12.2), vegetation management (as discussed further in Chapter 5, section 5.8), Site C operating costs (as discussed further in Chapter 5, section 5.10), the Electrification Plan (as discussed further in Chapter 10), the non-integrated area diesel reduction strategy, and Mandatory Reliability Standards (as discussed further in Chapter 5, section 5.7) .

Planned operating costs for the Integrated Planning Business Group are approximately $364 million in fiscal 2023, approximately $371 million in fiscal 2024 and approximately $387 million in fiscal 2025. The operating costs for the Integrated Planning Business Group are summarized by KBU in Figure 5A-1. Additional cost details are provided in Table 5A-1 below.

Figure 5A-1 Integrated Planning Net Operating Costs by KBU (Fiscal 2023 Plan) ($ million)

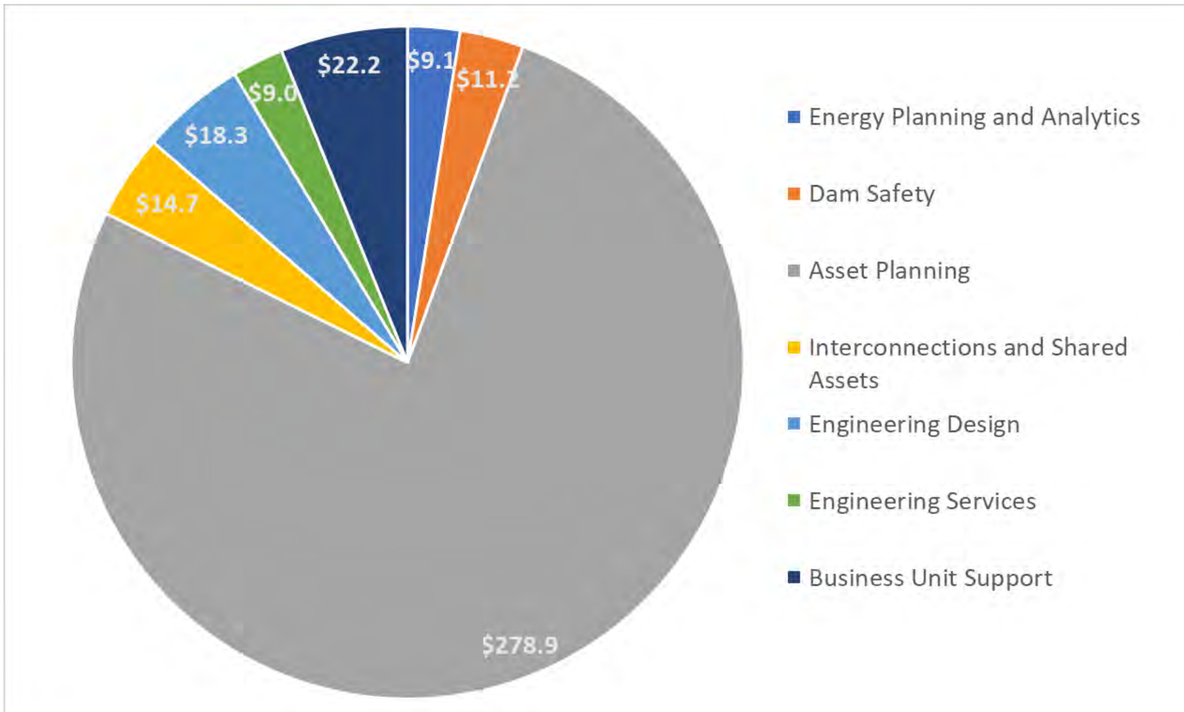


Table 5A-1 Integrated Planning Net Operating Costs by KBU

	($ million)	Schedule Reference	F2021 Actual	F2022 Decision	F2023 Plan	F2024 Plan	F2025 Plan
			1	2	3	4	5
1	Energy Planning and Analytics	5.1 L1	8.8	9.0	9.1	8.7	9.4
2	Dam Safety	5.1 L2	10.4	11.4	11.2	11.4	11.9
3	Asset Planning	5.1 L3	236.8	270.4	278.9	286.3	294.1
4	Interconnections and Shared Assets	5.1 L4	15.4	13.1	14.7	14.1	14.2
5	Engineering Design	5.1 L5	17.3	18.2	18.3	18.4	18.9
6	Engineering Services	5.1 L6	7.2	9.0	9.0	9.3	9.5
7	Business Unit Support	5.1 L7+L10	21.8	21.9	22.2	22.6	28.8
8	Total	5.1 L13	317.7	353.0	363.5	370.7	386.7

The FTEs for the Integrated Planning Business Group are summarized by KBU in Figure 5A-2. Additional details are provided in Table 5A-2 below.

Figure 5A-2 Integrated Planning FTEs by KBU (Fiscal 2023 Plan)

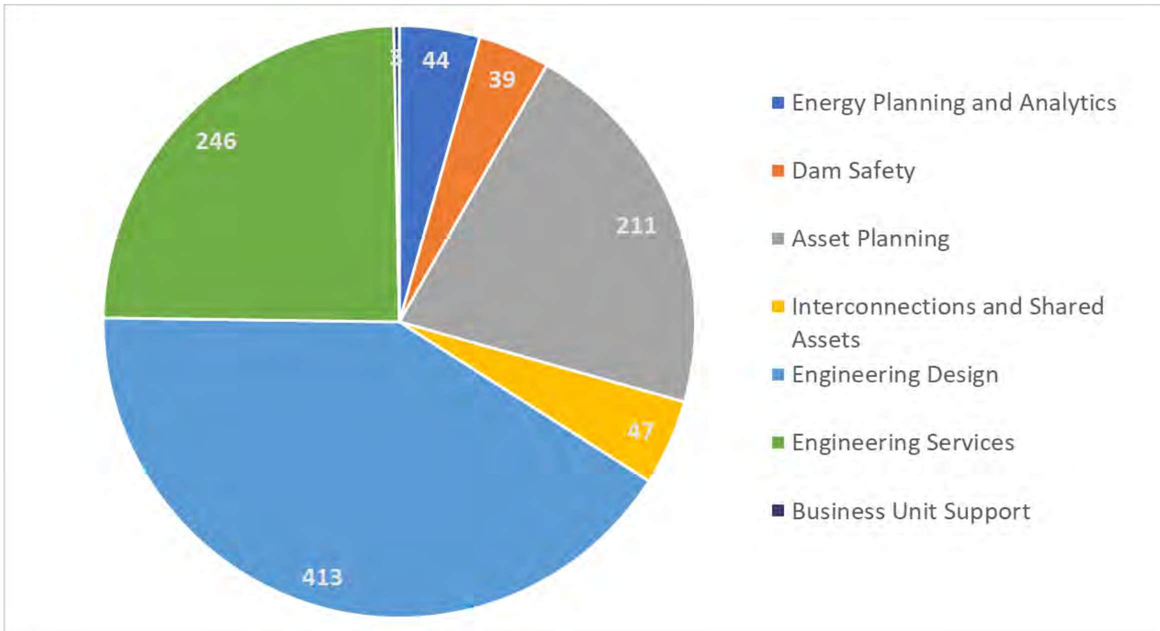


Table 5A-2 Integrated Planning FTEs by KBU

	(FTEs)	Schedule Reference	F2021 Actual	F2022 Decision	F2023 Plan	F2024 Plan	F2025 Plan
			1	2	3	4	5
1	Energy Planning and Analytics	16.0 L1	45	44	44	44	45
2	Dam Safety	16.0 L2	36	39	39	39	41
3	Asset Planning	16.0 L3	198	200	211	211	211
4	Interconnections and Shared Assets	16.0 L4	48	46	47	47	47
5	Engineering Design	16.0 L5	432	408	413	414	415
6	Engineering Services	16.0 L6	224	239	246	247	248
7	Business Unit Support	16.0 L7	3	3	3	3	3
8	Total	16.0 L8	986	980	1,004	1,005	1,010

Table 5A-3 below provides a continuity table which highlights changes to the Integrated Planning Business Group from the Previous Application. An overall discussion of these changes, at a company-wide level, is provided in Chapter 5, section 5.5.3. Further details, by KBU, are provided in the sections below.

Table 5A-3 Integrated Planning Operating Costs Continuity Schedule

	($ million)	Ref	F2023 Plan	F2024 Plan	F2025 Plan
1	**F2022 Revenue Requirement Application Plan**	a	**352.2**		
2	**Compliance Filing Adjustment**	b	0.8		
3	Reorganizational Impact	c	-		
4	**F2022 Decision (Schedule 5.1, line 13)**	d= a+b+c	**353.0**		
5	Budget Transfers Between Business Groups	e	0.9		
6	**F2022 Forecast (Schedule 5.1, line 13)**	f = d+e	**353.9**	**363.5**	**370.7**
7	Budget Transfers Between Business Groups	g	-	-	-
8	**Current Year Incremental Adjustments:**				
9	Waneta 2/3rd Operating Costs		(0.1)	0.2	0.2
10		h	**(0.1)**	**0.2**	**0.2**
11	**Test Period Net Cost Increase/Decrease**				
12	**Uncontrollable Cost Increases**				
13	Current Service Costs and Other Labour Costs		(2.7)	4.3	4.8
14		i	(2.7)	4.3	4.8
15	**Reliability Investments**				
16	Vegetation Management		8.1	3.9	4.6
17	Mandatory Reliability Standards		0.2	(0.7)	(1.1)
18		j	8.3	3.2	3.5
19	**Site C**	k	0.3	0.8	7.3
20	**Strategic Initiatives**				
21	NIA - diesel reduction strategy		0.7	0.3	-
22	Electrification initiatives		0.4	0.6	0.5
23		l	1.1	0.9	0.5
24	**Third Party Billable Work**				
25	Interconnection study and project costs		1.8	(1.5)	(0.7)
26		m	1.8	(1.5)	(0.7)
27	**Net Cost Savings**				
28	Electric Vehicle Charging Infrastructure Costs		1.0	-	-
29	Work Program Resources		0.5	0.0	0.0
30	IRP Funding		0.3	(0.6)	0.3
31	Test Period Savings		(0.9)	-	-
32		n	0.9	(0.6)	0.3
33	**Total Test Period Net Increase/(Decrease)**	o =∑ i to n	**9.7**	**7.0**	**15.8**
34	**F2023 Net Operating Costs (Schedule 5.1, line 13)**	p = f+g+h+o	**363.5**	**370.7**	**386.7**

Table may not add due to rounding

5A.4 Energy Planning and Analytics KBU

5A.4.1 Responsibilities

The Energy Planning and Analytics KBU is responsible for the development of BC Hydro's energy plans, the delivery of integrated planning and analytics services, and the prioritization of investments within BC Hydro's capital plans.

There have been no material changes to the responsibilities of the Energy Planning and Analytics KBU since the Previous Application:

The Energy Planning and Analytics KBU is comprised of the following three departments:

- Energy Planning Department;
- Portfolio Optimization and Management Department; and
- Reliability and Performance Assessment Department.

5A.4.1.1. Energy Planning Department

The Energy Planning department consists of four teams:

- Integrated Resource Planning;
- Integrated Resource Modelling;
- Load Forecasting; and
- Network Integration.

The Integrated Resource Planning team produces analyses of system and regional load-resource balances, reference prices and resource options to support a range of business decisions and regulatory proceedings. They also spearhead the development of BC Hydro's Integrated Resource Plans.

The Integrated Resource Modelling team executes system portfolio modelling runs to inform internal business decisions and regulatory proceedings, including

BC Hydro's Integrated Resource Plans, while supporting resource planning initiatives in partnership with stakeholders such as the City of Vancouver, the Government of B.C. and the Government of Canada.

The Load Forecasting team produces a suite of load forecast products that are used in various BC Hydro activities, including long-term planning (e.g., Integrated Resource Plans), medium-term investments, and operational and forecasting activities. BC Hydro's load forecast is used to provide decision-making information for electricity rates, as well as where, when, and how much electricity we expect to need from the BC Hydro system. BC Hydro's load forecasting activities also include the preparation of a number of time and location specific forecasts to meet more specific user requirements.

The Network Integration team manages the development and submission of transmission service requests to the Market Policy and Operations department in the Transmission and Distribution System Operations KBU. This team also represents BC Hydro's transmission interests as a transmission customer at the Western Electricity Coordinating Council (**WECC**). In addition, the team is responsible for integrated resource planning for the Fort Nelson area. The Fort Nelson area is not connected to BC Hydro's integrated system, but is grid connected to local generation resources and to Alberta's grid through a radial transmission line.

5A.4.1.2. Portfolio Optimization and Management Department

The Portfolio Optimization and Management department leads the integration and prioritization of investments across BC Hydro's enterprise capital portfolio. In doing this work, the department aligns the enterprise capital plan with BC Hydro's strategic direction and objectives. In support of this, the department leads the integration of Stations, Line, Interconnection and Dam Safety investments, within the Integrated Planning Business Group, into a cohesive portfolio of projects and programs as part of the annual capital planning process. BC Hydro's Capital Plan is discussed in Chapter 6.

5A.4.1.3. Reliability and Performance Assessment Department

The Reliability and Performance Assessment department provides Asset Health and Reliability reporting and analytics to the Asset Planning KBU to support customer reliability. This team works with asset management business units to ensure asset data and storage locations are current and consistent with business requirements and Mandatory Reliability Standards compliance, which includes setting up preventative maintenance work orders and ensuring they are completed in compliance with maintenance standards.

5A.4.2 Overview of Operating Costs and FTEs

Table 5A-4 Energy Planning and Analytics KBU Fiscal 2022 Decision Operating Costs and FTEs by Department

	($ Millions)	Labour	Services - Other	Materials	Building & Equipment	Capitalized Overhead	External Recoveries	Total Operating	Total FTEs
1	Energy Planning	4.4	0.7	0.1	0.2	0.0	0.0	**5.4**	22
2	Portfolio Optimization & Management	1.3	0.0	0.0	0.0	0.0	0.0	**1.3**	6
3	Reliability & Performance Assessment	2.1	0.2	0.0	0.0	0.0	0.0	**2.3**	16
4	**Total (Sch 5.1 L1, Sch 16.0 L1)**	**7.8**	**0.9**	**0.1**	**0.2**	**0.0**	**0.0**	**9.0**	**44**

5A.4.2.1. Energy Planning Department

Since fiscal 2021, the overall operating budget for the Energy Planning department has remained stable despite the increased complexity of the planning environment and external expectations.

For example, BC Hydro’s 20-year load forecast must build detailed models of reliable predictors of future sales such as GDP or industrial activity. In recent years, the relationship between these predictors and energy sales at a point in time appears to be changing, requiring more detailed analysis and investigation. In addition, resource planners must now consider the potential for emerging supply technologies such as solar generation or battery storage, which will impact the way energy is produced in future. These activities drive an increased demand for load forecasting and resource planning analysis.

Approximately 80 per cent of the Energy Planning department budget is related to labour costs for 22 FTEs. The 22 FTEs are spread across the Energy Planning teams as follows:

- Three FTEs representing the Director of Energy Planning and Analytics, an Administrative Assistant and a Project Manager who is managing the IRP, as well as vacancy factor adjustments. Vacancy factor adjustments are additional FTEs planned at the individual department level, with offsetting negative two FTEs in the Energy Planning department. These negative FTEs reflect vacancies that will occur during the year. As a result, there is in a net zero FTE and cost impact to the KBUs and to BC Hydro overall;
- Seven FTEs on the Integrated Resource Planning team who produce analyses of system and regional load-resource balances, reference prices and resource options to support a range of business decisions and regulatory proceedings;
- Three FTEs on the Integrated Resource Modelling team to execute system portfolio modelling runs in support of internal and external resource planning initiatives;
- Seven FTEs on the Load Forecasting team who produce a suite of load forecast products for long-term planning, medium-term investments, and operational & forecasting activities; and
- Four FTEs on the Network Integration team to manage the development and submission of transmission service requests to the Market Policy and Operations department in the Transmission and Distribution System Operations KBU. This team also represents BC Hydro's transmission interests as a transmission customer at the WECC. In addition, the team is responsible for integrated resource planning for the Fort Nelson area. The Fort Nelson area is not connected to BC Hydro's integrated system, but is grid connected to local generation resources and to Alberta's grid through a radial transmission line.

The $0.7 million in Services expenditures for this department are primarily related to professional consulting services to inform the development of BC Hydro's load forecasts and energy planning. The $0.1 million in Materials expenditures are for subscriptions to research services, and to inform the development of load forecasts. The $0.2 million in Buildings and Equipment expenditures are primarily related to subscriptions for capacity expansion and market price forecast modelling software.

5A.4.2.2. Portfolio Optimization and Management Department

Six FTEs in the Portfolio Optimization and Management department are responsible for coordinating the annual capital planning process for the Power System portfolio including the prioritization of more than 1,400 discrete investments and managing in-year adjustments to a capital portfolio which was forecasted at approximately $1.0 billion in fiscal 2022.

BC Hydro must be flexible and responsive to the investment needs of the system. As part of the annual capital planning cycle, more than 50 per cent of the investments within the capital portfolio require detailed review, revision and prioritization based on investment cost, timing and alignment with strategies so that the Capital Plan is updated and prioritized to respond to the latest information on the system risks and needs.

5A.4.2.3. Reliability and Performance Assessment Department

This department consists of 16 FTEs who are responsible for:

- Maintaining asset registry records for over 4 million BC Hydro assets;
- Creating and monitoring the execution of 80,000 maintenance work orders annually to ensure assets are maintained as scheduled and meet regulatory compliance;
- Creating and modifying asset management programs in response to updates or additions to a library of over 20,000 maintenance standards; and

- Providing support for Mandatory Reliability Standards compliance for thousands of assets critical to the BC Hydro system.

The $0.2 million in Services expenditures for this department are primarily related to Information Technology contractors and research memberships that support ongoing efforts to automate the setting up and processing of maintenance work orders that are currently processed manually.

5A.4.3 Fiscal 2023 to Fiscal 2025 Plan Operating Costs and FTEs

Table 5A-5 Energy Planning and Analytics KBU Operating Costs and FTEs

		Schedule Reference	F2021 Actual	F2022 Decision	F2023 Plan	F2024 Plan	F2025 Plan
			1	2	3	4	5
1	**Energy Planning and Analytics KBU**						
2	Operating Costs ($ million)	5.1 L1	8.8	9.0	9.1	8.7	9.4
3	FTEs	16.0 L1	45	44	44	44	45

Operating costs are increasing by approximately $0.1 million from the fiscal 2022 Decision amounts to the fiscal 2023 plan due to an additional $0.3 million to support the BCUC process surrounding the review of the 2021 Integrated Resource Plan (Clean Power 2040). This increase is offset by a labour reduction of $0.2 million due to a decrease in the Standard Labour Rates.

Operating costs are decreasing by $0.4 million in fiscal 2024 plan compared to fiscal 2023 plan due to the completion of the Integrated Resource Plan in fiscal 2023 resulting in a $0.6 million reduction, which is partially offset by $0.2 million increase due to Standard Labour Rate increases.

Operating costs are increasing by approximately $0.7 million in fiscal 2025 plan compared to fiscal 2024 plan, primarily due to the following drivers:

- $0.3 million for the initiation phase of the next Integrated Resource Plan;
- $0.2 million due to Standard Labour Rate increases; and

- $0.1 million due to the addition of one FTE to the Reliability and Performance Assessment department to maintain the increase in assets as the result of Site C (as discussed further in Chapter 5, section 5.10).

FTEs are planned to remain constant from fiscal 2022 Decision amounts to fiscal 2024 plan. As mentioned above, FTEs are planned to increase by one from fiscal 2024 plan to fiscal 2025 plan in order to maintain the increase in assets due to Site C.

5A.5 Dam Safety KBU

5A.5.1 Responsibilities

The primary function of the Dam Safety KBU is to administer and implement BC Hydro's Dam Safety Program. Since the Previous Application there have been some organizational changes within the KBU, but the primary functions of business group remain unchanged.

BC Hydro currently owns, operates, and maintains 85 dams at 41 sites throughout B.C. as a major part of our generating system. As a dam owner, BC Hydro is accountable to the Government of B.C. for overseeing the safety of BC Hydro dams in accordance with the British Columbia Dam Safety Regulation. BC Hydro representatives communicate regularly with the Comptroller of Water Rights, who represents the Government of B.C. on dam safety matters.

Through our Dam Safety Program, BC Hydro manages the risks associated with our dams, reservoirs and water passages to protect against significant adverse impacts from their mis-operation or failure and to support continued reliability of electricity supply.

Since the Previous Application, the Dam Safety KBU has implemented organizational changes that increase its asset management capabilities to provide oversight of water retention and conveyance assets through the full asset life cycle. The Regulatory and Asset Planning department was created to oversee the management of the assets and the regulatory compliance activities associated with their ongoing operation. The new department was created to increase the capacity and capabilities in these areas but does not change the overall responsibilities of the KBU from the Previous Application. The new department was created from existing budgets and FTEs from within the Dam Safety KBU and from Stations Asset Planning within the Asset Planning KBU.

Following the organizational changes, the Dam Safety KBU includes the following departments:

- Director and Business Unit Support Department;
- Regulatory and Asset Planning Department; and
- Surveillance Department.

5A.5.1.1. Director and Business Unit Support Department

The Director and Business Unit Support department is responsible for establishing and overseeing the development, maintenance and implementation of BC Hydro’s Dam Safety Program and its enabling Management System, and for overseeing BC Hydro’s overall compliance with the requirements of the Dam Safety Regulation. The department also provides administrative support for the Regulatory and Asset Planning department and the Surveillance department. Key activities in the department include:

- Developing strategies and objectives for dam safety risk reduction and management;
- Developing, reviewing and updating expectations and procedures in the Dam Safety Program Management System through the Governance and Implementation Manuals;

- Overseeing and assessing the performance of the Dam Safety Program and providing status reports to the Senior Vice-President, Integrated Planning, to the President and Chief Executive Officer, and to the Board of Directors;
- Communicating with the Comptroller of Water Rights to confirm compliance with the Dam Safety Regulation; and
- Providing administrative support for personnel, financial and record-keeping activities within the Dam Safety KBU and for the Dam Safety Program.

5A.5.1.2. Regulatory and Asset Planning Department

The Regulatory and Asset Planning department is responsible for producing the deliverables for compliance with the requirements of the Dam Safety Regulation, as well as the prioritization, initiation, implementation and management of the Dam Safety Investigations Program and the Dam Safety Maintenance and Capital Plans. Key activities in the department include:

- Managing the Dam Safety Reviews, including scheduling of reviews in accordance with the requirements of the Dam Safety Regulation, procuring and assigning independent external reviewers, compiling background reference documents and drawings for the reference of the reviewers, and coordinating the production and distribution of the Dam Safety Review reports;
- Updating the Operation, Maintenance and Surveillance Manuals for all of BC Hydro's dams in accordance with the Dam Safety Regulation;
- Providing program-level oversight of planned maintenance activities for water retention and conveyance infrastructure at BC Hydro's dam sites, including prioritizing work and, in collaboration with other BC Hydro KBUs, and developing the annual maintenance plan;
- Managing the Dam Safety Investigations Program, including the development of prioritized short-term and long-term plans for Dam Safety investigations based on risk level as well as initiating the Investigations, developing and

approving the Investigations' scope, and providing oversight of Investigations until completion and acceptance;

- Developing and updating the Dam Safety component of BC Hydro's Capital Plan so that Dam Safety risk reduction targets are achieved and are aligned with other asset management strategies; and
- Initiating capital projects, including approving the project scope, and providing oversight of the project risk reduction objectives until completion and acceptance.

5A.5.1.3. Surveillance Department

The Surveillance department is responsible for performing or overseeing all dam safety related activities at the dams and reservoirs including inspections, instrumentation monitoring and maintenance, and reporting of any unusual conditions. Key activities in the department include:

- Conducting and documenting the semi-annual and annual inspections of the dams and reservoir slopes;
- Reviewing the results of weekly and monthly dam safety inspections completed by site operations staff;
- Providing dam safety training for site operations staff;
- Conducting increased or enhanced surveillance in response to unusual conditions at dams, such as during floods or other high reservoir events;
- Monitoring and collecting data from the various dams' performance monitoring instrumentation and ensuring the quality and integrity of the data;
- Establishing warning and alarm thresholds for all instrumentation;
- Identifying unusual observations, conditions, or instrumentation readings and documenting them in the Dam Safety issues database as required;

- Tracking, rating and documenting within the Dam Safety issues database all identified physical deficiencies and Program non-conformances;
- Overseeing the implementation and approval of Interim Dam Safety Risk Management Plans in response to circumstances where construction or maintenance activities have potential to damage the dam or impede critical functions, or where risks that are above established targets must be retained until upgrades have been completed;
- Liaising with site management employees in the Operations Business Group to provide information on current dam safety issues and to arrange for required support from the Operations Business Group for routine weekly and monthly inspections;
- Participating in and providing input to Emergency Preparedness exercises; and
- Staffing the Dam Safety on-call process to provide 24/7 coverage of alarms and other dam safety related matters.

5A.5.2 Overview of Operating Costs and FTEs

Table 5A-6 Dam Safety KBU Fiscal 2022 Decision Operating Costs and FTEs by Department

	($ Millions)	Labour	Services - Other	Materials	Building & Equipment	Capitalized Overhead	External Recoveries	Total Operating	Total FTEs
1	Director and Business Unit Support	0.8	0.2	0.0	0.1	0.0	0.0	**1.1**	4
2	Regulatory and Asset Planning	2.7	2.7	0.0	0.0	0.0	0.0	**5.4**	8
3	Surveillance	4.1	0.6	0.1	0.0	0.0	0.0	**4.9**	27
4	**Total (Sch 5.1 L2, Sch 16.0 L2)**	**7.5**	**3.6**	**0.1**	**0.2**	**0.0**	**0.0**	**11.4**	**39**

The Dam Safety KBU is resourced to the level required to administer and implement the Dam Safety Program in accordance with accepted Canadian and international practices.

No two dam owners organize and delegate responsibilities relating to their dam safety programs in the same manner, nor do any two dam owners hold the same level of risk and complexity within their fleets of dams. As a result, direct comparisons of costs and assigned workforces on dam safety are difficult, if not impossible to make. Therefore, BC Hydro considers assessments and audits of the Program's performance to be the best means available to demonstrate whether staffing and monetary resources assigned to the Dam Safety KBU are sufficient and appropriate.

BC Hydro conducted an internal audit as well as an internal review of its Dam Safety Program in 2017 and 2018. BC Hydro believes that these assessments demonstrate that the staffing and monetary resources assigned to the Dam Safety KBU are sufficient and appropriate:

- The Dam Safety Program is audited every five years. The most recent audit was completed in September 2018 and was conducted by a team that included international subject matter experts in dam safety management and hazardous process industries. The audit found that "BC Hydro has a well-established Dam Safety Program that is in line with international practices with some aspects operating at best practice levels." The audit also included recommendations for improvements to some aspects of the Program where issues and opportunities for improvement had been identified. In response to the audit's recommendations, the Dam Safety KBU was reorganized and the Regulatory and Asset Planning department was created, as described in section 5A.5.1 above; and
- Similar findings resulted from a self-assessment performed by the Dam Safety KBU in 2017 to 2018, using a methodology that was developed by the Dam Safety Interest Group of CEATI International and is being used by a number of dam owners across North America. This assessment was facilitated by an international dam safety consulting firm that is familiar with the methodology, and assessed levels were supported by evidence and documentation to the satisfaction of the facilitator.

The next audit of BC Hydro's Dam Safety Program is scheduled for calendar 2023.

5A.5.2.1. Director and Business Unit Support Department

The majority of this department's budget is related to labour costs for four FTEs that include the Director of Dam Safety, an administrative assistant and two technical roles that support the Dam Safety program.

The department's Services budget includes $0.2 million for outreach and development activities to improve BC Hydro's Dam Safety Program, reinforce best practices, and influence the development of industry practices so that BC Hydro's Dam Safety Program remains relevant and adaptable to changing conditions.

5A.5.2.2. Regulatory and Asset Planning Department

The Regulatory and Asset Planning department consists of eight FTEs. These FTEs account for approximately $1.5 million of the total $2.7 million of labour costs in this department and are responsible for:

- Managing Dam Safety Reviews and preparing updates to the dams' Operations, Maintenance and Surveillance Manuals; an average of five each per year;
- Planning, managing and overseeing a program of investigations to identify deficiencies and issues and their means of remediation;
- Planning, initiating and overseeing capital projects to remediate identified deficiencies. At any given time, BC Hydro typically has more than 30 active Dam Safety projects; and
- Planning, initiating and overseeing planned maintenance activities for water retention and conveyance infrastructure at BC Hydro's dam sites.

The remaining $1.2 million in labour costs for this department and the $2.7 million in Services represent costs to:

- Engage consultants to perform independent Dam Safety Reviews and to make occasional use of contractors to supplement internal staff in preparing major updates to various dams' Operations, Maintenance and Surveillance Manuals; and

- Engage other BC Hydro KBUs (e.g., Engineering Design, Construction Services), external engineering consultants and contractors to perform dam safety investigations. The balance between the use of internal and external resources is based on resource availability and the need for specific expertise, which can vary from year-to-year depending on the investment requirements.

5A.5.2.3. Surveillance Department

The majority of this department's budget is related to labour costs for 27 FTEs, primarily made up of instrumentation technologists and dam safety engineers. This department's labour costs also include:

- Approximately $0.3 million for work performed by other KBUs in BC Hydro and charged to this department, such as Engineering Services; and
- Approximately $0.1 million in overtime for staffing the Dam Safety on-call process to provide 24/7 coverage and adequate response to alarms on key dam performance monitoring instruments and to address other dam safety related matters.

This department's Services budget includes approximately $0.6 million to support the surveillance component of the Dam Safety Program. This is primarily related to helicopter services for dam and reservoir slopes inspections and surveying by external contractors.

This department's Materials budget provides funding for the repair and maintenance of the performance monitoring instrumentation and data acquisition systems.

5A.5.3 Fiscal 2023 to Fiscal 2025 Plan Operating Costs and FTEs

Table 5A-7 Dam Safety KBU Operating Costs and FTEs

		Schedule Reference	F2021 Actual	F2022 Decision	F2023 Plan	F2024 Plan	F2025 Plan
			1	2	3	4	5
1	**Dam Safety KBU**						
2	Operating Costs ($ million)	5.1 L2	10.4	11.4	11.2	11.4	11.9
3	FTEs	16.0 L2	36	39	39	39	41

Operating costs are decreasing by $0.2 million from fiscal 2022 Decision amounts to fiscal 2023 plan primarily due to a decrease in Standard Labour Rates. Operating costs are increasing by $0.2 million from fiscal 2023 plan to fiscal 2024 plan due to Standard Labour Rate increases. Operating costs are increasing by $0.5 million from fiscal 2024 plan to fiscal 2025 plan due to an increase of two FTEs for Site C (refer to Chapter 5, section 5.10) and Standard Labour Rate increases.

FTEs are expected to remain stable from fiscal 2022 Decision to fiscal 2023 and 2024 plans. From fiscal 2024 to fiscal 2025, FTEs will increase by two for Site C (refer to Chapter 5, section 5.10).

5A.6 Asset Planning KBU

5A.6.1 Responsibilities

Since the Previous Application, Stations Asset Planning and Line Asset Planning have been consolidated into a single KBU called Asset Planning. The Line Asset Planning and Stations Asset Planning department structures will remain, with some minor re-structuring, and the functions of this KBU remain consistent with the Previous Application. BC Hydro refers to these two department structures as sub-KBUs in Chapter 5A.

Bringing the two KBUs together reporting to the Vice President of Asset Planning will increase consistency of planning and asset management across the asset classes. It will also support BC Hydro’s ongoing efforts to strengthen our Mandatory Reliability Standards program and to implement and sustain new Standards and functions, including implementing a new Planning Coordinator function, which is discussed in Chapter 5, section 5.7.

Stations Asset Planning Sub-KBU

The primary role of the Stations Asset Planning sub-KBU is the development and management of the maintenance and capital investment plans for the generating station and substation assets, including Non-Integrated Areas. The portfolio of assets managed by Stations Asset Planning includes:

- 30 hydroelectric generating facilities;
- Two thermal generating facilities;
- One synchronous condenser facility;
- 323 substations; and
- 29 generation/distribution assets that are not connected to the grid, in the Non-Integrated Area Portfolio.

The Stations Asset Planning sub-KBU consists of the following departments:

- Substations Growth and Sustainment Department; and
- Generating Stations Asset Planning Department.

Line Asset Planning Sub-KBU

The primary role of the Line Asset Planning sub-KBU is the development and management of the maintenance and capital investment plans for the transmission and distribution system line assets, including vegetation management, meter asset management, smart grid technologies and grid telecommunications assets management. The portfolio of assets managed by Line Asset Planning includes:

- Approximately 18,500 km of overhead transmission circuits;
- Approximately 60,000 km of overhead and underground distribution circuits;

- Approximately 77,000 hectares of transmission circuit rights-of-way;
- Approximately 2.1 million Revenue Meters;
- 98 Direct Current Fast Chargers (located at 68 sites);
- 168 Microwave sites, supporting the bulk electric system; and
- Protection and control systems in the 323 substations.

The Line Asset Planning sub-KBU is organized into the following departments:

- Transmission Asset Planning Department;
- Distribution Asset Planning Department;
- Telecommunications, Protection and Control Department;
- Future Grid and Modernization Department; and
- Vegetation Management Department.

5A.6.1.1. Substations Growth and Sustainment Department (Stations Asset Planning)

Since the Previous Application, the Non-Integrated Area Planning team was added to the Substations Growth and Sustainment department. Key activities in the department include:

- Producing and updating Facility Asset Plans;
- Conducting detailed area studies to determine substation and area configurations to serve new and existing loads and to interconnect new generation;
- Developing the 10-Year Capital Plan for the substation assets, including assets in the Non-Integrated areas, and assuming the initiator role for the subsequent capital projects;

- Developing substation plans and initiating projects to accommodate for load growth;
- Planning and initiating required maintenance and end of life replacement work for existing in-service substation assets;
- Supporting integrated planning work to optimize investments between the stations, distribution and transmission lines assets; and
- Supporting adherence to Mandatory Reliability Standards for infrastructure protection as appropriate, including internal reporting and WECC onsite audit preparation.

5A.6.1.2. Generating Stations Asset Planning Department (Stations Asset Planning)

Since the Previous Application, changes to this department include the consolidation of the Generation Asset Management department and the Generating Stations Maintenance Planning department. Key activities in the department include:

- Producing and updating Facility Asset Plans;
- Developing the 10-Year Capital Plan for the generating station assets, and assuming the initiator role for the subsequent capital projects;
- Planning and initiating required maintenance and end of life replacement work for existing in-service generating station assets; and
- Supporting adherence to Mandatory Reliability Standards for infrastructure protection as appropriate, including internal reporting and WECC onsite audit preparation.

5A.6.1.3. Distribution Asset Planning Department (Line Asset Planning)

Since the Previous Application, changes to this department include the consolidation of the Distribution Planning department with the Distribution portion of the Asset Sustainment department. Key activities in the department include:

- Developing system planning guidelines and strategies for asset sustainment, end of life replacement and reliability;
- Planning and initiating required maintenance and end of life replacement work for existing in-service distribution lines assets;
- Establishing reliability targets;
- Developing the 10-Year Capital Plan for the distribution lines assets, and assuming the initiator role for the subsequent capital projects;
- Conducting short- and long-term capacity and reliability planning;
- Reviewing load and distributed generation customer interconnections; and
- Integrating intelligent and automated equipment.

5A.6.1.4. Transmission Asset Planning Department (Line Asset Planning)

Since the Previous Application, changes to this department include the consolidation of the Transmission Planning department with the transmission portion of the Asset Sustainment department. Key activities in the department include:

- Developing asset sustainment and end of life replacement strategies;
- Developing the 10-Year Capital Plan for the transmission lines assets, and assuming the initiator role for the subsequent capital projects;
- Planning and initiating required maintenance and end of life replacement work for existing in-service transmission lines assets, including points of access;
- Developing the operational limits and operating instructions for the secure and reliable operation of the Power System;
- Conducting the technical planning required to interconnect new industrial loads and generation to the transmission system; and

- Supporting adherence to Mandatory Reliability Standards for infrastructure protection as appropriate, including internal reporting and WECC onsite audit preparation.

5A.6.1.5. Telecommunications, Protection and Control Department (Line Asset Planning)

Key activities in this department include:

- Developing asset strategies, standards, and investment plans involving the acquisition, construction and maintenance of the telecommunications, protection and control assets;
- Developing the 10-Year Capital Plan for the telecommunications, protection and control assets and assuming the initiator role for the subsequent capital projects;
- Planning and initiating required maintenance and end of life replacement work for existing in-service assets; and
- Supporting adherence to Mandatory Reliability Standards for infrastructure protection as appropriate, including internal reporting and WECC onsite audit preparation.

5A.6.1.6. Future Grid and Modernization Department (Line Asset Planning)

Since the Previous Application, this department was formed from FTEs within the Line Asset Planning sub-KBU. Key activities in this department include:

- Developing the future grid roadmap and long-term grid modernization strategies, including smart metering and grid automation;
- Managing the planning, supply, testing and maintenance of BC Hydro’s revenue metering assets in compliance with Measurement Canada Requirements;

- Identifying and testing new grid innovations, including research and development of new metering technologies; and
- Quantifying the impact of climate change on the future grid and how to adapt.

5A.6.1.7. Vegetation Management Department (Line Asset Planning)

Since the Previous Application, the responsibilities of this department were moved out of the Distribution Asset Planning department to a separate department reporting directly to the Vice President of Asset Planning. Key activities in this department include:

- Developing the vegetation management strategies and standards to ensure public and worker safety, system reliability and compliance with environmental regulations and Mandatory Reliability Standards;
- Developing annual and long-term maintenance programs and budgets for transmission rights-of-way, distribution corridors, and facilities (substations, switchyards, and microwave sites);
- Enabling assurance of quality in vegetation program development and execution; and
- Supporting adherence to Mandatory Reliability Standards for infrastructure protection as appropriate, including internal reporting and WECC onsite audit preparation.

5A.6.2 Overview of Operating Costs and FTEs

Table 5A-8 Asset Planning KBU Fiscal 2022 Decision Operating Costs and FTEs by Department

	($ Millions)	Labour	Services - Other	Materials	Building & Equipment	Capitalized Overhead	External Recoveries	Total Operating	Total FTEs
1	Asset Planning VP	2.7	5.4	0.0	0.0	0.0	-	**8.0**	16
2	Stations Asset Planning	57.6	35.2	10.3	0.0	0.0	-	**103.2**	56
3	Line Asset Planning	51.0	113.4	3.3	0.4	0.0	(9.0)	**159.2**	128
4	**Total (Sch 5.1 L3, Sch 16.0 L3)**	**111.3**	**154.0**	**13.6**	**0.4**	**0.0**	**(9.0)**	**270.4**	**200**

Since the Previous Application, five of the incremental Mandatory Reliability Standards FTEs were transferred from the Safety and Compliance Business Group to the Asset Planning VP department. These FTEs are not reflected in the fiscal 2022 Decision amounts shown in Table 5A-8 above.

5A.6.2.1. Asset Planning VP Department

The Line Asset Planning Director department was re-named as the Asset Planning VP department. This department's budget is related to labour costs for 16 FTEs including: The Vice President of Asset Planning, one administrative assistant, one FTE supporting strategic programs, 13 FTEs supporting vegetation management and approximately $5.3 million in non-labour budget for LiDAR acquisition (supporting FAC-003 and FAC-008). The 13 FTEs for vegetation management will be transferred to their appropriate departments within fiscal 2022.

Table 5A-9 Stations Asset Planning Sub-KBU Fiscal 2022 Decision Operating Costs and FTEs by Department[310]

	($ Millions)	Labour	Services - Other	Materials	Building & Equipment	Capitalized Overhead	External Recoveries	Total Operating	Total FTEs
1	Stations Asset Maintenance	47.2	33.6	10.3	0.0	0.0	0.0	**91.1**	-
2	Stations Asset Planning, Director	0.7	0.1	0.0	0.0	0.0	0.0	**0.8**	3
3	Substations Growth and Sustainment	3.8	0.2	0.0	0.0	0.0	0.0	**4.1**	27
4	Generating Stations Asset Planning	5.8	1.3	0.0	0.0	0.0	0.0	**7.2**	26
5	**Total**	**57.6**	**35.2**	**10.3**	**0.0**	**0.0**	**0.0**	**103.2**	**56**

5A.6.2.2. Stations Asset Maintenance Department (Stations Asset Planning)

This department holds the budget for the required maintenance work on BC Hydro's generating station and substation assets. Stations Asset Maintenance is discussed further in Chapter 5, section 5.15.2.2.

[310] As discussed in section 5A.6.1 Substations Growth and Sustainment department also includes the Non-Integrated Area Planning team. The Generating Stations Asset Planning department consists of the former Generation Asset Management and Generating Stations Maintenance Planning departments.

5A.6.2.3. Stations Asset Planning Director Department (Stations Asset Planning)

This department's budget is related to labour costs for three FTEs including: The Director of Stations Asset Planning, one administrative assistant and one technical role that supports the Stations Asset Planning department.

5A.6.2.4. Substations Growth and Sustainment Department (Stations Asset Planning)

The majority of this department's budget relates to labour costs for 27 FTEs.

There are 17 FTEs on the Substation Growth and Sustainment team, and they are responsible for:

- Developing the sustaining capital plan and managing the annual substation maintenance work plan as well as the substation component of the asbestos management and PCB remediation work plans;
- Developing and updating 60 to 70 maintenance standards, maintaining 17 asset class strategies and producing 10 to 15 asset plans each year;
- Producing 40 to 60 substation planning studies to address load, sustainment and system needs;
- Conducting three to five annual area planning studies to review substation capability to meet long-term area growth; and
- Producing 40 system impact studies for customer and generation interconnections.

There are seven FTEs on the Non-Integrated Area Team. A significant portion of the costs associated with these positions are charged out to maintenance programs and capital projects. These FTEs are responsible for:

- Developing and managing the annual maintenance work program for non-integrated areas; and

- Developing, managing, and delivering the capital program for the non-integrated area assets. Further information on maintenance is provided in Chapter 5, section 5.15.

The remaining three FTEs represent the department manager as well as two FTEs on the analytical studies team who conduct approximately 30 studies each year on the interaction between equipment specifications and system operating performance.

5A.6.2.5. Generating Stations Asset Planning Department (Stations Asset Planning)

The majority of this department's budget relates to labour costs for 26 FTEs.

There are nine FTEs on the Generation Asset Management team, and they are responsible for:

- Developing and sustaining long-term strategies for BC Hydro's 32 generating stations and one synchronous condenser station;
- Developing the annual 10-Year Capital Plan to meet the sustainment needs of the BC Hydro generating assets and facilities, initiating approximately 10 to 20 capital projects, valued at approximately $150 million to $300 million, each year; and
- Overseeing the generating Asset Health Rating program and reviewing and accepting approximately 100 Asset Health Ratings per year.

There are 17 FTEs on the Generating Stations Maintenance Planning team, and they are responsible for:

- Developing and overseeing the annual generating stations maintenance work plan;

- Developing and overseeing the annual sustainment and improvement work plan that includes: Mandatory Reliability Standards, maintenance program optimization and maintenance standards;
- Identifying regional capital needs and initiating approximately $20 million to $25 million in small capital projects per year;
- Developing and implementing governance for managing asset performance during the operating life of our assets. management governance and 25 asset-class performance strategies; and
- Developing and implementing 25 asset-class performance strategies as part of the standardized maintenance framework.

The department's non-labour budget is primarily for external resources used to augment the internal workforce of the Generation Stations Maintenance Planning team to meet work demands. This includes work to support implementation of Mandatory Reliability Standards.

Table 5A-10 Line Asset Planning Sub-KBU Fiscal 2022 Decision Operating Costs and FTEs by Department[311]

	($ Millions)	Labour	Services - Other	Materials	Building & Equipment	Capitalized Overhead	External Recoveries	Total Operating	Total FTEs
1	Line Asset Maintenance	30.6	103.6	3.2	0.3	-	(9.0)	**128.7**	-
2	Distribution Asset Planning	5.7	1.1	0.0	0.0	-	-	**6.9**	28
3	Transmission Asset Planning	7.6	6.6	0.0	0.1	-	-	**14.2**	46
4	Telecommunications, Protection and Control	3.8	0.6	-	-	-	-	**4.4**	21
5	Future Grid and Modernization	2.8	0.4	0.0	0.0	-	-	**3.3**	30
6	Vegetation Management	0.6	1.0	0.0	0.0	-	-	**1.6**	3
7	**Total**	**51.0**	**113.4**	**3.3**	**0.4**	**0.0**	**(9.0)**	**159.2**	**128**

311 As discussed in section 5A.6.1 Transmission Asset Planning consists of the former Transmission Planning department the transmission portion of the Asset Sustainment department. Distribution Asset Planning consists of the former Distribution Planning department and the Distribution portion of the Asset Sustainment department.

5A.6.2.6. Line Asset Maintenance Department (Line Asset Planning)

This department holds the budget for the required maintenance work on BC Hydro's transmission lines, distribution lines, and telecommunications assets. Line Asset Maintenance is discussed further in Chapter 5, section 5.15.2.1.

5A.6.2.7. Distribution Asset Planning Department (Line Asset Planning)

This department's budget primarily consists of labour costs for 28 FTEs, and they are responsible for:

- Developing and maintaining approximately 20 distribution system strategies, planning criteria, procedures and guidelines;
- Developing the annual 10-Year Capital Plan to meet the sustainment and growth needs of the BC Hydro distribution system assets;
- Managing plans for over 1,500 distribution feeders and approximately 1,700 distribution automation devices on the system;
- Developing approximately 15 studies including feeder evaluations, integrated planning studies and distribution area plans annually;
- Developing annual peak demand forecasts for approximately 220 substations based on load forecast guidelines;
- Developing maintenance plans to maintain 900,000 distribution poles and approximately 60,000 kilometers of distribution lines and all associated distribution equipment and components; and
- Evaluating approximately 700 distributed energy resource customer requests annually.

The department's non-labour budget is primarily used to fund distribution system planning studies and asset failure studies.

5A.6.2.8. Transmission Asset Planning Department (Line Asset Planning)

This department's budget primarily consists of labour costs for 46 FTEs, and they are responsible for:

- Developing maintenance plans to maintain 116,000 transmission poles and approximately 19,000 kilometers of transmission lines, all within compliance with approximately 100 asset standards;
- Initiating approximately 20 transmission asset failure investigations each year;
- Developing the annual 10-Year Capital Plan to meet the sustainment and growth needs of the BC Hydro transmission system assets;
- Performing an average of 65 transmission customer load connection request studies annually based on external needs;
- Reviewing and updating operating orders as required; and
- Meeting Mandatory Reliability Standards requirements for transmission planning. Each year, the department conducts an average of 14 transmission system planning performance assessments and an average of 25 operational planning and model verifications.

The majority of this department's non-labour budget is for facility rating studies associated with Mandatory Reliability Standard FAC-008.

5A.6.2.9. Telecommunications, Protection and Control Department (Line Asset Planning)

This department's budget primarily consists of labour costs for 21 FTEs, and they are responsible for:

- Planning the telecommunications requirements for approximately 150 capital projects and interconnection requests annually;
- Initiating approximately 55 projects and programs annually;

- Managing asset plans for telecommunications, protection and control system failures;
- Managing the annual maintenance programs;
- Meeting telecommunications requirements to connect approximately 6,000 additional meters annually; and
- Managing lifecycle planning for telecommunications assets, including 168 microwave sites supporting the bulk electric system, 194 mobile radio sites supporting field staff, 2,100 Cisco grid routers supporting 2.1 million smart meters, and protection and control systems in 323 substations.

The majority of the department's non-labour budget is for implementing improvements to the Mandatory Reliability Standards Critical Infrastructure Protection (**CIP**) program for medium impact facilities.

5A.6.2.10. Future Grid and Modernization Department (Line Asset Planning)

This department's budget primarily consists of labour costs for 30 FTEs, and they are responsible for:

- Developing BC Hydro's strategy and roadmap for the future grid;
- Planning system innovations including public electric vehicle charging infrastructure;
- Planning, engineering, compliance, testing, and performing quality assurance of over 2.1 million revenue meters; and
- Developing approximately 50 complex meter solutions each year for large industrial customers and IPPs.

The department's non-labour budget is primarily used to fund testing equipment calibration, new equipment research and testing, climate change and innovation studies.

5A.6.2.11. Vegetation Management Department (Line Asset Planning)

This department's budget currently reflects labour costs associated with three FTEs. Of the 13 FTEs for vegetation management mentioned in section 5A.6.2.1, seven will be moved to this department in fiscal 2022. These ten FTEs are responsible for:

- Initiating vegetation management for approximately 77,000 hectares of transmission rights-of-way;
- Initiating vegetation management of distribution corridors for over 48,600 km of overhead distribution circuits; and
- Conducting quality assurance reviews of the planning and execution of the vegetation management annual plan.

The department's non-labour budget is for the Ministry of Forests Wildfire Response Agreement.

5A.6.3 Fiscal 2023 to Fiscal 2025 Plan Operating Costs and FTEs

Table 5A-11 Asset Planning KBU Operating Costs and FTEs

	Schedule Reference	F2021 Actual	F2022 Decision	F2023 Plan	F2024 Plan	F2025 Plan
		1	2	3	4	5
Asset Planning KBU						
Operating Costs ($ million)	5.1 L3	236.8	270.4	278.9	286.3	294.1
FTEs	16.0 L3	198	200	211	211	211

Within the Asset Planning KBU, the following FTE transfers and additions have occurred since the Previous Application:

- Five FTEs transferred to Asset Planning from the Safety and Compliance Business Group in support of Mandatory Reliability Standards, as mentioned earlier in section 5A.6.2;
- One FTE transferred to Asset Planning from the Safety and Compliance Business Group in support of hazardous program management (asbestos, PCBs, etc.); and

- Six FTEs transferred from Asset Planning to the Engineering Design (four FTEs) and Engineering Services (two FTEs) KBUs as part of the development of the LiDAR program for vegetation management.

The increase in FTEs from the fiscal 2022 Decision to the fiscal 2023 plan is discussed below.

Table 5A-12 Asset Planning VP Operating Costs and FTEs

		F2021 Actual	F2022 Decision	F2023 Plan	F2024 Plan	F2025 Plan
		1	2	3	4	5
1	**Asset Planning VP KBU**					
2	Operating Costs ($ million)	0.8	8.0	0.7	0.7	0.7
3	FTEs	4	16	3	3	3

For the Asset Planning VP department, operating costs are decreasing by $7.3 million and FTEs are decreasing by 13 from the fiscal 2022 Decision as FTEs associated with vegetation management and Mandatory Reliability Standards are transferred to the Line Asset Planning sub-KBU.

Table 5A-13 Stations Asset Planning Sub-KBU Operating Costs and FTEs

		F2021 Actual	F2022 Decision	F2023 Plan	F2024 Plan	F2025 Plan
		1	2	3	4	5
1	**Stations Asset Planning KBU**					
2	Operating Costs ($ million)	93.2	103.2	103.9	106.5	109.2
3	FTEs	54	56	61	61	61

For the Stations Asset Planning sub-KBU, operating costs are increasing by $0.7 million from the fiscal 2022 Decision amount to the fiscal 2023 plan primarily due to approximately $0.1 million for stations planning support of the Electrification Plan, $0.7 million for the NIA – Diesel Reduction Strategy (discussed in Chapter 5, section 5.5.3.4) and $0.3 million for maintenance related to Site C assets that are planned to be operational during the fiscal year, as discussed in Chapter 5, section 5.10. These increases are partially offset by a $0.7 million decrease in Standard Labour Rates.

From fiscal 2023 plan to fiscal 2024 plan operating costs are increasing by $2.6 million primarily due to $0.8 million for maintenance related to Site C assets that are planned to be operational during the fiscal year, $0.3 for the NIA – Diesel Reduction Strategy and $1.5 million due to Standard Labour Rate increases.

From fiscal 2024 to fiscal 2025 operating costs are increasing by $2.7 million primarily due to $1.1 million for maintenance related to Site C assets that are planned to be operational during the fiscal year and a $1.7 million due to Standard Labour Rate increases.

Stations Asset Planning FTEs are planned to increase by five from the fiscal 2022 Decision amount to the fiscal 2023 plan. Two FTEs are to conduct studies in support of the Electrification Plan, and three FTEs are in support of BC Hydro's NIA – Diesel Reduction Strategy (discussed in Chapter 5, section 5.5.3.4). For fiscal 2024 plan and fiscal 2025 plan, the Stations Asset Planning FTEs are planned to remain constant.

Table 5A-14 Line Asset Planning Sub-KBU Operating Costs and FTEs

		F2021 Actual	F2022 Decision	F2023 Plan	F2024 Plan	F2025 Plan
		1	2	3	4	5
1	**Line Asset Planning KBU**					
2	Operating Costs ($ million)	142.8	159.2	174.3	179.1	184.2
3	FTEs	140	128	147	147	147

For the Line Asset Planning sub-KBU, operating costs are increasing by $15.1 million from the fiscal 2022 Decision amount to the fiscal 2023 plan. Approximately $7 million in operating costs were transferred from the VP Asset Planning department related to the vegetation management incremental increase from the Previous Application and funding for LiDAR surveys in support of vegetation management and line rating studies. The remainder is primarily due to $0.4 million for transmission planning support of the Electrification Plan and $7.5 million associated with the new Vegetation Management Strategy, which is discussed in Chapter 5, section 5.8. These increases are offset by a $0.8 million decrease in Standard Labour Rates and a $0.4 million decrease from the fiscal 2022 Decision amount for one-time Mandatory Reliability Standards expenses as discussed in Chapter 5, section 5.7.

From fiscal 2023 to fiscal 2024 operating costs are increasing by $4.8 million primarily due to $3.9 million for the new Vegetation Management Strategy, $1.4 million due to Standard Labour Rate increases, partially offset by a $0.4 million decrease for one-time Mandatory Reliability Standards expenses as discussed in Chapter 5, section 5.7.

From fiscal 2024 to fiscal 2025 operating costs are increasing by $5.1 million primarily due to $4.6 million for the new Vegetation Management Strategy, $1.6 million due to Standard Labour Rate increases, partially offset by a $1.1 million decrease for one-time Mandatory Reliability Standards expenses as discussed in Chapter 5, section 5.7.

Line Asset Planning FTEs are increasing by 19 from the fiscal 2022 Decision amount. Of these, seven FTEs are re-allocated from the Asset Planning VP department in support of vegetation management, five FTEs were transferred from the Safety and Compliance Business Group in support of Mandatory Reliability Standards as mentioned earlier, and one FTE is a transfer from the Stations Asset Planning sub-KBU in support of Mandatory Reliability Standards. The remaining six FTEs are incremental in fiscal 2023; a planned increase of four for Mandatory Reliability Standards and two to conduct studies in support of the Electrification Plan. For fiscal 2024 plan and fiscal 2025 plan, the Line Asset Planning FTEs are planned to remain constant.

5A.7 Interconnections and Shared Assets KBU

5A.7.1 Responsibilities

There have been no material changes to the organization or responsibilities of the Interconnections and Shared Assets KBU since the Previous Application.

The Interconnections and Shared Assets KBU is responsible for:

- Setting interconnections policies and strategies, including managing, revising and enforcing asset-related agreements and tariff requirements;
- Designing and implementing the process of interconnecting loads and generators, and modifying BC Hydro's transmission and distribution infrastructure, resulting from third party requests;
- Setting business practices for interconnection activities, including quality control, cost estimating, establishing timelines, reporting and prioritizing;
- Managing the relationship and contract with TELUS as Joint Owner of over 80 per cent of the distribution wood poles; and
- Managing third party telecommunication attachments to distribution and transmission infrastructure.

The interconnection of residential and small commercial load customers on the distribution system is managed by the Distribution Design and Customer Connections KBU within the Operations Business Group as discussed in Chapter 5C, section 5C.7.

This KBU consists of the following departments:

- Customer Interconnections and Policy Department;
- Joint Use and Shared Assets Department;
- Interconnections and Shared Assets Director Department; and

- Interconnections and Shared Assets Customer Projects.

5A.7.1.1. Customer Interconnections and Policy Department

The Customer Interconnections and Policy department manages customer requests to interconnect, supply, or receive electrical services from the transmission and distribution system. These requests are from new and existing generators, transmission loads and major distribution loads. In addition, the department manages third party requests to relocate BC Hydro transmission and distribution infrastructure as well as conduct pipeline proximity and crossing studies. It is also responsible for managing specialized transmission contracts, technical and commercial agreements with the U.S., Alberta and intra-provincial utilities. Relevant tariffs, policies and agreements that govern all of the above customer driven requests are managed by this department.

5A.7.1.2. Joint Use and Shared Assets Department

The Joint Use and Shared Assets department manages the joint ownership and use agreement with TELUS (co-owner of approximately 800,000 of our distribution poles) as well as third-party co-location requests which generate additional revenue from our existing transmission and distribution infrastructure. Activities carried out to support these responsibilities include:

- Establishing contractual agreements;
- Managing agreements and billings;
- Managing the licensee application process;
- Maintaining joint ownership and licensee attachment records;
- Coordinating with other groups within BC Hydro so that the co-location of third-party assets does not compromise the effective operation of the BC Hydro system; and

- Working with other groups within BC Hydro to deliver on contractual obligations and resolve any issues that arise.

5A.7.1.3. Interconnections and Shared Assets Director Department

This department is the Office of the Interconnections and Shared Assets Director and provides overall management for the Interconnections and Shared Assets KBU.

5A.7.1.4. Interconnections and Shared Assets Customer Projects Department

This department holds the budget for the customer project work such as conceptual reviews, feasibility studies and system impact studies as described in Chapter 6, section 6.2.3.

5A.7.2 Overview of Operating Costs and FTEs

Table 5A-15 Interconnections and Shared Assets KBU Fiscal 2022 Decision Operating Costs and FTEs by Department

	($ Millions)	Labour	Services - Other	Materials	Building & Equipment	Capitalized Overhead	External Recoveries	Total Operating	Total FTEs
1	Customer Interconnections and Policy	5.2	0.1	0.0	0.0	0.0	0.0	**5.4**	29.0
2	Joint Use and Shared Assets	2.2	0.6	0.0	0.0	0.0	(0.4)	**2.5**	15.0
3	Interconnections and Shared Assets Director	0.4	0.3	0.0	0.0	0.0	0.0	**0.7**	2.0
4	Interconnections and Shared Assets Customer Projects	1.2	3.4	0.0	0.0	0.0	0.0	**4.6**	-
5	**Total (Sch 5.1 L4, Sch 16.0 L4)**	**9.0**	**4.4**	**0.0**	**0.0**	**0.0**	**(0.4)**	**13.1**	**46**

5A.7.2.1. Customer Interconnections and Policy Department

The majority of this department's budget relates to labour costs for 29 FTEs as follows:

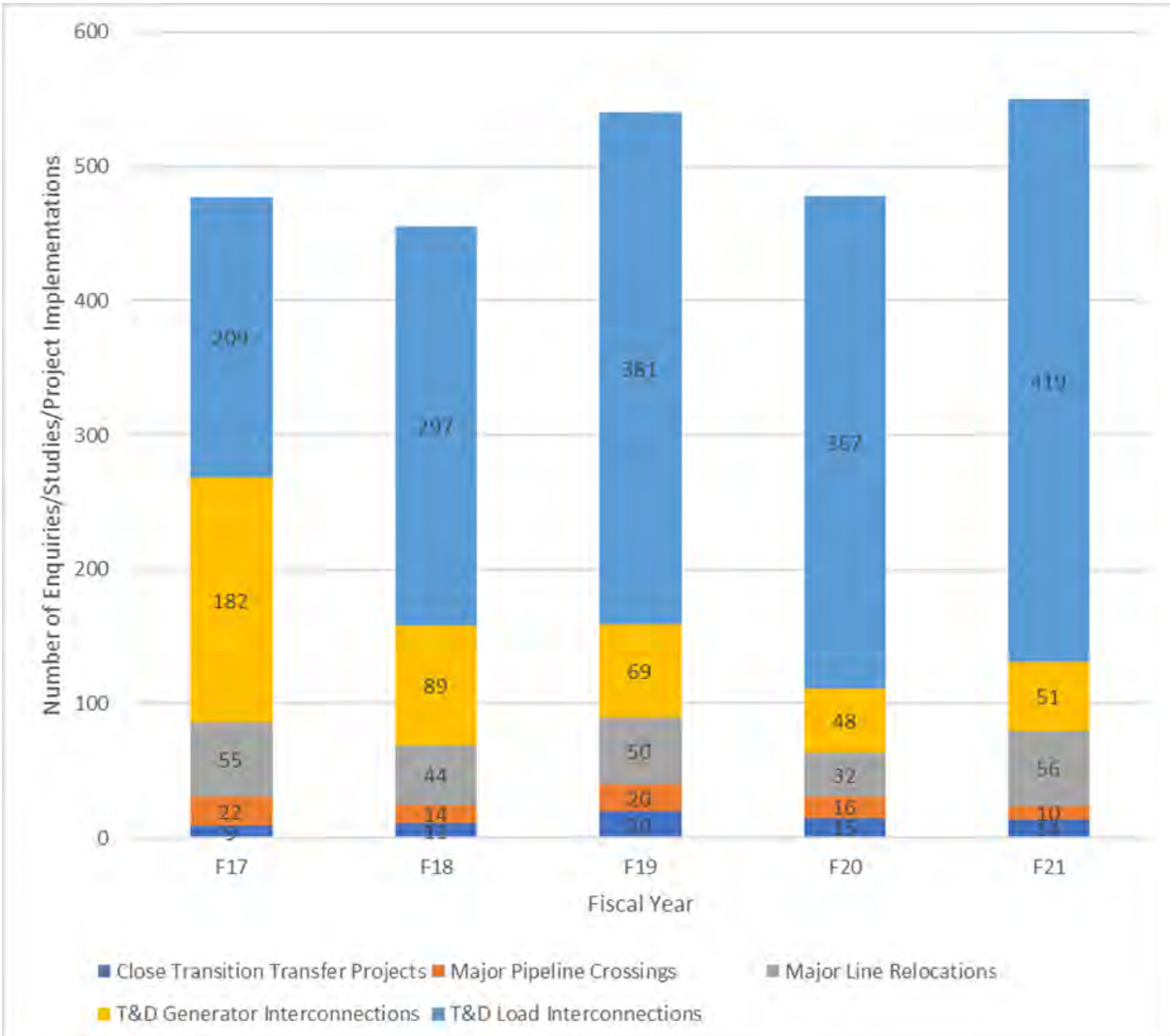
- 23 FTEs manage over 500 new customer interconnection enquiries, studies and implementation projects each year; and
- Six FTEs manage the development and application of tariffs and policies as well as strategic commercial agreements, such as the Ministry of Transportation and Infrastructure protocol agreement.

The department's non-labour budget primarily funds external consultants for interconnection studies.

As shown in Figure 5A-3 below, despite a decrease in work associated with new generator interconnection requests, primarily due to the indefinite suspension of the Standing Offer Program in fiscal 2019 (discussed in F2020-F2021 RRA Chapter 4, section 4.3.2), increases in new load interconnection requests, regulatory compliance work and tariff work, such as responding to FERC Order 845,[312] have increased the total volume of work managed by this department. One FTE was transferred out to the Distribution Design and Customer Connections KBU within the Operations Business Group because the administration activities for some customer programs such as providing credits or refunds to distribution customers were transferred to that KBU. One FTE was transferred in from the Interconnections and Shared Assets Director Department due to a reporting structure change within the KBU to achieve better organizational alignment. As a result, the number of FTEs in this department has remained the same.

312 FERC Order No. 845 is the reform of the OATT Generator Interconnection Procedures and Agreements.

1 **Figure 5A-3 Interconnections Project Activity**[313]



2 During the Test Period, BC Hydro expects that generator activities will remain similar
3 to fiscal 2021 levels as existing projects will continue to move through the
4 interconnection process and ongoing work will be required with BC Hydro
5 generators, load displacement projects, and operating generators. BC Hydro also

[313] This graph shows the number of activities but does not represent the workload related to the complexity of each activity. A project is shown as one activity, regardless of whether it is a low complexity project or a high complexity project.

expects that new load interconnection requests and activities will increase during the Test Period in part due to the Electrification Plan.

5A.7.2.2. Joint Use and Shared Assets Department

The majority of this department's budget relates to labour costs for 15 FTEs as follows:

- Eight FTEs on the Joint Use team, five of which are 50 per cent funded by TELUS through the Joint Use Office which administers the joint ownership and use agreement, maintains records, and manages financial recoveries from TELUS. The external recoveries shown in Table 5A-15 primarily relate to the TELUS contributions to joint pole construction and replacement; and
- Seven FTEs on the Shared Assets team. This team manages five program offerings and processes over 500 applications annually. Six FTEs on this team are 50 per cent funded through individual application fees related to processing new attachment requests on poles as well as project work to prepare and install licensee equipment on poles. The remaining 50 per cent of the labour costs associated with these FTEs are funded through commercially-agreed annual rental attachment rates. Shared assets annual revenue is included as a part of Miscellaneous Revenue as shown in Appendix A, Schedule 15, line 11 and line 16, and is forecast to be $8.9 million in fiscal 2022.

The department's non-labour budget of $0.6 million primarily funds external consultants for the Joint Use Office of which $0.4 million is offset by recoveries.

5A.7.2.3. Interconnections and Shared Assets Director Department

The majority of this department's budget relates to labour costs for two FTEs – the KBU Director and an administrative assistant. The number of FTEs has decreased by one in fiscal 2021 because one FTE was transferred out to the Customer Interconnections and Policy Department due to a reporting structure change within the KBU to achieve better organizational alignment.

The department's non-labour budget of $0.3 million primarily funds external resources to assist with various commercial negotiations and project support for the KBU Director to support other two departments.

5A.7.2.4. Interconnections and Shared Assets Customer Projects Department

This department holds the budget for the customer project work as described in section 5A.7.1.4. There are no FTEs in this department. The customer project work is managed by FTEs in Customer Interconnections and Policy Department or Joint Use and Shared Assets Department depending on the types of customer requests. Internal labour of $1.2 million from other KBUs such as Asset Planning, Engineering and Capital Infrastructure Project Delivery is supplemented with external services of $3.4 million to complete customer project work. Costs associated with the customer project work are offset by miscellaneous revenues.

5A.7.3 Fiscal 2023 to Fiscal 2025 Plan Operating Costs and FTEs

Table 5A-16 Interconnections and Shared Assets KBU Operating Costs and FTEs

		Schedule Reference	F2021 Actual	F2022 Decision	F2023 Plan	F2024 Plan	F2025 Plan
			1	2	3	4	5
1	**Interconnections and Shared Assets KBU**						
2	Operating Costs ($ million)	5.1 L4	15.4	13.1	14.7	14.1	14.2
3	FTEs	16.0 L4	48	46	47	47	47

Operating costs from the fiscal 2022 Decision to fiscal 2023 plan are increasing by $1.6 million. From fiscal 2023 to fiscal 2024, operating costs are decreasing by $0.6 million. From fiscal 2024 to fiscal 2025, operating costs are relatively stable.

Based on historical trending and the expected increase in future volume of interconnections work, the operating cost are increasing in fiscal 2023, fiscal 2024 and 2025 plan to complete the studies and project work for the Test Period. The average operating costs of the three previous years (fiscal 2019, 2020 and 2021 actuals) were used to forecast the operating costs for interconnections studies and project work for fiscal 2023 to fiscal 2025 plan. From fiscal 2022 Decision to fiscal 2023 plan, there is a planned increase of costs of $1.8 million. From fiscal 2023 to fiscal 2024, there is a decrease of $1.5 million. From fiscal 2024 to fiscal 2025, there is a decrease of $0.7 million. The changes in costs are offset by changes in revenues from customers.

The fiscal 2023, 2024 and 2025 plans also include minor decrease or increase compared to fiscal 2022 Decision amounts due to changes in Standard Labour Rates. From the fiscal 2022 Decision to fiscal 2023 plan, operating costs are decreasing by $0.2 million. From fiscal 2023 to fiscal 2024, there is an increase of $0.2 million. From fiscal 2024 to fiscal 2025, there is an increase of $0.2 million.

Expenditures for interconnection study and project work to support the Electrification Plan are deferred. Further information on the Electrification Plan is provided in Chapter 10.

In fiscal 2023 plan, Interconnections and Shared Assets FTEs are planned to increase by one. This is a result of the increase in interconnections work for the Electrification Plan. Further information on the Electrification Plan is provided in Chapter 10.

5A.8 Engineering Design KBU

5A.8.1 Responsibilities

As noted in the fiscal 2022 Decision, Engineering was split into two KBUs – Engineering Design and Engineering Services. This change was headcount and budget neutral, and the functions previously performed by the former single Engineering KBU are still performed within either Engineering Design or Engineering Services. This change facilitates collaboration and consistency by grouping similar teams together within the respective two KBUs.

The Engineering Design KBU is responsible for providing:

- Engineering design on capital projects for power system assets;
- Owner's Engineering oversight on capital projects;
- Engineering standards for power system assets;
- Engineering expertise for complex customer interconnection requests; and
- Technical coordination on high risk, system-wide, and cross-discipline design, technical, and operational issues.

The Engineering Design KBU consists of the following departments:

- Director, Engineering Design Department;
- Generation Design Department;
- Transmission Design Department; and
- Distribution Engineering and Standards Department.

BC Hydro's delivery model for engineering services relies upon a combination of internal staff and external service providers. This model is internally known as the Owner's Engineer Plus model, where a portion of BC Hydro's engineering work is completed by external service providers and the review and oversight for that work is performed by internal BC Hydro resources (i.e., the Owner's Engineer).

As the Owner's Engineer, the Engineering Design KBU is accountable for verifying that the overall BC Hydro system is technically capable of safely meeting operational requirements and the demands of its stakeholders, customers, and employees.

All BC Hydro, power system engineering work performed by external service providers is subject to Owner's Engineer reviews. This department completes approximately 1,300 Owner's Engineer reviews each year. The level of oversight provided varies depending on the contractual arrangement, type of project, project risk, and phase of project implementation. The “Plus” part of the Owner’s Engineer Plus model requires that BC Hydro retain its capability as a knowledgeable owner through employees having the opportunity to build and maintain their engineering skill sets and technical knowledge by performing engineering design, particularly in high risk and complex subject matter areas. This model is in the best interest of BC Hydro and its customers for the long term as it enables leveraging the detailed system and design knowledge of internal engineers with the capacity, resource flexibility, and broader capabilities of the external service providers to manage the variations in workload.

In February 2021 and since the filing of the Previous Application, the *Professional Governance Act* came into force, replacing the Engineers and Geoscientists Act in British Columbia. The *Professional Governance Act* requires that Engineers and Geoscientists B.C. regulate firms such as BC Hydro that are engaged in the practice of professional engineering and/or geoscience. In fiscal 2022, BC Hydro will register for a Permit to Practice with Engineers and Geoscientists BC, which is one of our compliance requirements under the *Professional Governance Act*. While the *Professional Governance Act* is not yet driving significant costs, it will result in increased regulatory activities for BC Hydro to ensure we maintain compliance with the Act, including submitting and maintaining a Professional Practice Management Plan, adhering to Engineers and Geoscientists BC’s annual reporting requirements, and submitting evidence for compliance audits.

5A.8.1.1. Director, Engineering Design Department

The Director, Engineering Design department provides overall management for the Engineering Design KBU. The department is responsible for engineering design and standards, and facilitates coordination on high risk, system-wide, and cross-discipline design, technical, and operational issues. This department is accountable for providing engineering design and oversight to power system capital projects to ensure the system will meet the requirements of BC Hydro.

5A.8.1.2. Generation Design Department

The Generation Design department is responsible for generation engineering design expertise, Owner's Engineer oversight on generation and Dam Safety capital projects, and technical support to planning and operations. As Owner's Engineer, the Generation Design department is accountable for ensuring the BC Hydro generation system and assets are technically capable and safe to operate. Engineering work on capital projects managed by Project Delivery follows the design and project processes in the Project and Portfolio Management (**PPM**) System (refer to Chapter 6, section 6.2) including Engineering work package agreements to detail scope, deliverables, schedules, and budgets. The department provides design to approximately 135 capital projects annually with 35 per cent of engineering from engineering service providers. The department also provides specific planning expertise, root cause analysis, and critical outage responses as needed. Asset Planning, Dam Safety, Operations, and Generation Resource Management rely upon Generation Design's asset and system knowledge and engineering expertise.

5A.8.1.3. Transmission Design Department

The Transmission Design department is responsible for transmission engineering design expertise and Owner's Engineer oversight on transmission lines, transmission stations, and telecommunication capital projects. As Owner's Engineer, the Transmission Design department is accountable for ensuring the BC Hydro transmission system is technically capable and safe to operate. Engineering work on capital projects managed by Project Delivery follows the design and project processes in the PPM System (refer to Chapter 6, section 6.2) including Engineering work package agreements to detail scope, deliverables, schedules, and budgets. The department provides design to approximately 177 capital projects annually with 50 per cent of engineering from engineering service providers. The department also provides transmission line, telecommunications, and protection and control maintenance and planning expertise; root cause analysis; Mandatory Reliability Standards sustainment and mitigation support, engineering expertise associated with complex customer interconnections projects; and critical outage responses as needed. The Asset Management and Operations KBUs rely upon Transmission Design's asset and system knowledge and engineering expertise.

5A.8.1.4. Distribution Engineering and Standards Department

The Distribution Engineering and Standards department has two teams: Distribution Engineering and Distribution Standards.

Distribution Engineering is responsible for distribution engineering design expertise and Owner's Engineer oversight on distribution lines and distribution stations capital projects. The department provides engineering support to approximately 2,300 distribution design projects annually. As Owner's Engineer, the division is accountable for ensuring the BC Hydro distribution system is technically capable and safe to operate. The division also provides planning expertise, root cause analysis, and critical outage responses as needed. The Asset Management and Operations KBUs rely upon Distribution Engineering's asset and system knowledge and engineering expertise.

The Distribution Standards team is responsible for creating and updating the standards used for the distribution system and for investigating power quality issues with approximately 60 distribution standards being updated and 200 power quality issues completed annually. The Asset Management and Operations KBUs rely upon Distribution Standard's asset and system knowledge and engineering expertise. The Distribution Design and Customer Connections KBU (refer to Chapter 5C, section 5C.7) relies upon Distribution Standards' engineering standards to do its work.

5A.8.2 Overview of Operating Costs and FTEs

**Table 5A-17 Engineering Design KBU
Fiscal 2022 Decision Operating Costs
and FTEs by Department**

	($ Millions)	Labour	Services - Other	Materials	Building & Equipment	Capitalized Overhead	External Recoveries	Total Operating	Total FTEs
1	Director, Engineering Design	0.5	0.0	0.0	0.0	0.0	0.0	**0.6**	(15)
2	Generation Design	4.2	0.4	0.1	0.2	0.0	0.0	**4.8**	147
3	Transmission Design	6.4	0.5	0.1	0.3	0.0	0.0	**7.3**	211
4	Distribution Engineering and Standards	4.1	1.2	0.1	0.1	0.0	0.0	**5.5**	65
5	**Total (Sch 5.1 L5, Sch 16.0 L5)**	**15.3**	**2.0**	**0.2**	**0.7**	**0.0**	**0.0**	**18.2**	**408**

5A.8.2.1. Director, Engineering Design Department

This department primarily consists of labour costs for two FTEs, the Director of the Engineering Design KBU and an administrative assistant. The FTE count for this department is negative because it reflects vacancy factor adjustment of 17 FTEs (4 per cent for the KBU). Vacancy factor adjustments are additional FTEs planned at the individual department level, with offsetting negative FTEs in the Director, Engineering Design department. These negative FTEs reflect vacancies that will occur during the year. As a result, there is a net zero FTE and cost impact to the KBUs and to BC Hydro overall.

5A.8.2.2. Generation Design Department

The Generation Design department has 147 FTEs, which reflects the level of resources required to deliver BC Hydro’s capital plan and maintenance and operations support requirements. Approximately 79 per cent of the regular labour costs for these FTEs are not included in this department’s budget as these costs are primarily charged to capital projects. Labour costs included in the budget are for non-chargeable time spent on activities such as engineering studies and category management strategies implementation as well as administrative activities such as managing staff, team meetings, professional development, and safety training.

The department’s $0.4 million Services budget includes funding for employee travel and training expenses, employee professional dues and fees, and for engineering contractor support. The department's $0.2 million Building and Equipment budget primarily consists of software licensing maintenance costs.

5A.8.2.3. Transmission Design Department

The Transmission Design department has 211 FTEs, which reflects the level of resources required to deliver BC Hydro's capital plan and maintenance and operations support requirements. Approximately 79 per cent of the regular labour costs for these FTEs are not included in this department's budget as these costs are primarily charged to capital projects. Labour costs included in the budget are for non-chargeable time spent on activities such as engineering studies and category management strategies implementation as well as administrative activities such as managing staff, team meetings, professional development, and safety training.

The department's $0.5 million Services budget includes amounts for employee travel and training expenses, employee professional dues and fees, and budget for engineering contractor support. The department's $0.3 million Building and Equipment budget primarily consists of software licensing maintenance costs.

5A.8.2.4. Distribution Engineering and Standards Department

The Distribution Engineering and Standards department has 65 FTEs, which reflects the level of resources required to deliver BC Hydro's capital plan and maintenance and operations support requirements. Approximately 59 per cent of the regular labour costs for these FTEs are not included in this department's budget as these costs are primarily charged to capital projects. The labour budget for this department is higher than for others as Distribution Standards FTEs primarily work on developing and updating distribution standards which is an operating expense. In addition, labour costs included in the budget are for non-chargeable time spent on activities such as engineering studies and category management strategies implementation as well as administrative activities such as managing staff, team meetings, professional development, and safety training.

The $1.2 million Services budget includes $0.9 million for Innovation and Technical memberships and project funding which enables BC Hydro to participate in, contribute to, and influence industry standards and research that affect BC Hydro and the power system.

5A.8.3 Fiscal 2023 to Fiscal 2025 Plan Operating Costs and FTEs

Table 5A-18 Engineering Design KBU Operating Costs and FTEs

		Schedule Reference	F2021 Actual	F2022 Decision	F2023 Plan	F2024 Plan	F2025 Plan
			1	2	3	4	5
1	**Engineering Design KBU**						
2	Operating Costs ($ million)	5.1 L5	17.3	18.2	18.3	18.4	18.9
3	FTEs	16.0 L5	432	408	413	414	415

The changes between the fiscal 2022 Decision amounts and the fiscal 2023 plan includes $0.6 million for Mandatory Reliability Standards (refer to Chapter 5, section 5.7.) and $0.1 million to support the Electrification Plan (refer to Chapter 10, section 10.4.5). The $0.7 million increase is offset by a $0.3 million decrease in the Standard Labour Rate, $0.2 million from a transfer of two FTEs to the Engineering Services KBU, and $0.1 million of travel savings.

From fiscal 2023 plan to fiscal 2024 plan, operating costs are increasing by $0.4 million due to Standard Labour Rate increases which is partially offset by a $0.3 million decrease in Mandatory Reliability Standards funding (refer to Chapter 5, section 5.7).

From fiscal 2024 plan to fiscal 2025 plan, operating costs are increasing by $0.4 million due to Standard Labour Rate increases and $0.1 million related to Site C (refer to Chapter 5, section 5.10).

FTEs are increasing by five from fiscal 2022 Decision amounts to the fiscal 2023 Plan due to the following:

- An increase of four FTEs from the Asset Planning KBU as part of the development of the LiDAR program for vegetation management; and

- An increase of three FTEs to support the Electrification Plan; partially offset by,
- A reduction of two FTEs for transfers to the Engineering Services KBU.

One FTE will be added in fiscal 2024 to Transmission Design for Mandatory Reliability Standards.

One FTE will be added in fiscal 2025 to Transmission Design to support Site C (refer to Chapter 5, section 5.10).

5A.9 Engineering Services KBU

5A.9.1 Responsibilities

As noted in the Previous Application, Engineering was split into two KBUs – Engineering Design and Engineering Services. This change was headcount and budget neutral, and the functions previously performed by the former single Engineering KBU are still performed within either Engineering Design or Engineering Services. This change facilitates collaboration and consistency by grouping similar teams together within the respective two KBUs.

The Engineering Services KBU is responsible for multi-disciplinary shared engineering services that are used across the company, including Stations Maintenance, Estimating and Project Engineering, Quality and Geomatics, and Drafting.

The Engineering Services KBU consists of the following departments:

- Director, Engineering Services Department;
- Operations Services Department; and
- Drafting Services Department.

5A.9.1.1. Director, Engineering Services Department

The Director, Engineering Services department has overall responsibility for Stations Maintenance, Estimating and Project Engineering, Quality and Geomatics, and Drafting. The director provides overall leadership and management for the Engineering Services KBU and business input to asset planning and risk, and capital project planning and oversight reviews.

5A.9.1.2. Operations Services Department

The teams within Operations Services includes the following:

- Stations Maintenance;
- Estimating and Project Engineering; and,
- Quality and Geomatics.

Stations Maintenance

Stations Maintenance provides multi-disciplinary field maintenance and specialist maintenance engineering services for Generation Stations and Transmission Stations equipment and operations. The team provides technical services and support to field crews for operations, troubleshooting, maintenance, safety, and regulatory compliance. The team also provides input and technical advice to capital projects including equipment specifications, operations, maintenance, and safety by design. On average, this division completes approximately $7.2 million in technical services per year for transmission and generation stations maintenance and operations.

Stations Maintenance is organized as follows:

- Generation Stations Field Maintenance Engineering;
- Transmission Stations Maintenance Engineering;
- Mechanical Maintenance Engineering;

- Electrical Maintenance Engineering; and,
- Civil Maintenance Engineering.

Estimating and Project Engineering

The Estimating and Project Engineering team supports Capital Infrastructure Project Delivery managed projects for the following power system assets:

- Transmission Lines;
- Transmission Stations;
- Generation Stations; and
- Dam Safety.

Estimating produces power system project cost estimates to support planning and implementation, aid in the selection of a preferred project alternative, and to obtain capital funding approval. Estimating also provides expertise to assist with project and construction planning, construction methodology, and sequencing.

For Capital Infrastructure Project Delivery-managed capital projects of over $1 million, the Estimating team will either produce estimates internally or review estimates prepared by external service providers. On average, the team prepares over 100 estimates per year ranging in size from $1 million to greater than $1 billion. The dollar value and volume of estimates varies each year, depending on the number of projects that have progressed to the stage of estimate preparation. The effort to prepare an estimate typically ranges from 100 to 1,000 hours dependent on project complexity and stage, with some complex estimates requiring up to 1,500 hours to prepare. To meet project estimate workload demands, the Estimating team also retains temporary external consultants to supplement existing team resources. As of fiscal 2022, approximately 32 per cent of the team are temporary external consultants.

The Project Engineering team coordinates the engineering on the more complex, higher risk multi-disciplinary generating stations, transmission substations, and some transmission lines and distribution lines projects. This team has the overall responsibility for coordinating the engineering scope, schedule, and cost of a project through to completion, and is responsible for assessing whether end products are fit for purpose and meet the requirements of BC Hydro. As of the end of fiscal 2021, Project Engineering team members were leading engineering work on approximately 96 major capital projects. In fiscal 2022, the Project Engineering Team is expected to be supporting over 110 projects, nearly doubling the number of projects since fiscal 2019. These large, complex projects typically have a duration of five to 10 years and range in size from $10 million to greater than $500 million. Similar to Estimating, temporary external consultants have been retained to help meet the increasing workload over the past several years. As of fiscal 2022, approximately 50 per cent of the team are temporary external consultants.

Estimating and Project Engineering both align with the requirements of the PPM System (refer to Chapter 6, section 6.2.2). Engineering work package agreements are developed, and schedules and budgets are monitored.

Quality and Geomatics

The Quality and Geomatics Division has two key responsibilities:

- Quality Assurance Services; and,
- Geomatics Services.

The Quality team is responsible for assessing the conformance of engineered equipment and materials supplied by vendors to BC Hydro’s standards and requirements. Team members work directly with manufacturers, engineering service providers, and contractors to perform these assessments. This team provides quality services for an average of 150 capital projects each year, including sourcing and managing third-party quality services around the world which are valued at over

$2 million per year. In addition, this team also develops and executes quality processes and inspections for over 5,000 unique material identifiers with a value of approximately $160 million per year. Similar to Estimating and Project Engineering, Quality has retained temporary external consultants to help meet the increasing workloads over the past several years. As of fiscal 2022, approximately 17 per cent of the Quality Engineers are temporary external consultants

Geomatics Services has two core areas of service: survey and photogrammetry.

Survey Services provides survey products and technical support services for legal surveys and descriptions, topographic and technical surveys, construction layout, monitoring surveys and reports, bathymetric and hydrographic surveys, crown land applications, cadastral mapping, Land Title and Survey Authority and Canada Lands records searches for historic records, surveys on Canada Lands, and consultation on land tenure and regulatory matters. The survey team supports over 340 requests per year for various business groups and projects across BC Hydro.

Photogrammetry Services provides technical expertise and procurement support for various forms of earth imagery data including LiDAR, satellite imagery, aerial photography, orthophoto production, topographic mapping, volume surveys of reservoirs, route location mapping, and other mapping products. On average, the Photogrammetry team supports over 250 requests per year, which includes managing BC Hydro’s Light Data and Ranging (**LiDAR**) surveys valued at over $0.6 million per year. In fiscal 2022, LiDAR surveys are expected to be valued at over $4 million given the ongoing transmission and vegetation modelling requirements for Mandatory Reliability Standards compliance. In fiscal 2023, LiDAR surveys are expected to continue at approximately $3 million per year, dependent on modelling requirements to support Mandatory Reliability Standards compliance.

5A.9.1.3. Drafting Services Department

The Drafting Services Department is comprised of drafters that support power system capital projects and operations. The department uses Computer-Aided

Design and Drafting tools to create two-dimensional and three-dimensional representations of BC Hydro power system assets. On average, Drafting Services produces over 50,000 drawings per year ranging in effort from approximately one to five hours for simple drawings to more than 30 hours for complex drawings. Key responsibilities of the department include:

- Produce new and revise existing engineering drawings for power system assets;
- Support the development and application of drawing and drafting standards and processes;
- Assess drawing quality and compliance to BC Hydro's standards for the large volume of drawings produced by external consultants and equipment suppliers; and
- Create, maintain, and update drawings for the operation of BC Hydro's system, including within the Geographic Information System.

5A.9.2 Overview of Operating Costs and FTEs

Table 5A-19 Engineering Services KBU Fiscal 2022 Decision Operating Costs and FTEs by Department

	($ Millions)	Labour	Services - Other	Materials	Building & Equipment	Capitalized Overhead	External Recoveries	Total Operating	Total FTEs
1	Director, Engineering Services	0.4	0.0	0.0	0.0	0.0	0.0	**0.5**	(8)
2	Operations Services	4.7	0.4	0.1	0.1	0.0	0.0	**5.3**	150
3	Drafting Services	2.6	0.3	0.0	0.2	0.0	0.0	**3.1**	97
4	**Total (Sch 5.1 L6, Sch 16.0 L6)**	**7.7**	**0.7**	**0.2**	**0.3**	**0.0**	**0.0**	**9.0**	**239**

5A.9.2.1. Director, Engineering Services Department

This department primarily consists of labour costs for FTEs: The Director of the Engineering Services KBU and an Administrative Assistant. The FTE count for this department is negative because it reflects vacancy factor adjustment of 10 FTEs (4 per cent for the KBU). Vacancy factor adjustments are additional FTEs planned at the individual department level, with offsetting negative FTEs in the Director, Engineering Services department. These negative FTEs reflect vacancies that will occur during the year. As a result, there is a net zero FTE and cost impact to the KBUs and to BC Hydro overall.

5A.9.2.2. Operations Department

The Operations department has 150 FTEs, which reflects the level of resources required to deliver BC Hydro's capital plan and maintenance and operations support requirements. Approximately 79 per cent of the regular labour costs for these FTEs are not included in this department's budget as these costs are charged primarily to capital projects and other KBU operating budgets. The labour costs included in this department are for non-chargeable time spent on internal activities such as standards development, geomatics systems updates, and process improvements as well as administrative activities such as managing staff, team meetings, professional development, and safety training.

The department's $0.4 million Services budget includes amounts for employee travel and training expenses, employee professional dues and fees, and engineering contractor labour.

5A.9.2.3. Drafting Department

This department consists of 97 FTEs, which reflects the level of resources required to deliver BC Hydro's capital plan and maintenance and operations support requirements. Approximately 76 per cent of the regular labour costs for these FTEs are not included in the department's budget as these costs are charged primarily to capital projects and other KBU operating budgets. Labour costs included in this department are for non-chargeable time spent on internal activities such as standards development and system improvements as well as administrative activities such as managing staff, team meetings, professional development, and safety training.

The department's $0.3 million Services budget includes amounts for IT software support and drafting contract labour employee travel and training expenses, and drafting printer lease costs.

The $0.2 million Buildings and Equipment budget in this department is primarily for software licensing and maintenance.

5A.9.3 Fiscal 2023 to Fiscal 2025 Plan Operating Costs and FTEs

Table 5A-20 Engineering Services KBU Operating Costs and FTEs

		Schedule Reference	F2021 Actual	F2022 Decision	F2023 Plan	F2024 Plan	F2025 Plan
			1	2	3	4	5
1	**Engineering Services KBU**						
2	Operating Costs ($ million)	5.1 L6	7.2	9.0	9.0	9.3	9.5
3	FTEs	16.0 L6	224	239	246	247	248

The changes between the fiscal 2022 Decision amount and fiscal 2023 Plan include a $0.2 million decrease in Standard Labour Rates and $0.1 million in travel savings. This decrease is partially offset by $0.2 million increase due to a transfer of two FTEs from Engineering Design, which is net neutral between the two KBUs.

In both the fiscal 2024 and fiscal 2025 plans, there is a $0.3 million and $0.2 million increase, respectively, due to increases in Standard Labour Rates.

FTEs are planned to increase by seven from the fiscal 2022 Decision amount to fiscal 2023 plan due to:

- Two FTEs in Geomatics from the Asset Planning KBU as part of the development of the LiDAR program for vegetation management;
- One FTE in Estimating and Project Engineering to support Electrification;
- One FTE in Stations Maintenance to support Site C; and
- Three FTEs that transferred from Engineering Design to the Stations Maintenance Division.

To support Site C, there is an increase of one FTE in Stations Maintenance in each of the fiscal 2024 plan and fiscal 2025 plan as part of the staffing complement required to provide the technical support to maintain and operate the facility.

Refer to Chapter 5, section 5.8 for more information on Vegetation Management, Chapter 10 for Electrification, and Chapter 5, section 5.10 for Site C.

5A.10 Business Unit Support KBU

5A.10.1 Responsibilities

The Integrated Planning Business Unit Support KBU holds the budget for the Senior Vice President, Integrated Planning and for business group costs that are not specifically related to any KBU.

5A.10.2 Overview of Operating Costs and FTEs

Table 5A-21 Business Unit Support KBU Fiscal 2022 Decision Operating Costs and FTEs by Department

	($ Millions)	Labour	Services - Other	Materials	Building & Equipment	Capitalized Overhead	External Recoveries	Total Operating	Total FTEs
1	SVP, Integrated Planning	0.8	0.2	0.0	0.0	0.0	-	**1.0**	3
2	Waneta	0.0	8.7	0.0	0.0	0.0	-	**8.7**	-
3	Common Costs	0.0	3.5	0.7	0.0	0.0	(3.3)	**0.9**	-
4	Project O&M	6.4	4.9	0.0	0.0	0.0	-	**11.3**	-
5	**Total (Sch 5.1 L5.7+L10, Sch 16.0 L7)**	**7.2**	**17.3**	**0.7**	**0.0**	**0.0**	**(3.3)**	**21.9**	**3**

5A.10.2.1. SVP, Integrated Planning Department

The majority of this department's budget relates to labour costs for three FTEs – the Senior Vice President of Integrated Planning, a Senior Strategic Business Advisor and an Administrative Assistant. The department's non-labour budget provides funding for contract services, employee travel and training.

5A.10.2.2. Waneta

The Waneta department contains the maintenance budget for the Waneta generating facility of which $6.1 million in costs are offset in Miscellaneous Revenue, as shown in Appendix A, Schedule 15.0.

5A.10.2.3. Common Costs Department

This department does not have any FTEs. The $3.5 million in Services - Other is comprised of the following amounts:

- $1.6 million is for First Nations Community Fund payments in lieu of taxation; and
- $1.9 million is a reserve to fund emergent and unplanned operating activities that arise through the year. Examples of activities the reserve has been used to fund are:
  - Temporary standby diesel generation when required for redundancy during capital projects which do not qualify for capitalization;
  - Funding for engagement and consultation with First Nations that does not meet the duty to consult criteria and therefore cannot be capitalized; and
  - Funding for process improvement and efficiency programs.

The $0.7 million in Materials is for minor materials, such as nuts and bolts, used in maintenance programs.

5A.10.2.4. Project Operations and Maintenance Department

This department's budget includes costs to determine or confirm a need or opportunity for a capital project, and to develop, review and recommend conceptual alternatives for the potential project.

These costs are incurred by a project after its release but prior to the identification of a leading alternative solution and are referred to as Capital Project Investigation expenditures. This department's budget may also fund chartered planning study costs for discrete study work to be completed prior to the release of a project. These chartered studies supplement and support the base study work done in the Integrated Planning KBUs.

Capital Project Investigation expenditures vary year-to-year depending on the size, complexity and volume of projects.

5A.10.3 Fiscal 2023 to Fiscal 2025 Plan Operating Costs and FTEs

Table 5A-22 Business Unit Support KBU Operating Costs and FTEs

		Schedule Reference	F2021 Actual	F2022 Decision	F2023 Plan	F2024 Plan	F2025 Plan
			1	2	3	4	5
1	**Business Unit Support KBU**						
2	Operating Costs ($ million)	5.1 L7+L10	21.8	21.9	22.2	22.6	28.8
3	FTEs	16.0 L7	3	3	3	3	3

Operating costs are planned to increase from fiscal 2022 Decision to fiscal 2023 from fiscal 2022 Decision amount to fiscal 2024 plan. For fiscal 2025, operating costs are planned to increase by $6.2 million primarily due to $5.8 million for contract commitments related to the Site C project (as discussed further in Chapter 5, section 5.10).

FTEs are planned to remain constant from fiscal 2022 Decision amount to fiscal 2023, fiscal 2024 and fiscal 2025 plans.

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Fiscal 2023 to Fiscal 2025
Revenue Requirements Application

Chapter 5B

Operating Costs
Capital Infrastructure Project Delivery
Business Group

BUILD

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5B.1 Introduction – Capital Infrastructure Project Delivery Business Group

Chapter 5B details the composition of, and rationale for, the operating costs of the Capital Infrastructure Project Delivery Business Group. The Capital Infrastructure Project Delivery Business Group is one of six Business Groups in the organization and is responsible for building BC Hydro's assets. It serves as the Build function of the Plan-Build-Operate-Support model.

The Capital Infrastructure Project Delivery Business Group budget was developed as part of the budgeting process outlined in Chapter 5, section 5.4, which the BCUC found to be reasonable in its decision on the Previous Application.[314] The budgeting approach includes both bottom-up and top-down elements and examines more than just incremental costs. The information provided in Chapter 5B demonstrates the basis for the entirety of the Business Group and KBU budgets, rather than focussing only on incremental cost requirements. This information is provided in a format and level of detail consistent to that presented in the equivalent chapter in the F2020-F2021 RRA.

Chapter 5B is organized as follows:

- Section 5B.2 provides an overview of the organization and responsibilities of the Capital Infrastructure Project Delivery Business Group;
- Section 5B.3 provides the operating costs and FTE information for the Capital Infrastructure Project Delivery Business Group as a whole;[315]
- Sections 5B.4 to 5B.8 provide more detailed information on the responsibilities, cost and FTEs for each KBU within the Capital Infrastructure Project Delivery

[314] BCUC Decision and Order No. G-187-21, Fiscal 2022 Revenue Requirements Application (June 17, 2021), page 27: "The Panel considers BC Hydro's budgeting process involving top-down and bottom-up elements goes beyond the examination of incremental changes from the prior year and continues to be reasonable for forecasting operating costs. Therefore, for these reasons, the Panel finds the final 2022 operating costs requested for recovery to be reasonable."

[315] Please note the amounts presented in the tables in these sections may not add due to rounding.

Business Group. The operating costs and FTE information for each KBU is broken out into two sections.[315]

- Overview of Operating Costs and FTEs – This section explains the starting operating costs and FTEs for the KBU based on the fiscal 2022 Decision amounts; and
- Fiscal 2023 to Fiscal 2025 Plan Operating Costs and FTEs – This section explains any incremental changes in the KBU between the fiscal 2022 Decision amounts and the fiscal 2023 to fiscal 2025 plan.

5B.2 Overview of Capital Infrastructure Project Delivery Business Group Organization and Responsibilities

There have been no material changes to the organization of this Business Group since the Previous Application, and the responsibilities remain consistent as well.

The Capital Infrastructure Project Delivery Business Group is responsible for delivering BC Hydro's larger and more complex capital projects while also providing cross-company services relating to the management and support of Indigenous relations, environment, and properties. Given the intersection between lands, the environment, Indigenous Nations, and capital projects, it makes sense to have the KBUs with responsibility for these key areas within the same Business Group. These KBUs work together to secure the necessary permitting, approvals, support, and land rights to successfully deliver BC Hydro's capital projects in an increasingly complex environment.

During the Test Period, the Capital Infrastructure Project Delivery Business Group plans to deliver approximately 50 per cent of BC Hydro's overall Capital Plan (excluding the Site C Project). This includes the majority of the generation, stations, dam safety, and transmission projects as well as some larger distribution and properties projects. These projects can be expected to give rise to the environmental, land, and Indigenous relations considerations that are the responsibility of the KBUs in this Business Group.

The Capital Infrastructure Project Delivery Business Group consists of the following KBUs:

Business Group	Key Business Unit
Capital Infrastructure Project Delivery	Project Delivery Indigenous Relations Environment Properties Business Unit Support

5B.3 Fiscal 2023 to Fiscal 2025 Plan Operating Cost and FTE Summaries

This section addresses planned operating costs and FTEs for the Capital Infrastructure Project Business Group. The following are some key points of note with respect to the information provided in Figure 5B-1, Table 5B-1 and Figure 5B-2, Table 5B-2and Table 5B-3:

- The majority of the FTEs in this Business Group charge a portion of their labour to capital projects. For example, the Project Delivery KBU charges out approximately 80 per cent of its labour costs to capital projects; and
- Approximately $47 million (55 per cent) of the total operating expenditures of this Business Group are non-labour expenditures, directly attributable to BC Hydro building maintenance and environmental programs such as the Fish & Wildlife Compensation Program, non-remissible Water Rights projects, and the Williston Dust Management Program.

Planned operating costs for the Capital Infrastructure Project Delivery Business Group are $84.8 million in fiscal 2023, $86.3 million in fiscal 2024, and $87.6 million in fiscal 2025. The operating costs for the Capital Infrastructure Project Delivery

Business Group are summarized by KBU in Figure 5B-1. Additional cost detail is provided in Table 5B-1 below.[316]

Figure 5B-1 Capital Infrastructure Project Delivery Net Operating Costs by KBU (Fiscal 2023 Plan) ($ million)

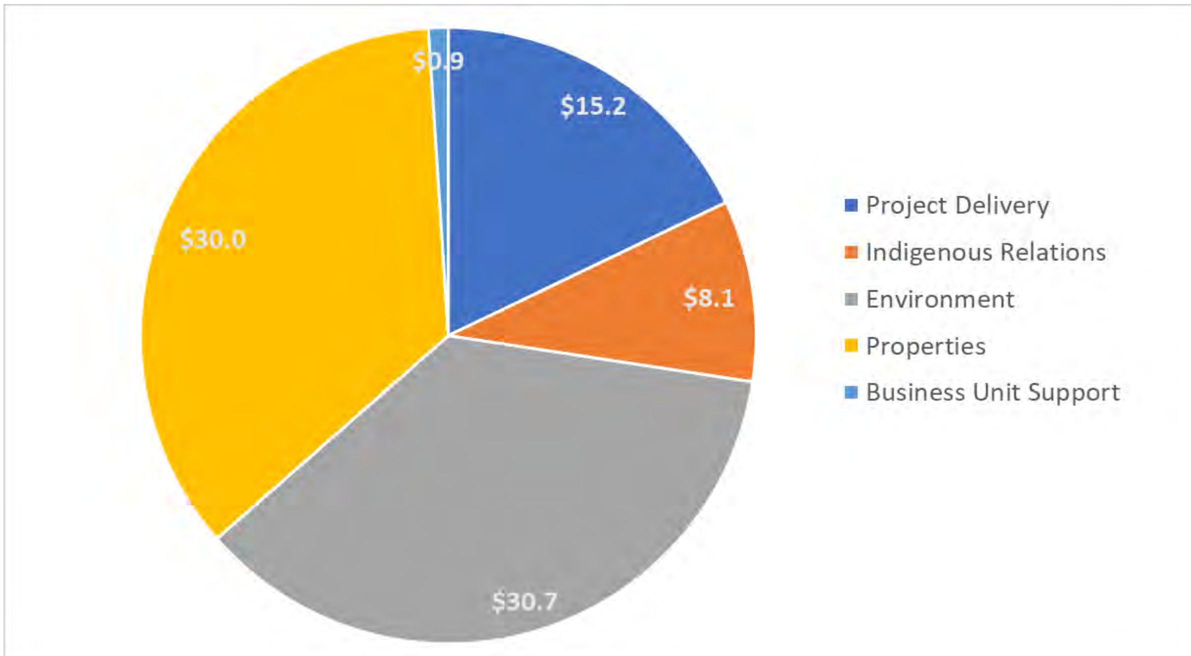

Table 5B-1 Capital Infrastructure Project Delivery Net Operating Costs by KBU

	($ million)	Schedule Reference	F2021 Actual	F2022 Decision	F2023 Plan	F2024 Plan	F2025 Plan
			1	2	3	4	5
1	Project Delivery	5.2 L1	13.2	15.4	15.2	15.5	15.9
2	Indigenous Relations	5.2 L2	7.4	6.7	8.1	8.6	8.8
3	Environment	5.2 L3	28.9	31.0	30.7	31.0	31.4
4	Properties	5.2 L4	30.5	30.3	30.0	30.3	30.5
5	Business Unit Support	5.2 L5	0.8	0.9	0.9	0.9	0.9
6	Total	5.2 L11	80.8	84.3	84.8	86.3	87.6

[316] Please note that a significant portion of costs in the Project Delivery KBU are charged out to capital projects and not included in the KBU's operating cost budget.

The FTEs for the Capital Infrastructure Project Delivery Business Group are summarized by KBU in Figure 5B-2. Additional detail is provided in Table 5B-2 below.

Figure 5B-2 Capital Infrastructure Project Delivery FTEs by KBU (Fiscal 2023 Plan)

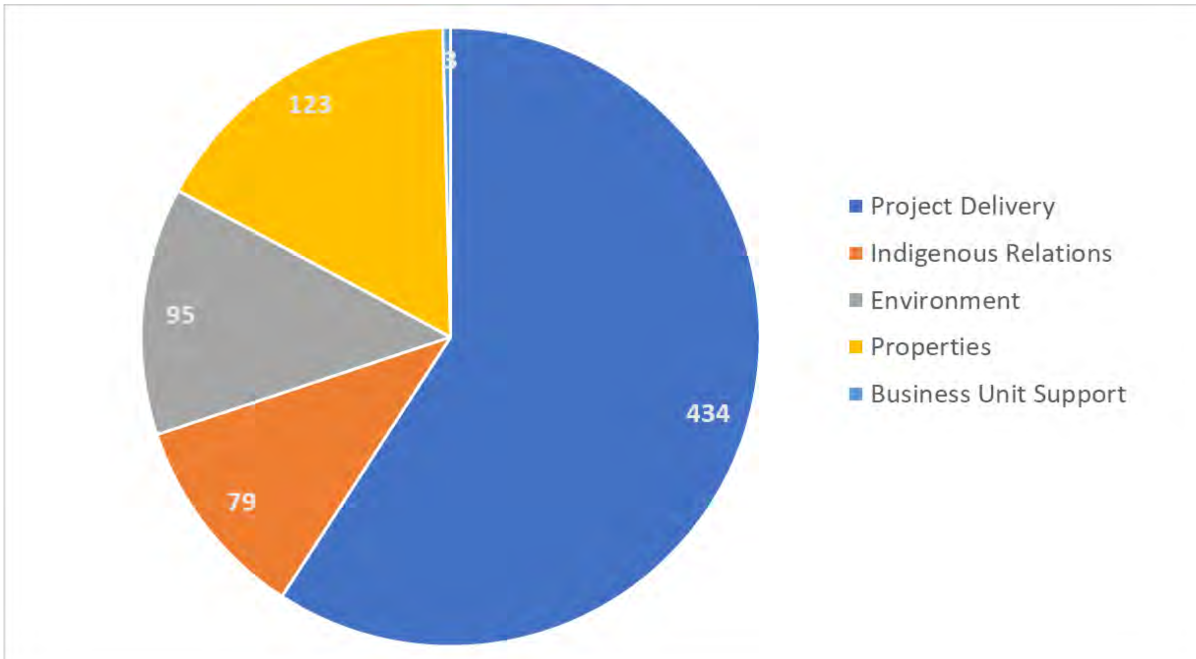

Table 5B-2 Capital Infrastructure Project Delivery FTEs by KBU

	(FTEs)	Schedule Reference	F2021 Actual	F2022 Decision	F2023 Plan	F2024 Plan	F2025 Plan
			1	2	3	4	5
1	Project Delivery	16.0 L9	434	431	434	439	439
2	Indigenous Relations	16.0 L10	60	74	79	74	74
3	Environment	16.0 L11	93	95	95	95	95
4	Properties	16.0 L12	116	123	123	123	123
5	Business Unit Support	16.0 L13	3	3	3	3	3
6	Total	16.0 L14	706	726	733	733	733

Table 5B-3 below provides a continuity table which highlights changes to the Capital Infrastructure Project Delivery Business Group from the Previous Application. There have been no material changes to the organization of this Business Group since the Previous Application, and the responsibilities remain consistent as well.

An overall discussion of these changes, at a company-wide level, is provided in Chapter 5, section 5.5.3. Further details, by KBU, are provided in the sections below.

Table 5B-3 Capital Infrastructure Project Delivery Operating Costs Continuity Schedule

	($ million)	Ref	F2023 Plan	F2024 Plan	F2025 Plan
1	**F2022 Revenue Requirement Application Plan**	a	**84.3**		
2	**Compliance Filing Adjustment**	b	-		
3	Reorganizational Impact	c	-		
4	**F2022 Decision (Schedule 5.2, line 11)**	d= a+b+c	**84.3**		
5	Budget Transfers Between Business Groups	e	(0.6)		
6	**F2022 Forecast (Schedule 5.2, line 11)**	f = d+e	**83.7**	**84.8**	**86.3**
7	Current Year Budget Transfers Between Business Groups	g	0.7	-	-
8	**Test Period Net Cost Increase/Decrease**				
9	**Uncontrollable Cost Increases**				
10	Current Service Costs and Other Labour Costs		(0.8)	1.0	1.2
11		h	(0.8)	1.0	1.2
12	**Site C**	i	-	-	0.1
13	**Strategic Initiatives**				
14	UNDRIP Work		1.6	0.4	-
15	Electrification initiatives		0.0	-	-
16		j	1.6	0.4	-
17	**Net Cost Savings**				
18	Test Period Savings		(0.3)	-	-
19		k	(0.3)	-	-
20	**Total Test Period Net Increase/(Decrease)**	l =∑ h to k	**0.5**	**1.4**	**1.3**
21	**F2023 Net Operating Costs (Schedule 5.2, line 11)**	m = f+g+l	**84.8**	**86.3**	**87.6**

Table may not add due to rounding

5B.4 Project Delivery KBU

5B.4.1 Responsibilities

There have been no material changes to the responsibilities of this KBU since the Previous Application.

The Project Delivery KBU is responsible for safely delivering a multi-billion dollar portfolio of Power System[317] capital projects on time and on budget. During fiscal 2023 through fiscal 2025 Project Delivery will manage approximately 300 dam safety, stations, lines and interconnection projects, which represent over 50 per cent or $2.2 billion of BC Hydro's Power System Capital Plan (excluding Site C). Further information on the capital plan is provided in Chapter 6, section 6.4. Projects managed by Project Delivery typically range in cost from $1 million to $1 billion, with durations of one year to more than ten years.

The Project Delivery KBU provides the following functions:

- Overall project and portfolio management;
- Project Services including project standards and controls, document management, cost and schedule management, and risk management; and
- Project construction and contract management.

For consistent project management throughout the project life cycle, projects managed by the Project Delivery KBU continue to use the Project and Portfolio Management System, which is discussed further in Chapter 6, section 6.2.2, and in Appendix N, section 2.7. The Project and Portfolio Management System was initiated in 2009 and has been described in prior applications. It aligns and integrates with work from other KBUs to deliver projects on time and on budget while meeting our Indigenous relations, stakeholder and environmental commitments.

[317] Power System includes Generation, Dam Safety, Transmission and Distribution assets.

The Project Delivery KBU consists of the following departments:

- Three Project Delivery Portfolio Departments: Dam Safety Projects and Programs, Stations Projects, and Lines and Interconnection Projects;
- Capital Construction Department; and
- Project Services Department.

5B.4.1.1. Project Delivery Portfolio Departments

The portfolios in this KBU continue to be organised by asset type in alignment with the Integrated Planning and Operations Business Groups. Project Managers from each of the three Portfolio Departments, Dam Safety Projects and Programs, Stations Projects, and Lines and Interconnection Projects, follow the Project and Portfolio Management System to deliver capital projects safely, on time, on budget and to meet project requirements. Responsibilities include the following key activities throughout the project lifecycle:

- Ensuring project alternatives are evaluated to best address the needs and objectives of the project and BC Hydro;
- Managing the scope, risk, schedule and cost of the project; and
- Delivering projects in accordance with approved policies and practices.

5B.4.1.2. Capital Construction Department

Capital Construction works with project managers and on-site contractors during the Implementation Phase to deliver projects safely, on time, on budget and to project requirements. Capital Construction’s responsibilities include the following:

- Mitigating project cost and schedule risk by delivering constructability reviews during the project lifecycle;

- Providing contract and claims management during pre-award and post-award phases to ensure all contractual requirements are met by BC Hydro contractors;
- Planning and managing on-site project construction and commissioning activities;
- Overseeing the on-site safety of BC Hydro employees and contractors in accordance with applicable safety and technical standards; and
- Performing quality assurance, testing and acceptance to verify new equipment will perform as expected over the life of the asset.

This department primarily supports the Project Delivery KBU but also manages contracts for other KBUs involved in delivering the Power System Capital Plan.

5B.4.1.3. Project Services Department

The Project Services department is responsible for the Project and Portfolio Management System that ensures industry standard project practices are consistently used to deliver capital projects, and for portfolio level planning, management and reporting. The department also provides resources for projects in specific services. Project Services' responsibilities include the following:

- Standards, controls and tools: develop, maintain and continuously improve the Project and Portfolio Management system and tools, providing training, and conducting conformance reviews;
- Portfolio management: undertake portfolio reporting and analytics, resource management analysis, portfolio processes facilitation and executive performance reports;
- Schedule and cost management services: develop and maintain reliable project schedules, cost forecasts and actuals, and related analysis;

- Commercial management services: prepare business cases, undertake alternative analysis and facilitate structured decision making, and support preparation of project regulatory applications; and
- Document management services: ensuring compliance with corporate records policies in the management of project and contract documents and records throughout the project lifecycle including project closure and archiving.

5B.4.2 Overview of Operating Costs and FTEs

Table 5B-4 Project Delivery KBU Fiscal 2022 Decision Operating Costs and FTEs by Department

	($ Millions)	Labour	Services - Other	Materials	Building & Equipment	Capitalized Overhead	External Recoveries	Total Operating	Total FTEs
1	Office of Vice President Project Delivery	(0.4)	0.0	0.0	0.0	0.0	0.0	**(0.4)**	(24)
2	Project Delivery Portfolio	2.2	0.2	0.0	0.0	0.0	0.0	**2.4**	87
3	Capital Construction	5.2	0.7	0.1	0.2	0.0	0.0	**6.1**	215
4	Project Services	6.7	0.5	0.1	0.0	0.0	0.0	**7.2**	153
5	**Total (Sch 5.2 L1, Sch 16.0 L9)**	**13.7**	**1.4**	**0.1**	**0.2**	**0.0**	**0.0**	**15.4**	**431**

Overall FTEs in the Project Delivery KBU are primarily driven by the size of the Power System Capital Plan. This KBU forecasts its human resource requirements in the same manner as described in prior applications, which is by using the Project Delivery Resource Management approach. It involves:

- Determining labour demand for planned and active projects based on resource-loaded schedules;
- Modelling and determining labour demand for planned projects using historic inputs from previous projects;
- Comparing labour demand, per discipline, with internal resource capacity;
- Determining the appropriate resource allocation strategy. To meet demand, projects are resourced from a base level of BC Hydro employees and augmented by external services providers as needed. This provides flexibility to respond to changes in the size or complexity of the capital plan; and
- Monitoring resource needs and overtime to adjust resourcing as required.

Within the Project Delivery KBU, this approach is used to forecast demand for project managers, construction managers, contract managers, construction officers, contract professionals, schedulers, cost analysts, commercial managers and document controllers. This approach covers approximately 75 per cent of the project resource demand from the Project Delivery KBU.

In the minority of cases where this approach is not used (e.g., project standards and controls, portfolio management, site engineering and commissioning, and administration), we forecast resource demand based on expected workload, compared with available capacity.

Approximately 80 per cent of total Project Delivery KBU labour costs are charged out to capital projects and are thus not included in the KBU's operating costs. The remaining 20 per cent of labour costs make up approximately 88 per cent of the KBU's overall operating costs. The remaining 12 per cent of the KBU's operating costs are related to services, equipment and materials.

Under IFRS (the accounting rules applicable to BC Hydro), several activities required to deliver the BC Hydro's Power System Capital Plan cannot be capitalized. The Finance KBU reviews projects costs as part of the financial due diligence review process to assess the appropriate accounting treatment for project costs in accordance with IFRS. This includes determining which project costs are eligible for capitalization. Examples of non-capitalized project management related labour includes management and reporting, Project and Portfolio Management System enhancement and sustainment, safety training, professional development and administrative support.

5B.4.2.1. Office of Vice President Project Delivery Department

This department contains the labour costs for the Vice President of Project Delivery and an administrative assistant. The FTE count for this department is negative because it reflects vacancy factor adjustment of 26 FTEs. Vacancy factor adjustments are additional FTEs planned at the individual department level, with offsetting negative FTEs in the Office of the Vice President Project Delivery department. These negative FTEs reflect vacancies that will occur during the year. As a result, there is a net zero FTE and cost impact to the KBUs and to BC Hydro overall.

5B.4.2.2. Project Delivery Portfolio Departments

Project managers report to either a team lead or a Project Delivery Director for delivery of projects against approved scope and objectives in accordance with approved policies and practices. More information is provided in Chapter 6, section 6.2.2.

Project managers are expected to manage one to eight projects at any one time (the average is four projects per BC Hydro project manager). The number of projects varies based on project complexity, project size, project timing and experience of the project manager. The labour capitalization rate for project managers is 93 per cent. The capitalization rate for all positions across all three portfolios (Dam Safety Projects and Programs, Stations Projects, and Lines and Interconnection Projects) is 85 per cent.

There is a total of 87 FTEs across the three Project Delivery portfolio departments. The current labour mix is approximately 80 per cent internal resources and 20 per cent external service providers and contractors (based on project count). This provides sufficient flexibility for BC Hydro to respond to changes to the capital plan.

5B.4.2.3. Capital Construction Department

The Capital Construction department workload is primarily driven by Power System capital projects in the Implementation Phase. At any one time, the department is supporting over 400 projects (including other KBUs involved in delivering the Power System Capital Plan and excluding Site C), and is managing more than

1,400 contracts, with more than 400 vendors, with a total value of more than $1.9 billion.

Construction managers and construction officers have a blended labour capitalization rate of 89 per cent. The blended labour capitalization rate for the department is 84 per cent.

There are 215 FTEs across the Capital Construction department, organized into the following teams:

- Office of the Director of Capital Construction – eight FTEs provide construction planning and construction practice management;
- Contract Management – 57 FTEs provide contract management, claims management and administration services of over 1,400 contracts;
- Site Engineering and Commissioning – 41 FTEs provide on-site testing and commissioning; and
- Construction Management – 109 FTEs provide on-site project construction management.

Management targets a resource mix of 70 per cent internal and 30 per cent external resources. This provides sufficient flexibility to adjust for changes in the capital plan, as well as location and seasonality of work.

The Capital Construction department's services budget is mainly comprised of employee training and equipment maintenance.

5B.4.2.4. Project Services Department

The Project Services department supports Power System capital projects throughout the project lifecycle. At any one time, the department is supporting approximately 300 projects. The labour capitalization rate for the overall Project Services department is 69 per cent. Project resources, such as schedulers, cost analysts, commercial managers, and document controllers, have a higher capitalization rate of 85 per cent to 90 per cent.

This department consists of 153 FTEs organized into the following teams:

- Office of the Director of Project Services – Two FTEs;
- Portfolio Management – 14 FTEs provide regular (mostly monthly) contracts, projects and portfolio reporting and analytics for the Project Delivery portfolio of projects, facilitate portfolio processes (including the release of an average of 40 projects from the Integrated Planning Business Group annually), model and analyze resource demand for up to 70 disciplines, and prepare executive performance reports;
- Standards, Controls and Tools - 17 FTEs provide practices, tools and learning for the Project and Portfolio Management System as well as prepare over 150 compliance, quality and project closure reports and conduct 48 conformance audits annually to ensure that the practices and process of the Project and Portfolio Management System are consistently applied;
- Project Scheduling and Costing – 64 FTEs provide scheduling and cost analyst services to support the planning, analysis and reporting for all Project Delivery projects. Annually this team leads over 3,500 monthly project schedule and cost forecast updates for 7,000 plus work packages;
- Commercial Management – ten FTEs provide commercial management services to complex Project Delivery projects (typically over $20 million) including developing business cases, conducting risk workshops, and conducting the structured decision-making process and undertaking financial modeling and analysis to support the evaluation of project alternatives. This team is also responsible for ensuring that project-specific regulatory applications are developed in a timely manner and for preparing the related regulatory compliance filings; and

- Document Management – 46 FTEs provide document control and archiving services for all Project Delivery projects. Each year this team manages approximately 900,000 project documents within the Project and Portfolio Management document system, processes approximately 30,000 contract transmittals and submittals, and archives approximately 90,000 project documents. Mandatory Reliability Standards have added additional regulatory requirements and some workload to this team. Specifically, documents with Critical Infrastructure Protection (**CIP**) confidential information are reviewed and filed in a designated Bulk Electric Cyber System Information (**BCSI**) Repository that is managed by this team (including repository permissions).

The Project Services department's services budget is mainly for maintaining and enhancing Project and Portfolio Management practices and processes, and employee training.

5B.4.3 Fiscal 2023 to Fiscal 2025 Plan Operating Costs and FTEs

Table 5B-5 Project Delivery KBU Operating Costs and FTEs

		Schedule Reference	F2021 Actual	F2022 Decision	F2023 Plan	F2024 Plan	F2025 Plan
			1	2	3	4	5
1	**Project Delivery KBU**						
2	Operating Costs ($ million)	5.2 L1	13.2	15.4	15.2	15.5	15.9
3	FTEs	16.0 L9	434	431	434	439	439

Operating costs are decreasing by approximately $0.2 million from the fiscal 2022 Decision amounts to the fiscal 2023 plan mainly due to a decrease in Standard Labour Rates.

Operating costs are increasing by approximately $0.3 million in fiscal 2024 compared to fiscal 2023 mainly due to Standard Labour Rate increases.

Operating costs are increasing by approximately $0.4 million in fiscal 2025 compared to fiscal 2024 mainly due to Standard Labour Rate increases.

FTEs are planned to increase by three from the fiscal 2022 Decision amount to the fiscal 2023 plan due to one FTE transferred from Program Contract Management KBU to manage the Columbia Hydro Constructors contract and two FTEs added to the Project Delivery KBU related to the Electrification Plan. Please refer to Chapter 10, section 10.4 for discussion of resources to support the Electrification Plan.

FTEs are planned to increase by five from fiscal 2023 plan to the fiscal 2024 plan due to FTEs returned to the Project Delivery KBU from the Indigenous Relations KBU related to a two-year pilot Indigenous Professionals in Development program.

5B.5 Indigenous Relations KBU

5B.5.1 Responsibilities

There have been no material changes to the responsibilities of this KBU since the Previous Application.

The Indigenous Relations KBU is responsible for developing and maintaining meaningful relationships with Indigenous Nations through consultation, engagement and the negotiation and implementation of mutually beneficial agreements. The group supports BC Hydro by building relationships with Indigenous Nations which enables BC Hydro to better understand their interests so that they can be incorporated, where possible, into capital projects, programs and operations activities. Additionally, the Indigenous Relations KBU is responsible for supporting the advancement of reconciliation across the organization. This approach aligns with:

- BC Hydro’s Statement of Indigenous Principles which guides how we engage with Indigenous Nations;
- Our legal obligation to consult with and, where appropriate, accommodate Indigenous Nations; and

- Our commitment to reconciliation, implementing the United Nations Declaration on the Rights of Indigenous Peoples (**UNDRIP**) and the Calls to Action of the Truth and Reconciliation Commission, and working with Indigenous Nations to understand their interests and how we address and support them.

UNDRIP is a declaration which establishes an international framework of minimum standards for the “survival, dignity, and well-being” of Indigenous peoples and recognizes Indigenous peoples’ basic human rights. BC Hydro is mandated by the provincial government to implement UNDRIP as it relates to our specific work and context. We have been working to implement UNDRIP and advance reconciliation for some time, but this work will be formalized through the development of an UNDRIP implementation plan. BC Hydro will be co-developing the UNDRIP implementation plan with Indigenous Nations in B.C.

The actions included in the final version of the UNDRIP implementation plan are likely to impact all areas of the business and take efforts from all business groups to deliver. The plan is expected to build on efforts already underway across the company and will put increased focus on increasing cultural awareness throughout the organization to advance reconciliation and UNDRIP implementation, for years to come.

A key performance indicator of BC Hydro’s effectiveness in Indigenous relations is attaining a fourth consecutive gold-level certification for Progressive Aboriginal Relations (**PAR**), from the Canadian Council for Aboriginal Business.[318] PAR is a certification program that confirms corporate performance in Indigenous relations at the Bronze, Silver or Gold level. It evaluates four areas of performance including: leadership actions, employment, business development and community relations. PAR certification provides a high degree of assurance to Indigenous communities as the designation is supported by an independent, third-party verification and is

[318] The Canadian Council for Aboriginal Business is a non-partisan / non-profit organization founded in 1984, to support the participation of Aboriginal Peoples in Canada’s economy. There are approximately 36 Canadian organizations participating in the PAR program, at various levels of certification.

determined by a jury comprised of Indigenous business people. Additionally, achieving a gold level Progressive Aboriginal Relations designation is also a BC Hydro Service Plan performance measure.

BC Hydro has attained three consecutive gold level certifications since 2012 (each certification is for three years) and made its 2021 submission for PAR certification on March 31, 2021 for a further three years. BC Hydro will find out its certification level in September 2021.

The Indigenous Relations KBU consists of the following departments:

- Indigenous Relations Director Department
- Regional Relationship and Consultation Departments (Southwest, Southeast, and North); and
- Business Operations and Negotiations Department, which includes both the Indigenous Employment and Training and Communications teams.

5B.5.1.1. Indigenous Relations Director Department

This department includes the Indigenous Relations Director and an administrative assistant.

5B.5.1.2. Regional Relationship and Consultation Departments

The three regional departments are responsible for managing BC Hydro's overall relationships and consultation with Indigenous Nations across the province. This ensures that BC Hydro meets its legal obligation to consult with Indigenous Nations, and that capital projects, programs and operating activities are effectively delivered.

The regional departments develop and implement agreements with Indigenous Nations who may be impacted by the operation of BC Hydro's Power System and upcoming capital projects.

5B.5.1.3. Business Operations & Negotiations and Indigenous Employment and Training

The Business Operations and Negotiations department is responsible for developing and administering Indigenous Relations' engagement and consultation practices that support the delivery of capital projects and programs and operations activities so that we avoid or mitigate any impacts to Indigenous Nation's rights and thereby advance reconciliation. This department is responsible for tracking emerging policy (e.g., UNDRIP and Truth and Reconciliation Commission) and case law to ensure that our engagement and consultation practices are aligned with industry best practices. As such, the group also develops and implements the necessary initiatives, plans and strategies to support the implementation of UNDRIP, Truth and Reconciliation Commission recommendations, BC Hydro agreements and the advancement of reconciliation with Indigenous Nations.

The department is also responsible for leading agreement negotiations, managing the consultation and commitment tracking information system, and performance reporting.

The Indigenous Employment and Training team enables BC Hydro to attract and retain Indigenous employees in its workforce, and to meet its commitments in agreements with Indigenous Nations regarding employment. The team provides direct support to Indigenous Nations and peoples at a community level as well as scholarships/ bursary programs, and apprenticeships.

The Indigenous Relations Communications team is responsible for the development and execution of communications to employees, Indigenous people, and the public.

5B.5.2 Overview of Operating Costs and FTEs

Table 5B-6 Indigenous Relations KBU Fiscal 2022 Decision Operating Costs and FTEs by Department

	($ Millions)	Labour	Services - Other	Materials	Building & Equipment	Capitalized Overhead	External Recoveries	Total Operating	Total FTEs
1	Indigenous Relations Director	0.4	0.1	0.0	0.0	0.0	0.0	**0.5**	2
2	Regional Relationship and Consultation	2.2	0.7	0.0	0.0	0.0	0.0	**2.9**	41
3	Business Operations & Negotiations and Indigenous Employment and Training	2.5	0.8	0.0	0.0	0.0	0.0	**3.3**	31
4	**Total (Sch 5.2 L2, Sch 16.0 L10)**	**5.1**	**1.6**	**0.1**	**0.0**	**0.0**	**0.0**	**6.7**	**74**

This KBU consists of 74 FTEs. Approximately 45 per cent of the KBU's total labour costs are charged to capital projects. The remaining 55 per cent of labour costs make up 76 per cent of the total operating costs for the Indigenous Relations KBU.

The non-labour costs are required to develop and implement agreements with Indigenous Nations and to attract and retain Indigenous employees.

5B.5.2.1. Indigenous Relations Director Department

This department includes labour costs for the Director of Indigenous Relations and an administrative assistant. Non-labour costs include funding to support agreements with Indigenous Nations, and employee training, travel and expenses.

5B.5.2.2. Regional Relationship and Consultation Departments

Approximately 76 per cent of the operating cost budget for the Indigenous Relations' regional departments is related to labour for 41 FTEs. These FTEs charge out 61 per cent of their labour directly to capital projects.

These FTEs are organized into three regions and include two primary roles – project leads or relationship leads. The project leads carry out consultation and oversee the implementation of commitments that are made throughout consultation and in project related agreements. The relationship leads facilitate relationships with Indigenous Nation communities and develop and implement relationship agreements. Support roles in the regions include public affairs officers, records analysts, and managers.

Collectively, the FTEs in the three regional departments manage the following activities:

- Engagement and consultation on projects;[319]
- Implementation of finalized relationship agreements: BC Hydro has 16[320] finalized relationship agreements with Indigenous Nations in implementation; and
- Implementation of Impact Benefit Agreements (**IBAs**): BC Hydro has 22 finalized IBAs with Indigenous Nations in implementation (including Site C).

The remaining non-labour costs in this department include funding to develop and implement agreements with Indigenous Nations, and employee training, travel and expenses.

5B.5.2.3. Business Operations & Negotiations and Indigenous Employment and Training

Approximately 76 per cent of this department's budget relates to labour costs for 31 FTEs. These FTEs charge out 25 per cent of their labour costs directly to capital projects.

Collectively, these FTEs complete the following activities:

- Tracking, quality control and reporting of finalized agreements with Indigenous Nations in implementation: BC Hydro has 16 finalized relationship agreements in implementation;
- Consultation adequacy assessments: approximately 54 consultation adequacy assessments for BC Hydro projects;

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[319] Engagement and consultation activities can include: meetings and correspondence with Indigenous Nations, coordinating their involvement in project activities such as field work and site visits, and documenting these activities in the Indigenous Relations information tracking system.

[320] Includes thirteen relationship agreements finalized between fiscal 2016 and fiscal 2021, plus BC Hydro's agreements with St'at'imc, Tsay Keh Dene and Kwadacha.

- Project screening for Indigenous Nations interests: approximately 108 project screens for impacts to Indigenous Nations interests;
- Organizing a range of skills building and work experience events with approximately 200 participants; and
- Awarding over 35 provincial scholarships and bursaries across the province.

The remaining non-labour costs in this department include funding for relationship building, scholarships, bursaries, program costs and employee training, travel and expenses.

5B.5.3 Fiscal 2023 to Fiscal 2025 Plan Operating Costs and FTEs

Table 5B-7 Indigenous Relations KBU Operating Costs and FTEs

		Schedule Reference	F2021 Actual	F2022 Decision	F2023 Plan	F2024 Plan	F2025 Plan
			1	2	3	4	5
1	**Indigenous Relations KBU**						
2	Operating Costs ($ million)	5.2 L2	7.4	6.7	8.1	8.6	8.8
3	FTEs	16.0 L10	60	74	79	74	74

Operating costs are increasing by approximately $1.4 million from the fiscal 2022 Decision amounts to the fiscal 2023 plan, largely driven by the Indigenous Relations KBU's need to add an additional five FTEs due to the implementation of UNDRIP, further described in the next paragraph. This is partially offset by Standard Labour Rate decreases. Operating costs are increasing by approximately $0.5 million from the fiscal 2023 plan to the fiscal 2024 plan due to further incorporation of UNDRIP and Standard Labour Rate increases. Operating costs are increasing by approximately $0.2 million from the fiscal 2024 plan to the fiscal 2025 plan due to Standard Labour Rate increases.

The increase in five FTEs from the fiscal 2022 Decision amounts to the fiscal 2023 plan reflects resources needed in developing the UNDRIP implementation plan in collaboration with Nations. The development of the plan requires significant engagement over an extended period of time across all regions of the province and then development and implementation of specific activities to support the plan. The five FTEs will be split between the Business Operations and Negotiations and Regional Relationship and Consultation teams.

FTEs are expected to decrease by five from fiscal 2023 plan to fiscal 2024 plan due to the two-year pilot Indigenous Professionals in Development program coming to an end and those FTEs returning to the Project Delivery KBU. BC Hydro's current workforce profile indicates there is a gap in our pipeline for Indigenous leaders in middle and senior management, and the Indigenous Professionals in Development program is one way to address this gap. This program is rotating five university graduates across key divisions in BC Hydro, offering them the ability to apply their skills and abilities across BC Hydro teams to learn more about the type of work BC Hydro does and to gain on-the-job experience.

The Indigenous Relations KBU will review the success of the program upon completion of the two-year pilot and determine the appropriate path forward, making every effort to renew the Indigenous Professionals in Development program if the intended outcomes have been achieved, reallocating existing FTEs if necessary.

FTEs are planned to remain constant in fiscal 2025.

5B.6 Environment KBU

5B.6.1 Responsibilities

There have been no material changes to the responsibilities of this KBU since the Previous Application.

The Environment KBU's role is to provide a consistent company-wide approach to environmental management and governance. BC Hydro's infrastructure has a significant footprint on the landscape of British Columbia. It is important that we build and operate our system in an environmentally responsible and compliant way.

The Environment KBU enables BC Hydro to build projects and operate in compliance with environmental requirements and in line with our regulatory and other commitments. Examples of our regulatory and other commitments include the:

- Water Licence Requirements Program associated with Water Use Plans;
- Fish & Wildlife Compensation Program;
- Fish Entrainment Strategy Program; and
- Williston Dust Management Program.

This KBU creates and implements policies, standards and procedures to avoid, minimize or mitigate impacts to the environment resulting from BC Hydro's capital projects and operations. The KBU manages a risk review process so that environment and related risks are systematically considered and addressed in decision making. A company-wide Statement of Environmental Principles provides environmental guidance to all staff and contractors.

The Environment KBU consists of the following departments:

- Director, Environment Department;
- Project Environmental Risk Management, Regulatory and Policy Department;
- Environmental Field Operations Department;
- Land Program Department;
- Water Program Department; and
- Fish & Wildlife Compensation Program Department.

5B.6.1.1. Director, Environment Department

This department contains the Director, Environment and an administrative assistant.

5B.6.1.2. *Project Environmental Risk Management, Regulatory and Policy Department*

This department provides environmental services for the planning and execution of capital projects and programs including obtaining regulatory permits and authorizations, oversight of environmental compliance and risk management, contract management, and management of environmental and heritage components. This department also delivers training to project teams, tracks environmental regulatory changes and prepares BC Hydro for new regulatory and compliance requirements.

5B.6.1.3. Environmental Field Operations Department

This department provides regional environmental services for the planning and execution of operations, maintenance and program work. This includes obtaining regulatory permits and authorizations, oversight of environmental compliance and risk management, contract management, and management of environmental and heritage components. Environmental Field Operations responds to environmental incidents and emergencies through regionally based teams and provides after hours standby support to operations teams. This department conducts environmental verifications to evaluate compliance and use of best management practices, develops and delivers training to field crews and reports on company wide environmental performance. Environmental Field Operations is also responsible for the Williston Dust Mitigation Program.

5B.6.1.4. Land Program Department

This department manages land and air-based environmental impacts and compliance requirements by developing corporate environmental standards and providing expert advice and service to avoid or address land and air-based environmental risks. This department's subject matter experts work with professionals in other Environment KBU departments and other KBUs in Integrated Planning and Operations, to develop and implement effective environmental standards for capital asset planning, capital projects, field programs and operational needs. This department also manages compliance and risk management programs in areas such as contaminated sites, pollution prevention, spill response, wildlife ecology and mitigation, archaeology and heritage, as well as greenhouse gas emission reporting and climate change mitigation.

5B.6.1.5. Water Program Department

This department manages water-based environmental impacts and compliance requirements by developing corporate environmental standards and providing expert advice and service to avoid or address water-based environmental risks. In parallel with the Land Program department, this department's subject matter experts work with professionals in other Environment KBU departments and other Business Groups such as Integrated Planning and Operations, to ensure that effective standards are in place for all planning, project, program and operational needs for water-based subjects.

This department, in partnership with the Generation System Operations KBU, is responsible for keeping BC Hydro in compliance with the regulatory requirements of our *Water Sustainability Act* Orders, Water Licence conditions and *Fisheries Act* Authorizations as well as other regulatory requirements and commitments including the Fish Passage Framework, Fish Entrainment Strategy and the Invasive Aquatic Species program.

5B.6.1.6. Fish & Wildlife Compensation Program Department

The Fish and Wildlife Compensation Program manages BC Hydro's water licence compensation obligations in the Columbia and Peace regions to address historical impacts to fish and wildlife associated with the construction of the dams. BC Hydro has made voluntary commitments to address similar impacts in the Coastal Region. The responsibilities of this department include working with the program's three regional boards, which include representation from the Government of B.C., Fisheries and Oceans Canada, Indigenous Nations, public stakeholders and

BC Hydro, to carry out direction and decisions of the boards, and supporting implementation of conservation based projects in watersheds where BC Hydro has had an historical impact.

5B.6.2 Overview of Operating Costs and FTEs

Table 5B-8 Environment KBU Fiscal 2022 Decision Operating Costs and FTEs by Department

	($ Millions)	Labour	Services - Other	Materials	Building & Equipment	Capitalized Overhead	External Recoveries	Total Operating	Total FTEs
1	Director, Environment	-0.1	0.0	0.0	0.0	0.0	-	**0.0**	1
2	Project Env Risk Mgmt, Reg & Policy	1.2	0.5	0.0	0.0	0.0	-	**1.8**	22
3	Environment Field Operations	4.8	4.0	0.0	0.1	0.0	-	**8.9**	34
4	Land Program	1.8	1.8	0.0	0.0	0.0	-	**3.7**	14
5	Water Program	2.9	17.9	0.0	0.1	0.0	(13.9)	**7.0**	20
6	Fish & Wildlife Compensation Program	0.2	9.6	0.0	0.0	0.0	-	**9.8**	5
7	**Total (Sch 5.2 L3, Sch 16.0 L11)**	**10.9**	**33.8**	**0.1**	**0.1**	**0.0**	**(13.9)**	**31.0**	**95**

The Environment KBU's operating costs and FTEs are primarily driven by three requirements:

- Overseeing environmental compliance across capital projects and programs as well as operations;
- Delivering our regulatory commitments through programs such as the Water License Requirements and the Fish & Wildlife Compensation Program; and
- Providing input to and working with the Indigenous Relations KBU to increase Indigenous Nations participation in environmental components of projects, programs and operations.

Approximately 35 per cent of total Environment KBU's planned labour costs are charged to capital and work programs and are not included in the labour costs provided in Table 5B-8 above. External recoveries (explained in section 5B.6.2.5) offset approximately 31 per cent of the operating costs in this KBU.

The Environment KBU's primary approach to work plan delivery is to retain an in-house oversight role and to contract on-the-ground requirements, such as environmental monitoring. The Environment KBU applies a consistent approach to evaluate and determine FTE and contractor requirements. This approach involves:

- Assessing the workload volume, complexity, and risk associated with capital projects and operations, and work plans to deliver environmental programs;
- Assessing current resource requirements in comparison with historic records or through expert assessment of requirements;
- Assigning work component resource estimates to internal staff, based on their expertise, experience and available time;
- Considering other options when FTE availability is insufficient to meet demands including the use of short-term contractors to augment peaks in workload; and
- Monitoring delivery performance by tracking measures such as overtime, and milestone delivery and then modifying or reassigning resources as required to address priorities and improve delivery.

5B.6.2.1. Director, Environment Department

This department contains the labour costs for the Director of the Environment KBU and an administrative assistant, as well as vacancy factor adjustments. Vacancy factor adjustments are additional FTEs planned at the individual department level, with offsetting negative FTEs in the Director, Environment department. These negative FTEs reflect vacancies that will occur during the year. As a result, there is in a net zero FTE and cost impact to the KBUs and to BC Hydro overall.

5B.6.2.2. Project Environmental Risk Management, Regulatory and Policy Department

This department consists of 22 FTEs. The majority of these FTEs are environmental professionals who support capital projects. Approximately 76 per cent of the regular labour costs for these FTEs are charged to capital projects.

This department is responsible for providing environmental work package requirements for approximately 450 Power System capital projects, Properties capital projects, and Distribution capital projects and programs each year. Each FTE in this department oversees work package requirements for approximately 20 capital projects.

In addition, the Project Environmental Risk Management, Regulatory and Policy department reviews the requirements of and changes to six major federal acts, eight provincial acts, and over 100 regulations and related documentation, as well as maintains documentation and manages extension processes for 22 *Fisheries Act* Authorizations.

This department's non-labour costs of $0.5 million includes funding for professional and safety training and the delivery of post-project environmental commitments.

5B.6.2.3. Environmental Field Operations Department

This department consists of 34 FTEs. Most of these FTEs are environmental professionals who support Operations to meet environmental requirements. Approximately eight per cent of the regular labour costs for these FTEs are charged to Operations Business Group.

This department provides the following key deliverables:

- Working directly with Operations managers and crews to implement best practices for fish and fish habitat, wildlife, archaeology and heritage sites and pollution prevention to meet compliance requirements and to avoid or minimize operational impacts to land, air and water;
- Providing 24/7 emergency response to events such as fires, floods and oil spills from overhead and underground transformers and substation equipment;
- Developing environmental training for over 2,000 BC Hydro field staff plus contractors;

- Conducting approximately eight environmental compliance evaluations and 140 environmental verifications (assessments to check procedures are followed) annually as well as investigating all significant incidents and developing corrective actions (12 investigations and 206 corrective actions were completed in fiscal 2021); and
- Tracking and reporting on environmental performance across BC Hydro, conducting the annual risk review and preparing quarterly Board reports.

This department's non-labour costs of $4.1 million includes $2.8 million for the Williston Dust Management Program.[321] The remainder supports reservoir fertilization, debris management, post-project and other monitoring, educational materials development, environmental compliance evaluations, and professional and safety training.

5B.6.2.4. Land Program Department

The Land Program department consists of 14 FTEs. Approximately 21 per cent of the regular labour costs for these FTEs are primarily charged to capital projects.

The Land Program department manages land-based environmental impacts and compliance requirements by developing corporate environmental standards and providing expert advice and service to avoid or address land-based environmental risks.

This department provides the following key deliverables:

- Subject area expertise (e.g., pollution prevention, archaeology and heritage, wildlife, and greenhouse gas reporting), and development of related environmental standards, programs, procedures, and environmental screening tools;

[321] The Williston Dust Management Program is a Contribution Agreement with the Tsay Keh Dene Nation to address air quality issues. The Tsay Keh Dene Nation conducts work that reduces the impact of dust emissions from the drawdown zone on their communities when the reservoir level is low.

- Delivery of compliance reporting requirements for applicable pollution prevention legislation, and coordination of the Contaminated Sites Management Program with an inventory of 400 sites and active management of approximately 40 contaminated properties; and
- Delivery of the multi-year Reservoir Archaeology Program for 26 reservoirs to comply with and meet commitments under the B.C. *Heritage Conservation Act* and to provide support for Indigenous Nations relationships and agreements.

This department's non-labour costs of $1.8 million supports the Reservoir Archaeology Program, Cultural Heritage Information Plans, pollution prevention compliance actions, wildlife compliance, greenhouse gas reporting and professional and safety training.

5B.6.2.5. Water Program Department

This department consists of 20 FTEs. Approximately 21 per cent of the regular labour costs for these FTEs are primarily charged to capital projects.

The Water Program manages water-based environmental impacts and compliance requirements by developing corporate environmental standards and providing expert advice and service to avoid or address water-based environmental risks.

This department provides the following key deliverables:

- 23 Water Use Plan orders and the approximately 350 associated monitoring studies and physical works necessary for compliance under BC Hydro's Water Licences; and
- *Fisheries Act* Authorization requirements at 30 BC Hydro facilities, as well as other regulatory requirements and commitments including the Fish Passage Framework, Fish Entrainment Strategy responses at 15 facilities with high entrainment risks and the Invasive Aquatic Species program.

This department's non-labour costs of $18.0 million provide funding to deliver the Water License Requirements program as ordered by the Comptroller of Water Rights, and other regulatory commitments. Most of these costs are offset by planned external recoveries, which totals $13.9 million in fiscal 2022. External recoveries capture reimbursement of expenses credited against annual B.C. provincial water rental fees paid by BC Hydro. These Water Use Planning Remissions recoveries result when additional expenses are incurred as a result of projects or constraints ordered by the Comptroller of Water Rights that were not originally contemplated in BC Hydro's Water Licences.

The remaining costs not covered by external recoveries primarily support Comptroller of Water Rights ordered projects which are not remissible and support regulatory commitments to fisheries and invasive species programs.

5B.6.2.6. Fish & Wildlife Compensation Program Department

This department consists of five FTEs who manage all aspects of the Fish & Wildlife Compensation Program. The labour costs associated with regional managers are charged to the regional programs and are not captured in the labour costs for this department.

The Fish & Wildlife Compensation Program Department's fiscal 2022 Decision amount of $9.8 million includes $5.7 million for the Columbia region, $2.3 million for the Coastal region, $1.6 million for the Peace region and $0.2 million for management costs. Management costs include labour for the department management, and other department related expenses not covered by the Columbia, Peace or Coastal programs.

This department's budget fulfills BC Hydro's obligation to the Fish & Wildlife Compensation Program's three regions. The program and regional budgets are based on historical agreements negotiated with regulators. These agreements provide the three regions with annual funding increases tied to the Consumer Price

Index and allow for any annual under spend to be carried forward to subsequent years.

5B.6.3 Fiscal 2023 to Fiscal 2025 Plan Operating Costs and FTEs

Table 5B-9 Environment KBU Operating Costs and FTEs

		Schedule Reference	F2021 Actual	F2022 Decision	F2023 Plan	F2024 Plan	F2025 Plan
			1	2	3	4	5
1	**Environment KBU**						
2	Operating Costs ($ million)	5.2 L3	28.9	31.0	30.7	31.0	31.4
3	FTEs	16.0 L11	93	95	95	95	95

Operating costs are decreasing by approximately $0.3 million from the fiscal 2022 Decision amounts to the fiscal 2023 plan due to a $0.2 million decrease in the Standard Labour Rates and $0.1 million decrease in travel costs.

From fiscal 2023 plan to the fiscal 2024 plan operating costs are increasing by $0.3 million due to Standard Labour Rate increases.

From fiscal 2024 plan to the fiscal 2025 plan operating costs are increasing by $0.4 million of which $0.3 million is due to Standard Labour Rate increases.

FTEs are planned to remain constant over the Test Period.

5B.7 Properties KBU

5B.7.1 Responsibilities

There have been no material changes to the responsibilities of the Properties KBU since the Previous Application.

The Properties KBU is accountable for the management of BC Hydro's provincial property portfolio, including lands, buildings and rights of way. The services provided by the Properties KBU include facilities operations and maintenance for BC Hydro's field and corporate buildings and infrastructure; office services and space management; property rights acquisitions, dispositions and management required to support BC Hydro's electric systems and infrastructure; property acquisitions, sales and leasing; building asset management and construction of new facilities. The KBU is also responsible for BC Hydro's property assessment reviews and tax payments.

The Properties KBU oversees and provides real estate expertise for a extensive and diverse portfolio which includes over 74,000 acres of land, made up of over 4,000 individual land parcels as well as extensive statutory rights of way in support of 86,000 kilometres of distribution and transmission lines and Crown land tenures for 26 generation reservoirs and 81 dams.

In addition, the KBU manages lands and buildings that accommodate BC Hydro's corporate headquarters and field buildings which total 105 facilities, comprising approximately three million square feet in size. The size, scope, complexity and importance of BC Hydro's property and real estate interests to our operations and projects drives the main functions of the Properties KBU, which include:

- Managing existing property rights for BC Hydro's Power System infrastructure (transmission and distribution lines, substations, reservoirs, dams, powerhouses, access roads);
- Managing the acquisition of land and property rights to facilitate the upgrades and expansion of the Power System and field facilities;
- Managing property leases and licences, and sales of surplus property;
- Developing asset management and capital plans for the 105 BC Hydro headquarters and field buildings that make up the Properties' managed building portfolio;[322]

[322] Facilities that house the Power System infrastructure (i.e., substations, generating stations) are the responsibility of the Integrated Planning Business Group and the Operations Business Group and are outside the portfolio managed by the Properties KBU, given the specific safety and operational requirements for the electrical assets.

- Managing the delivery of building replacement and upgrade capital projects for BC Hydro's headquarters and field buildings; and
- Operating and maintaining BC Hydro's headquarters and field buildings that house approximately 6,000 BC Hydro employees and contractors who work from these facilities. Services provided to support operations across the province also include workspace planning and work location moves and mail distribution.

The Properties KBU is organized into the following departments:

- Properties Director's Office Department;
- Real Estate Planning and Project Delivery Department;
- Facilities and Space Management Department;
- Property Rights Management Department; and
- Real Estate Services Department.

5B.7.1.1. Properties Director's Office Department

This department includes the Properties Director and an administrative assistant.

5B.7.1.2. Real Estate Planning and Project Delivery Department

The Real Estate Planning and Project Delivery department is responsible for long term and capital planning for BC Hydro's property and real estate assets, managing capital project delivery, and delivering property information management services. This includes:

- Long-term planning and forecasting for BC Hydro's corporate and field office real estate across British Columbia, including properties surplus to BC Hydro's needs;
- Developing and managing the capital investment plans for the Properties' managed building portfolio. The department manages the asset information,

including condition and age, in order to identify those assets that need replacement or refurbishment, and develops the prioritised capital plan to address these needs. Proactively identifying and planning for the replacement of building assets avoids the additional costs and operational disruption associated with completing emergency repairs and replacements;

- Executing the Properties capital plan, through project delivery oversight, ensuring projects are completed to schedule and budget, meeting BC Hydro business needs and standards as well as regulatory, environmental, safety and building code requirements. The department establishes the construction and product standards for BC Hydro's buildings and determines the construction methodology. While this department completes the assessment of operational business needs, sets the standards and engages with key stakeholders, construction work is undertaken by external construction companies. In addition, the majority of projects are managed by contract project managers with experience in industrial building construction project delivery. The department's delivery of building renovation and development projects ensures that BC Hydro's operations are housed in safe, secure and seismically resilient facilities; and
- Maintaining the physical and electronic records for the entire portfolio of BC Hydro's property interests through a centralized information system. This system captures key property information for every land parcel that BC Hydro owns (e.g., legal documents such as purchase and sale agreements, Right-of-Way agreements, leases and licences and facilities asset information). This database supports BC Hydro's oversight and management of its property interests in support of capital projects and operations.

5B.7.1.3. Facilities and Space Management Department

The Facilities and Space Management department is responsible for the maintenance and operations of BC Hydro's 105 field and office facilities and provides business services and workspace management services (including workstation design, physical moves, and space reconfigurations) for BC Hydro's operations across the province. This includes:

- Ensuring buildings and facilities assets are efficiently operated, maintained and repaired to meet BC Hydro's expectations and needs, including business continuity (24/7 emergency response) as well as environmental, health, and safety standards. To achieve these outcomes BC Hydro contracts with a single outsourced provider for the larger facilities and multiple service providers for the smaller and more remote facilities. This department provides contract management and oversight as BC Hydro's representative and also plays an important role overseeing the interface between building occupants and contractors;
- Managing the operations and maintenance of facilities across the province. This centralized approach allows for coordinated and standardized maintenance, and investments across the facilities. If the facility component assets are not maintained, their deterioration would impact worker health and safety, productivity, emergency response capability and components would need to be replaced more often, increasing overall asset life cycle costs;
- Coordinating workspace moves for the majority of BC Hydro employees and contractors. This department ensures that workspace designs and reconfigurations maximize space usage and use standardized layouts and furniture to allow for maximum flexibility and reduced costs while meeting all code requirements for access and egress; and
- Sorting and distributing internal and external mail across all occupied BC Hydro facilities as well as managing the contracts for province-wide courier services, food services, and parkade management.

5B.7.1.4. Property Rights Management Department

The Property Rights Management department manages BC Hydro's property rights and interests over Crown, Indigenous Nations[323] and private lands, fulfilling an important support role that enables BC Hydro to reliably and safely operate, access and maintain our dams and reservoirs, generation facilities, and transmission and distribution systems. This includes:

- Working directly with property owners to secure BC Hydro's rights to access their land, access BC Hydro owned infrastructure, undertake our maintenance work, such as vegetation management, or to construct new infrastructure;
- Managing all interactions with third parties, such as landowners, community groups, municipalities and pipeline companies, who request use of or access through BC Hydro land and rights-of-way. These secondary use requests must be compatible with BC Hydro's operational, safety and security requirements, given the risk of damage, electrical safety and related liabilities; and
- Providing subject matter expertise to represent BC Hydro's interests during the Government of B.C.'s proposed Crown land dispositions with Indigenous Nations for Treaty Settlements or other government agreements. This representation is critical to ensure that BC Hydro's rights to continue to operate its existing Power System on Indigenous Nations lands are maintained, and that rights are in place for future lines and reservoir operations.

5B.7.1.5. Real Estate Services Department

The Real Estate Services department acquires land and property rights for BC Hydro's development of the Power System and field facilities, conducts property sales, manages property leases and licences and administers BC Hydro's property tax portfolio. This includes:

[323] Indigenous Nations lands include Indigenous Nations Reserve, Treaty, and Title Lands.

- Undertaking the acquisition of land and property rights for BC Hydro’s capital projects, customer interconnection projects, and BC Hydro field facility development projects;
- Managing rights acquisition agreements in support of new distribution system connections across the province. The timely and legal acquisition of suitable property interests is necessary to enable BC Hydro to access and occupy sites as well as construct, operate and maintain system assets;
- Managing BC Hydro's property sales including ensuring all due diligence, legal, environmental clearances and Indigenous Nations consultation activities are completed prior to property sales. This department has a target of achieving net sales of $100 million by the end of fiscal 2024, an important contribution to maintaining affordable rates, through sales proceeds and reduced holding costs on surplus properties. Actual surplus property sales are captured by the Real Property Sales Regulatory Account, which is discussed further in Chapter 7, section 7.3.3.7;
- Managing all property leasing and licencing agreements, representing BC Hydro as landlord for BC Hydro owned property and as a tenant for leased space; and
- Managing BC Hydro’s property tax assessments and ensuring that BC Hydro is compliant with regulations to pay taxes and grants. BC Hydro is one of the largest property taxpayers in the province with an annual property tax payments (Grants in Lieu and School Taxes) of approximately $300 million on assets assessed at over $11.5 billion. Given the significant size of this obligation, the department identifies opportunities to reduce current and future tax assessments. For example, in fiscal 2020 and fiscal 2021, combined annual savings of around $3.4 million were achieved through negotiations and appeals that will be reflected in reductions in future years’ assessments.

5B.7.2 Overview of Operating Costs and FTEs

**Table 5B-10 Properties KBU
Fiscal 2022 Decision Operating Costs
and FTEs by Department**

	($ Millions)	Labour	Services - Other	Materials	Building & Equipment	Capitalized Overhead	External Recoveries	Total Operating	Total FTEs
1	Properties Director's Office	0.4	0.2	0.0	0.0	0.0	0.0	**0.6**	2
2	Real Estate Planning and Project Delivery	1.3	1.6	0.1	0.1	0.0	0.0	**3.1**	21
3	Facilities and Space Management	2.9	17.1	0.1	1.4	0.0	0.0	**21.5**	28
4	Property Rights Management	1.4	0.1	0.0	0.0	0.0	0.0	**1.4**	32
5	Real Estate Services	1.7	0.3	0.0	1.7	0.0	0.0	**3.7**	40
6	**Total (Sch 5.2 L4, Sch 16.0 L12)**	**7.7**	**19.2**	**0.1**	**3.2**	**0.0**	**0.0**	**30.3**	**123**

Approximately 48 per cent of the KBU's total labour costs are charged to capital projects. The remaining 52 per cent of labour costs make up 25 per cent of the total operating costs for the Properties KBU.

75 per cent of non-labour costs consist of contractor services to manage and maintain the facilities. The remaining 25 per cent of non-labour costs are for external office space operating leases, operating costs related to capital projects and workspace and office management costs.

5B.7.2.1. Properties Director's Office Department

The budget for this department relates to labour costs for two FTEs – the Director of the Properties KBU and an administrative assistant.

5B.7.2.2. Real Estate Planning and Project Delivery Department

Approximately 42 per cent of this department's budget is related to labour costs. The 21 FTEs in this department charge approximately 50 per cent of their time to capital projects.

The workforce requirements for this department are mainly driven by the volume and complexity of Properties managed capital projects as well as the volume of work in other departments in the Properties KBU. The majority of the capital project managers are contracted resources, with oversight provided by internal FTEs in this department. This resourcing approach allows for maximum flexibility as the volume and complexity of capital projects can vary significantly from year-to-year. This department also relies on subject matter experts from other KBUs (e.g., Safety, Environment, Indigenous Relations) to support project delivery.

The Real Estate Planning and Project Delivery department is responsible for:

- Planning for more than 14,000 assets at 105 facilities;
- Delivering an average of 75 property capital projects per year with a total capital budget of approximately $44 million; and
- Managing approximately 142,000 physical records and the creation or transfer of approximately 13,600 files per year.

The non-labour budget for this department is primarily related to operating costs for capital projects such as temporary lease costs and moving costs.

5B.7.2.3. Facilities and Space Management Department

Approximately 80 per cent of this department's budget is related to costs to service BC Hydro's 105 facilities across the province. These facilities comprise approximately three million square feet of office and industrial space. Service provider costs include facility services as well as repairs and maintenance to building components. Preventative maintenance is completed on critical building components and work is carefully managed to balance affordability with the reliability and safety of our facilities.

Approximately 13 per cent of the Facilities and Space Management department's budget is related to labour for 28 FTEs. This department manages the contract for the single provider of outsourced facility management services, covering approximately 40 per cent of BC Hydro's facilities, and also manages more than 200 vendors who provide services to the remaining 60 per cent of facilities that are managed directly by the department. The department also coordinates workspace moves for BC Hydro employees and contractors. Workspace moves are required for various reasons, including the collapse of leases, renovations and capital projects, new hires and employee transfers.

The remaining seven per cent of the Facilities and Space Management budget is for courier services to handle more than 500,000 pieces of internal and external mail annually for all of BC Hydro's occupied facilities throughout the province.

As facility operations, maintenance and repair activities are contracted out, the department's size is commensurately small. When workload pressures occur, contractors are used on a short-term or project basis.

5B.7.2.4. Property Rights Management Department

Almost all of this department's budget relates to labour costs for 32 FTEs. The FTEs in this department charge approximately 60 per cent of their labour to projects in other KBUs.

The resourcing requirements of this department are driven by the volume and complexity of work requests received including capital projects that require rights acquisitions, secondary use and rights of way access requests by third-parties, as well as Indigenous Nations property rights acquisitions and Provincial Treaty settlement negotiations.

This department manages:

- More than 2,600 secondary use requests per year;
- Over 7,000 external property related questions and requests per year
- Over 80 property rights acquisitions each year for distribution system connections on Indigenous Nations lands;
- Over 45 government land agreements with Indigenous Nations; and

- Approximately 7,100 agreements for Generation reservoir and dam related property rights and approximately 85,000 agreements for Transmission and Distribution property rights.

While the number of work requests has remained consistent in recent years, the mix and complexity of the requests has increased, adding to the workload of the department. This additional workload is managed through supplementing existing resources with temporary contractors, reassigning of resources from other departments in the Properties KBU and managing backlogs.

5B.7.2.5. Real Estate Services Department

Approximately 49 per cent of this department's operating budget is related to rent paid to lease facilities throughout the province.

Approximately 46 per cent of this department's budget is related to labour costs for 40 FTEs. The FTEs in this department charge approximately two-thirds of their time to projects and programs in other KBUs.

The workforce requirements for this department are mainly driven by the volume and complexity of work activities and transactions processed. For example, the number and scale of capital construction projects that require land or rights acquisitions and the volume of distribution connection requests.

On an annual basis, this department manages approximately:

- 85 Power System capital projects;
- 1,800 distribution system requests;
- 1,300 leasing and licencing agreements;
- 36 active surplus sales processes; and
- 4,400 property tax assessments.

The workforce of this department is sized to deliver services responsively to capital project teams, and other parts of BC Hydro, such as the Distribution Design Customer Connections KBU. When additional resources are required, the department manages resources with planned reliance on overtime, reassigned resources from other departments in the Properties KBU and, in peak times, contractors, to manage workload and backlogs.

The remaining five per cent of the department's budget is for contract services and consultant fees including independent appraisals and additional contractor support for complex lease and sales files.

5B.7.3 Fiscal 2023 to Fiscal 2025 Plan Operating Costs and FTEs

Table 5B-11 Properties KBU Operating Costs and FTEs

		Schedule Reference	F2021 Actual	F2022 Decision	F2023 Plan	F2024 Plan	F2025 Plan
			1	2	3	4	5
1	**Properties KBU**						
2	Operating Costs ($ million)	5.2 L4	30.5	30.3	30.0	30.3	30.5
3	FTEs	16.0 L12	116	123	123	123	123

Operating costs are decreasing by $0.3 million from fiscal 2022 Decision amounts to fiscal 2023 plan primarily due to a decrease in Standard Labour Rates. Operating costs are increasing by $0.3 million from fiscal 2023 plan to fiscal 2024 plan due to Standard Labour Rate increases. Operating costs are increasing by $0.2 million from fiscal 2024 plan to fiscal 2025 plan due to Standard Labour Rate increases. FTEs are planned to remain stable over the Test Period.

5B.8 Business Unit Support KBU

5B.8.1 Responsibilities

The Capital Infrastructure Project Delivery Business Unit Support KBU includes the budget for the Office of the Senior Vice President of Capital Infrastructure Project Delivery.

5B.8.2 Overview of Operating Costs and FTEs

Table 5B-12 Business Unit Support KBU Fiscal 2022 Decision Operating Costs and FTEs by Department

	($ Millions)	Labour	Services - Other	Materials	Building & Equipment	Capitalized Overhead	External Recoveries	Total Operating	Total FTEs
1	SVP,Capital Infrastructure Project Delivery	0.8	0.1	0.0	0.0	0.0	0.0	**0.9**	3
2	**Total (Sch 5.2 L5, Sch 16.0 L13)**	**0.8**	**0.1**	**0.0**	**0.0**	**0.0**	**0.0**	**0.9**	**3**

The budget for this department relates to labour costs for three FTEs – the Senior Vice President of Capital Infrastructure Project Delivery, a Senior Strategic Business Advisor and an Administrative Assistant.

5B.8.3 Fiscal 2023 to Fiscal 2025 Plan Operating Costs and FTEs

Table 5B-13 Business Unit Support KBU Operating Costs and FTEs

		Schedule Reference	F2021 Actual	F2022 Decision	F2023 Plan	F2024 Plan	F2025 Plan
			1	2	3	4	5
1	**Business Unit Support KBU**						
2	Operating Costs ($ million)	5.2 L5	0.8	0.9	0.9	0.9	0.9
3	FTEs	16.0 L13	3	3	3	3	3

Operating costs and FTEs are planned to remain stable from the fiscal 2022 Decision amounts to the fiscal 2023 to fiscal 2025 plan.

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Chapter 5C

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5C.1 Introduction – Operations Business Group

Chapter 5C details the composition of, and rationale for the operating costs of the Operations Business Group. The Operations Business Group is one of six business groups in the organization and is responsible for operating BC Hydro's facilities and assets. It serves as the Operate function of the Plan-Build-Operate-Support model. There have been no material changes to the organization or responsibilities of this Business Group since the Previous Application.

The Operations Business Group budget was developed as part of the budgeting process outlined in Chapter 5, section 5.4, which the BCUC found to be reasonable in its decision on the Previous Application.[324] The budgeting approach includes both bottom-up and top-down elements and examines more than just incremental costs. The information provided in Chapter 5C demonstrates the basis for the entirety of the Business Group and KBU budgets, rather than focusing only on incremental cost requirements. This information is provided in a format and level of detail consistent to that presented in the equivalent chapter in the F2020-F2021 RRA.

Chapter 5C is organized as follows:

- Section 5C.2 provides an overview of the organization and responsibilities of the Operations Business Group;
- Section 5C.3 provides the operating costs and FTE information for the Operations Business Group;[325] and
- Sections 5C.4 to 5C.11 provide more detailed information on the responsibilities, cost and FTEs for each KBU within the Operations Business

[324] BCUC Decision and Order No. G-187-21, Fiscal 2022 Revenue Requirements Application (June 17, 2021), p. 27: "The Panel considers BC Hydro's budgeting process involving top-down and bottom-up elements goes beyond the examination of incremental changes from the prior year and continues to be reasonable for forecasting operating costs. Therefore, for these reasons, the Panel finds the fiscal 2022 operating costs requested for recovery to be reasonable."

[325] Please note the amounts presented in the tables in these sections may not add due to rounding.

Group. The operating costs and FTE information for each KBU is broken out into two sections:[325]

- Overview of Operating Costs and FTEs – This section explains the starting operating costs and FTEs for the KBU based on the fiscal 2022 Decision amounts; and
- Fiscal 2023 to Fiscal 2025 Plan Operating Costs and FTEs – This section explains any incremental changes in the KBU between fiscal 2022 Decision amounts and fiscal 2023 to fiscal 2025 plan.

5C.2 Overview of Operations Business Group Organization and Responsibilities

The role of the Operations Business Group is to:

- **Safely and Efficiently Execute Work:** Maintenance and smaller scale capital work identified by the Integrated Planning Business Group is directed to the Program and Contract Management KBU of the Operations Business Group for delivery. The Program and Contract Management KBU then develops annual program and project delivery plans and assigns work to the primary field construction groups of the Line Field Operations KBU, Stations Field Operations KBU, Construction Services KBU or external contractors;
- **Connect Customers to the Distribution System:** The Distribution Design and Customer Connections KBU provides design work, project coordination and work packages for new connections of distribution voltage customers (25 kV and under) as well as distribution system improvement and end of life asset replacement programs. The execution of this work is then assigned to the primary delivery groups of the Line Field Operations KBU, the Construction Services KBU, or external contractors;
- **Operation of the Integrated System to Maximize Overall Value:** The Generation System Operations KBU is responsible for planning the operation of

BC Hydro's reservoirs and generation facilities and for integrating other energy resources into those operations to meet BC Hydro's load obligations. The Transmission and Distribution System Operations KBU is responsible for managing the real time operation of the BC Hydro generation, transmission, distribution and telecommunication systems.

Larger and more complex capital projects are implemented by the Project Delivery KBU of the Capital Infrastructure Project Delivery Business Group, as discussed in Chapter 5B, section 5B.4. The Operations Business Group consists of the following KBUs:

Business Group	Key Business Unit
Operations	Program and Contract Management Line Field Operations Stations Field Operations Distribution Design and Customer Connections Construction Services Generation System Operations Transmission and Distribution System Operations Business Unit Support

5C.3 Fiscal 2023 to Fiscal 2025 Plan Operating Cost and FTE Summaries

This section addresses planned operating costs and FTEs for the Operations Business Group. The following are some key points of note with respect to the information provided in Figure 5C-1, Table 5C-1, Figure 5C-2, Table 5C-2 and Table 5C-3:

- The Line Field Operations KBU, Stations Field Operations KBU and Construction Services KBU make up approximately 60 per cent of the Operations Business Group's operating budget. They are primarily comprised of trades staff, responsible for executing the operations, maintenance and capital work required on BC Hydro's Transmission, Distribution and Generation systems;

- Over the Test Period, the Operations Business Group makes up approximately 39 per cent of BC Hydro's total FTEs, while only accounting for approximately 23 per cent of the base operating costs. This difference is primarily because large portions of the Operations Business Group's work are charged to the maintenance work programs that are budgeted in the Integrated Planning Business Group, as well as to capital projects. This is described in further detail within the individual KBU sections in this chapter; and
- The increase in the Operations Business Group's operating budget from fiscal 2022 Decision amounts to fiscal 2025 plan is largely driven by net increases to Standard Labour Rates (as discussed further in Chapter 5, section 5.12.2), Work Program Delivery Resource requirements (as discussed further in Chapter 5, section 5.11); a ramp up period of operating costs related to the Site C Generating Station that will transition from the construction phase to the operating phase starting in fiscal 2023 (as discussed further in Chapter 5, section 5.10); and Water Use Planning order review project costs (as discussed further in Chapter 5, section 5.5.3.1); partially offset by a reduction in employee training (as discussed further in Chapter 5, section 5.5.3.6) and a reduction in Storm Restoration costs (as discussed further in Chapter 5, section 5.5.3.6).

Planned operating costs for this Business Group are $266.8 million in fiscal 2023, $269.2 million in fiscal 2024 and $275.3 million in fiscal 2025. The operating costs for the Operations Business Group are summarized by KBU in Figure 5C-1. Additional cost details are provided in Table 5C-1 below.

Figure 5C-1 Operations Net Operating Costs by KBU (Fiscal 2023 Plan) ($ million)

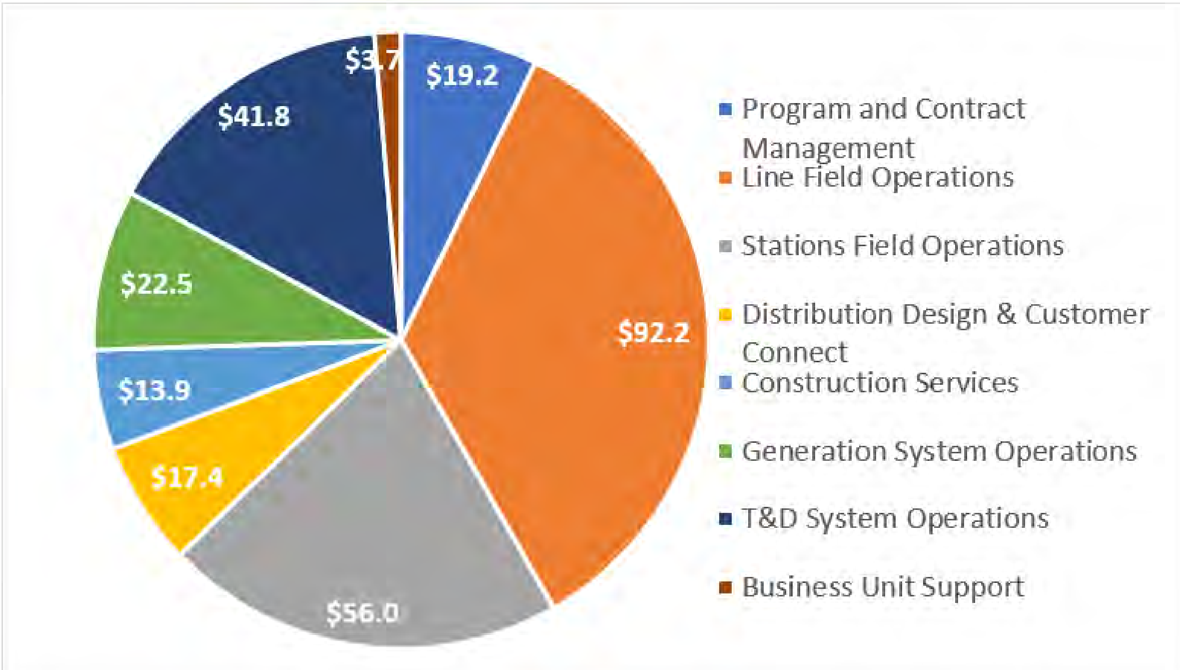


Table 5C-1 Operations Net Operating Costs by KBU

	($ million)	Schedule Reference	F2021 Actual	F2022 Decision	F2023 Plan	F2024 Plan	F2025 Plan
			1	2	3	4	5
1	Program and Contract Management	5.3 L1	14.4	17.3	19.2	19.7	20.2
2	Line Field Operations	5.3 L2	103.1	92.3	92.2	91.8	92.1
3	Stations Field Operations	5.3 L3	57.7	55.8	56.0	56.5	59.7
4	Distribution Design & Customer Connect	5.3 L4	14.6	16.4	17.4	17.9	18.4
5	Construction Services	5.3 L5	14.8	14.9	13.9	14.0	14.3
6	Generation System Operations	5.3 L6	19.4	19.8	22.5	22.9	23.3
7	T&D System Operations	5.3 L7	40.3	41.6	41.8	42.6	43.5
8	Business Unit Support	5.3 L8	0.6	3.3	3.7	3.7	3.8
9	Total	5.3 L14	265.0	261.4	266.8	269.2	275.3

The FTEs for the Operations Business Group are summarized by KBU in Figure 5C-2. Additional details are provided in Table 5C-2 below.

Figure 5C-2 Operations FTEs by KBU (Fiscal 2023 Plan)

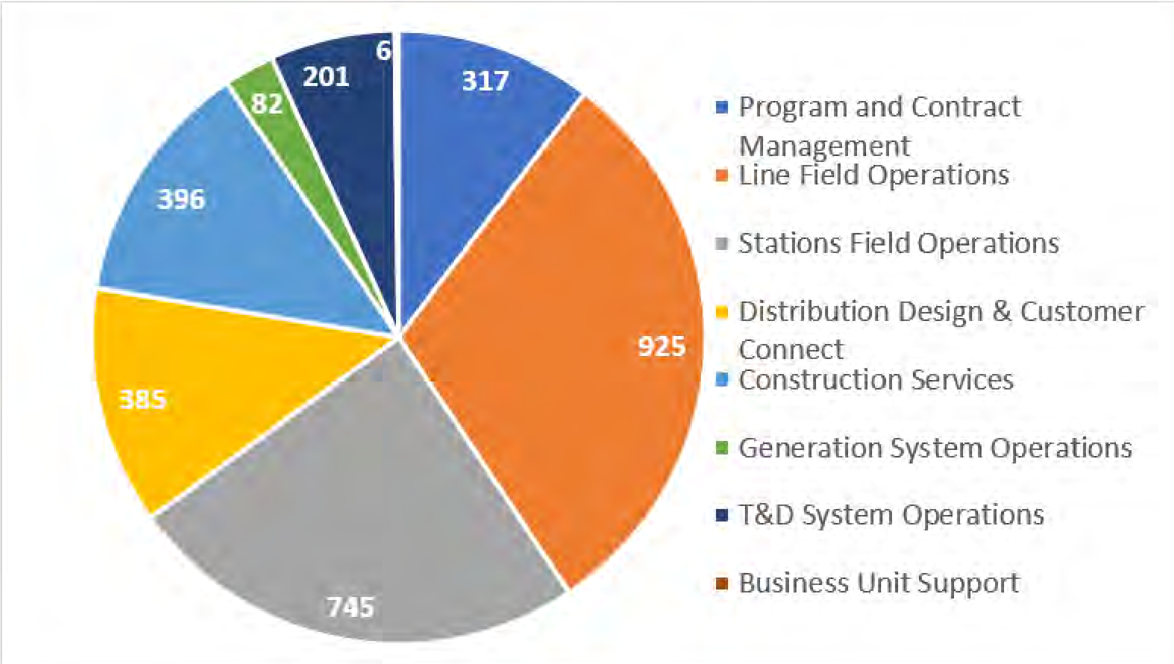


Table 5C-2 Operations FTEs by KBU

	(FTEs)	Schedule Reference	F2021 Actual	F2022 Decision	F2023 Plan	F2024 Plan	F2025 Plan
			1	2	3	4	5
1	Program and Contract Management	16.0 L15	272	280	317	318	318
2	Line Field Operations	16.0 L16	907	924	925	925	925
3	Stations Field Operations	16.0 L17	710	724	745	745	760
4	Distribution Design & Customer Connect	16.0 L18	370	379	385	391	394
5	Construction Services	16.0 L19	416	397	396	396	396
6	Generation System Operations	16.0 L20	89	81	82	82	82
7	T&D System Operations	16.0 L21	204	197	201	201	201
8	Business Unit Support	16.0 L22	5	4	6	6	6
9	Total	16.0 L23	2,972	2,985	3,057	3,063	3,082

Table 5C-3 below provides a continuity table which highlights changes to the Operations Business Group from the Previous Application. An overall discussion of these changes, at a company-wide level, is provided in Chapter 5, section 5.5.3. Further details, by KBU, are provided in the sections below.

Table 5C-3 Operations Operating Costs Continuity Schedule

	($ million)	Ref	F2023 Plan	F2024 Plan	F2025 Plan
1	**F2022 Revenue Requirement Application Plan**	a	**261.4**		
2	**Compliance Filing Adjustment**	b	**-**		
3	Reorganizational Impact	c	-		
4	**F2022 Decision (Schedule 5.3, line 14)**	d= a+b+c	**261.4**		
5	Budget Transfers Between Business Groups	e	1.4		
6	**F2022 Forecast (Schedule 5.3, line 14)**	f = d+e	**262.8**	**266.8**	**269.2**
7	Current Year Budget Transfers Between Business Groups	g	(0.5)	-	-
8	**Test Period Net Cost Increase/Decrease**				
9	**Uncontrollable Cost Increases**				
10	Current Service Costs and Other Labour Costs		(2.8)	4.6	5.2
11	Water Use Plan Order Review Program		2.2	-	-
12		h	(0.6)	4.6	5.2
13	**Reliability Investments**				
14	Mandatory Reliability Standards		1.5	-	-
15	Vegetation Management		0.1	-	-
16		i	1.6	-	-
17	**Site C**	j	0.1	(0.0)	2.1
18	**Strategic Initiatives**				
19	Electrification initiatives		0.6	0.2	0.1
20		k	0.6	0.2	0.1
21	**Third Party Billable Work**				
22	Customer Driven Work		1.2	-	-
23	Damage to Plant		0.5	-	-
24		l	1.7	-	-
25	**Net Cost Savings**				
26	Routine Trouble Work		3.2	(1.4)	(1.4)
27	Work Program Resources		2.9	0.0	0.1
28	Test Period Savings		(5.1)	(1.0)	-
29		m	1.0	(2.4)	(1.3)
30	**Total Test Period Net Increase/(Decrease)**	n =∑ h to m	**4.4**	**2.4**	**6.1**
31	**F2023 Net Operating Costs (Schedule 5.3, line 14)**	o= f+g+n	**266.8**	**269.2**	**275.3**

Table may not add due to rounding

5C.4 Program and Contract Management KBU

5C.4.1 Responsibilities

There have been no material changes to the responsibilities of the Program and Contract Management KBU since the Previous Application.

The Program and Contract Management KBU is the single point of contact for the annual delivery of the maintenance and small capital investment portfolios that is developed and optimized by the Integrated Planning Business Group. This KBU is responsible for leading the development of delivery strategies that consider the volumes of work types in each region as well as the forecast internal and external resource capacity to deliver this work. During the Test Period, the Program and Contract Management KBU will deliver capital projects and programs totalling approximately $1.3 billion and maintenance programs totalling approximately $650 million. More specifically, this KBU:

- **Develops annual program and project plans to deliver work:** Once the annual maintenance and small capital investment portfolio is received from the Integrated Planning Business Group, the Program and Project Managers in the Program and Contract Management KBU develop annual program and project plans to deliver the work in consultation with various KBUs across BC Hydro. Once internal resource commitments to deliver the work are obtained, the Program and Project Managers develop contracting plans to deliver the balance of the annual maintenance and small capital portfolio;
- **Assign work to internal groups and contractors, as appropriate:** Work is assigned to the internal and external Engineering and Design teams and to the field execution teams in Line Field Operations KBU, Stations Field Operations KBU, Construction Services KBU and external contractors.

  More than half of the work is performed by internal staff. External contractors provide scalability and help respond to fluctuations in demand, including providing support for trouble and storm response work. The KBU seeks external contractors that are cost competitive and are willing to work collaboratively through longer term relationships with BC Hydro. Contractors are identified through a competitive tendering process, with the Program and Contract Management KBU providing centralized management throughout the life of each contract;

- **Monitor progress and adjust as required:** On a monthly and quarterly basis, the Program and Project Managers monitor the progression of the program and project plans, manage change controls, manage external contractor performance and adjust work allocations to the field execution teams as necessary. The Program and Project Managers complete program and project Completion Reports annually or at the end of multi-year programs; and
- **Shares accountability for delivery of Power System capital:** The Program and Contract Management KBU is one of three KBUs accountable for the delivery of the Power System capital projects. The other KBUs responsible for delivering these projects are the Project Delivery KBU (discussed in Chapter 5B, section 5B.4) and the Distribution Design and Customer Connections KBU (discussed below in section 5C.7). Specifically, the Program and Contract Management KBU is responsible for delivering smaller scale less complex capital projects, typically with a forecast capital cost of less than $1 million. Approximately 30 per cent (or $1.3 billion) of the $4.3 billion total planned capital investments in the Power System in fiscal 2023 to fiscal 2025 will be delivered by the Program and Contract Management KBU.

The Program and Contact Management KBU is comprised of the following departments:

- Line Programs Department;
- Work Planning and Portfolio Services Department;

- Contract and Field Management Department;
- Stations Programs Department;
- Vegetation and Access Management Department; and
- PCM Projects Department.

5C.4.1.1. Line Programs Department

The Line Programs department is responsible for the management of high volume and repetitive transmission and distribution electrical equipment maintenance and replacement (capital) delivery programs. This equipment includes the conductor lines, underground cables, support structures such as wood poles, platforms, and associated equipment. A key responsibility of the department is to coordinate the allocation of work between BC Hydro's internal workforce and external contractors.

5C.4.1.2. Work Planning and Portfolio Services Department

The Work Planning and Portfolio Services department provides scheduling, project cost reporting and administration, and systems support to the delivery teams in the Program and Contract Management KBU.

The Work Planning and Portfolio Services department is responsible for forecasting operations labour and equipment resource demand and assessing any resourcing risk to the capital and operating and maintenance plans. The department also facilitates the development of mitigating strategies for the risk. These responsibilities balance two objectives: providing sufficient labour and equipment to execute planned work and optimizing planned use of resources for overall productivity, safety, and quality over both the short and long-term.

5C.4.1.3. Contract and Field Management Department

The Contract and Field Management department is responsible for contracting electrical and line work to third parties.

The department undertakes the following work related to external contracting:

- Pre-qualifying contractors to bid on BC Hydro work;
- Coordinating work allocation between various groups that execute the work, evaluating and awarding work packages, and onboarding contractors;
- Acting as the BC Hydro representative on contracts and providing change order management, customer contact and issues management, outage management and coordination, materials coordination, and coordination with the Distribution Design department; and
- Providing supplier relationship management including authorizing contractor employees to work on the BC Hydro system, providing quality management of work completed and ensuring corrective actions are taken as needed.

The department is responsible for civil inspection and survey activities as well as inspections of work completed by internal line crews and external line contractors to confirm that structures are built to engineering standards and that the quality of construction is acceptable. This department also supports the delivery of distribution maintenance programs and manages external contractors who deliver civil inspection, surveying, engineering and design services and traffic service contractors.

5C.4.1.4. Stations Programs Department

The Stations Programs department provides program management for the delivery of recurring capital program work (typically less than $1 million) and repetitive maintenance program work on Stations infrastructure. This includes generation, substation and telecom facilities. A key responsibility of the department is to coordinate the allocation of work between BC Hydro’s internal workforce and external contractors for stations work.

5C.4.1.5. Vegetation and Access Management Department

The Vegetation and Access Management department is responsible for the execution of all vegetation and access management on the transmission and distribution systems. This work includes:

- Transmission line, substation, and distribution line vegetation management maintenance programs as well as right of way access maintenance programs;
- Vegetation management, right of way clearing, and access management planning and construction in support of transmission and distribution capital projects;
- Storm response to aid in the removal of vegetation causing outages or access issues for restoration; and
- Management of the contracts and relationships with vegetation management and access contractors.

5C.4.1.6. PCM Projects Department

The PCM Projects department delivers smaller, lower complexity and lower risk projects for Lines and Stations from the Definition phase through to the Implementation phase and close-out. This department delivers: internal growth projects to provide increased system capacity, sustainment projects to improve reliability, interconnection projects for customers and specialty distribution submarine cable replacement projects.

5C.4.2 Overview of Operating Costs and FTEs

Table 5C-4 Program and Contract Management KBU Fiscal 2022 Decision Operating Costs and FTEs by Department

	($ Millions)	Labour	Services - Other	Materials	Building & Equipment	Capitalized Overhead	External Recoveries	Total Operating	Total FTEs
1	Director, Program and Contract Management	0.5	0.1	0.0	0.0	0.0	0.0	**0.6**	3
2	Line Programs	0.5	0.0	0.0	0.0	0.0	0.0	**0.6**	11
3	Work Planning and Portfolio Services	5.0	0.2	0.0	0.0	0.0	0.0	**5.2**	84
4	Contract and Field Management	4.9	0.2	0.0	0.0	0.0	0.0	**5.2**	74
5	Stations Programs	1.2	0.1	0.0	0.0	0.0	0.0	**1.3**	19
6	Vegetation and Access Management	3.4	0.3	0.1	0.1	0.0	0.0	**3.8**	75
7	PCM Projects	0.5	0.0	0.0	0.0	0.0	0.0	**0.5**	14
8	**Total (Sch 5.3 L1, Sch 16.0 L15)**	**16.0**	**0.9**	**0.2**	**0.2**	**0.0**	**0.0**	**17.3**	**280**

The number of FTEs in the Program and Contract Management KBU reflect the labour requirements to deliver the maintenance, capital programs and capital projects assigned by the Integrated Planning Business Group. The budget for this work is held by the Integrated Planning Business Group.

5C.4.2.1. Director, Program and Contract Management Department

The majority of this department's budget is related to labour. This represents three FTEs: A Director, an administrative assistant and a Human Resources Advisor (to manage the Columbia Hydro Constructors contract).

The $0.1 million in non-labour costs for this department represents funding for travel costs and annual dues.

5C.4.2.2. Line Programs Department

The majority of this department's budget is related to labour. This represents 11 FTEs including: one Department Manager, six Program Managers, four Work Package Managers. Due to high workload, this team is supplemented by approximately 25 external Work Package Managers during peak times.

5C.4.2.3. Work Planning and Portfolio Services Department

The majority of this department budget is related to labour. This represents 84 FTEs including: one Department Manager, one administrative assistant, four Resource

Strategy and Management Advisors/Specialists, seven Planning and Scheduling Managers, 34 Area Planner/Schedulers for Stations, one Program Technologist Manager, 17 Program Technologists supporting all Program and Contract Management programs, one Resource Planning Manager, 10 Distribution Maintenance Analysts, one Program Manager and five Work Package Managers. Two FTE represents overtime which is driven by peak demand.

5C.4.2.4. Contract and Field Management Department

The majority of this department's budget is related to labour. This represents 74 FTEs including: one Department Manager, 11 Contract Managers, one Business Operations Manager, seven Line Field Representatives, 21 Service Contract Administrators, two Civil Contracts and Inspection Managers, 21 Civil Inspectors and two administrative assistants. Eight FTEs represent overtime which is driven by peak demand. The FTEs are supplemented by approximately 14 external inspectors during peak times.

5C.4.2.5. Stations Programs Department

The majority of this department's budget is related to the labour. This represents 19 FTEs including: one Department Manager, six Program Managers and 12 Work Package Managers. The FTEs are supplemented by approximately 10 external Work Package Managers during peak times.

5C.4.2.6. Vegetation and Access Management Department

The majority of this department's budget is related to labour. This represents 75 FTEs including: 13 Regional and Program Managers, six Vegetation Specialists and Foresters, 38 Vegetation Coordinators, three Administrators, one contract manager, and four Pole Maintenance Coordinators. 10 FTEs represent overtime which is driven by peak demand.

The $0.5 million in non-labour costs for this department represents travel costs, annual dues, employee training and office supplies.

5C.4.2.7. PCM Projects Department

The majority of this department's budget is related to labour. This represents 14 FTEs including: one Department Manager, five Program Managers and eight Work Package Managers. The FTEs are supplemented by approximately seven external Work Package Managers during peak times.

5C.4.3 Fiscal 2023 to Fiscal 2025 Plan Operating Costs and FTEs

Table 5C-5 Program and Contract Management KBU Operating Costs and FTEs

		Schedule Reference	F2021 Actual	F2022 Decision	F2023 Plan	F2024 Plan	F2025 Plan
			1	2	3	4	5
1	**Program and Contract Management KBU**						
2	Operating Costs ($ million)	5.3 L1	14.4	17.3	19.2	19.7	20.2
3	FTEs	16.0 L15	272	280	317	318	318

Operating costs are increasing by $1.9 million from fiscal 2022 Decision amounts to fiscal 2023 plan primarily due to:

- $1.0 million increase for Work Program Delivery Resource requirements to ensure that adequate project and field resources and support are in place for the Operations Business Group to deliver the workplan and to address increased compliance requirements across most work categories, as discussed further in Chapter 5, section 5.11.2;
- $0.5 million increase related to a net transfer in of three FTEs, as discussed further below;
- $0.3 million increase for Electrification Plan resources, as discussed further in Chapter 10, section 10.4.1.5;
- $0.2 million increase for Mandatory Reliability Standards sustainment resources, as discussed further in Chapter 5, section 5.7; and

- $0.1 million increase for vegetation management resources to support increases in the vegetation management program, as discussed further in Chapter 5, section 5.8.3; partially offset by:
- $0.3 million reduction due to Standard Labour Rate decreases.

Operating costs are increasing by $0.5 million from fiscal 2023 plan to fiscal 2024 plan and $0.5 million from fiscal 2024 plan to fiscal 2025 plan primarily due to Standard Labour Rate increases.

FTEs are planned to increase by 37 from fiscal 2022 Decision amounts to fiscal 2023 plan due to:

- 16 FTEs for Work Program Delivery Resource requirements, as discussed further in Chapter 5, section 5.11.2;
- Eight FTEs for vegetation management resources, as discussed further in Chapter 5, section 5.8.3;
- Six FTEs for Electrification Plan resources, as discussed further in Chapter 10, section 10.4.1.5;
- Three FTEs related to overtime driven by peak demand;
- Two FTEs transferred in from the Safety and Compliance Business Group for Mandatory Reliability Standards positions included in the fiscal 2022 Decision;
- Two FTEs transferred in from the Human Resources KBU; and
- One FTE for Mandatory Reliability Standards sustainment resources, as discussed further in Chapter 5, section 5.7; partially offset by:
- One FTE transfer out to the Project Delivery KBU in the Capital Infrastructure Project Delivery Business Group to manage the Columbia Hydro Constructors contract.

FTEs are planned to increase by one over the Test Period for a resource to support the Site C Generating Station transition from the construction phase to the operating phase starting in fiscal 2023, as discussed further in Chapter 5, sections 5.10.2,5.10.3, and 5.10.4.

5C.5 Line Field Operations KBU

5C.5.1 Responsibilities

There have been no material changes to the responsibilities of the Line Field Operations KBU since the Previous Application.

The Line Field Operations KBU is responsible for executing the day to day operational activities on BC Hydro's distribution and transmission line system. Key activities performed by this KBU include:

- **New customer connections to the BC Hydro system:** Once customers have approved designs to connect to the BC Hydro system, Line Field Operations KBU crews complete the connections in accordance with BC Hydro customer service targets for connection times;
- **Preventative, corrective, and condition-based maintenance activities as directed by the Integrated Planning Business Group:** Planned maintenance activities are based on system need determined by the Integrated Planning Business Group, and are executed by Distribution, Transmission and Trouble Line Field Operations crews;
- **End-of-life equipment replacements and small system improvement projects:** This work is organized as projects, managed by the Program and Contract Management KBU, and generally consists of smaller-scale projects not requiring the full level of project oversight associated with larger capital projects. Distribution and Transmission Line Field Operations crews deliver this work;

- **Restoration work due to emergent trouble response including major storm events:** When the Power System incurs damage due to weather, natural disasters such as wildfires, or other situations such as motor vehicle accidents, Distribution, Transmission and Trouble Line Field Operations crews are all dispatched to repair the system and restore customers. The work is performed with the assistance of the Hydro Restoration Center, which triages the damage and dispatches emergent work to crews. For larger events such as major storms, Power Line Technicians respond in the field, supported by field managers and administrators working in Storm Rooms and Regional Emergency Operations Centers, assisted by the Hydro Restoration Center;
- **Maintenance, installation, and replacement of customer meters:** New customer connections and changes to both residential and commercial customers' service requirements require meters to be installed, changed or upgraded. This work is performed by the Provincial Metering Operations department of this KBU; and
- **Switching operations, as directed by the Transmission and Distribution Systems Operations KBU:** Since the Transmission and Distribution Systems Operations KBU has a view of the entire transmission and distribution system, it has insight into opportunities to open and close field devices to enable repairs to take place or to minimize customer outages. Distribution, Transmission and Trouble Line Field Operation crews perform these switching duties as directed by Transmission and Distribution Systems Operations KBU.

The Line Field Operations KBU is comprised of the following departments:

- Distribution Line Field Operations Department;
- Transmission Line Field Operations Department;
- Trouble Line Field Operations and Operations Support Department; and
- Provincial Metering Operations Department.

5C.5.1.1. Distribution Line Field Operations Department

This department is responsible for maintenance and construction activities on approximately 56,000 km of distribution overhead and underground lines and cable and executing switching operations as directed by the Transmission and Distribution System Operations KBU. The department is also responsible for initial storm and major event response and restoration in BC Hydro's service area, and response to routine trouble outside of the Greater Vancouver area and Victoria, where first response is generally provided by the Trouble Line Field Operations department. Distribution Line Field Operations also constructs customer connections, executes small system improvement projects, and performs routine maintenance. The department is primarily comprised of Power Line Technicians.

5C.5.1.2. Transmission Line Field Operations Department

This department is responsible for maintenance and construction activities on approximately 18,000 km of overhead, underground, and submarine transmission lines, underground distribution feeder cable, and executing switching operations as directed by the Transmission and Distribution System Operations KBU. Maintenance work carried out by this department includes visual inspections, testing, repair, and replacement of transmission and distribution underground equipment. The Transmission Line Field Operations department also provides emergency response and restoration for the BC Hydro transmission system, including routine trouble and major storm damage, and supports distribution line restoration in storms once transmission lines have been restored. The department is primarily comprised of Power Line Technicians and Cable Splicers.

5C.5.1.3. Trouble Line Field Operations and Operations Support Department

This department consists of the Trouble Line Field Operations team and the Operations Support team.

The Trouble Line Field Operations team is responsible for day-to-day routine outage restoration on the distribution system within the Greater Vancouver area and

Victoria. The department also supports Distribution Line Field Operations and Transmission Line Field Operations when those departments are responding to storm events. This team is primarily comprised of Power Line Technicians.

The Operations Support team provides administrative and operational support to the front-line managers and crew. It consists of the Hydro Restoration Center and the Operations Support Processing Center teams:

- The Hydro Restoration Center team provides support for Power System restoration activities. The team dispatches Distribution or Trouble field crews to respond to customer outages based on information from customer calls, smart meters and protection equipment such as re-closers and circuit breakers. The team also works closely with First Responders to provide them with BC Hydro support when required in the case of community emergencies that involve BC Hydro equipment; and
- The Operations Support Processing Center team provides planned outage notifications and processes work order completions. The team also provides centralized administration of timesheets and expense processing mostly for field crews in various groups, such as in the Line Field Operations KBU, Stations Field Operations KBU, and Construction Services KBU.

5C.5.1.4. Provincial Metering Operations Department

This department is responsible for complex metering installations and repairs, as well as management in the field across the province. This department is primarily comprised of Meter Technicians.

5C.5.2 Overview of Operating Costs and FTEs

Table 5C-6 Line Field Operations KBU Fiscal 2022 Decision Operating Costs and FTEs by Department

	($ Millions)	Labour	Services - Other	Materials	Building & Equipment	Capitalized Overhead	External Recoveries	Total Operating	Total FTEs
1	Director, Line Field Operations	0.4	0.3	0.0	0.0	0.0	0.0	**0.8**	2
2	Apprentices	0.4	0.0	0.1	0.0	0.0	0.0	**0.5**	0
3	Distribution Line Field Operations	20.0	1.2	2.2	1.7	0.0	0.0	**25.1**	591
4	Transmission Line Field Operations	4.8	0.3	0.8	0.4	0.0	0.0	**6.3**	166
5	Trouble Line Field Operations and Operations Support	32.5	23.3	1.3	0.0	0.0	0.0	**57.2**	131
6	Provincial Metering Operations	1.0	0.1	0.1	0.0	0.0	0.0	**1.3**	34
7	Disconnect Reconnect Work	0.8	0.2	0.0	0.0	0.0	0.0	**1.0**	0
8	**Total (Sch 5.3 L2, Sch 16.0 L16)**	**60.1**	**25.4**	**4.7**	**2.1**	**0.0**	**0.0**	**92.3**	**924**

5C.5.2.1. Director, Line Field Operations Department

This department holds the budget for the Director of the Line Field Operations KBU. It primarily consists of labour costs for the Director and an administrative assistant. Non-labour costs include funding for monthly Front Line Employee Councils and travel for regional visits.

5C.5.2.2. Apprentices Department

This department does not have any FTEs. The labour budget in this department is for apprentices in the Learning and Development KBU who incur training or meeting time that cannot be charged to work programs or projects. The non-labour budget is for small tools and crew supplies.

5C.5.2.3. Distribution Line Field Operations Department

This department is organized into three regional teams: Lower Mainland, Interior and Vancouver Island. Across the three regions, there are 47 managers, three administrative assistants, 37 Field Service Administrators, and 365 trades FTEs, located in 60 District offices. An additional 139 FTEs represent overtime which is driven by peak demand. This is primarily for Trouble response outside of normal operating hours but also to accommodate customer schedules and to minimize the costs incurred to demobilize active crews and mobilize new crews in their place if the job extends past core hours.

The level of resourcing in this department is driven by BC Hydro's customer service objective to respond to Trouble incidents within one hour in urban locations and two hours in rural locations. It also reflects regional work volumes for maintenance, capital, and customer driven work.

Approximately 90 per cent of the labour costs for the trades positions in this department are charged out to distribution capital projects and maintenance programs. Overtime is charged out 100 per cent to these projects and programs. The time not charged to projects and programs is for safety training, technical training and for team, management and safety meetings as well as shop time.

Non-labour costs in this department are for the purchase of personal protective equipment, small tools and crew supplies, required cyclical tool testing and travel to complete training requirements.

5C.5.2.4. Transmission Line Field Operations Department

This department is organized into two regional teams: Lower Mainland/Vancouver Island and South Interior/North Interior. Across these two teams, there are 14 managers, one Administrative Assistant, six Field Service Administrators, 10 Transmission Technologists, and 95 trades FTEs, located in 16 District offices. An additional 40 FTEs in overtime is budgeted for when seasonal demand exceeds supply.

The number of FTEs in this department is driven by regional work volumes on transmission maintenance programs and transmission capital projects. In fiscal 2022, it is planned that these crews will deliver about 123,000 hours of work on recurring Transmission and Distribution Capital Programs and Projects and will deliver another 51,000 hours of work on Corrective and Preventative Transmission Maintenance activities.

Approximately 90 per cent of the labour costs for positions in this department are charged out to transmission maintenance programs and transmission capital projects. Overtime is charged out 100 per cent to projects and programs. The time not charged to projects and programs is for safety training, technical training and for other management and administrative activities such as safety and team meetings.

Non-labour costs in this department are for the purchase of personal protective equipment, small tools and crew supplies, required cyclical tool testing and travel to complete training requirements.

5C.5.2.5. Trouble Line Field Operations and Operations Support Department

This department consists of the Trouble Line Field Operations team and the Operations Support team. It also holds the budget for Distribution Restoration maintenance. Maintenance is discussed in Chapter 5, section 5.15.

The Trouble Line Field Operations team consists of 73 FTEs: nine managers, one Administrative Assistant, two Field Service Administrators, 44 trades FTEs, and 17 FTEs in overtime is budgeted each year, primarily to respond to overall restoration work demand.

Approximately 90 per cent of the labour costs for trades positions in this department are charged out to Distribution Restoration maintenance programs, which are discussed further in Chapter 5, section 5.15. Overtime is charged out 100 per cent to these programs. The time not charged to projects and programs is allocated to safety training, technical training and to activities such as safety and team meetings and shop work.

Non-labour costs in this department are for the purchase of personal protective equipment, protective clothing and small tools as well as required cyclical tool testing and travel for training requirements.

The Operations Support team consists of 58 FTEs which is comprised of the Hydro Restoration Center team and the Operations Support Processing Center team:

- **The Hydro Restoration Center team** operates four Dispatch stations to respond to power outage calls. Two Dispatch stations are operated 24/7 and two additional Dispatch stations are operated from 7:00 a.m. to 11:00 p.m., when call volumes are higher. The team consists of 22 FTEs: a manager, an analyst and 20 dispatchers. In fiscal 2021, this team answered approximately 85,000 calls.
- **The Operations Support Processing Center team** includes a team that processes timesheets and expenses for BC Hydro trades employees as well as a team that completes Planned Outage Notifications to customers for work being completed on the Distribution system. The Operations Support Processing Center team consists of 36 FTEs: two managers, 33 Field Service Administrators, and one FTE in overtime is budgeted each year, primarily to respond to the overall volume of timesheets and expense claims. In fiscal 2021, this team processed approximately 135,000 timesheets and 93,000 employee expense claims and issued approximately 6,600 planned outage notifications.

Non-labour expenses for this department include training, team activities, and office supplies.

5C.5.2.6. Provincial Metering Operations Department

This department consists of two Field Metering teams. One team provides service to Lower Mainland North and Vancouver Island and the other team provides service to Lower Mainland South and the Interior.

Across the two teams, there are three managers, a Meter Operations Coordinator, and 24 trades FTEs. In addition, there are six FTEs that represent overtime which is driven by peak demand. This is associated with the accommodation of customer installation schedules and minimizing mobilization and demobilization costs.

Approximately 90 per cent of the labour costs for positions in this department are charged out to projects and programs. Overtime is charged out 100 per cent to projects and programs. The time not charged to customer capital projects and other programs is allocated to safety training, technical training and other management and administrative activities such as safety and team meetings.

Non-labour costs in this department are for the purchase of personal protective equipment, small tools and crew supplies, required cyclical tool testing and travel to complete training requirements.

In fiscal 2021, this department completed approximately 4,000 customer connections installing over 36,000 meters along with 6,300 meter exchanges and 2,000 in-situ tests.

5C.5.2.7. Disconnect Reconnect Work Department

This department does not contain any FTEs. When internal or external field crews manually disconnect or reconnect meters, they charge their time to this department.

BC Hydro may perform a manual disconnection or reconnection:

- To allow customers to safely perform non-electrical maintenance;
- To enable customers to perform electrical maintenance or repairs on their own;
- When a meter is not within the Smart Meter service area; or
- When service is no longer required at an address.

5C.5.3 Fiscal 2023 to Fiscal 2025 Plan Operating Costs and FTEs

Table 5C-7 Line Field Operations KBU Operating Costs and FTEs

		Schedule Reference	F2021 Actual	F2022 Decision	F2023 Plan	F2024 Plan	F2025 Plan
			1	2	3	4	5
1	**Line Field Operations KBU**						
2	Operating Costs ($ million)	5.3 L2	103.1	92.3	92.2	91.8	92.1
3	FTEs	16.0 L16	907	924	925	925	925

Operating costs are decreasing by $0.1 million from fiscal 2022 Decision amounts to fiscal 2023 plan primarily due to:

- $2.3 million reduction due to the five-year average that drives the storm response budget, as discussed further in Chapter 5, section 5.5.3.6;
- $1.0 million decrease for IBEW employee training reductions to partially revert to funding levels prior to fiscal 2022, as discussed further in Chapter 5, section 5.5.3.6; and
- $0.7 million reduction due to Standard Labour Rate decreases; partially offset by:
- $3.2 million increase for Routine Trouble Work, as discussed further in Chapter 5, section 5.5.3.6);

  $0.5 million increase for Damage to Plant Work, as discussed further in Chapter 5, section 5.5.3.5); and
- $0.2 million increase due to a transfer of one FTE from the Construction Services KBU.

Operating costs are decreasing by $0.4 million from fiscal 2023 plan to fiscal 2024 plan due to $1.4 million Routine Trouble Work reductions and $0.4 million for IBEW employee training reductions to revert to funding levels prior to fiscal 2022, partially offset by $1.5 million due to Standard Labour Rate increases.

Operating costs are increasing by $0.3 million from fiscal 2024 plan to fiscal 2025 plan due to $1.7 million for Standard Labour Rate increases, partially offset by $1.4 million Routine Trouble Work reductions.

FTEs are planned to increase by one from fiscal 2022 Decision amounts to fiscal 2023 plan due to the Constructions Services KBU transferring one FTE to the Line Field Operations KBU. FTEs are planned to remain constant from fiscal 2023 plan to fiscal 2025 plan.

5C.6 Stations Field Operations KBU

5C.6.1 Responsibilities

There have been no material changes to the responsibilities of the Stations Field Operations KBU since the Previous Application.

The Stations Field Operations KBU is a technical frontline management and trades team responsible for executing maintenance, operating stations equipment, and supporting capital projects at over 300 generation, transmission, and distribution stations assets. Key activities performed by this KBU include:

- **Executing maintenance work** that is planned and scheduled by either the Stations Field Operations KBU trades staff themselves (for less complex work / work requiring less coordination with outages, other trade crews, materials and services) or the Program and Contract Management KBU (for more complex work / work requiring more coordination with outages, other trade crews, materials and services);
- **Stations equipment switching, isolation, and manual operations** in accordance with safety system requirements and direction given by Generation System Operations KBU and Transmission and Distribution System Operations KBU;
- **Equipment maintenance** such as inspections, cleaning, testing, measurements, repairs, calibration, fluid and filter changes, and troubleshooting;
- **Trades staff support** for capital projects implementation including site access, Safety watching responsibilities, equipment isolation, installation, testing, commissioning, troubleshooting, manual operations of stations equipment, and providing support with local knowledge;
- Spillway operations and water conveyance;

- Safety, environmental and Mandatory Reliability Standards inspections;
- Emergency response; and,
- Visual checks and other inspection activities on in-service equipment in accordance with prescribed maintenance and inspection checklists.

The Stations Field Operations KBU is primarily comprised of the Stations Operations Department.

5C.6.1.1. Stations Operations Department

This department is organized into four regions:

- Northern Interior;
- Southern Interior;
- Lower Mainland/Bridge River; and
- Vancouver Island/Thermal/Non-Integrated Areas.

Each region is managed by a Regional Manager and comprised primarily of trades employees with Senior Field Managers, Field Managers, and Field Administrators all of whom are located throughout the different headquarters for trades and work management.

The trades employees in each region include Electricians, Mechanics (Millwrights and Machinists), General Trades (Carpenters, Welders and other Red Seal ticketed tradespersons), Driver/Helpers, Communication Protection and Control Technologists, Lockkeepers, Dam Caretakers, and Plant Operators. Administrative support for both managers and trades teams is provided throughout the province by Field Administrators, and equipment-specific technical expertise is provided by Apparatus Testers.

One region, Vancouver Island/Thermal/Non-Integrated Areas, also includes two Project Managers and a Construction Contracts Specialist, whose roles are described below.

Regional Managers have overall accountability for the business performance in each region. Each of the Senior Field Managers oversees three to five Field Managers who in turn are accountable for work execution, supervision and safety of the trades staff. The span of control averages one Field Manager for approximately 13 trades employees.

In addition to line management duties, Stations Field Operations managers also spend a portion of their time on KBU and Business Group priorities such as safety programs, capital projects, process improvements, regulatory requirements, and company-wide initiatives.

Collectively, trades employees execute maintenance, manual equipment operations, capital projects implementation support, and other duties such as work planning and scheduling, at the stations facilities across the province to ensure safe and reliable service to BC Hydro’s customers.

The Project Managers provide oversight of technical functions or contracts for thermal operations and low voltage diesel station contract operators for non-integrated assets.

The Construction Contracts Specialist is BC Hydro’s representative to InPower, the partner entity for the John Hart Generating Station public-private partnership contract.

Field Administrators are accountable for office and administrative duties to support the Stations Operations workforce as a whole, which includes reception, manager administration support, safety information filing and archiving, library and drawing management, contracts administration, invoice processing and expenses, safety and training administration, meeting and training organization, and emergency response support.

Apparatus Testers specialize in maintenance, testing, repairs, and installation on major electrical power apparatus and equipment for stations assets throughout the province.

5C.6.2 Overview of Operating Costs and FTEs

Table 5C-8 Stations Field Operations KBU Fiscal 2022 Decision Operating Costs and FTEs by Department

	($ Millions)	Labour	Services - Other	Materials	Building & Equipment	Capitalized Overhead	External Recoveries	Total Operating	Total FTEs
1	Director, Stations Field Operations	0.7	1.2	0.0	0.0	0.0	0.0	**1.8**	3
2	SFO Third Party Work	0.1	0.0	0.0	0.0	0.0	0.0	**0.1**	-
3	SFO Apprentices and Trades Trainees	0.1	0.0	0.0	0.0	0.0	0.0	**0.1**	-
4	Stations Operations	34.2	16.3	1.8	1.4	0.0	0.0	**53.8**	721
5	**Total (Sch 5.3 L3, Sch 16.0 L17)**	**35.1**	**17.5**	**1.8**	**1.4**	**0.0**	**0.0**	**55.8**	**724**

5C.6.2.1. Director, Stations Field Operations Department

This department holds the budget for the Director of the Stations Field Operations KBU. It consists of labour budget for the Director, a Transition Manager, and an administrative assistant.

Non-labour costs include funding for Public Safety Management Program reviews, consistent with regulatory compliance requirements at Stations facilities, as well as funding to cover any physical security upgrades that do not meet the criteria to be capitalized. This budget also includes funding to account for unanticipated operating costs which cannot be absorbed within the fiscal year budget by reprioritizing previously planned work.

5C.6.2.2. SFO Third Party Work Department

This department does not have any FTEs. Stations Operations staff occasionally complete work requests for industry partners, including apparatus testing and equipment fault investigation and repairs. The labour required to complete these requests is charged to this department and offset through revenue collected through invoices to those industry partners.

5C.6.2.3. SFO Apprentices and Trades Trainees Department

This department does not have any FTEs. The labour budget in this department is for apprentices and trade trainees in the Learning and Development KBU who are working on Stations assets and incur training or meeting time that cannot be charged to work programs or projects. The non-labour budget is for small tools and consumable supplies.

5C.6.2.4. Stations Operations Department

This department is the workforce required to safely and effectively maintain and operate the Stations assets. The total FTEs for this department include 70 manager and professional roles, 491 trades roles, and 54 technical and administrative roles as well as 106 FTEs for overtime.

The number of FTEs in the Stations Operations department is driven by the work volumes required to complete maintenance, equipment operations, off-hours equipment trouble response, and capital projects support for the Stations assets in each region. In fiscal 2022, it is planned that this department will deliver approximately 436,000 hours of maintenance, 246,000 hours of capital projects support and 111,000 hours of operations work. The labour budget held within this department is for operations work. The labour budgets for maintenance are held within the Integrated Planning Business Group. The labour budgets for capital projects support are held within the Capital Infrastructure Project Delivery Business Group or the Program and Contract Management KBU.

The 106 FTEs of overtime included in this department are used primarily by trades employees to meet seasonal and overall work demand peaks for manual equipment operations, off-hours equipment trouble response, maintenance, and capital projects support. These demand peaks occur as a result of seasonal constraints on work volumes due to equipment availability requirements for system loads, environmental and inflow conditions, and water license requirements.

The non-labour budget for this department includes services-other, materials, and building and equipment.

The services-other portion of $16.3 million includes $6.9 million for the John Hart Generating Station public-private partnership contract with InPower, $2.3 million of funding to sustain confidential compliance activities as detailed in Confidential Appendix JJ, $0.5 million for the General Electric emergency support engine lease and the distributed control system support at the Fort Nelson Gas Generating Station, $0.7 million for the Mica Emergency Response Team, and the remainder for other costs, such as tools and equipment calibration and testing, and employee training and travel expenses.

The materials portion of $1.8 million includes shop supplies, fire retardant clothing and personal protective equipment, as well as office supplies.

The building and equipment portion of $1.4 million includes the Campbell River Ironwood office lease, the Burrard Generating Station foreshore lease, and internet and communications charges for the Mica, Hudson Hope, and Bridge River employee accommodations.

5C.6.3 Fiscal 2023 to Fiscal 2025 Plan Operating Costs and FTEs

Table 5C-9 Stations Field Operations KBU Operating Costs and FTEs

		Schedule Reference	F2021 Actual	F2022 Decision	F2023 Plan	F2024 Plan	F2025 Plan
			1	2	3	4	5
1	**Stations Field Operations KBU**						
2	Operating Costs ($ million)	5.3 L3	57.7	55.8	56.0	56.5	59.7
3	FTEs	16.0 L17	710	724	745	745	760

Operating costs are increasing by $0.2 million from fiscal 2022 Decision amounts to fiscal 2023 plan primarily due to:

- $0.8 million increase for Work Program Delivery Resource requirements to ensure that adequate project and field resources and support are in place for the Operations Business Group to deliver the workplan and to address increased compliance requirements across most work categories, as discussed further in Chapter 5, section 5.11.3;
- $0.6 million increase for Mandatory Reliability Standards sustainment resources, as discussed further in Chapter 5, section 5.7;
- $0.2 million increase due to a transfer in of one FTE from the Safety and Compliance Business Group for a Mandatory Reliability Standards position included in the fiscal 2022 Decision; and
- $0.1 million increase to support the Site C Generating Station transition from the construction phase to the operating phase starting in fiscal 2023, as discussed further in Chapter 5, section 5.10.2.1; partially offset by:
- $0.9 million decrease for IBEW employee training reductions to partially revert to funding levels prior to fiscal 2022, as discussed further in Chapter 5, section 5.5.3.6; and
- $0.5 million reduction due to Standard Labour Rate decreases.

Operating costs are increasing by $0.5 million from fiscal 2023 plan to fiscal 2024 plan primarily due to $0.9 million due to Standard Labour Rate increases, partially offset by $0.4 million for IBEW employee training reductions to revert to funding levels prior to fiscal 2022.

Operating costs are increasing by $3.2 million from fiscal 2024 plan to fiscal 2025 plan primarily due to $2.1 million to support the Site C Generating Station transition from the construction phase to the operating phase and $1.0 million due to Standard Labour Rate increases.

FTEs are planned to increase by 21 from fiscal 2022 Decision amounts to fiscal 2023 plan primarily due to:

- 11 FTEs for Work Program Delivery Resource requirements, as discussed further in Chapter 5, section 5.11.3;
- Eight FTEs for Mandatory Reliability Standards sustainment resources, as discussed further in Chapter 5, section 5.7;
- One FTE for resources to support the Site C Generating Station transition from the construction phase to the operating phase starting in fiscal 2023, as discussed further in Chapter 5, section 5.10.2.3; and
- One FTE transfer in from the Safety and Compliance Business Group for a Mandatory Reliability Standards position included in the fiscal 2022 Decision.

FTEs are planned to remain at 745 from fiscal 2023 plan to fiscal 2024 plan. FTEs are planned to increase by 15 from fiscal 2024 plan to fiscal 2025 plan for resources to support the Site C Generating Station transition from the construction phase to the operating phase, as discussed further in Chapter 5, sections 5.10.3.2 and 5.10.4.4.

5C.7 Distribution Design and Customer Connections KBU

5C.7.1 Responsibilities

Since the Previous Application there have been two changes to the structure of the Distribution Design and Customer Connections KBU through the re-organization of existing departments:

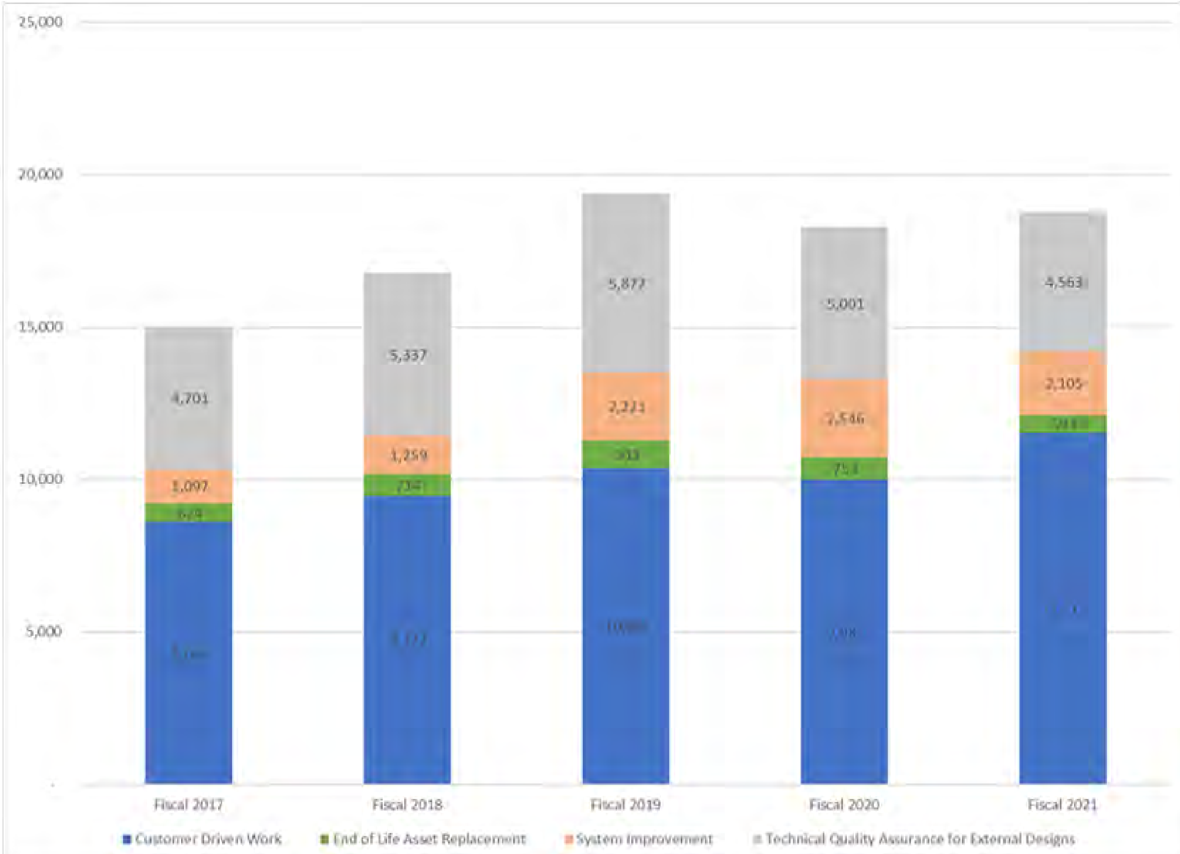
- Provincial Services division was formed by reorganizing the existing Vancouver Island Design division to include the Customer Program Office along side the existing Design Programs and Services and Express Connections teams; and
- Within the Distribution Design department, the Interior and Vancouver Island Distribution Design teams were consolidated into one group. Lower Mainland Distribution Design remains as a separate group.

Although organized differently, the responsibilities of the KBU remain consistent with the Previous Application.

The Distribution Design and Customer Connections KBU is a technical and customer facing frontline group that leads the customer connections program for distribution voltage customers (25 kV and under). This KBU provides design and project coordination for this distribution work along with technical quality assurance for externally designed work. The KBU designed and the externally designed work includes customer driven work and other distribution system improvement and end of life asset replacement programs. This KBU manages a high-volume business area, producing over 37,000 service orders and 18,000 work order packages annually. The Designers in this KBU are also regularly deployed in emergency roles as damage assessors and wire guards to support wildfire and storm response because of their technical expertise and knowledge of the distribution system.

The breakdown for the volume of work being delivered by the Distribution Design and Customer Connections KBU is shown in Figure 5C-3. The overall work delivery continues to increase with the largest increases in Customer Driven work.

1 Figure 5C-3 Distribution Design and Customer
2 Connections Project Activity[326]



3 The work is performed by staff located in 29 district offices throughout the province,
4 including Electrical Service Coordinators working in centralized Express Connect
5 contact centres in Kamloops, Burnaby and Nanaimo.

6 The customer connection work, driven by customer connection requests, is the
7 highest priority and largest work program for the Distribution Design and Customer
8 Connections KBU. Customer work is the provision of new or upgraded electrical
9 services as requested by current and future residential, commercial or industrial
10 BC Hydro customers. By their nature, all these requests are "unplanned" throughout

[326] This graph shows the number of activities but does not represent the workload related to the complexity of each activity. A project is shown as one activity, regardless of whether it is a low complexity project or a high complexity project.

the year and range from simple electrical services to very large and complex multi million-dollar projects. The customer work involves liaising with customers and their consultants and contractors, electrical and civil design, estimating and quoting, work package development and project management activities. Chapter 6, section 6.4.3.1 provides additional information on the Customer Capital Program managed by Distribution Design and Customer Connections KBU, including customer contributions in aid of construction.

Planned work programs such as end-of-life and system improvement projects make up the remainder of the work for this KBU. This work includes the technical quality assurance of designs that are completed by external service providers. These programs are described further in Chapter 6, sections 6.4.3.1 and 6.4.3.2.

The Distribution Design and Customer Connections KBU is comprised of the following departments:

- Distribution Design Department;
- Provincial Services Department; and
- Customer Connect Work Programs Department.

5C.7.1.1. Distribution Design Department

This department plans, designs, and provides project coordination for customer connections to BC Hydro’s distribution system and other province wide distribution system improvement and asset replacement projects and programs that require design, estimating and work packages. The department issues approximately 18,000 work order packages to distribution line crews and civil contractors every year.

5C.7.1.2. Provincial Services Department

This department consists of three teams that have provincial scope as outlined below:

Customer Program Office Team

The Customer Program Office team provides program management for the customer capital program and monitors the customer connection processes through metrics and reporting. It also initiates and leads process and technology improvement projects, such as new online capabilities, to increase efficiency and improve customer service and experience.

Design Programs and Services Team

The Design Programs and Services team provides quality assurance of work designed by BC Hydro approved professional engineering firms and provides technical design for large system improvement projects.

Express Connections Team

The Express Connections team responds to over 37,000 customer requests each year for simple new service connections, upgrades, and service disconnects. Through a provincial contact centre with staff located in three regions, technically trained Electric Service Coordinators handle calls and applications from customers and issue simple work orders that do not require design by Designers to crews.

5C.7.1.3. Customer Connect Work Programs Department

This department does not contain any FTEs. It contains costs associated with services requested by customers that are not directly related to new or upgraded services. Examples include temporary re-locations and installing flag lines and/or equipment barriers of overhead lines for house moves and active construction sites, customer electrical vault isolations and temporary construction power. Customers are charged for these services and payments are received as revenue.

5C.7.2 Overview of Operating Costs and FTEs

Table 5C-10 Distribution Design and Customer Connections KBU Fiscal 2022 Decision Operating Costs and FTEs by Department

	($ Millions)	Labour	Services - Other	Materials	Building & Equipment	Capitalized Overhead	External Recoveries	Total Operating	Total FTEs
1	Director, Distribution Design & Customer Connections	0.4	0.2	0.0	0.0	0.0	0.0	**0.6**	2
2	Distribution Design	8.7	1.0	0.2	0.1	0.0	0.0	**10.0**	289
3	Provincial Services	3.0	0.2	0.0	0.1	0.0	0.0	**3.3**	87
4	Customer Connect Work Programs	0.7	1.5	0.4	0.0	0.0	0.0	**2.5**	-
5	**Total (Sch 5.3 L4, Sch 16.0 L18)**	**12.7**	**2.8**	**0.7**	**0.2**	**0.0**	**0.0**	**16.4**	**379**

The level of economic activity in the province is the single largest driver of the Customer Capital Program and workload for Distribution Design and Customer Connections KBU. Residential, commercial and industrial starts, multi-year provincial infrastructure investments, and new industries such as cannabis grow operations have contributed to a construction boom over the past five years. This, in turn, has led to an unprecedented volume of distribution customer connection requests resulting in an increase in the Customer Capital Program capital expenditures from $170 million in fiscal 2016 to $265 million in fiscal 2021.

The work involved to complete these customer service requests has become increasingly complex over the past five years due to increased environmental and safety regulations and municipal planning requirements. Evolving customer needs and expectations also require new processes and capabilities. To support this, the Distribution Design and Customer Connections KBU has implemented broader web–based services for electrical service applications and electronic payments.

The high customer activity levels are expected to remain for another three years through the Test Period, based on what is in the current work plan. The expected impacts of the Electrification Plan will also drive additional FTE resources and operating cost increases, as discussed further in Chapter 10, section 10.4.1.4.

The average planned utilization rate for capital work is approximately 84 per cent for the Distribution Design department, 82 per cent for the Design Programs and Services team and 83 per cent for the Express Connections team. The capital work includes the Customer Capital Program and other Distribution growth and sustaining capital work programs and projects, as discussed further in Chapter 6, section 6.4.3.1 and 6.4.3.2. The planned non-utilized time not charged to capital work is allocated as operating costs and includes activities such as training and administrative time.

5C.7.2.1. Director, Distribution Design and Customer Connections Department

This department primarily consists of labour budget for the Director and an administrative assistant.

5C.7.2.2. Distribution Design Department

This department consists of 289 FTEs including two Division Managers, five Senior Design Managers, one Business Operations Manager, 15 frontline Design Managers, 37 Design Assistants and Administrators, 209 Designers, and 20 FTEs that represent overtime which is driven by peak demand.

Every year, the Resource Strategy and Management department in the Program and Contract Management KBU models demand for distribution design services against design capacity. The model includes internal Designer headcount and demographics (trainees and experienced Designers), overtime and the availability of external engineering service providers to augment capacity at a regional level. This modelling currently shows the work exceeds internal Designer capacity with a need for contractors to meet the forecasted workload. If there was a slowdown in customer work, there is enough contracted work that could be pulled back in-house to keep internal Designers fully utilized.

Although engineering firms can provide design services for system improvement and end of life projects, they are currently unable to undertake the estimating, quoting and local customer communications work required for customer projects that need to interpret and apply the Electric Tariff and extension policy. Therefore, internal Designers based out of local district offices deliver the majority of the customer-initiated work, with the exception of a few large projects where external firms provide the technical design and the small Customer Build Program for residential subdivisions where BC Hydro quoting is not required.

This department holds non-labour budget of $1.3 million, which primarily consists of $0.8 million for employee expense costs and $0.5 million for supplemental labour and other contract services costs.

5C.7.2.3. Provincial Services Department

This department's 87 FTEs consists of one Division Manager, one administrative assistant and the remaining 85 FTEs among the three teams as discussed below.

Customer Program Office Team

This team consists of four FTEs, including one Senior Program Manager, two Project Managers and one Business Improvement Manager, focused on business improvement, budgeting, compliance, reporting, and enterprise IT projects and initiatives.

Design Programs and Services Team

This team consists of 19 FTEs, including 10 Designers, six Distribution Project Coordinators, two Services and Design Assistants, and one front-line Design Manager.

Express Connections Team

This team consists of 62 FTEs, including one Provincial Express Connect Manager, three regional front-line Express Connect Managers, 47 Electric Service Coordinators, and 11 FTEs that represent overtime which is driven by peak demand.

The scope of express connection services provided by BC Hydro is unique among Canadian and U.S. utilities and provides an efficient model that minimizes design work effort.

While the volume of service requests has increased and become more complex, response times for express customer connections continue to be maintained with a high level of customer service. BC Hydro conducts a monthly customer satisfaction survey which indicates the overall satisfaction level was 94 percent in fiscal 2021. Connection times averaged seven days over the same period.

5C.7.2.4. Customer Connect Work Programs Department

This department does not contain any FTEs. This department holds labour budget of $0.7 million primarily for PLTs from the Line Field Operations KBU performing customer services requests that are not capitalized, like temporary services and "make safe" activities like the WorkSafeBC 30M33 process for construction sites. This department also holds non-labour budget of $1.9 million, which is primarily comprised of line contractor costs to perform customer services requests.

5C.7.3 Fiscal 2023 to Fiscal 2025 Plan Operating Costs and FTEs

Table 5C-11 Distribution Design and Customer Connections KBU Operating Costs and FTEs

		Schedule Reference	F2021 Actual	F2022 Decision	F2023 Plan	F2024 Plan	F2025 Plan
			1	2	3	4	5
1	**Distribution Design and Customer Connect KBU**						
2	Operating Costs ($ million)	5.3 L4	14.6	16.4	17.4	17.9	18.4
3	FTEs	16.0 L18	370	379	385	391	394

Operating costs are increasing by $1.0 million from fiscal 2022 Decision amounts to fiscal 2023 plan primarily due to:

- $1.2 million increase for Customer Connect Work Programs costs, as discussed further in Chapter 5, section 5.5.3.5 (i.e., Customer Driven Work); and
- $0.3 million increase for Electrification Plan resources; partially offset by:

- $0.3 million transfer to the Technology KBU related to applications support for in-service capital investments that will be managed by the Technology KBU; and
- $0.2 million reduction due to Standard Labour Rate decreases.

Operating costs are increasing by $0.5 million from fiscal 2023 plan to fiscal 2024 plan due to $0.3 million for Standard Labour Rate increases and $0.2 million for Electrification Plan resources. Operating costs are increasing by $0.5 million from fiscal 2024 plan to fiscal 2025 plan due to $0.4 million for Standard Labour Rate increases and $0.1 million for Electrification Plan resources.

FTEs are planned to increase by six from fiscal 2022 Decision amounts to fiscal 2023 plan due to Electrification Plan resources, as discussed further in Chapter 10, section 10.4.1.4. FTEs are planned to increase by six from fiscal 2023 plan to fiscal 2024 plan and three from fiscal 2024 plan to fiscal 2025 plan due to Electrification Plan resources.

5C.8 Construction Services KBU

5C.8.1 Responsibilities

There have been no material changes to the responsibilities of the Construction Services KBU since the Previous Application.

The Construction Services KBU provides a range of services supporting the capital replacement, maintenance and capital expansion of transmission, distribution, station, and generation assets. This KBU is comprised of full-time regular managers and office staff who manage and support a workforce of approximately 266 trade employees. Of the 266 trade employees, approximately 90 per cent are scalable full-time temporary employees and approximately 10 per cent are full-time regular employees.

The Construction Services KBU is comprised of the following departments:

- Regional Department; and
- Project Planning and Coordination Department.

5C.8.1.1. Regional Department

This department has a Lower Mainland / Vancouver Island team and Southern Interior / Northern Interior team. The teams are organized by geographic boundaries and are responsible for the four regional offices located in the regions they serve:

- Prince George (Northern Interior);
- Vernon (Southern Interior);
- Surrey (Lower Mainland); and
- Nanaimo (Vancouver Island).

The Construction Services KBU delivers an integrated bundle of services with on-demand skilled construction trades including power line technicians, electricians, general trades (carpenters, millwrights, and mechanics), winders, and equipment operators who help implement the BC Hydro maintenance and capital programs. This internal construction group is used in place of contract resources where the implementation risks are more appropriately managed with the use of internal crews.

This KBU also provides specialized services, such as construction expertise in planning stages of utility projects, specialty concrete repairs of generation civil infrastructure and asbestos abatement in energized environments.

In addition to increasing BC Hydro's operational flexibility, the Construction Services KBU performs the following:

- Employing highly trained crews who are familiar with BC Hydro facilities, policies, procedures and systems;
- Deploying resources in response to urgent and emergent work;

- Providing solutions to complex, multi-disciplinary projects, particularly when safety or system reliability challenges exists (i.e., brownfield work), or when the construction risk is more appropriately managed by internal BC Hydro resources rather than being transferred to external contractors;
- Partnering with local First Nations to create development opportunities, and increase engagement through involvement with project work, consistent with BC Hydro's Indigenous Relations strategy;
- Providing timely access to scarce, skilled trades (e.g., winders and specialized civil); and
- Maintaining a workforce that is scalable, mobile and transferrable and can respond to overall changes in long-term capital demand as well as short-term project-based work.

5C.8.1.2. Project Planning and Coordination Department

This department consists primarily of Construction Technologists. It is responsible for developing and maintaining construction and project management practices and processes. The department also supports the Construction Services KBU field staff in planning, implementing and monitoring construction projects.

5C.8.2 Overview of Operating Costs and FTEs

Table 5C-12 Construction Services KBU Fiscal 2022 Decision Operating Costs and FTEs by Department

	($ Millions)	Labour	Services - Other	Materials	Building & Equipment	Capitalized Overhead	External Recoveries	Total Operating	Total FTEs
1	Director, Construction Services	0.5	0.1	0.0	0.0	0.0	0.0	**0.6**	3
2	Regional	9.5	1.9	1.8	0.3	0.0	0.0	**13.6**	376
3	Project Planning and Coordination	0.6	0.0	0.0	0.0	0.0	0.0	**0.7**	19
4	**Total (Sch 5.3 L5, Sch 16.0 L19)**	**10.7**	**2.1**	**1.8**	**0.3**	**0.0**	**0.0**	**14.9**	**397**

5C.8.2.1. Director, Construction Services Department

This department primarily consists of labour costs for the Director, an administrative assistant and a Business Operations Manager.

5C.8.2.2. Regional Department

The regional departments' workforce assists with the delivery of the Transmission, Generation, and Distribution capital and maintenance programs. The overall demand for the workforce is driven by the expansion or contraction of capital and maintenance expenditures in these programs. There are 376 FTEs charged to these programs for work performed, of which approximately 71 FTEs represents overtime which is driven by seasonal or peak demand. Across the four regions combined, there are 24 managers, 15 Field Service Administrators, and 266 trades people.

The labour budget for trade positions in these departments are charged out 90 per cent to projects and programs. Overtime is charged out 100 per cent to projects and programs. The time not charged to projects and programs is allocated to safety training, technical training and other management and administrative activities such as team and safety meetings.

The non-labour expenses budgeted in these departments are for the purchase of personal protective equipment, small tools and crew supplies, required cyclical tool testing and travel for training requirements.

5C.8.2.3. Project Planning and Coordination Department

Almost all of the Project Planning and Coordination department's budget is related to labour. This represents 19 FTEs including two managers, 13 temporary construction technologists, three permanent construction technologists, and one temporary construction coordinator. Most of the roles in this department are temporary to allow the workforce to be scaled according to project volumes. FTE construction technologists in this department charge approximately 90 per cent of their time to projects and programs. The labour costs associated with this time are not included in the department's operating budget. The time not charged to projects and programs is allocated to Safety Training, Technical and Professional Training, and management and administrative activities such as team and safety meetings.

5C.8.3 Fiscal 2023 to Fiscal 2025 Plan Operating Costs and FTEs

Table 5C-13 Construction Services KBU Operating Costs and FTEs

		Schedule Reference	F2021 Actual	F2022 Decision	F2023 Plan	F2024 Plan	F2025 Plan
			1	2	3	4	5
1	**Construction Services KBU**						
2	Operating Costs ($ million)	5.3 L5	14.8	14.9	13.9	14.0	14.3
3	FTEs	16.0 L19	416	397	396	396	396

Operating costs are decreasing by $1.0 million from fiscal 2022 Decision amounts to fiscal 2023 plan primarily due to:

- $0.5 million for IBEW employee training reductions to partially revert to funding levels prior to fiscal 2022, as discussed further in Chapter 5, section 5.5.3.6;
- $0.2 million due to a transfer out of one FTE to the Line Field Operations KBU; and
- $0.2 million due to Standard Labour Rate decreases.

Operating costs are increasing by $0.1 million from fiscal 2023 plan to fiscal 2024 plan due to $0.3 million for Standard Labour Rate increases partially offset by $0.2 million for IBEW employee training reductions to revert to funding levels priors to fiscal 2022.

Operating costs are increasing by $0.3 million from fiscal 2024 plan to fiscal 2025 plan due to Standard Labour Rate increases.

FTEs are planned to decrease by one from fiscal 2022 Decision amounts to fiscal 2023 plan due to transferring out of one FTE to the Line Field Operations KBU. FTEs are planned to remain constant from fiscal 2023 plan to fiscal 2025 plan.

5C.9 Generation System Operations KBU

5C.9.1 Responsibilities

There have been no material changes to the responsibilities of the Generation System Operations KBU since the Previous Application.

The Generation System Operations KBU is responsible for planning the operation of BC Hydro's reservoirs and generation facilities and for integrating other resources into those operations to meet BC Hydro's load obligations.

This KBU plans short to mid-term (hourly up to three years) dispatch of both the Heritage Assets and the dispatchable Non-Heritage generating resources. This involves the consideration of inputs such as loads, inflows, outages, and market conditions. This KBU also determines the surplus system capability available to BC Hydro's electricity trading subsidiary, Powerex.

In addition, the KBU manages BC Hydro's water licenses as well as the Columbia River Treaty, Canal Plant Agreement, Keenleyside Entitlement Agreement and the Waneta Co-Possessors and Operating Agreement with Teck.

The KBU is also responsible for procuring electricity from Independent Power Producers (**IPPs**) and third-party suppliers aligned with the policy objectives in the *Clean Energy Act*, and it manages the IPP portfolio to support BC Hydro's needs for cost-effective energy.

The Generation System Operations KBU is comprised of the following departments:

- Business Operations Department;
- Hydrology Department;
- IPP Portfolio Management Department;
- Operations Planning Department;
- Resource Planning and Coordination Department;

- System Optimization; and
- Water Licencing Department.

5C.9.1.1. Business Operations Department

This department ensures that the KBU has the appropriate resources, tools, and support needed to fulfil its responsibilities. The department's primary areas of responsibility include contract management, application support, and administrative services.

5C.9.1.2. Hydrology Department

This department provides weather, inflow and wind forecasts for operational purposes throughout BC Hydro. It also manages a hydro-meteorological data collection network, maintains records of generation facility operations, and leads climate change science research for BC Hydro.

5C.9.1.3. IPP Portfolio Management Department

This department is responsible for procuring electricity from IPPs and third-party suppliers. The department aligns this procurement with the policy objectives in the *Clean Energy Act* and manages the IPP portfolio to support BC Hydro's needs for cost-effective energy. The department assists in meeting BC Hydro's energy requirements by negotiating commercial agreements; ensuring BC Hydro and IPP compliance with those agreements; and, carrying out due diligence for invoices submitted by IPPs.

5C.9.1.4. Operations Planning Department

This department is responsible for planning water releases and generation while incorporating uncertainty. Operating Planning Engineers model and instruct individual facility operations for the next-day to one-year time horizon, in consideration of constraints and forecasted conditions and in support of the system outages and needs. Planning, Scheduling and Operations direct the real-time operation of the BC Hydro generation system and water release facilities. This includes scheduling hourly generation of the BC Hydro system and contracted IPPs and identifying Powerex trade limits. Planning, Scheduling and Operations operates a 24/7 Generation Shift Office and a Next Day Planning Office.

5C.9.1.5. Resource Planning and Coordination Department

This department is responsible for coordination agreements including the Columbia River Treaty and Canal Plant Agreement, and system analysis and modelling to characterize operational and financial benefits and impacts.

In the Previous Application, this department was named as the Planning and Licensing department. After the filing of the Previous Application, the licensing component of this department was moved to a newly created Water Licensing department. The Planning and Licensing department was re-named to the Resource Planning and Coordination department.

5C.9.1.6. System Optimization Department

This department is responsible for conducting the monthly Energy Study (further discussed in Chapter 4, section 4.3.1) and managing system constraints (e.g., outages) to plan the operation of BC Hydro's generation system to reliably meet domestic load and inter-utility agreements such as the Columbia River Treaty operations and related coordination agreements. This department also manages the execution of the 2020 Transfer Price Agreement.

5C.9.1.7. Water Licencing Department

This department is responsible for managing BC Hydro's water licenses including regulatory compliance and reporting to the Comptroller of Water Rights, conducting Water Use Plan Order reviews, and renewing water licenses. In addition, this department manages Water Use Agreements with other water users, such as Metro Vancouver.

As mentioned above, this is a new department since the Previous Application. Operating costs and FTEs related to the licensing component of the former Planning and Licensing Department were moved to the Water Licensing Department.

5C.9.2 Overview of Operating Costs and FTEs

Table 5C-14 Generation System Operations KBU Fiscal 2022 Decision Operating Costs and FTEs by Department

	($ Millions)	Labour	Services - Other	Materials	Building & Equipment	Capitalized Overhead	External Recoveries	Total Operating	Total FTEs
1	Director, Generation System Operations	0.4	0.0	0.0	0.0	0.0	0.0	**0.4**	2
2	Business Operations	1.1	0.1	0.0	0.4	0.0	0.0	**1.6**	8
3	Hydrology	2.0	3.2	0.0	0.0	0.0	0.0	**5.1**	13
4	IPP Portfolio Management	3.1	0.3	0.0	0.0	0.0	0.0	**3.5**	17
5	Operations Planning	4.0	0.5	0.0	0.1	0.0	0.0	**4.6**	21
6	Planning and Licensing	2.4	0.4	0.0	0.0	0.0	0.0	**2.8**	12
7	System Optimization	1.7	0.0	0.0	0.0	0.0	0.0	**1.8**	8
8	**Total (Sch 5.3 L6, Sch 16.0 L20)**	**14.7**	**4.5**	**0.0**	**0.5**	**0.0**	**0.0**	**19.8**	**81**

5C.9.2.1. Director, Generation System Operations Department

This department's budget primarily consists of labour budget for the Director and an administrative assistant.

5C.9.2.2. Business Operations Department

This department consists of eight FTEs including two managers, one administrative assistant, four Business System Analysists, and one Project Technologist.

The non-labour budget of $0.5 million primarily consists of various license and subscriptions, and system maintenance costs.

5C.9.2.3. Hydrology Department

This department consists of 13 FTEs. The department has one manager and two team leads organized into weather and run-off forecasting, hydroclimate monitoring and data management, and generation data analysis, as well as two engineers, and eight meteorologists, hydrologists and other specialists.

The Hydrology department holds non-labour budget of $3.2 million, primarily for service contracts including:

- A cost sharing program with the Government of B.C. and Environment and Climate Change Canada on the operations and maintenance of Canada's Water Survey hydrometric monitoring stations in British Columbia;
- Environmental consultants who maintain BC Hydro's network of weather, snow and water monitoring stations across B.C.;
- An agreement with the University of British Columbia to provide numerical weather and wind forecasts; and
- Funding to support the Pacific Climate Impacts Consortium quantitative studies on the impacts of climate change in the Pacific region.

5C.9.2.4. IPP Portfolio Management

This department mainly consists of labour budget for 17 FTEs, which includes two managers, six Contract Managers, and nine Energy Procurement Professionals.

This department holds non-labour budget of $0.3 million, primarily for external services expenditures which includes consultant fees related generally to permitting, technical and other due diligence assessments of IPPs.

5C.9.2.5. Operations Planning Department

This department's budget mainly consists of labour budget for 21 FTEs, which includes one manager, two team leads, and 18 Engineers.

This department holds non-labour budget of $0.6 million, which is primarily comprised of $0.3 million related to the monitoring and operations of BC Hydro's generating facilities along the Peace River and $0.3 million for dedicated specialized desktop and local area network support due to the criticality of the technology used by the department.

5C.9.2.6. Planning and Licensing Department

The Planning and Licensing department's budget consists mainly of labour budget from 12 FTEs.

As mentioned in section 5C.9.1.5 above, after the filing of the Previous Application, the licensing component of this department was moved to a newly created Water Licensing department and the Planning and Licensing department was re-named to the Resource Planning and Coordination department. In this section, the Water Licensing department and the re-named Resource Planning and Coordination department are included in the overall Planning and Licensing department. The 12 FTEs were allocated as follows: five FTEs were moved to the Water Licensing department and seven FTEs remained in the re-named Resource Planning and Coordination department.

The Water Licensing department consists of five FTEs, which includes one manager, one project manager and three specialists who work on regulatory compliance and reporting to the Comptroller of Water Rights, Water Licence renewals, Water Use Plan Order Reviews, and managing Water Use Agreements with other water users.

The Resource Planning and Coordination department consists of one manager and six engineers and specialists who manage coordination agreements including the Columbia River Treaty and Canal Plant Agreement and perform mid-term and long-term multi-year system modelling.

The former Planning and Licensing department held non-labour budget of $0.4 million, which primarily consists of $0.3 million in service contracts related to Water Use Plan Order Review project costs.

5C.9.2.7. System Optimization Department

This department's budget mainly consists of labour budget for eight FTEs, which includes one manager and seven engineers.

5C.9.3 Fiscal 2023 to Fiscal 2025 Plan Operating Costs and FTEs

Table 5C-15 Generation System Operations KBU Operating Costs and FTEs

		Schedule Reference	F2021 Actual	F2022 Decision	F2023 Plan	F2024 Plan	F2025 Plan
			1	2	3	4	5
1	**Generation System Operations KBU**						
2	Operating Costs ($ million)	5.3 L6	19.4	19.8	22.5	22.9	23.3
3	FTEs	16.0 L20	89	81	82	82	82

Operating costs are increasing by $2.7 million from fiscal 2022 Decision amounts to fiscal 2023 plan primarily due to:

- $2.4 million increase for Water Use Plan Order Review project costs, as discussed further in Chapter 5, section 5.5.3.1, to fulfill the requirements and to maintain compliance under the *Fisheries Act* (funded by $2.2 million of incremental operating costs and $0.2 million re-allocation of funds from Business Unit Support);
- $0.5 million increase due to a re-allocation of funds from Business Unit Support primarily related to various climate and water monitoring contracts; and
- $0.1 million increase due to a transfer in of one FTE from the Customer Service KBU in the Customer and Corporate Affairs Business Group; partially offset by:
- $0.3 million reduction due to in Standard Labour Rate decreases.

Operating costs are increasing by $0.4 million from fiscal 2023 plan to fiscal 2024 plan and $0.4 million from fiscal 2024 plan to fiscal 2025 plan due to Standard Labour Rate increases.

FTEs are planned to increase by one from fiscal 2022 Decision amounts to fiscal 2023 plan due to the transfer in of one FTE from the Customer Service KBU in the Customer and Corporate Affairs Business Group for an Energy Procurement Professional to perform duties related to regulatory and compliance requirements. FTEs are planned to remain constant from fiscal 2023 plan to fiscal 2025 plan.

5C.10 Transmission and Distribution System Operations KBU

5C.10.1 Responsibilities

There have been no material changes to the responsibilities of the Transmission and Distribution System Operations KBU since the Previous Application.

The Transmission and Distribution System Operations KBU is responsible for managing the real time operation of the BC Hydro generation, transmission, distribution and telecommunication systems as well as day-ahead planning of the electricity grid. This KBU relies on input from other BC Hydro departments responsible for scheduling generation, maintenance, and the interconnection of new facilities. It also coordinates with other registered entities in B.C. to ensure the reliable operation of non-BC Hydro facilities such as IPPs and B.C. entities with generation and/or transmission assets.

In addition, this KBU is responsible for management of unplanned outages, implementing BC Hydro's safety policies and procedures for transmission and distribution safety isolations and clearances and supporting and implementing emergency management preparedness plans. This KBU facilitates fair and open access to the transmission grid for all customers through administration of the Open Access Transmission Tariff and the operation of the wholesale transmission market.

The Transmission and Distribution System Operations KBU is comprised of the following departments:

- Real Time Systems Department;
- Real Time Operations Department;
- Operations Planning Department;
- Market Policy and Operations Department;
- Provincial Reliability Coordination Operations Department;

- Grid Telecom Operations Department; and
- Business Services and Administration Department.

5C.10.1.1. Real Time Systems Department

The Real Time Systems department supports the real time computer systems and applications used for electric system monitoring and control by the Real Time Operations department. This involves on-site support to the system control centres during business hours as well as on-call support at all other times. The department is also responsible for compliance with the Critical Infrastructure Protection Standards applicable to the Transmission and Distribution System Operations KBU, which are among the Mandatory Reliability Standards adopted by the BCUC.

5C.10.1.2. Real Time Operations Department

The Real Time Operations department controls and monitors in real time more than 80,000 kilometers of transmission and distribution circuits, over 30 generating stations, and over 300 substations from BC Hydro’s Fraser Valley Control Centre and the Southern Interior Control Centre, providing safe and reliable service to customers. These control centres remotely monitor/operate transmission and generation facilities while meeting various aspects of Mandatory Reliability Standards. They also operate the distribution system and restore service when outages occur. From a safety perspective, control centres are instrumental in administering BC Hydro’s safety systems for issuing isolations and clearances to various front-line workers and contractors when they are working on high voltage electrical equipment. The function is performed 24/7.

This department also performs the outage scheduling function, so that planned outages of generation, transmission, and distribution facilities (including Independent Power Producers and major customers) are safely and efficiently coordinated to enable maintenance of existing facilities and commissioning of new facilities.

5C.10.1.3. Operations Planning Department

The Operations Planning department consists primarily of Power System Engineers. The department prepares reliability assessments, plans the daily operation of the electrical grid, and coordinates operations with other utilities connected to BC Hydro. This involves examining planned outages of generation and transmission facilities as well as the addition of new facilities to determine their impact on the grid. Assessments of load demand and potential imports and exports are used to forecast the Total Transfer Capability of the BC Hydro system for internal and external transfers of energy. The department develops contingency plans to prepare operating staff to manage unplanned events on the grid should they arise.

The department is also responsible for compliance with requirements of the Transmission Operations standards, which are among the Mandatory Reliability Standards adopted by the BCUC.

5C.10.1.4. Market Policy and Operations Department

The Market Policy and Operations department is the point of contact for BC Hydro's Open Access Transmission Tariff customers. The department is responsible for wholesale transmission market policies, contracts, and the administration of wholesale transmission services under the Open Access Transmission Tariff. This includes transmission pre-scheduling, settlements and billing, energy accounting, revenue reporting and forecasting, data reporting, as well as business systems sustainment and enhancements.

5C.10.1.5. Provincial Reliability Coordination Operations Department

The Provincial Reliability Coordination Operations department is responsible for assessing transmission reliability, coordinating system operations, and directing actions to preserve the integrity and reliability of the Bulk Electric System for all of B.C.

The Reliability Coordinator function is staffed by employees who have been certified by the North American Electric Reliability Corporation, meet annual training requirements, and have significant experience in operating or planning the Bulk Electric System. Employees in this department use operational tools and information to analyze the reliability of the Power System on a continuous basis. They are also responsible for the coordination and oversight necessary to operate the interconnected grid across western U.S. and Canada. In the event of disturbances or blackouts, these employees intervene to ensure that the grid is restored in a coordinated manner.

5C.10.1.6. Grid Telecom Operations Department

The Grid Telecom Operations department is responsible for the real-time operations of the BC Hydro telecommunications network that supports critical infrastructure throughout the BC Hydro electrical system. The telecommunications network provides bulk electric system protection, visibility, and control across the province from the system control centres. Employees in this department provide 24/7 technical support to the system control centres and field workers. These employees are augmented by a support team which tests existing and new telecommunication hardware and software in a controlled laboratory environment. The testing conducted by this team identifies issues early and limits the amount of changes that are required after equipment has already been deployed onto the system.

5C.10.1.7. Business Services and Administration Department

This department provides administrative support to employees at the Fraser Valley Control Centre and the Southern Interior Control Centre.

5C.10.2 Overview of Operating Costs and FTEs

Table 5C-16 Transmission and Distribution System Operations KBU Fiscal 2022 Decision Operating Costs and FTEs by Department

	($ Millions)	Labour	Services - Other	Materials	Building & Equipment	Capitalized Overhead	External Recoveries	Total Operating	Total FTEs
1	Director, Transmission and Distribution System Operations	0.3	0.0	0.0	0.0	0.0	0.0	**0.3**	1
2	Real Time Systems	4.8	0.7	0.0	1.9	0.0	0.0	**7.4**	33
3	Real Time Operations	15.0	0.3	0.1	0.2	0.0	0.0	**15.5**	95
4	Operations Planning	1.7	0.0	0.0	0.2	0.0	0.0	**1.9**	10
5	Market Policy and Operations	0.8	0.0	0.0	0.0	0.0	0.0	**0.9**	6
6	Provincial Reliability Coordination Operations	2.4	0.6	0.0	0.1	0.0	0.0	**3.1**	13
7	Grid Telecom Operations	2.5	0.7	0.1	0.5	0.0	0.0	**3.8**	35
8	Business Services and Administration	0.4	0.0	0.0	0.0	0.0	0.0	**0.4**	4
9	Inter-utility Operations	0.0	4.5	0.0	0.0	0.0	0.0	**4.5**	-
10	Transmission Control Centres	0.6	0.0	0.0	0.0	0.0	0.0	**0.6**	-
11	Distribution-Load Dispatch-Engineering Support	1.4	0.1	0.0	0.0	0.0	0.0	**1.5**	-
12	Distribution-Load Dispatch-Field Operations Support	1.6	0.1	0.0	0.0	0.0	0.0	**1.7**	-
13	**Total (Sch 5.3 L7, Sch 16.0 L21)**	**31.6**	**7.0**	**0.2**	**2.9**	**0.0**	**0.0**	**41.6**	**197**

5C.10.2.1. Director, Transmission and Distribution System Operations Department

This department holds the budget for the Director of the Transmission and Distribution System Operations KBU. It primarily consists of labour costs for the Director.

5C.10.2.2. Real Time Systems Department

This department manages the real time systems and consists of 33 FTEs that provide extended hours of on-site technical support for the critical hardware and applications to operate the Power Systems at the Fraser Valley Control Centre and the Southern Interior Control Centre.

This department holds non-labour budget of $2.6 million, which primarily consists of licenses, and support and maintenance contracts with external vendors to support the real time computer systems and applications.

5C.10.2.3. Real Time Operations Department

This department consists of 95 FTEs which are required to support 24/7 operation of the Fraser Valley Control Centre and the Southern Interior Control Centre. This includes one Senior System Control Manager, 12 System Control Managers, one Principal Engineer, one Specialist Engineer, one Engineering Technical Assistant, and 79 Operators. The Operators are assigned to consoles at the Fraser Valley Control Centre and the Southern Interior Control Centre from which they control various portions of the Power System across the province. The Operator staffing model is built around providing 24/7 coverage and meeting mandatory training needs, while recognizing that staffing can be reduced to a minimum during weekends, evenings and holidays when there is less planned work on the Power System.

This department holds non-labour budget of $0.6 million, which primarily consists of $0.3 million for employee expense costs and $0.2 million for system maintenance contract and software costs.

5C.10.2.4. Operations Planning Department

This department consists of 10 FTEs. These employees:

- Assess approximately 7,500 planned transmission system outage requests per year. These requests can take anywhere from 30 minutes to multiple days to assess and involve engagement with field staff or customers, analysis, and the preparation of contingency plans;
- Create support plans for approximately 30 major distribution outages per year, to reduce or eliminate customer impacts. These plans take multiple days to complete including consultation and coordination;
- Develop approximately 20 restoration and mitigation plans per year. These plans are developed in real time during major storm and fire events and take approximately one to two days to complete; and
- Draft and update approximately 500 base operating procedure documents per year. These documents include detailed technical requirements for advanced power system controls, Mandatory Reliability Standards required Operations Planning Assessments and Operating Plans. Drafting these documents can take multiple days to complete.

This department holds non-labour budget of $0.2 million primarily for outage management software costs.

5C.10.2.5. Market Policy and Operations Department

This department consists of six FTEs including one manager, one Contracts Professional, one Business System Specialist, and three analysts. This department manages pre-scheduled sale of transmission service and ancillary services. In fiscal 2021, the department billed over 31.3 million MWh of transmission service and generated $19.3 million in revenue from non-BC Hydro customers.

5C.10.2.6. Provincial Reliability Coordination Operations Department

This department consists of 13 FTEs including one manager, one Specialist Engineer, two Senior Engineers, seven Reliability Coordinator Operations Specialists, one Compliance Advisor, and one administrative assistant. This department is responsible for assessing transmission reliability, coordinating system operations, and directing actions to preserve the integrity and reliability of the Bulk Electric System for all of B.C.

This department holds non-labour budget of $0.7 million, which primarily consists of $0.5 million California Independent System Operator (**CAISO**) subscription costs and $0.2 million computer software and employee expense costs.

5C.10.2.7. Grid Telecom Operations Department

This department consists of 35 FTEs including one department Manager, one Lab/Project Manager, three Senior Engineers, 10 IBEW Telecom Network Controllers, 13 IBEW Communication Protection and Control Technologists, two MoveUp Project Coordinators, one Field Service Administrator, and four FTEs that represent overtime which is driven by peak demand. These FTEs operate BC Hydro’s telecom infrastructure, maintain 24/7 network controller desks, maintain 40 applications, operate and maintain a central telecom lab, and provide Project, Engineering and technical support and direction for over 1,800 telecom assets and 3,000 data paths at 200 sites.

This department holds non-labour budget of $1.3 million, which primarily consists of $1.1 million for telecommunication support software and contract costs.

5C.10.2.8. Business Services and Administration Department

This department consists of four FTEs who provide administrative support to the 150 employees based at the Fraser Valley Control Centre and the Southern Interior Control Centre.

5C.10.2.9. Inter-utility Operations Department

This department does not contain any FTEs. It holds the funding for BC Hydro's mandatory annual membership fees for Western Electricity Coordinating Council (**WECC**) and Northwest Power Pool as well as WECC Congestion Management fees.

5C.10.2.10. Transmission Control Centres Department

This department does not contain any FTEs. When Communication Protection and Control Technologists from the Stations Field Operations KBU perform corrective work that supports real time monitoring and control, they charge to this department. Approximately 8,000 hours of work is charged to this department each year. This program is managed by the Real Time Operations department.

5C.10.2.11. Distribution-Load Dispatch-Engineering Support Department

This department does not contain any FTEs. When engineers from the Integrated Planning Business Group conduct power quality investigations, they charge to this department. Approximately 24,000 hours of work is charged to this department each year. This program is managed by the Operations Planning department.

5C.10.2.12. Distribution-Load Dispatch-Field Operations Support Department

This department does not contain any FTEs. When the PLTs from the Line Field Operations KBU perform customer switching activities on distribution equipment to restore power, they charge to this department. Approximately 17,000 hours of work is charged to this department each year. This program is managed by the Real Time Operations department.

5C.10.3 Fiscal 2023 to Fiscal 2025 Plan Operating Costs and FTEs

Table 5C-17 Transmission and Distribution System Operations KBU Operating Costs and FTEs

		Schedule Reference	F2021 Actual	F2022 Decision	F2023 Plan	F2024 Plan	F2025 Plan
			1	2	3	4	5
1	**Transmission and Distribution System Operations KBU**						
2	Operating Costs ($ million)	5.3 L7	40.3	41.6	41.8	42.6	43.5
3	FTEs	16.0 L21	204	197	201	201	201

Operating costs are increasing by $0.2 million from fiscal 2022 Decision amounts to fiscal 2023 plan primarily due to:

- $0.3 million increase for Mandatory Reliability Standards program assurance resources, as discussed further in Chapter 5, section 5.7;
- $0.2 million increase due to a transfer in of one FTE from the Safety and Compliance Business Group for a Mandatory Reliability Standards position included in the fiscal 2022 Decision; and
- $0.2 million increase for Work Program Delivery Resource requirements, as discussed further in Chapter 5, section 5.11.4; partially offset by:
- $0.5 million reduction due to Standard Labour Rate decreases.

Operating costs are increasing by $0.8 million from fiscal 2023 plan to fiscal 2024 plan and $0.9 million from fiscal 2024 plan to fiscal 2025 plan due to Standard Labour Rate increases.

FTEs are planned to increase by four from fiscal 2022 Decision amounts to fiscal 2023 plan due to:

- Two FTEs for Mandatory Reliability Standards program assurance resources, as discussed further in Chapter 5, section 5.7
- One FTE transfer in from the Safety and Compliance Business Group for a Mandatory Reliability Standards position included in the fiscal 2022 Decision; and
- One FTE for Work Program Delivery Resource requirements, as discussed further in Chapter 5, section 5.11.4.

FTEs are planned to remain constant from fiscal 2023 to fiscal 2025.

5C.11 Business Unit Support KBU

5C.11.1 Responsibilities

There have been no material changes to the responsibilities of the Business Unit Support KBU since the Previous Application.

The Operations Business Unit Support KBU holds the budget for the Executive Vice-President of Operations and for business group costs that are not specifically related to any KBU.

5C.11.2 Overview of Operating Costs and FTEs

Table 5C-18 Business Unit Support KBU Fiscal 2022 Decision Operating Costs and FTEs by Department

	($ Millions)	Labour	Services - Other	Materials	Building & Equipment	Capitalized Overhead	External Recoveries	Total Operating	Total FTEs
1	Executive VP	1.0	1.7	0.0	0.0	0.0	0.0	**2.7**	4
2	Business Support	0.4	0.2	0.0	0.0	0.0	0.0	**0.6**	-
3	**Total (Sch 5.3 L8, Sch 16.0 L22)**	**1.4**	**1.9**	**0.0**	**0.0**	**0.0**	**0.0**	**3.3**	**4**

The Executive VP department includes four FTEs: The Executive Vice-President of Operations, a Strategic Business Advisor, an administrative assistant and a Project

Manager who oversees various non KBU-specific initiatives and projects within the Operations Business Group.

This KBU holds $1.4 million in labour costs for the four FTEs as well as labour costs for Operations Business Group employees conducting union business for IBEW and MoveUp. These costs are invoiced to IBEW and MoveUp. In addition, this KBU includes the labour budget for BC Hydro's annual Safety Rodeo.

Non-labour costs in this KBU are primarily for unanticipated and emerging initiatives that cannot be absorbed within the fiscal year budget by reprioritizing previously planned work. As discussed below, there will be a re-allocation of some of these funds within the Operations Business Group in fiscal 2023.

5C.11.3 Fiscal 2023 to Fiscal 2025 Plan Operating Costs and FTEs

Table 5C-19 Business Unit Support KBU Operating Costs and FTEs

		Schedule Reference	F2021 Actual	F2022 Decision	F2023 Plan	F2024 Plan	F2025 Plan
			1	2	3	4	5
1	**Business Unit Support KBU**						
2	Operating Costs ($ million)	5.3 L8	0.6	3.3	3.7	3.7	3.8
3	FTEs	16.0 L22	5	4	6	6	6

Operating costs are increasing by $0.4 million from fiscal 2022 Decision amounts to fiscal 2023 plan primarily due to:

- $0.9 million increase for Work Program Delivery Resource requirements, as discussed further in Chapter 5, section 5.11; and
- $0.4 million increase for Mandatory Reliability Standards sustainment resources, as discussed further in Chapter 5, section 5.7; partially offset by:
- $0.7 million reduction due to the re-allocation of funds to the Generation System Operations KBU primarily related to various climate and water monitoring contracts.

Operating costs are planned to remain relatively constant from fiscal 2023 to fiscal 2025.

FTEs are planned to increase by two from fiscal 2022 Decision amounts to fiscal 2023 plan due to Mandatory Reliability Standards sustainment resources, as discussed further in Chapter 5, section 5.7. FTEs are planned to remain constant from fiscal 2023 to fiscal 2025.

Fiscal 2023 to Fiscal 2025

Revenue Requirements Application

Chapter 5D

Operating Costs

Safety and Compliance

Business Group

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5D.1 Introduction – Safety and Compliance Business Group

Chapter 5D details the composition of, and rationale for, the operating costs of the Safety and Compliance Business Group. The Safety and Compliance Business Group is one of six business groups in the organization and is responsible for facilitating BC Hydro's management of safety and compliance risks, including Mandatory Reliability Standards. It serves as a Support function of the Plan-Build-Operate-Support model.

The Safety and Compliance Business Group budget was developed as part of the budgeting process outlined in Chapter 5, section 5.4, which the BCUC found to be reasonable in its decision on the Previous Application.[327] The budgeting approach includes both bottom-up and top-down elements and examines more than just incremental costs. Similarly, the information provided in Chapter 5D demonstrates the basis for the entirety of the Business Group and KBU budgets, rather than focussing only on incremental cost requirements. This information is provided in a format and level of detail consistent to that presented in the equivalent chapter in the F2020-F2021 RRA.

Chapter 5D is organized as follows:

- Section 5D.2 provides an overview of the organization and responsibilities of the Safety and Compliance Business Group, references our use of metrics to measure and benchmark performance, and explains our progression to an integrated safety and compliance risk management structure;
- Section 5D.3 responds to Directive 23 of the BCUC's Decision on the F2020-F2021 RRA. It describes how BC Hydro's performance has improved,

[327] BCUC Decision and Order No. G-187-21, Fiscal 2022 Revenue Requirements Application (June 17, 2021), p. 27: "The Panel considers BC Hydro's budgeting process involving top-down and bottom-up elements goes beyond the examination of incremental changes from the prior year and continues to be reasonable for forecasting operating costs. Therefore, for these reasons, the Panel finds the fiscal 2022 operating costs requested for recovery to be reasonable."

and how the planned operating costs and FTEs for the Safety and Compliance Business Group as a whole will help to sustain that improvement;

- Section 5D.4 provides the summary operating costs and FTE information for the Safety and Compliance Business Group as a whole;[328] and
- Sections 5D.5 to 5D.9 provide more detailed information on the responsibilities, cost and FTEs for each KBU within the Safety and Compliance Business Group. The operating costs and FTE information for each KBU is broken out into two sections:[328]
    - Overview of Operating Costs and FTEs – This subsection explains the starting operating costs and FTEs for the KBU based on the Previous Application Decision amounts; and
    - Fiscal 2023 through Fiscal 2025 Plan Operating Costs and FTEs – This subsection explains any incremental changes in the KBU between fiscal 2022 Decision amounts and fiscal 2023 to fiscal 2025 plan.

5D.2 Overview of Safety and Compliance Business Group Organization and Responsibilities

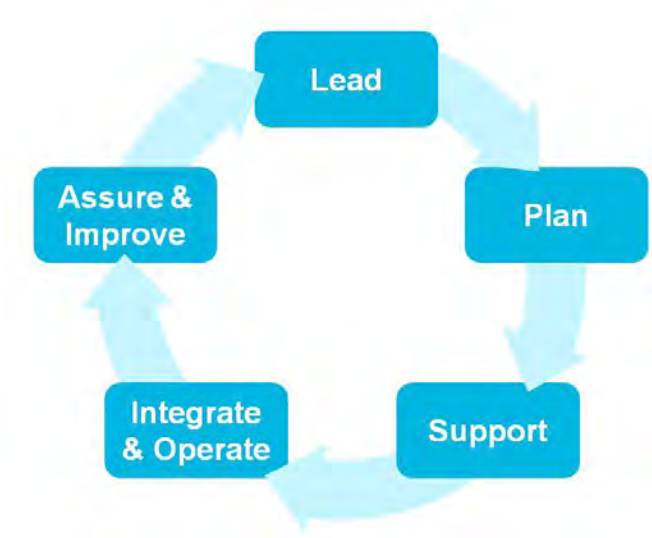
BC Hydro operates in an industry of high safety risk and complex regulatory responsibilities. To safely provide our customers with reliable electricity, BC Hydro must manage its safety risks and achieve, sustain and demonstrate compliance with safety regulations and Mandatory Reliability Standards.

The Safety and Compliance Business Group was created in fiscal 2020. Since that time, it has been responsible for facilitating BC Hydro's management of employee, contractor and public safety risks and demonstration of safety and reliability compliance.

[328] Please note the amounts presented in the tables in these sections may not add due to rounding.

The Integrated Safety and Compliance Framework, illustrated in Figure 5D-1 below, and further discussed in section 5D.2.1.7, provides BC Hydro with a consistent and overarching five-element structure for safety and reliability risk management, which aids in effective and efficient implementation of safety and compliance processes and programs.

Figure 5D-1 Integrated Safety and Compliance Framework



The Safety and Compliance Business Group consists of the following KBUs:

Business Group	Key Business Unit
Safety and Compliance	Safety Learning and Development Security and Emergency Management Reliability Standards Assurance Business Unit Support

Since the Previous Application, the former Safety System and Assurance KBU and former Field Safety Services KBU were combined to form a single Safety KBU that efficiently addresses all the responsibilities in alignment with the Integrated Safety and Compliance Framework. Section 5D.5.1 provides further details on this integration.

5D.2.1 Safety Key Performance Results and Risk Management Approach

We track our safety progress using industry standard metrics which are further discussed below. In fiscal 2021, results improved in all key areas. This performance reflects positively on prior investments and has allowed BC Hydro to advance to a focus on sustainment and continual improvement that is governed by an efficient integrated framework.

5D.2.1.1. BC Hydro Uses Standard Safety Performance Measures

In its 2021/22 - 2023/24 Service Plan, BC Hydro includes three performance measures[329] for its Goal 1: Safety Above All:

- Zero Fatality and Serious Disabling Injury;[330]
- Lost Time Injury Frequency;[331] and
- Timely Completion of Corrective Actions (%).[332]

Zero Fatality and Serious Disabling Injury is BC Hydro's most important safety performance measure. The target of zero represents our commitment to ensuring everyone goes home safely every day.

5D.2.1.2. Fatality and Serious Disabling Injury Performance Has Improved

Between April 1999 and August 2010, eight BC Hydro employees lost their lives at work (all electrical workers). As of March 2021, BC Hydro has recorded over 10 years (3,880 days) without an employee losing their life to a workplace incident. This is the longest period without a fatality in over 30 years of recorded data.

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[329] Performance measures do not include contractor or public safety injuries or fatalities.

[330] Measure of an incident where there has been a loss of life or an injury has resulted in a permanent disability (for which a disability pension has been received or is expected).

[331] Lost Time Injury Frequency is a standard measure that shows the number of injuries resulting in lost time per 200,000 hours worked. Lost time injuries are those where the employee was absent from work beyond the day of injury.

[332] The percentage of safety corrective actions closed on, or before, the scheduled due date on an annual basis.

Between April 2005 and August 2012, 15 BC Hydro employees suffered permanent disabling injuries on the job (approximately two per year), with two more occurring between September 2012 and March 2021. Year-to-date in fiscal 2022 there has been one additional serious incident where a BC Hydro employee suffered a permanent disabling injury at work. BC Hydro continues to monitor and review incidents and near-miss incidents that have the potential to result in a fatality or serious disabling injury, such as those related to four high-risk hazards: electrical contact, fall from heights, mechanical or transportation. This represents our highest priority opportunity to continually improve safety performance.

5D.2.1.3. Lost Time Injury Frequency Performance Has Improved

BC Hydro has improved Lost Time Injury Frequency (**LTIF**) performance over the past five years, as shown in Figure 5D-2 below. This downward trend includes a reduction of more than 10 per cent from fiscal 2017 to fiscal 2020.

In fiscal 2021, we observed a significant reduction of more than 30 per cent. This drop requires context as the COVID-19 pandemic reduced risk exposure for many employees working from home. Our first quarter in fiscal 2022 is indicating a return to previously observed improvement trends prior to fiscal 2021 and the COVID-19 pandemic.

BC Hydro's Lost Time Injury Frequency continues to be higher compared to a subset of utilities that are members of the Canadian Electricity Association (**CEA**).[333] Fiscal 2021 performance represents a significant step towards closing that gap; however, further analysis and performance monitoring will assess sustainability.

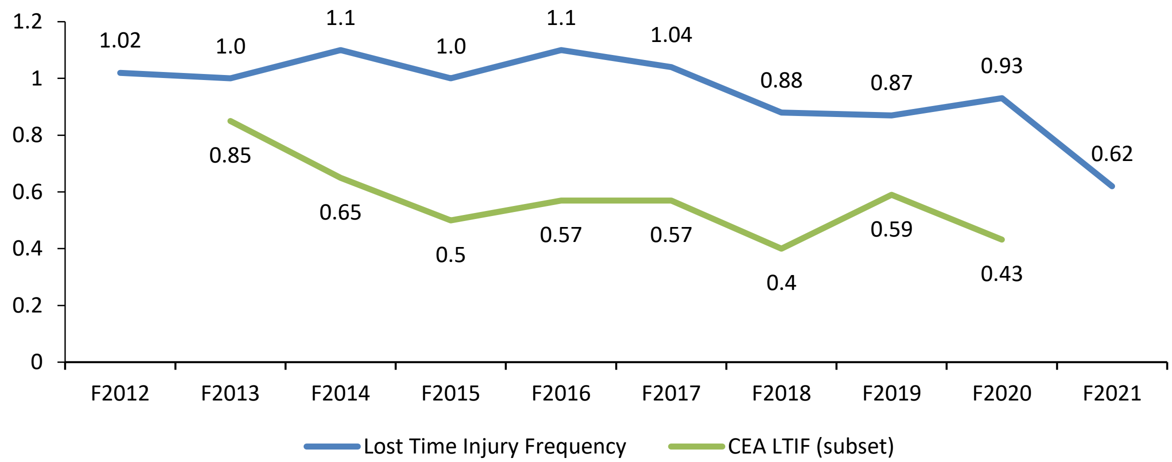
BC Hydro's current benchmarking practice compares it against a CEA composite. This grouping includes nuclear and non-integrated utilities. BC Hydro would get a

[333] CEA LTIF includes a subset of companies with over 1,500 employees. This subset includes companies with a mix of generation, transmission, and distribution work, as well as construction. CEA results are published based on calendar years and aligned with BC Hydro's fiscal years as best possible. For example, CEA results for calendar 2019 are aligned with BC Hydro Fiscal 2020. Published results for calendar 2020 (fiscal 2021) are expected by August 30, 2021.

more accurate benchmark with a better comparison group which would feature other integrated hydro-electric utilities of similar generating capacity, asset structure and service area.

BC Hydro is refining its benchmarking standard to improve accuracy and validate safety performance. The improved benchmarking will be reflected in future revenue requirements applications.

Figure 5D-2 Lost Time Injury Frequency – Employees [334]



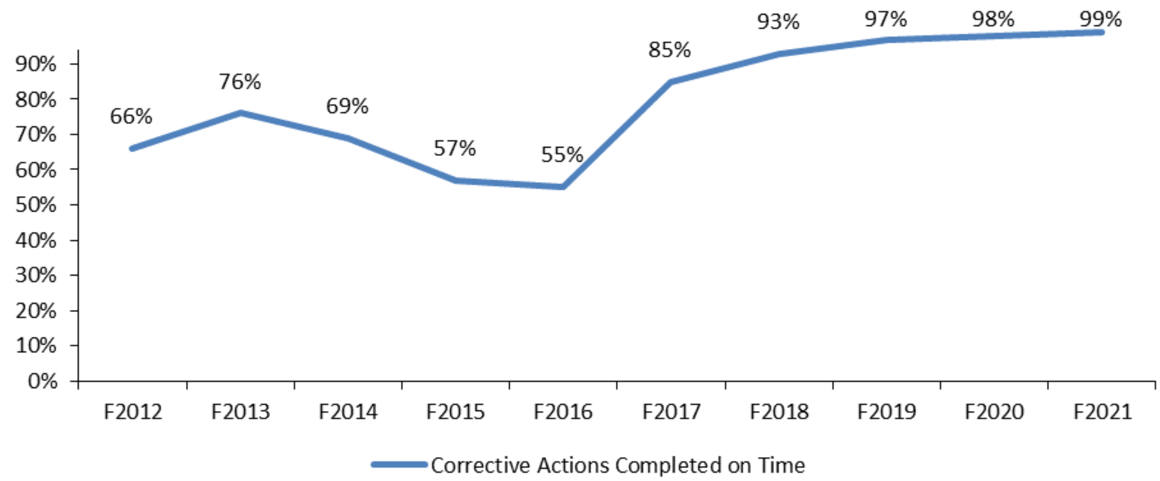
5D.2.1.4. Timely Completion of Corrective Actions Performance Has Improved

Figure 5D-3 below shows that BC Hydro continues to implement corrective actions on time after completing safety incident reviews and audits and has reached 99 per cent of corrective actions closed on, or before, the scheduled due date. Developing effective corrective actions is an important component to continually improving safety performance over time. Given sustained exceptional results over

[334] BC Hydro LTIF numbers on this graph are aligned with LTIF numbers reported in BC Hydro's Annual Reports. This is different from the F2020-F2021 RRA in which LTIF numbers were calculated for that particular submission, resulting in slight variations (due to the nature of the data) from what was reported on the annual reports. As of fiscal 2022, BC Hydro has developed reporting standards to ensure consistency in reporting and avoid this from happening again.

multiple years, BC Hydro is reviewing the utility and further contribution value to overall performance of maintaining this metric in the Service Plan.

Figure 5D-3 Corrective Actions Completed on Time



5D.2.1.5. Performance Metrics Have Changed from the F2020 to F2021 Revenue Requirements Application

In the F2020-F2021 RRA, BC Hydro included two additional safety performance metrics: All Injury Frequency and Employee Near-Miss/Good-Catch Reporting. All Injury Frequency[335] is not included in this Application because it has been retired from CEA reporting, and benchmarking data will no longer be available. It is important to note that BC Hydro's All Injury Frequency performance improved in fiscal 2021, compared to the previous years. Near-Miss and Good-Catch reporting is not included as it was based on the volume of near-misses and good-catches. BC Hydro's focus shifted from volume to quality at the end of fiscal 2020; this adjustment enables additional and timely review of serious near-misses and good-catches, followed by faster implementation of corrective actions. As a result of

[335] All injury Frequency is defined as the total number of employee medical aid and lost-time injuries occurring in the last 12 months per 200,000 hours worked. Medical aid injuries are those where a medical practitioner has provided services beyond the level defined as first aid and the employee was not absent from work after the day of the injury. Lost-time injuries are those where the employee is absent beyond the day of injury.

this shift, BC Hydro has observed an expected decrease in Near-Miss and Good-Catch reporting.

5D.2.1.6. BC Hydro Is Prioritizing Continual Improvement in Safety Performance

The decrease in fatalities and disabling injuries, combined with trending improvements to Lost Time Injury Frequency and Corrective Actions Completed on Time, reflect BC Hydro's concerted effort over prior test periods. Given our progress, BC Hydro is transitioning its safety approach from a focus on initiatives to a phase of sustainment and continual improvement as a base work function that aligns to the Integrated Safety and Compliance Framework.

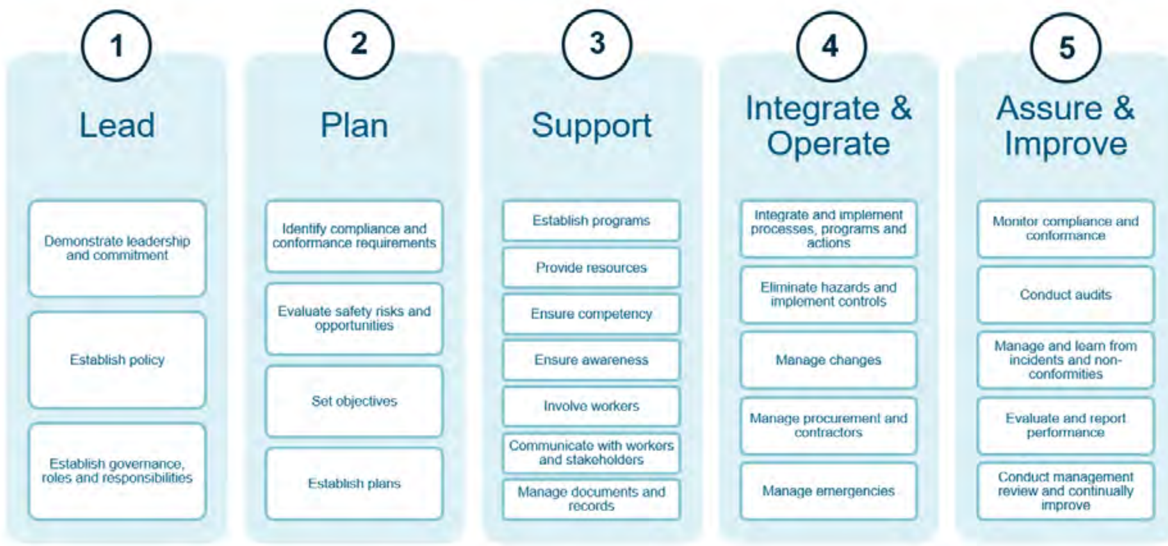
Since the F2020-F2021 RRA, BC Hydro established its Safety Framework as an evolutionary improvement and to supersede the previous Safety and Health Management System. Using the Safety Framework, BC Hydro continues to identify important opportunities to learn and improve, with a focus on conducting reviews of injuries and near-miss incidents with the potential for fatality and serious injury.

5D.2.1.7. Safety Framework Aligns Safety Management Processes, Programs and Responsibilities Under One Structure

The Safety Framework aligns BC Hydro's safety management processes, programs and responsibilities under one connected structure, intended to support effective safety risk management and to demonstrate compliance across the enterprise with safety legal requirements. The Safety Framework structure uses the five elements of BC Hydro's Integrated Safety and Compliance Framework and expands it to a list of components and requirements that align to the external Canadian Standards Association Z45001:19 (Occupational health and safety management systems) standard, improves consistency with other internal risk management frameworks such as Dam Safety.

Figure 5D-4 below provides a visual representation of the Safety Framework.

Figure 5D-4 Safety Framework



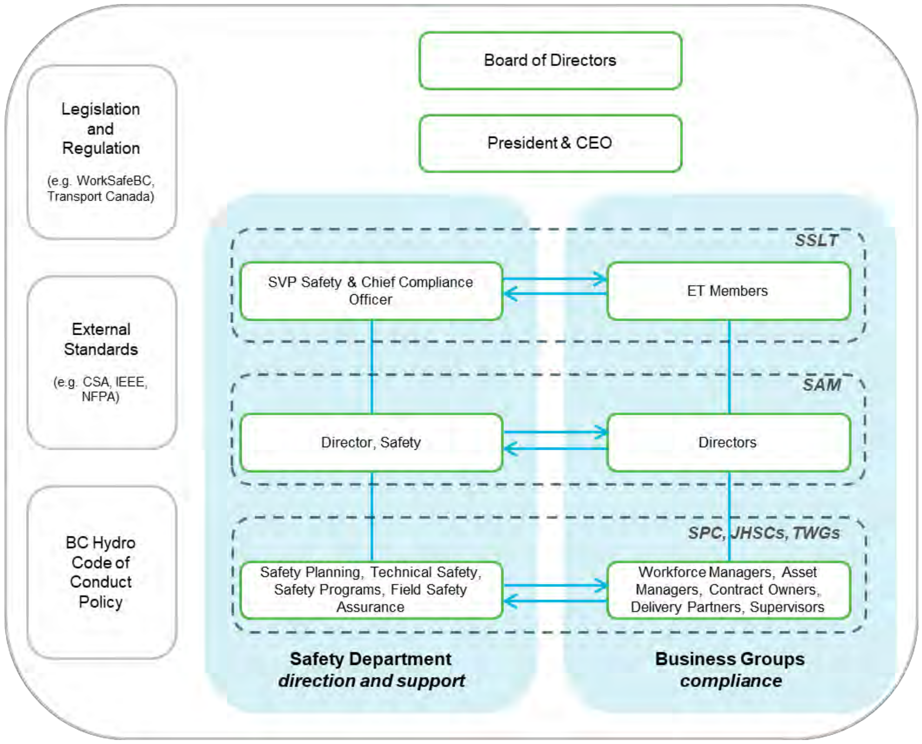
5D.2.1.8. BC Hydro Has a Documented Safety Governance Structure

To support implementation, sustainment and continual improvement of the Safety Framework, BC Hydro documented its Safety Governance Structure in a Safety Governance Manual which includes:

- Responsibilities BC Hydro has, as an owner and employer, to provide a safe workplace for workers;
- Safety management processes established within BC Hydro to meet those responsibilities;
- Assignment of those responsibilities within BC Hydro to ensure safety management processes are functioning effectively and sustainably; and
- Required governance structure to ensure implementation of an occupational health and safety management system.

Figure 5D-5 below provides a visual representation of the Safety Governance Structure.

Figure 5D-5 Safety Governance Structure[336]



5D.2.1.9. Sustained Focus on the Safety Framework

Over the Test Period, BC Hydro will focus on its safety performance by sustaining and continually improving effectiveness and efficiency of its Safety Framework. This includes:

- Sustaining the Safety Governance Structure and continuing to support BC Hydro employees at all levels to understand their safety accountabilities and responsibilities;
- Continuing to develop, implement, sustain and assure safety management processes and safety programs to demonstrate compliance and support employees in fulfilling their safety accountabilities and responsibilities; and

[336] Senior Safety Leadership Team (**SSLT**), Safety Accountability Meeting (**SAM**), Safety Practices Committee (**SPC**), Joint Health and Safety Committees (**JHSCs**), Technical Working Groups (**TWGs**)

- Developing, sustaining and improving safety technology systems and applications to enable effective and efficient implementation and integration of safety into business processes.

This focus on systematic risk management supported by an established governance structure will ensure that investments in safety initiatives and progress achieved in prior test periods are sustained and more importantly, further opportunities to reduce risk and improve performance are identified and executed. The responsibilities of the Safety KBU, Learning and Development KBU, and Security and Emergency Management KBU outlined in sections 5D.5, 5D.6 and 5D.7 below support the Safety Framework and this direction.

5D.2.2 Business Group Supports Mandatory Reliability Standards Implementation and Compliance

As discussed in Chapter 5, section 5.7, the expansion of the Mandatory Reliability Standards and the evolving maturity of the Mandatory Reliability Standards compliance program are driving increased investment during the Test Period.

The Mandatory Reliability Standards are important for the reliable operation of the Bulk Electric System. There are 13 Mandatory Reliability Standards domains, which include 102 Mandatory Reliability Standards comprised of 511 requirements, approved in B.C. which apply to BC Hydro's operations. The continued expansion of Mandatory Reliability Standards, including new requirements, increased scope and additional functions, drive costs during the Test Period. For example:

- There will be 26 new or revised Mandatory Reliability Standards, with a combined total of 126 additional specific requirements, coming into effect that will be applicable to BC Hydro during the Test Period;
- New versions of Critical Infrastructure Protection (**CIP**) Standards have significantly expanded the scope and complexity of the obligations on BC Hydro; and

- BC Hydro will need to comply with additional Mandatory Reliability Standards and requirements that define the key accountabilities for the Planning Coordinator function in accordance with the effective dates established by the BCUC.

The evolving maturity and key components of focus of BC Hydro's Mandatory Reliability Standards compliance program will result in stronger Mandatory Reliability Standards compliance performance and Bulk Electric System reliability. BC Hydro has established the Mandatory Reliability Standards Internal Compliance Program Framework in alignment with the structure of the Integrated Safety and Compliance Framework. The use of an integrated framework creates consistent, repeatable and a more efficient approach to managing our risks. The updated Mandatory Reliability Standards Internal Compliance Program has new and enhanced components (e.g., Mandatory Reliability Standards compliance program governance structure including the CIP Program Office, internal controls and compliance assurance, and Mandatory Reliability Standards awareness and training programs) and is implementing technology (e.g., compliance management system as referenced in Chapter 6, section 6.5.1) that strengthens our Mandatory Reliability Standards program.

The Learning and Development KBU, Security and Emergency Management KBU, and Reliability Standards Assurance KBU (discussed in sections 5D.6, 5D.7, and 5D.8 below) support BC Hydro's Internal Compliance Program Framework and the compliance related activities planned for this Test Period.

5D.3 BC Hydro is Focused on Zero Fatalities and Serious Disabling Injuries (Directive 23)

In its Decision on the Previous Application, the BCUC expressed concern that BC Hydro's results on Lost Time Injury Frequency and All Injury Frequency remained above the Canadian Electricity Association average.[337] The BCUC also asked BC Hydro to explain how a declining trend in targets on the Lost Time Injury Frequency metric demonstrated improvement.[338] Directive 23 of the BCUC's Decision on the F2020-F2021 RRA directed BC Hydro to evaluate, in this Application, whether more aggressive Lost Time Injury Frequency and Lost Time Injury Duration results could be achieved and the additional costs required to achieve those results.[339]

BC Hydro's performance on Lost Time Injury Frequency has improved while our performance on Lost Time Injury Duration has remained relatively stable. During the Test Period, we will maintain our efforts to improve performance on these metrics. Rather than target more aggressive improvements, we are focused on preventing fatalities and serious disabling injuries which we believe we can achieve through targeted investments, identified through our Safety Framework,[340] and funded within existing budgets.

Lost Time Injury Frequency is currently a performance measure in BC Hydro's Service Plan and is benchmarked against the Canadian Electricity Association composite average. It is a standard measure that shows the number of injuries resulting in lost time (i.e., an employee being absent from work beyond the day of injury) per 200,000 hours worked.

337 BCUC Decision and Order No. G-187-21, BC Hydro Fiscal 2022 Revenue Requirements Application (June 17, 2021), page 57.
338 BCUC Decision and Order No. G-187-21, BC Hydro Fiscal 2022 Revenue Requirements Application (June 17, 2021), page 58.
339 Directive 23; BCUC Decision and Order No. G-246-20, BC Hydro Fiscal 2020 to Fiscal 2021 Revenue Requirements Application (October 2, 2020), page 74.
340 Refer to section 5D.2.1.7 for a discussion on BC Hydro's Safety Framework.

Lost Time Injury Duration is defined by BC Hydro as the sum of all days lost due to an injury (capped at 180 days per injury) divided by the number of Lost Time Injuries. A Canadian Electricity Association benchmark is not available for this metric but a benchmark is available for Lost Time Injury Severity, which is similar. Lost Time Injury Severity is defined as the number of days lost (capped at 180 days per injury) per 200,000 hours worked.

5D.3.1.1. BC Hydro's Lost Time Injury Frequency Performance Has Improved

BC Hydro's Lost Time Injury Frequency results have improved from approximately 1.0 from fiscal 2012 to fiscal 2017 to 0.88 in fiscal 2018, 0.87 in fiscal 2019, 0.93 in fiscal 2020 and 0.62 in fiscal 2021. The significant improvement in fiscal 2021 reflects our continued improvement efforts as well as the COVID-19 pandemic which reduced exposure to safety risks for many employees working from home. Initial results in fiscal 2022 indicate a return to previously observed improvement trends prior to fiscal 2021 and the COVID-19 pandemic. BC Hydro's declining (i.e., improving) Service Plan targets on Lost Time Injury Frequency are informed by, and reflect, this trend of improvement.

While BC Hydro's results on Lost Time Injury Frequency remain above the most recently reported Canadian Electricity Association composite average of 0.43, this composite includes smaller utilities as well as nuclear and non-vertically integrated utilities, which typically have better safety performance than large vertically-integrated hydroelectric utilities such as BC Hydro. Manitoba Hydro and Hydro Quebec, which are more directly comparable to BC Hydro also have Lost Time Injury Frequency results above the Canadian Electricity Association composite average. Manitoba Hydro had a Lost Time Injury Frequency of 1.48 in calendar 2020 while Hydro Quebec had a Lost Time Injury Frequency of 0.98 in that same year. BC Hydro's Lost Time Injury Duration results are available from fiscal 2016 to fiscal 2021. BC Hydro's performance on this metric has varied from year to year, with an average result of 26.5 from fiscal 2016 to fiscal 2020. In fiscal 2021, the result improved to 18.4, again reflecting ongoing improvement efforts as well as reduced exposure to safety risks as a result of the COVID-19 pandemic.

As discussed above, a Canadian Electricity Association benchmark is available for Lost Time Injury Severity, which is similar to Lost Time Injury Duration. In calendar 2020, BC Hydro's Lost Time Injury Severity was 11.65. The Canadian Electricity Association composite benchmark was 10.83. For comparison, Manitoba Hydro had a Lost Time Injury Severity of 29.65 in calendar 2020 while Hydro Quebec had a Lost Time Injury Severity of 30.53 in that same year.

5D.3.1.2. Safety Framework Will Sustain Existing Programs to Reduce Lost Time Injury Frequency and Lost Time Injury Duration

The Safety Framework facilitates sustainment and continual improvement of safety programs and investments by establishing consistent roles, responsibilities and processes; this increases the effectiveness of existing safety programs. Within this framework and during the Test Period, BC Hydro will continue our existing safety programs and investments to reduce Lost Time Injury Frequency and Lost Time Injury Duration. This includes:

- Recovery and return to work support for BC Hydro employees who have experienced both occupational and non-occupational related injuries and illnesses. This program is delivered by BC Hydro's Health and Recovery Services Team in the Human Resources KBU. The costs related to this team are outlined in Chapter 5G, section 5G.3 and are part of BC Hydro's overall operating costs;
- Stay at work process offering modified work to employees who have been injured on the job, to enhance recovery at work and early return to work. BC Hydro continues to refine and communicate this process to reduce time loss and support recovery outcomes. This process is part of the recovery and return to work support provided by BC Hydro's Health and Recovery Services team in the Human Resources KBU; and

- A comprehensive and proactive Ergonomics Program designed to reduce musculoskeletal injuries related to overexertion/repetitive motion and lifting/pushing/pulling. This program identifies, assesses and controls musculoskeletal injury risks in both field and office work settings. It is communicated across the organization, has engaged ergonomic champions and includes web-based and in-person ergonomics training and self-assessment support. BC Hydro will continue to focus on proactive risk identification, assessment and control of musculoskeletal injury risks in field work settings, and on completion of training for existing and new employees. The program is supported by consultant services and Occupational Safety and Health Specialists from the Field Safety Assurance department.

Within the Safety Framework and during the Test Period, BC Hydro will also continue with the following that have improved Lost Time Injury Frequency performance:

- Annual hazard campaigns such as the winter safety campaign which includes information on reducing risks of slips/trips/falls;
- Development of engineering standards that consider how devices and systems are designed for human use; and
- Focus on corrective actions that effectively address ergonomic injuries, beyond the direct cause, such as job planning, hazard identification/mitigation and proper equipment selection.

5D.3.1.3. BC Hydro is Focused on Targeted Investments to Sustain and Improve Efforts to Prevent Fatalities and Serious Disabling Injuries

In response to the BCUC’s directive, we considered our performance on Lost Time Injury Frequency and Lost Time Injury Duration to determine whether more aggressive results could be achieved, and the additional costs required to achieve those results. A majority of the injuries captured in the Lost Time Injury Frequency metric are minor injuries such as slips, trips and falls. Lost Time Injury Duration captures ergonomic-related musculoskeletal injuries related to overexertion/repetitive motion and lifting/pushing/pulling. In other words, while Lost Time Injury Frequency and Lost Time Injury Duration are important measures of safety performance, they are largely driven by incidents that did not, or did not have the potential to, result in serious injuries.

BC Hydro agrees with the BCUC's statement in its Decision on the F2020-F2021 RRA that safety should continue to be a high priority given the danger involved in working with high voltage lines and BC Hydro's historical safety performance relative to the Canadian Electricity Association average. However, considering BC Hydro's recent improvement on Lost Time Injury Frequency and our performance on both Lost Time Injury Frequency and Lost Time Injury Severity, relative to more comparable utilities such as Manitoba Hydro and Hydro Quebec, we believe that we need to prioritize continued review and learning on incidents that have the potential to result in a fatality or serious disabling injury. Accordingly, we have decided to continue efforts to maintain our performance on Lost Time Injury Frequency and Lost Time Injury Duration and not make additional investments to achieve more aggressive results on those measures.

Our Safety Framework has processes that monitor risk and performance data, identify trends and then conduct analysis and reviews to determine key preventative and corrective action opportunities which then inform targeted investments to improve the effectiveness of safety programs. BC Hydro believes that we can continue to sustain and improve our efforts to prevent fatalities and serious disabling injuries by making targeted investments within existing budgets.

5D.4 Fiscal 2023 to Fiscal 2025 Plan Operating Cost and FTE Summaries

This section addresses planned operating costs and FTEs for the Safety and Compliance Business Group. The following are some key points of note with respect to the information provided in Figure 5D-6, Table 5D-1 and Figure 5D-7, Table 5D-2 and Table 5D-3:

- The Field Safety Assurance department and the Learning and Development KBU), charge out 28 and 38 per cent of their labour costs to maintenance and capital work programs, respectively; and
- Apprentice and trainee FTEs reside in the Learning and Development KBU and comprise over 34 per cent of the total FTEs in fiscal 2023 plan in the Safety and Compliance Business Group. These FTEs represent only 9 per cent of the total operating costs in fiscal 2023 plan for the Safety and Compliance Business Group because approximately 70 per cent of their labour costs are charged out to other KBUs or specific projects and the remaining 30 per cent is charged to training. The main categories for the apprenticeship and trainee roles include Power Line Technicians, Electricians, Mechanics, Utility Fleet Mechanics, Distribution Design and Customer Connect Technologists, Communication Protection and Control Technologists and Engineers in Training.

Planned operating costs for the Safety and Compliance Business Group are $65.6 million in fiscal 2023, $66.1 million in fiscal 2024 and $68.0 million in fiscal 2025. The operating costs for the Safety and Compliance Business Group are summarized by KBU in Figure 5D-6. Additional cost details are provided in Table 5D-1 below.

Figure 5D-6 Safety and Compliance Net Operating Costs by KBU (Fiscal 2023 Plan) ($ million)

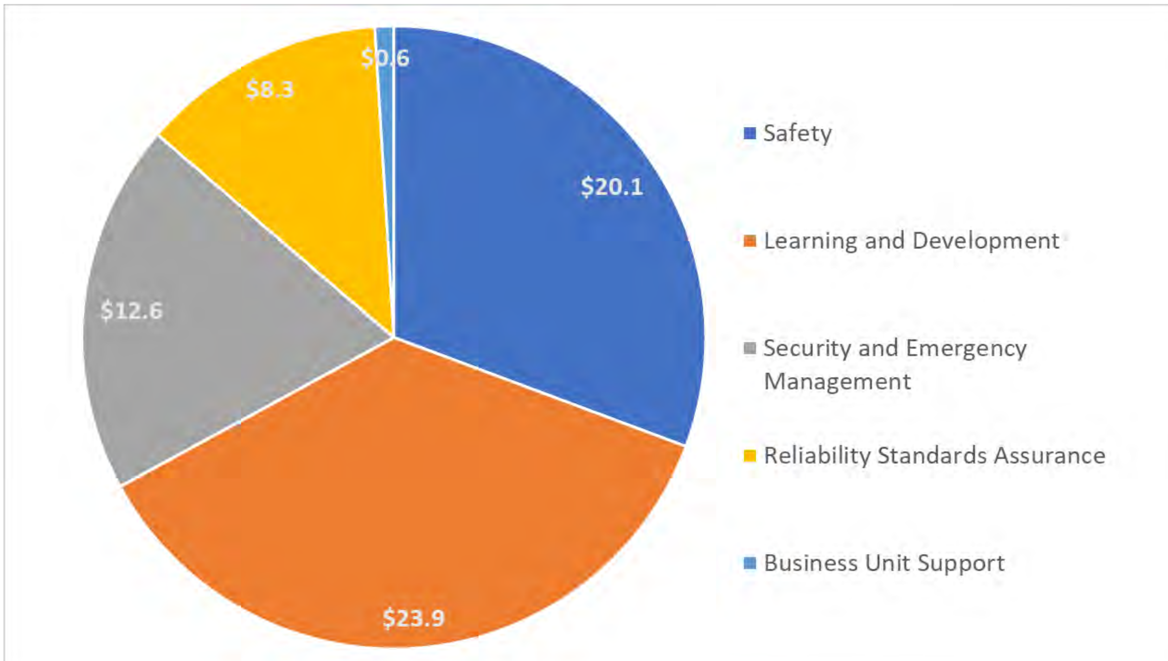


Table 5D-1 Safety and Compliance Net Operating Costs by KBU

	($ million)	Schedule Reference	F2021 Actual	F2022 Decision	F2023 Plan	F2024 Plan	F2025 Plan
			1	2	3	4	5
1	Safety	5.4 L1	19.4	22.5	20.1	20.5	20.7
2	Learning and Development	5.4 L2	19.2	24.5	23.9	25.3	27.0
3	Security and Emergency Management	5.4 L3	16.4	12.5	12.6	13.8	14.4
4	Reliability Standards Assurance	5.4 L4	8.0	8.1	8.3	5.9	5.2
5	Business Unit Support	5.4 L5	0.7	0.8	0.6	0.7	0.7
6	Total	5.4 L11	63.7	68.3	65.6	66.1	68.0

The FTEs for the Safety and Compliance Business Group are summarized by KBU in Figure 5D-7. Additional details are provided in Table 5D-2 below.

Figure 5D-7 Safety and Compliance FTEs by KBU (Fiscal 2023 Plan)

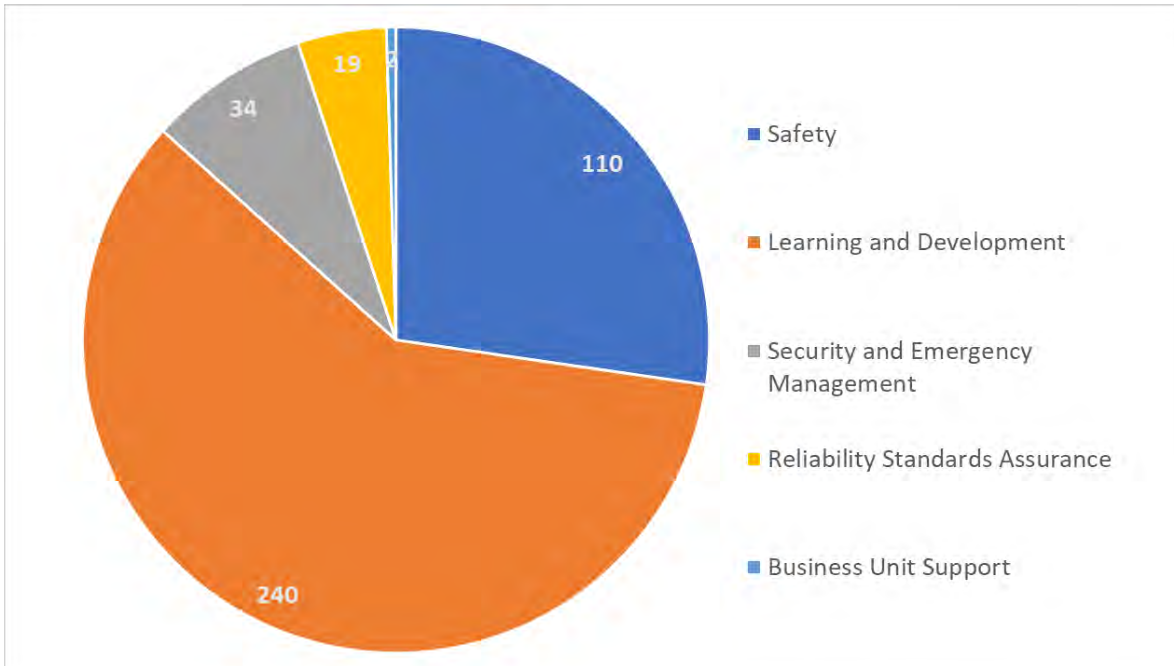


Table 5D-2 Safety and Compliance FTEs by KBU

	(FTEs)	Schedule Reference	F2021 Actual	F2022 Decision	F2023 Plan	F2024 Plan	F2025 Plan
			1	2	3	4	5
1	Safety	16.0 L24	117	112	110	110	111
2	Learning and Development	16.0 L25	290	246	240	256	274
3	Security and Emergency Management	16.0 L26	29	33	34	38	39
4	Reliability Standards Assurance	16.0 L27	9	22	19	22	22
5	Business Unit Support	16.0 L28	3	3	2	2	2
6	Total	16.0 L29	448	416	405	428	447

Table 5D-3 below provides a continuity table which highlights changes to the Safety Business Group from the Previous Application. An overall discussion of these changes, at a company-wide level, are provided in Chapter 5, section 5.5.3. Further details, by KBU, are provided in the sections below.

Table 5D-3 Safety and Compliance Operating Costs Continuity Schedule

	($ million)	Ref	F2023 Plan	F2024 Plan	F2025 Plan
1	**F2022 Revenue Requirement Application Plan**	a	**68.3**	**65.6**	**66.1**
2	**Compliance Filing Adjustment**	b	**-**		
3	Reorganizational Impact	c	**-**		
4	**F2022 Decision (Schedule 5.4, line 11)**	d = Σ a to c	**68.3**		
5	Budget Transfers Between Business Groups	e	(2.1)		
6	**F2022 Forecast (Schedule 5.4, line 11)**	f = d+e	**66.2**	**65.6**	**66.1**
7	Budget Transfers Between Business Groups	g	-	-	-
8	**Test Period Net Cost Increase/Decrease**				
9	**Uncontrollable Cost Increases**				
10	Current Service Costs and Other Labour Costs		(0.7)	1.1	1.2
11		h	(0.7)	1.1	1.2
12	**Reliability Investments**				
13	Mandatory Reliability Standards		1.7	(1.6)	(0.3)
14		i	1.7	(1.6)	(0.3)
15	**Site C**	j	-	-	0.1
16	**Net Cost Savings**				
17	Apprentice and trainee funding		0.5	1.0	1.1
18	Enterprise Compliance Resource		0.2	-	-
19	Test Period Savings		(2.3)	-	(0.3)
20		k	(1.6)	1.0	0.8
21	**Total Test Period Net Increase/(Decrease)**	l = Σ h to k	**(0.6)**	**0.5**	**1.9**
22	**F2023 Net Operating Costs (Schedule 5.4, line 11)**	m = f+g+l	**65.6**	**66.1**	**68.0**

Table may not add due to rounding

5D.5 Safety KBU

5D.5.1 Responsibilities

The Safety KBU is responsible for developing, implementing, sustaining and assuring the Safety Framework and its safety management processes and safety programs. The Safety KBU also provides occupational safety and health advice, coaching, and support to BC Hydro's workforce and work programs, including work completed by contractors.

Primary responsibilities of the Safety KBU include:

- Establishing and clarifying safety governance, responsibilities and requirements;
- Developing, implementing, sustaining and assuring safety management processes and safety programs;
- Providing procedures, information, systems and applications;
- Advising, coaching and supporting other KBUs in fulfilling their safety responsibilities and meeting requirements of safety programs; and
- Verifying and reporting safety compliance and performance.

As stated in section 5D.2, since the Previous Application the previous Safety System and Assurance KBU and Field Safety Services KBU were combined to form a new Safety KBU. Additional changes included moving the Electrical Safety Programs department from the Learning and Development KBU to the Safety KBU, and the function providing support and content management for the Qualification and Learning Management System[341] moved from the previous Safety System and Assurance KBU to the Learning and Development KBU. The re-organization was completed to align BC Hydro's safety functions with the Safety Framework and its documented responsibilities of the safety department. While the organization has

[341] The Qualification and Learning Management System is an Enterprise Learning Management System used to deliver, access, schedule and report on training activities. It is also used to manage employee qualifications.

changed, overall responsibilities of this KBU remains consistent with the predecessor KBUs.

The Safety Key Business Unit consists of the following departments:

- Director, Safety Department;
- Safety Planning Department;
- Technical Safety Department;
- Safety Programs Department; and
- Field Safety Assurance Department.

5D.5.1.1. Director, Safety Department

This department is responsible for overall management and administration of the Safety KBU.

5D.5.1.2. Safety Planning Department

The Safety Planning department is responsible for Safety Framework sustainment and assurance, regulatory support, information management, reporting and analytics, and incident management functions at the enterprise level. This department consists of the following six teams:

- Framework Sustainment and Reporting;
- Regulatory;
- Safety Assurance;
- Safety Systems;
- Reporting and Analytics; and
- Incident Management.

The Framework Sustainment and Reporting team oversees the maintenance and continual improvement of the Safety Framework and Safety Governance Structure.

This includes periodic updates to the Safety Framework Standard, Safety Governance Manual, Safety Department Responsibilities and General Safety Responsibilities, and coordination of Safety Framework documentation. The team also supports enterprise-level safety strategy and planning, coordinates BC Hydro's Safety Framework improvement efforts, coordinates management review, and prepares safety reports to BC Hydro's Board of Directors.

The Regulatory team manages BC Hydro's relationship with regulators. This includes monitoring and influencing changes to regulators' policies and regulations and coordinating efforts across BC Hydro to address complex regulatory interpretations, regulatory orders or appeals, and variance applications to safety regulators.

The Safety Assurance team leads the development, implementation and sustainment of the Safety Assurance Process, including requirements, procedures, tools and training. The team conducts safety audits to assess BC Hydro's compliance with occupational health and safety regulations, and conformance with requirements of BC Hydro's Safety Framework and its processes and programs. These field-focused audits support continual improvement by assessing observed practices in the field with regulatory and internal safety requirements. Audit findings lead to corrective actions that improve management of risk and safety performance, as well as the overall Safety Framework. The team assesses the status of implementation and effectiveness of Safety Framework processes and programs.

The Safety Systems team sustains and supports processes to enable frontline workers and others to receive and use safety and hazard information. This includes maintaining and improving the SafeHub[342] document management system and ensuring effective governance for documents that are added, updated or removed from the system each year. The team also governs and sustains information housed

[342] SafeHub is an online and offline (via an App) available compilation of all safety documentation. A significant amount of document cleanup and removal of duplication/conflicting documents was undertaken (and is ongoing) to populate the SafeHub repository.

on other platforms including safety documentation for contractors (safety Extranet) and Hydro web.

The Reporting and Analytics team produces reports on safety performance to assess and communicate risk to BC Hydro workers from hazards identified at BC Hydro workplaces. The team develops and analyzes lagging indicators to review past performance, as well as leading indicators to identify and highlight potential risks. The team liaises with other utilities and the Canadian Electricity Association to benchmark analytics across Canadian utilities, participating in joint activities to identify trends and proactively address changing safety risks in the industry. The team is also the owner of the safety Incident Management System,[343] and provides support and subject-matter expertise to the prioritization of requests, governance, business enhancements, and daily operations of the system.

Incident Management triages all safety incidents (injuries, near-miss incidents) and good catch events, provides subject matter expertise to assist front-line managers with investigations, leads the incident investigation process for complex investigations and ensures corrective actions address underlying causes and WorkSafeBC requirements. When appropriate, the team also conducts more in-depth reviews for specific BC Hydro incidents to determine if additional learnings can be acquired and shared across the company.

5D.5.1.3. Technical Safety Department

The Technical Safety department is comprised of two teams: Engineering and Electrical Safety.

The Engineering team supports BC Hydro’s workforce management by developing and maintaining clear work procedures to eliminate or mitigate hazards and by evaluating tools for some of the highest risk work on the Power System (e.g.,

[343] The Safety Incident Management System is a module of SAP, employed company-wide to report, investigate, and communicate safety incidents, and to document and track completion of related corrective actions.

energized/de-energized work, arc flash, fall hazards) and advises how to mitigate safety risk in our capital projects. The team conducts safety risk assessments for business processes, occupational health and safety topics, and complex issues in capital projects and asset management programs. They provide governance, advice and support to key safety processes such as Safety by Design,[344] Job Hazard Assessments,[345] and human factors and other technical safety issues.

The Electrical Safety team is responsible for developing electrical safety programs and worker protection systems and draws on resources throughout Learning and Development for implementation. To improve the safety of BC Hydro employees and contractors, Electrical Safety provides a framework to identify hazards and apply effective barriers. It also maintains authorization records of employees and contractors, identifying who is authorized to work on BC Hydro's Power System. The team is responsible for maintaining the rules, procedures, documents and information technology specific to the worker protection systems.

5D.5.1.4. Safety Programs Department

The Safety Programs department is responsible for the development, implementation, sustainment and assurance of BC Hydro's non-electrical safety programming. This department consists of the following three teams:

- Occupational Health and Safety Programs;
- Aircraft Operations; and
- Public Safety and Fire Risk Management.

The Occupational Health and Safety Programs team oversees governance of safety programs, working with business groups to develop, implement, sustain and assure required Occupational Health and Safety programs, including BC Hydro's Contractor

[344] Safety by Design is an application of engineering principles and standards for designing features into new and existing facilities to ensure they are inherently safe.

[345] Job Hazard Assessment is a process to identify potential hazards present in the steps of a task or job and recommend mitigation measures so that each step is safe.

Safety Program,[346] and related processes and documentation. In addition, the team provides leadership and expertise in Occupational Health and Safety regulatory compliance. The team collaborates with Technical Safety, Field Safety Assurance, Trades Training and others to deliver a range of programs and information products to support and improve safety at BC Hydro across a wide range of topics.

The Occupational Health and Safety Programs team includes an Industrial Hygiene group that advises on development of occupational hygiene programs and exposure control plans (e.g., asbestos, silica, noise and respiratory protection), and associated procedures for all areas of the business. This group also assesses hygiene risk and executes, analyzes and maintains hygiene monitoring data. The Occupational Hygienists provide subject matter expertise to Occupational Safety and Health (**OSH**) Specialists and others to address frontline occupational hygiene issues.

The Aircraft Operations team develops, implements, sustains and assures the Aircraft Operations Program. The program oversees all charter-related aviation activities including helicopter, fixed-wing and remotely piloted aerial vehicle work. The program's functions include aviation training requirements, policy development and adherence, risk assessment and mitigation, flight monitoring and internal flight coordination, as well as contract development and management.

The Public Safety and Fire Risk Management team coordinates safety programs and activities to support public safety and manage fire-related risks. The team conducts outreach activities and training to increase public awareness of electrical safety at home, at work and in the community, and oversees the public safety risk assessment process at BC Hydro's dams, adjacent waterways and in public use management areas (note: The Dam Safety KBU is accountable for the safety of BC Hydro's dams under both normal and extreme conditions).

[346] The Contractor Safety Program provides a systematic and consistent approach to ensuring BC Hydro meets its Owner duties, as described in the *Workers Compensation Act* section 25, for safety in contracted work.

The Public Safety and Fire Risk Management team also develops and maintains a program to assess fire-related risks, including wildfires, and provides technical support, governance and assurance functions. The program supports BC Hydro to meet its obligations under the *Wildfire Act* and acts as the internal authority on fire risk management, providing expert advice and support on compliance and conformance with the BC Fire Code, National Fire Protection Association standards and other relevant legislation.

5D.5.1.5. Field Safety Assurance Department

The Field Safety Assurance department provides occupational health and safety advice, coaching and support to BC Hydro's workforce, and assures the field-level effectiveness of BC Hydro's Safety Framework and safety programs. The team consists of safety managers and safety professionals geographically dispersed across the province and assists other business groups to implement safety programs, and properly use approved work procedures, with a focus on business units performing hazardous work.

The safety professionals in the Field Safety Assurance department along with management and administrative staff, are organized into three teams that support different lines of business within BC Hydro:

- Capital Project Delivery;
- Operations Safety Assurance; and
- Corporate Office Safety Assurance and Strategic Projects.

These teams are comprised of Safety Planning Leads, Capital OSH Specialists, and Operations and Maintenance OSH Specialists, Safety Managers and administrative staff.

Safety Planning Leads support and assure the Contractor Safety Program. This involves working with the numerous entities within BC Hydro that contract work to ensure safety requirements are incorporated into all aspects of the contracting process, especially in the early phases of contract development. A key responsibility of the Safety Planning Leads is oversight of the quality of Owner's Safety Plans, which outline how BC Hydro will fulfill its safety obligations as the owner of contracted work.

Capital OSH Specialists work closely with project teams to advise, coach and assure safety through all project phases. During construction, they ensure site safety coordination takes place and inspect job sites and work activities. A key responsibility is to work with contractors and hold them accountable for meeting their safety obligations. Capital OSH requirements are substantial given BC Hydro's large capital program.

Operations and Maintenance OSH Specialists support BC Hydro employees for work involving numerous hazards including asbestos, confined space, and working from heights. They advise, coach and assure in support of all safety aspects of work planning and execution, training delivery, hazard identification, risk assessment, and work procedure development. During work execution, they observe job activities and conduct inspections to ensure safety roles and responsibilities are being fulfilled, safety regulations are met, and work is performed safely and in accordance with procedures.

Safety Managers act as the single point of contact for KBUs throughout BC Hydro for all safety issues. Managers are also responsible for supporting the implementation of safety programs and initiatives.

Administrative staff provides services such as expenses and purchasing management, contract administration, and communications support.

5D.5.2 Overview of Operating Costs and FTEs

**Table 5D-4 Safety KBU
Fiscal 2022 Decision Operating Costs
and FTEs by Department**

	($ Millions)	Labour	Services - Other	Materials	Building & Equipment	Capitalized Overhead	External Recoveries	Total Operating	Total FTEs
1	Director Safety	0.4	0.1	0.0	0.0	0.0	0.0	**0.5**	2
2	Safety Planning	4.2	0.5	0.1	0.0	0.0	0.0	**4.8**	23
3	Technical Safety	2.2	1.1	0.0	0.0	0.0	0.0	**3.3**	13
4	Safety Programs	4.4	3.3	0.0	0.0	0.0	0.0	**7.7**	21
5	Field Safety Assurance	5.5	0.6	0.1	0.0	0.0	0.0	**6.2**	54
6	**Total (Sch 5.4 L1, Sch 16.0 L24)**	**16.6**	**5.6**	**0.2**	**0.1**	**0.0**	**0.0**	**22.5**	**112**

5D.5.2.1. Director, Safety Department

The majority of this department's budget relates to labour costs for two FTEs: the Director of the Safety KBU and one administrative assistant.

5D.5.2.2. Safety Planning Department

The majority of this department's budget relates to labour costs for 23 FTEs as follows:

- One FTE is the department manager;
- Two FTEs on the Framework Sustainment and Reporting team provide risk management system expertise, strategic planning and coordination for sustaining BC Hydro's Safety Framework and Safety Governance Structure. This team's activities include supporting development of BC Hydro's safety strategies and annual safety plans, maintaining safety governance documentation, coordinating delivery of Safety Framework improvement efforts, coordinating BC Hydro's safety management review activities and management reporting;
- Two FTEs on the Regulatory team are primarily responsible for managing BC Hydro's relationship with safety regulators, including WorkSafeBC. They monitor safety regulatory policy and regulations for over 30 safety-related Acts and regulations to identify, communicate, and oversee regulatory changes as well as participate in regulator engagement sessions to strategically influence

regulation change. The team responds to over 120 requests each year for regulatory interpretations or risk analysis and supports the assessment and response to over 40 regulatory inspection reports and ten to twenty regulatory orders, variances, or appeals annually;

- Two FTEs on the Safety Assurance team are trained auditors who complete a total of three to four safety audits in a typical year and coordinate audit findings across the entire organization. Each audit takes three to four months to complete and typically involves visiting more than ten sites across the BC Hydro system and conducting many interviews. These audits are focused on safety and on practices observed in field, which is different than the audits performed by the Internal Audit department of the Finance KBU. This team also leads the development, implementation, and sustainment of safety assurance requirements, processes, tools and training, involving hundreds of personnel across BC Hydro, to support BC Hydro in assuring, monitoring and reporting compliance and conformance with safety requirements;
- Five FTEs on the Safety Systems team sustain and support processes to enable frontline workers and others to receive and use safety and hazard information. This includes maintaining and improving the SafeHub[347] document management system which contains over 2,000 documents and ensuring effective governance for the approximately 300 documents that are added, updated or removed from the system each year. The team also governs and sustains information housed on other platforms including safety documentation for contractors (safety Extranet) and Hydro web;
- Six FTEs are the Reporting and Analytics team. All safety reporting and analytics are provided through this team including 15 monthly dashboards, management reports about BC Hydro's safety performance. This team

[347] SafeHub is an online and offline (via an App) available compilation of all safety documentation. A significant amount of document cleanup and removal of duplication/conflicting documents was undertaken (and is ongoing) to populate the SafeHub repository.

responds to 60 to 70 requests for information and analytics from other business groups every year to support their understanding of safety information and leads one or two larger reporting initiatives to support other Business Groups in Safety. This team also administers the Incident Management System, which receives an average of 7,000 entries per year, including employee and contractor injuries and near-miss incidents, good catches, vehicle damage, and regulatory inspections. The team also performs quality control of the data entered into the system to ensure accurate reporting, and gathers, prioritizes and tests an average of five to ten system enhancements per year; and

- Five FTEs are Safety Incident Investigators on the Incident Management team. This team triages all employee injuries and near-miss incidents reported to the Incident Management System and supports managers after an incident to perform incident investigations and complete corrective actions so that WorkSafeBC requirements are met. The team also performs deeper analysis of serious incidents, to uncover opportunities for continual improvement and facilitates development of complex corrective actions.

Labour plan amounts include funding for FTEs and labour charged in from other Business Groups to support project work. This department’s non-labour costs of $0.6 million include IT sustainment charges for safety apps, audit support services, employee travel and training, and technical writing consultant resources assigned to the Safety Systems team. These technical writers support ongoing improvement and transformation of safety documentation, introduced by the previous Field Access to Safety Information project. This work will make it easier for our workers to find the information they need to work safety and efficiently and reduce document administration burden.

5D.5.2.3. Technical Safety Department

The majority of this department's budget relates to labour costs for 13 FTEs as follows:

- One FTE is the department manager;
- Seven FTEs are engineers in the Engineering team. Each year, this team reviews and updates approximately 50 out of 300 existing safe work procedures and safety personal protective equipment, tools, and equipment specifications for electrical trade work that the team maintains. The team develops approximately 15 new procedures and equipment specifications each year to address gaps as well as changes to regulations and standards. The team also provides safety, workability and maintainability risk assessment leadership, training and support to BC Hydro, including active participation in an average of six complex, high value capital projects per year, in addition to supporting quality control assessment of approximately 24 capital projects per year through the Safety by Design process. This team also performs an average of six risk assessments per year on complex, cross-organizational, high risk topics and participates in serious incident reviews where specialist expertise is required. The team is developing and will be responsible for maintaining a set of Human Factors design standards and a Transmission Workability Standard for BC Hydro's Engineering functions; and
- Five FTEs on the Electrical Safety team manage electrical safety projects and programs. This includes BC Hydro's worker protection systems: Power System Safety Protection[348] and Worker Protection Practices.[349] The team maintains authorization records for over 11,000 workers consisting of both employees and

[348] Power System Safety Protection defines the constraints applied to the Power System to provide safety protection from Power System hazards during prescribed work on transmission and distribution lines and in substations.

[349] Work Protection Practices are the rules and procedures that govern how equipment at generating stations and associated facilities are isolated from potentially hazardous sources of energy and made safe to work on.

contractors. The team also maintains the related rules, procedures, documents, assurance processes and information technology application specific to Electrical Safety.

This department's non-labour budget of $1.1 million includes funding to support improvements to electrical safety programs, employee travel and training, and miscellaneous contractor services.

5D.5.2.4. Safety Programs Department

This department's labour costs consist of 21 FTEs as follows:

- Two FTEs are a department manager and one administrative assistant who provides SharePoint and records management support across the Safety KBU;
- Nine FTEs on the Occupational Health and Safety Programs team lead the development, implementation, sustainment and assurance of 29 formal safety programs. (e.g., asbestos and other hazardous materials, contractor safety, ergonomics, fall protection, confined space, storage rack safety, and winter safety). These safety programs are in place to protect workers and meets regulatory requirements by managing and controlling worker exposure to hazards in the workplace. Two of these FTEs are Occupational Hygienists who provide technical support and guidance to the OSH Specialists in the Field Safety Assurance department. These roles are field-focused and provide advice on development of occupational hygiene policies, standards and programs. In particular, Occupational Hygienists develop and provide guidance on field safe work procedures for high hazard situations and unusual circumstances (e.g., procedures for complex asbestos abatement work);
- Five FTEs are Aircraft Operations professionals on the Aircraft Operations team which was created as a corrective action following a 2008 incident that resulted in four fatalities. The department's functions include managing and administering all aspects of the Aircraft Operations Program including aviation

related training requirements, program sustainment and assurance, risk assessment and mitigation, flight monitoring and internal flight coordination, as well as contract development and management. This oversight function applies to both BC Hydro and contractors' use of chartered aircraft for BC Hydro work. The team supports between 2,000 to 3,000 flight events per year. For example, in fiscal 2021, the department provided oversight for 82 fixed wing charter flights,[350] 1,718 helicopter charter flights, and 629 remotely piloted aerial vehicle flights;

- Three FTEs on the Public Safety and Fire Risk Management team provide governance of safety programs related to fire, water and electrical hazards. These FTEs oversee adherence to the Canadian Dam Association Guidelines for Public Safety around Dams and Waterways. They perform ongoing and project-specific hazard and risk assessments and develop Public Safety Management Plans for BC Hydro's 31 generating stations and 20 Public Use Management Areas to document hazards, risk ratings and control measures required to keep the public safe. Annually the team conducts approximately 22 field risk assessments and implements controls; and

- Two FTEs on the Public Safety and Fire Risk Management team coordinate electrical safety awareness training and communications to the public, high risk trades and first responders. In fiscal 2020, training was delivered to 7,724 members of the public and trades. These FTEs are responsible for BC Hydro's 20 Public Use Management Areas[351] which have a total of approximately two million visitors annually. The operating costs for BC Hydro's Public Use Management Areas were $1.03 per visitor day in fiscal 2020 which

[350] The Aircraft Operations team noted a significant increase in fixed-wing flights during the COVID-19 pandemic due to the need to transport BC Hydro crews to remote areas where commercial flights would have typically been used.

[351] Public Use Management Areas are recreational facilities owned and operated by BC Hydro to manage public use and safety around reservoirs and redirect the public away from hazards associated with generating assets to sites under BC Hydro control where these hazards are managed.

compares favorably to operating costs of BC Parks.[352] This team also consists of Fire Risk Management professionals who advise approximately 25 capital projects with more complex fire risk management requirements each year. They develop or revise fire safety plans for all of BC Hydro's occupied buildings and critical stations. In addition, the team provides tactical support for major fires, requiring approximately five to ten follow-up investigations each year. The team also provides support to other fires that impact our system annually (e.g., wildfires).

Labour plan amounts include funding for FTEs and amounts for internal cross-charging to support project work. The non-labour costs for this department include $2.4 million for the operation of Public Use Management Areas which supports site management, lifeguards, maintenance (such as signage), parking controls and additional contracted services such as the RCMP. The remaining costs of $0.9 million fund public safety communications and support services for safety programs including ergonomics, public safety, and fire risk management.

5D.5.2.5. Field Safety Assurance Department

The Field Safety Assurance department provides occupational health and safety advice, coaching and support to:

- More than 2,100 BC Hydro field workers and front-line managers;
- Work completion in more than 300 substations and 30 generating stations and over 86,000 km of transmission and distribution lines;
- All KBUs across BC Hydro, including office workers, to assist them in the development of their annual safety plans and addressing safety and health issues;

[352] BC Parks operating costs/visitor days in most recent annual report is $2.38 or $1.37 after accounting for revenues from user fees. (refer to: https://bcparks.ca/research/statistic_report/statistic-report-2017-2018.pdf?v=1623948807457).

- BC Hydro's annual capital plan for construction and system upgrades; and
- Contractor safety management in all areas of the business.

The resourcing requirements for this department are driven by BC Hydro's ongoing capital and maintenance plan, safety programs, as well as existing and changing WorkSafeBC requirements. In recent years, WorkSafeBC has provided increased scrutiny through dedicated high-risk area inspection teams and higher financial penalties, especially for high-hazard areas.

The majority of this department's budget relates to labour costs for 54 FTEs as follows:

- Two FTEs are a department manager and an administrative assistant;
- 17 FTEs on the Capital Project Delivery team. The FTEs in this team charge approximately 80 per cent of their time to the capital projects they support. The resourcing requirements in this department are driven by BC Hydro's capital plan. These FTEs include temporary Capital OSH Specialists, which provides BC Hydro the ability to adjust these resources to meet the demands of capital plan requirements. During fiscal 2021, this department completed 360 contractor formal verifications, developed 37 Owner Safety Plans, and 341 Owner's Hazard Identifications and Risk Assessments. In addition, the team reviewed 844 procedures, 83 procurement requests, 444 COVID-19 response plans and approximately 500 Safety Management Plans;
- 28 FTEs on the Operations Safety Assurance team. This team includes:
  - One FTE is the manager of the team;
  - 22 FTEs support the Stations Field Operations and Line Field Operations KBUs including two managers and 18 OSH Specialists. The resourcing requirements for these FTEs are driven by daily operational needs which include supporting the confined space and asbestos safety programs into sustainment and assurance. The FTEs support crews in successfully

completing compliant confined space entries via field visits, observations, checking and entry documentation including 100 confined space entries. The FTEs also support the roll out of the asbestos program via bulk sampling, labelling, survey's and providing documentation. This group conducted 366 safe work observations, 162 compliance checks, 251 coaching sessions with operations, attended 248 safety meetings, delivered 48 training sessions, and responded to 27 emergencies from April 2020 to March 2021; and

- Five FTEs support the Construction Services KBU and are located in the four Construction Services headquarters across the province. The resourcing requirements for these FTEs are driven by BC Hydro's capital plan and the occupational health and safety needs of BC Hydro's Construction Services KBU. Between January 2020 and December 2020, these FTEs had 2,645 interactions with Construction Services KBU crews including 235 field verifications, 71 training events, 116 compliance checks, 108 confined space supervisions and other work related to job planning, work procedures and other support.

- Seven FTEs on the Corporate Office Safety Assurance and Strategic Projects team. Four of these FTEs focus on strategic safety projects delivered through Field Safety Assurance and provide occupational health and safety support to the Fleet Services and Materials Management departments, Properties department and BC Hydro's corporate groups. Between January 2020 and December 2020, the OSH Specialists on this team conducted 58 safe work observations, 50 compliance checks, attended 85 safety meetings, 74 manager meetings, 45 coaching sessions with operations, and reviewed/wrote 89 procedures. This team also includes three FTEs who provide administrative support to the Field Safety Assurance department.

This department's non labour costs of $0.7 million include employee travel, training, tools, office supplies and miscellaneous contractor services - mainly for strategic project support and procurement program reviews.

5D.5.3 Fiscal 2023 to Fiscal 2025 Plan Operating Costs and FTEs

Table 5D-5 Safety KBU Operating Costs and FTEs

		Schedule Reference	F2021 Actual	F2022 Decision	F2023 Plan	F2024 Plan	F2025 Plan
			1	2	3	4	5
1	**Safety KBU**						
2	Operating Costs ($ million)	5.4 L1	19.4	22.5	20.1	20.5	20.7
3	FTEs	16.0 L24	117	112	110	110	111

Operating costs are decreasing by approximately $2.4 million from fiscal 2022 Decision amounts to the fiscal 2023 plan primarily due to a $1.7 million net reduction in safety initiative funding provided in the Fiscal 2017 to Fiscal 2019 Revenue Requirements Application as the Safety KBU transitions to support sustainment and continual improvement. The remaining $0.7 million decrease is primarily due to changes in Standard Labour Rates and the repurposing of two administrative FTEs, one to the Reliability Standards Assurance KBU and one to the Learning and Development KBU.

Operating costs are increasing by approximately $0.4 million from fiscal 2023 plan to fiscal 2024 plan primarily due to Standard Labour Rate increases.

Operating costs increase by $0.2 million from fiscal 2024 plan to fiscal 2025 plan. The increase is primarily due to $0.4 million for Standard Labour Rate increases and $0.1 million for the addition of a 0.5 FTE to provide OSH Specialist support for Site C operations and funding to manage three Public Use Management Areas around the new Site C reservoir. These increases are partially offset by a $0.3 million net reduction in safety initiative funding.

FTEs are planned to decrease by two from the fiscal 2022 Decision amounts to the fiscal 2023 plan due to the repurposing of one FTE to the Reliability Standards Assurance KBU and one FTE to the Learning and Development KBU.

FTEs are planned to remain constant from fiscal 2023 plan to fiscal 2024 plan. FTEs are planned to increase by 0.5 FTE from fiscal 2024 plan to fiscal 2025 plan to provide OSH Specialist support for Site C operations.

5D.6 Learning and Development KBU

5D.6.1 Responsibilities

The Learning and Development KBU provides training and support to enable a safe, competent and qualified workforce at BC Hydro. The KBU's responsibility aligns to the Safety Framework and contributes to the reduction of BC Hydro's safety and compliance risks by providing training, mentoring and coaching to employees. It also facilitates the multi-year training programs associated with apprentices, trainees and Engineers in training. The Learning and Development KBU manages all BC Hydro training records within its learning management systems and supports BC Hydro with training standards, tools and processes. Since the Previous Application, there have been no material changes to the responsibilities of the Learning and Development KBU except for the Electrical Safety Programs department which has moved to the Safety KBU.

The Learning and Development KBU meets BC Hydro's training requirements by leveraging standardized processes and technology to deliver instructor led, virtual and web-based training. This KBU applies an industry standard model for training course content development that includes analyzing, designing, developing, implementing and evaluating courses and curriculum for training across BC Hydro. It oversees learning management systems that allow for enterprise wide training deployment and tracking. BC Hydro requires a reliable and agile learning management system to administer and track BC Hydro's training requirements and is planning for the future consolidation and replacement of our current learning management systems.[353] This replacement will allow Learning and Development to manage training in a more effective and efficient way and will allow managers to assure competency of their workers through improved self-serve capability.

The Learning and Development KBU oversees the Trades Training Centre which was built in 2013 to meet the classroom and practical training requirements associated with a utility such as BC Hydro and some contractors. Located on BC Hydro's Surrey Campus, it is also the only approved location within B.C. to provide the Industry Training Authority approved Red Seal Apprentice Power Line Technician program. The Trades Training Centre serves as a training and classroom facility for the entire BC Hydro workforce.

The Learning and Development KBU consists of the following departments:

- Training and Development Leadership Department;
- Training Services Department;
- Training Operations Department;
- Technical and Trades Training Department; and
- Trainees Department.

5D.6.1.1. Training and Development Leadership Department

This department is responsible for overall management and administration of the Learning and Development KBU.

5D.6.1.2. Training Services Department

This department consists of four teams:

- Safety Training;

[353] This work is reflected in Chapter 6 Capital Expenditures, section 6.5.1.5 Technology Capital Expenditures and Additions – Enhance Business Capability category within the Human Capital Management Foundation project.

- Instructional Design;
- Training Coordination and Support; and
- Training Systems.

The Safety Training team provides access to training which is required by regulation through a combination of internal trainers, external trainers and resources in Field Safety Assurance, so that workers can work safely and achieve regulatory compliance.

The Instructional Design team is responsible for BC Hydro's training quality assurance strategy, which includes developing courses and establishing processes and standards for courses and curriculum for both internally and externally developed content.

The Training Coordination and Support team plans, schedules and manages logistics for training courses and programs, and records training completions in BC Hydro's learning management systems.

The Training Systems team is responsible for management and administration of three enterprise learning management systems.

5D.6.1.3. Training Operations Department

This department is responsible for the Trades Training Centre and administrative support for the Learning and Development KBU.

5D.6.1.4. Technical and Trades Training Department

This department consists of the following teams:

- Powerline Technician Training;
- Communication, Protection and Control Technologist Training;
- Generation and Stations Electrician Training;

- Apprentice Programs; and
- Trainee Programs.

The Powerline Technician, Communication, Protection and Controls Technologist, Generation and Stations Electrician training teams serve as subject matter experts in the development of training, work methods and procedures and support implementation of electrical safety projects.

The Apprentice and Trainee Program teams provide program management support to our various programs.

5D.6.1.5. Trainees Department

This department consists of the apprentice and trainee labour and non labour budgets.

5D.6.2 Overview of Operating Costs and FTEs

Table 5D-6 Learning and Development KBU Fiscal 2022 Decision Operating Costs and FTEs by Department

	($ Millions)	Labour	Services - Other	Materials	Building & Equipment	Capitalized Overhead	External Recoveries	Total Operating	Total FTEs
1	Training & Development Leadership	0.4	0.2	0.0	0.0	0.0	0.0	**0.6**	2
2	Training Services	4.2	1.9	0.0	0.2	0.0	0.0	**6.2**	35
3	Training Operations	1.0	0.1	0.3	0.1	0.0	0.0	**1.5**	8
4	Technical & Trades Training	9.4	1.0	0.0	0.1	0.0	0.0	**10.5**	61
5	Trainees	4.0	1.5	0.2	0.0	0.0	0.0	**5.7**	139
6	**Total (Sch 5.4 L2, Sch 16.0 L25)**	**19.0**	**4.7**	**0.4**	**0.4**	**0.0**	**0.0**	**24.5**	**246**

To meet BC Hydro's training needs, the Learning and Development KBU supplements internal resources with contracted services and resources. Decisions on how to allocate training between internal and external providers are generally based on utility-specific knowledge, cost, efficiency and subject matter expertise.

5D.6.2.1. Training and Development Leadership Department

This department's labour costs are related to two FTEs – the Director of the Learning and Development KBU and an administrative assistant.

This department's non-labour budget includes $0.1 million for supplemental labour resources across the KBU to respond to workload fluctuations and $0.1 million for travel, conferences and training for KBU FTEs.

5D.6.2.2. Training Services Department

The majority of this department's budget relates to labour costs for 35 FTEs as follows:

- One FTE is the department manager;
- Seven FTEs lead and support the Safety Training program.
  - Five of these FTEs oversee approximately 200 courses required by workers to meet regulated and compliance training requirements and fill competency gaps. In fiscal 2021 approximately 800 instructor led safety training sessions were delivered across BC Hydro. This was achieved by overseeing a combination of internal trainers, external contractors and resources in the Safety KBU (formerly the Field Safety Assurance KBU). Of this department's non-labour budget of $2.1 million, $1.5 million covers costs for approximately 20 contracts for external training service providers and their travel costs when they travel to sites across the province to deliver training. These five Safety Training FTEs also provide program management for Mandatory Reliability Standards compliance and vegetation management training; and
  - Two FTEs are certified by the Insurance Corporation of British Columbia to deliver motor vehicle and equipment specific training, assessment and mentoring to support safety and regulatory compliance obligations for all of BC Hydro;
- 11 FTEs provide training instructional design and quality assurance.
  - Ten FTEs create new courses and maintain approximately 500 instructor led and virtual training and 100 web-based courses for trades and technical,

safety, electrical safety programs and business application systems topics. In fiscal 2021, 40 new and existing courses were developed and refreshed. These courses vary in length from 30 minutes to five days. These FTEs also perform quality checks on internally and externally developed content. The department's non-labour budget provides $0.3 million funding for approximately seven service agreements for external instructional design resources for course development work; and

- ▶ One FTE is responsible for BC Hydro's training quality assurance strategy which includes establishing processes and standards for course development, delivery and evaluation;

- Four FTEs administer training records and deploy web-based content in the learning management systems for employees and contractors, administer the system used for training assessments and course evaluations and support compliance requirements by preparing training completions reports; and
- 12 FTEs provide training scheduling and logistics services for safety, trades, technical and leadership development courses and apprentice and trainee programs. This includes arranging internal and external instructors and venues. These FTEs enter employee training records in the learning management system for all BC Hydro instructor led and virtual training.

The remaining $0.3 million of this department's $2.1 million non-labour planned costs are for software services, travel and training for department employees.

5D.6.2.3. Training Operations Department

The majority of this department's budget is related to labour costs for eight FTEs at the Trades Training Centre as follows:

- One FTE is the department manager;

- One FTE oversees the Trades Training Centre and its $0.8 million capital budget and its $0.5 million operating budget for centralized tools and equipment to maintain the facility; and
- Six FTEs provide administrative support for all Learning and Development employees and Trades Training Centre learning events. They also arrange travel logistics, tools and equipment purchases for approximately 50 trades training FTEs and two Fleet Safety trainer FTEs. In addition, the department processes payments for external apprentices and administers over 80 external learning contracts.

5D.6.2.4. Technical and Trades Training Department

The majority of this department's budget is for labour costs related to 61 FTEs as follows:

- One FTE represents the department manager;
- 54 FTEs are made up of program managers, instructors and Safety Advocates. This department provides trades training, building trade-specific skills and knowledge for approximately 2,100 field employees and front-line managers at BC Hydro. This team supports roles such as Power Line Technicians, Cable Splicer, Generation and Stations Electricians, Mechanics and Communications Protection and Controls Technologists. The 54 FTEs are comprised of:
  - Four FTEs are program managers and 40 FTEs are instructors. These FTEs provide trade and technical specific training in the classroom and on the job. To support front line employee knowledge retention and application, this team spends approximately 92 per cent of its time on course delivery, on the job training, conducting assessments and providing subject matter expertise. In fiscal 2021, this team delivered approximately 300 trade specific instructor led learning events. This team spends the remaining 8 per cent of its time

charging to other KBUs or specific projects to maintain their trades skills by performing in the field; and

- Ten FTEs are in the Safety Advocate role. The Safety Advocate role was established in 2012 in response to a high number of serious safety incidents. Safety Advocates work in the field with employees to resolve electrical safety issues and implement electrical safety projects by responding to crew and manager requests for coaching, field visits and attending work planning and safety meetings. The training delivered by the trades instructors is reinforced by the Safety Advocates through in-field coaching and mentoring. In fiscal 2021, this group made over 400 safe work observations. The observations made by this group are used throughout BC Hydro to identify additional learning and management intervention opportunities;

- Three FTEs provide program management and deliver courses, on-the-job training and mentoring to approximately 300 employees in the Distribution Design and Customer Connect KBU and 25 trainee FTEs; and
- Three FTEs manage the budget and program progression for 98 apprentice FTEs and 16 Engineers-in-Training FTEs. These programs are structured programs that develop and qualify employees in key occupations. *Apprentices and trainees are hired based on resource strategies, which consider attrition and future needs. These employees will become journey people once they graduate from their respective multi-year program.* This team provides program management and subject matter expertise for curriculum development and coordinates with trades instructors to comply with Industry Training Authority[354] requirements, including Red Seal certification for the Apprentice Power Line

[354] The Industry Training Authority leads and coordinates British Columbia's skilled trades system. The Industry Training Authority works with BC Hydro to set program standards and issue certifications for trades.

Technician program. BC Hydro is the only qualified institution in B.C. to provide this program.

This department's non-labour budget primarily consists of $0.7 million for employee travel costs, $0.1 million for the Power System Safety Protection and Worker Protection Practices program, $0.1 million for department employee training costs and $0.1 million for department tools and equipment. It also includes $0.1 million for external resources to provide additional training delivery resources when needed.

5D.6.2.5. Trainees Department

This department's budget is managed by the Technical and Trades Training department. The majority of this department's budget relates to labour costs for 139 FTEs who are apprentices and trainees, training for roles such as Power Line Technicians, Electricians, Mechanics, Utility Fleet Mechanics, Distribution Design and Customer Connect technologists, Communication Protection and Control technologists and Engineers. Approximately 74 per cent of their labour costs are charged out to other KBUs or specific projects and the remaining 26 per cent is charged to training.

This department's services budget of $1.5 million includes travel expenses and tuition for apprentices and trainees to attend third party institutions (e.g., British Columbia Institute of Technology, Thompson Rivers University and the University of the Fraser Valley), relocation costs for trainees as well as a small non-capital tools for new apprentice and trainee intakes.

This department's materials budget of $0.2 million provides funding for the initial set of personal protection equipment for apprentices and trainees.

5D.6.3 Fiscal 2023 to Fiscal 2025 Plan Operating Costs and FTEs

Table 5D-7 Learning and Development KBU Operating Costs and FTEs

		Schedule Reference	F2021 Actual	F2022 Decision	F2023 Plan	F2024 Plan	F2025 Plan
			1	2	3	4	5
1	**Learning and Development KBU**						
2	Operating Costs ($ million)	5.4 L2	19.2	24.5	23.9	25.3	27.0
3	FTEs	16.0 L25	290	246	240	256	274

The Learning and Development KBU's operating costs will increase during the Test Period. Operating costs for the apprentice and trainee department increase by $0.5 million in fiscal 2023, $1 million in fiscal 2024 and $1.1 million fiscal 2025 due to the increase in intake levels. The increases for apprentices and trainees are a forecast for the Test Period and subject to change each fiscal as workplans and attrition rates are reassessed. During the fiscal 2023, these costs will be offset by $0.3 million reduction in instructor overtime, $0.3 million reduction in travel costs, $0.3 million reduction from transferred positions and $0.2 million reduction for Standard Labour Rates. However, in fiscal 2024 and fiscal 2025, operating costs increase by $0.5 million and $0.6 million respectively due to Standard Labour Rate increases.

For fiscal 2023, one FTE is added from Safety, two FTEs are repurposed out to Reliability Standards Assurance, two FTEs are reduced from lower instructor overtime in Technical and Trades Training, and apprentice and trainee FTEs declined by three in fiscal 2023 but will increase by 16 FTEs in fiscal 2024 and 18 FTEs in fiscal 2025. The increases are the result of the resource planning process. This process takes into consideration maintenance and capital projects as well as retirement and age risks within the different trade areas.

5D.7 Security and Emergency Management KBU

5D.7.1 Responsibilities

The Security and Emergency Management KBU is responsible for developing, implementing, sustaining and assuring processes and programs that safeguard our people, assets and operations from emergencies and disasters related to natural or human-induced events. The KBU also defines controls to meet regulatory compliance including CIP Mandatory Reliability Standards and *B.C.'s Emergency Program Act*.

Primary responsibilities of the Security and Emergency Management KBU include providing:

- integrated physical security solutions, including the selection, standardization, operations and sustainment of physical security controls;
- a structured process to identify critical business functions and processes through a company-wide business impact analysis and other business continuity processes; and
- the framework for emergency preparedness, including plans and procedures to help the organization respond to and recover from a major event.

There has not been a change in responsibilities of this KBU since the Previous Application. There has however, been an increased focus to support the evolving CIP Mandatory Reliability Standards compliance requirements. The KBU has re-organized to better align with the goals of Safety and Compliance and more specifically, with the Safety Framework as outlined in section 5D.2.

The Security and Emergency Management KBU consists of the following departments:

- Planning and Delivery Department;
- Critical Infrastructure Protection Compliance Department;

- Program Services Department;
- Physical Security Department; and
- Emergency Management Department.

5D.7.2 Overview of Operating Costs and FTEs

Table 5D-8 Security and Emergency Management KBU Fiscal 2022 Decision Operating Costs and FTEs by Department

	($ Millions)	Labour	Services - Other	Materials	Building & Equipment	Capitalized Overhead	External Recoveries	Total Operating	Total FTEs
1	Planning & Delivery	1.2	0.0	0.0	0.0	0.0	0.0	**1.2**	8
2	Critical Infrastructure Protection Compliance	0.8	0.6	0.0	0.0	0.0	0.0	**1.4**	4
3	Program Services	0.7	0.1	0.0	0.0	0.0	0.0	**0.8**	4
4	Physical Security	2.0	5.8	0.0	0.0	0.0	0.0	**7.9**	12
5	Emergency Management	0.8	0.3	0.0	0.1	0.0	0.0	**1.2**	5
6	**Total (Sch 5.4 L3, Sch 16.0 L26)**	**5.5**	**6.8**	**0.1**	**0.1**	**0.0**	**0.0**	**12.5**	**33**

5D.7.2.1. Planning and Delivery Department

This department's labour budget is related to eight FTEs. The Planning and Delivery department has four primary responsibilities which are:

- Overseeing the design and build of the company's physical security system through established security standards, to strengthen compliance to the CIP Mandatory Reliability Standards requirements;
- Developing and maintaining the security asset management strategy and plan, prioritizing security-related capital projects, and ensuring integration with other capital planning processes across BC Hydro;
- Applying project management discipline over security-related projects to ensure effective delivery and cost management; and
- Monitoring the overall health of the security and emergency management framework, its governance and its programs, and identifying areas for continual improvement.

A security asset management strategy, aligned with BC Hydro capital planning and asset management processes, prioritizes security-related capital projects, helps to minimize asset replacement costs, and provides asset health awareness to support capital planning. The Planning and Delivery department collaborates with other business units to monitor the health of our physical security system and have processes in place to adjust capital plans and quickly implement security projects based on changing compliance requirements or threat risk assessments.

Finally, this department monitors the overall health of our security and emergency management framework and its governance. This includes reporting and identifying opportunities for continual improvement, keeping focus on areas for greatest benefit.

5D.7.2.2. Critical Infrastructure Protection Compliance Department

Four FTEs provide subject matter expertise and assurance activities related to effective CIP Mandatory Reliability Standards and associated requirements for security. The is a new, dedicated team to support the evolving CIP Mandatory Reliability Standards compliance requirements. They are responsible to support the development of security workflows, systems and controls that meet Mandatory Reliability Standards requirements. The team conducts quality assurance reviews and audits to assess BC Hydro’s compliance with Mandatory Reliability Standards compliance requirements, and conformance with requirements of BC Hydro’s Internal Compliance Program. The team provides oversight on physical security standards and processes and their application across BC Hydro, verifying that they meet regulatory requirements. The department provides ongoing compliance support for physical security sustainment activities, including physical access monitoring, training and engagement with other business groups such as Integrated Planning, Operations and Reliability Standards Assurance, as well as collection and submission of documentation to demonstrate compliance.

The non-labour budget of $0.6 million is primarily allocated for contract services to support physical security activities with a small amount for physical key management and employee travel, training, and supplies.

5D.7.2.3. Program Services Department

This is a new team that was formed subsequent to the Previous Application of existing FTEs and was put in place to enhance our programs and build more rigorous sustainment and assurance requirements. All security and emergency management programs will incorporate the Safety Framework, as described in section 5D.2.

The Program Services department is comprised of two FTEs responsible for the development, implementation, and assurance of BC Hydro's security and emergency management programming. This team works with other business groups to develop, implement, sustain and assure security and emergency management programs. In addition, the team understands current regulatory requirements and monitors for changes that potentially impact programs. The team delivers a range of programs and information products to collectively manage security risks and to prepare for emergencies which can impact the organization. The department sets requirements and processes to maintain BC Hydro's business impact analysis identifying our critical functions and the technology, people, workspace, information, and third-party suppliers they depend on.

Two FTEs are also included in this department's labour plan who are responsible for the overall management and administration of the Security and Emergency Management KBU.

The non-labour budget of $0.1 million is for employee travel, training, and supplies.

5D.7.2.4. Physical Security Department

This department's labour budget is comprised of 13 FTEs with one FTE located within the Information Technology business unit providing technical expertise for the ongoing management and maintenance of our physical security systems. This department is responsible for maintaining the physical security program and its associated operations and procedures.

The non-labour budget of $5.8 million is primarily allocated to fund BC Hydro's external security contract. An external security contract (Integrated Security Operator) provides security services including staffing a 24/7 security command centre, security guards, and security system technicians. Outsourced work includes guarding services as well as system technical at more than 150 facilities and 45 stations across B.C. with over 2,300 cameras, 4,500 intrusion points, and 2,800 access card readers. This allows BC Hydro to contract for specialized services at a lower cost and enables this department to act as a knowledgeable owner, with key oversight responsibilities kept in-house such as risk assessment, security planning and awareness, service and maintenance prioritization, and quality assurance. This model is consistent with other comparable Canadian utilities and Crown Corporations.

Included in this department's responsibilities are security threat assessments and investigations. Security assessments are a foundational component to the program, vary in complexity, and are required for CIP Mandatory Reliability Standards. These assessments form the basis of security plans and operations. Assessments are planned but often are reactive as threats evolve or are uncovered. Processes are established for planned and unplanned security threat assessments and include communication of such threats to those impacted or who are potentially impacted. These assessments are also used to help capital planning with the Planning and Delivery department. As assessments identify new security risks, the team prioritizes investments in upgraded or new physical security controls at sites. The department liaises with external law enforcement and intelligence agencies and is regularly called upon to share risk-related or investigative information to support their needs.

The team engages with other utilities and is a strong contributor to the Canadian Electricity Association's Security Infrastructure Protection Committee, sharing intelligence and security-related information across Canadian utilities and government agencies. This includes participating in joint activities to identify trends and proactively address changing security risks.

5D.7.2.5. Emergency Management Department

This department is comprised of five FTEs responsible for BC Hydro's emergency management program providing the framework to prepare for, respond to and recover from emergencies in a systematic and coordinated manner. BC Hydro aligns with B.C.'s *Emergency Program Act* and has adopted the Emergency Management Structure to improve response and recovery coordination and capabilities through role standardization, communication between organizations and a common understanding for response prioritization.

The team maintains the emergency management program, ensuring BC Hydro is response ready. This includes working with KBUs to maintain plans, conduct training and exercises, and maintaining processes and tools for response such as situational awareness, earthquake and building damage assessment applications and emergency centres. The department liaises with external agencies such as Emergency Management British Columbia, critical infrastructure owners, government agencies, First Nation communities, and emergency planning committees and stakeholders. An example of this work is our 15 emergency planning guides[355] which are shared externally and provide key information on BC Hydro's dams including inundation maps, contacts, and emergency and communication procedures.

The Emergency Management department maintains and provides specific training on the roles required for emergency preparedness and response, including any supporting equipment and tools. They conduct exercises to test processes and provide learning opportunities for employees working within the emergency management system during an event. From April 2019 to April 2021, 2,545 employees received role-specific training and all BC Hydro employees had access to web-based training and or awareness videos to know their roles. A total

[355] Requirement of the *Water Sustainment Act*, Dam Safety Regulation and are also issued annually to the Water Comptroller. An emergency planning guide may include numerous dams based on river system. For example, Campbell River emergency planning guides has all dams on the Campbell River System.

of 128 drills[356] and exercises were completed. In addition, this department maintains or supports six BC Hydro emergency centres (two corporate emergency coordination centres; four regional emergency operation centres) in a state of readiness and regularly reviews and updates standard operating procedures, including testing associated equipment.

During an emergency event, the department activates our emergency management structure which may include support from the Duty Coordinator[357] or an emergency centre and provides leadership and subject matter expertise for company-wide prioritization, internal and external coordination and situational awareness.

A key component to the Emergency Management program is continual improvement. This department compiles a report following each exercise or incident which identifies corrective actions to improve plans and procedures. It then manages completion of those corrective actions in coordination with KBUs. In fiscal 2020 and fiscal 2021, 131 corrective actions were identified and completed.

The non-labour budget of $0.4 million is to fund third party services to assist with emergency alerts, seismic preparedness, building damage assessment (should an event take place), and funding for employee travel, training, and supplies.

5D.7.3 Fiscal 2023 to Fiscal 2025 Plan Operating Costs and FTEs

Table 5D-9 Security and Emergency Management KBU Operating Costs and FTEs

		Schedule Reference	F2021 Actual	F2022 Decision	F2023 Plan	F2024 Plan	F2025 Plan
			1	2	3	4	5
1	**Security and Emergency Management KBU**						
2	Operating Costs ($ million)	5.4 L3	16.4	12.5	12.6	13.8	14.4
3	FTEs	16.0 L26	29	33	34	38	39

356 Drills may be for evacuation, radio communications, team check-ins or rapid building damage assessment.

357 Duty Coordinator provides round-the-clock coverage by a Senior Manager and Emergency Manager to support and coordinate response to emergencies that may not require activation of an emergency.

Operating costs are increasing in fiscal 2023 to 2025 by approximately $1.9 million. The increases are attributed to the growing workload and demand related to strengthening our compliance with CIP Mandatory Reliability Standards and more specifically, an additional 130 locations becoming subject to these requirements in fiscal 2023. Additional FTEs will be added with key responsibilities including security threat risk assessments and planning, security awareness, and security operations and investigations, particularly supporting security controls at the additional sites with CIP compliance requirements.

Operating costs are increasing by $0.1 million from fiscal 2022 Decision to fiscal 2023 plan. The increase is primarily due to $0.4 million, with $0.2 million for an additional FTE and $0.2 million for Integrated Security Operator security services (i.e., personnel and system service and maintenance) with partial offset by a $0.1 million decrease in labour due to Standard Labour Rates, a $0.1 million transfer of contract services to Safety, and a small reduction in travel.

In fiscal 2024, costs increase $1.1 million comprised of $0.7 million for four FTEs and $0.3 million for Integrated Security Operator security services, and $0.1 million for Standard Labour Rate increases.

In fiscal 2025 there is an increase of $0.7 million comprised of $0.3 million for Integrated Security Operator security services and $0.2 million for one FTE, and $0.2 million for Standard Labour Rate increases.

The increased costs reflect BC Hydro's priority to implement standardized physical security controls to protect our people, assets and operations and implement and sustain CIP Mandatory Reliability Standards requirements, as outlined in Chapter 5, section 5.7. Standardized physical security controls will be implemented at over 130 additional BC Hydro locations. To sustain CIP Mandatory Reliability Standards compliance requirements at these additional sites we will implement security controls and solutions that include such things as electronic access management, physical key management, perimeter protection, and video detection and surveillance. To meet the demand, support operations and to strengthen compliance with dynamic regulatory requirements, additional FTE and contractor resources are needed.

5D.8 Reliability Standards Assurance KBU

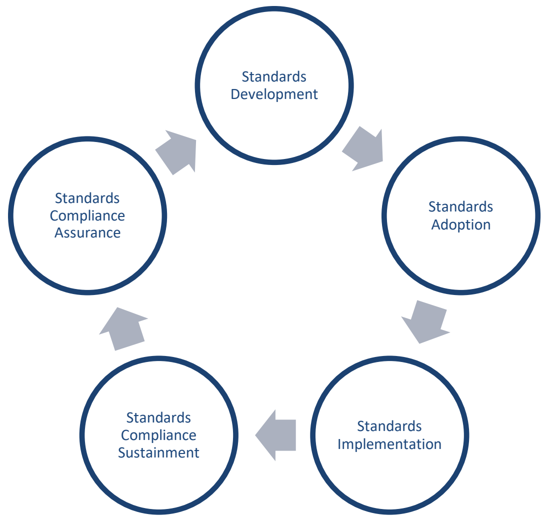
5D.8.1 Responsibilities

The Reliability Standards Assurance KBU is accountable for developing and executing the Mandatory Reliability Standards Internal Compliance Program and its operational procedures in alignment with the *Utilities Commission Act* and applicable BCUC rules.

The Mandatory Reliability Standards Internal Compliance Program establishes a systematic approach for achieving, sustaining and demonstrating compliance with applicable Mandatory Reliability Standards using appropriate governance, procedures, processes, documentation, tools, resources and training. The Mandatory Reliability Standards Internal Compliance Program and its associated Mandatory Reliability Standards Compliance Operational Procedures are designed to strengthen our Mandatory Reliability Standards program and reliability performance.

The Mandatory Reliability Standards Internal Compliance Program processes align with the Mandatory Reliability Standards Life-Cycle (refer to Figure 5D-8) and consists of Standards Development, Adoption, Implementation, Compliance Sustainment and Compliance Assurance.

Figure 5D-8 Mandatory Reliability Standards Life Cycle



For the Mandatory Reliability Standards Life Cycle:

- Standards Development is how the North American Electric Reliability Corporation) and the Western Electricity Coordinating Council (**WECC**) develops reliability standards changes with industry participation;
- Standards Adoption is the process by which the BCUC adopts North American Electric Reliability Corporation and WECC developed standards in B.C. after they have been adopted by the Federal Energy Regulatory Commission in the U.S.;
- Standards Implementation consists of implementing programs, policies, processes, procedures, controls and technology (as applicable) to comply with Mandatory Reliability Standards;
- Standards Compliance Sustainment encompasses activities to ensure compliance with Mandatory Reliability Standards is maintained and can be demonstrated; and

- Standards Compliance Assurance are activities to provide reasonable assurance that controls are effective to meet Mandatory Reliability Standards requirements.

The Reliability Standards Assurance KBU leads the BC Hydro processes for Standards Development, Adoption and Assurance. The Standards Implementation and Sustainment processes are the accountability of assigned key business units and the Reliability Standards Assurance KBU has a supporting role. More specifically, the Reliability Standards Assurance KBU has the following primary responsibilities:

- Stay apprised of industry standard developments and advocate BC Hydro’s position, including maintaining relationships with peer utilities, standards development bodies and industry associations;
- Develop the annual B.C. standards adoption Mandatory Reliability Standards Assessment Report for submission to the BCUC. The Mandatory Reliability Standards Assessment Report is developed with input from all entities registered under the BCUC Mandatory Reliability Standards Program in B.C. (currently 29 entities) and on average 20 new or revised standards are put forward for adoption annually;
- Work proactively with those accountable within BC Hydro for reliability standards compliance by providing subject matter expertise, guidance and coaching to strengthen our Mandatory Reliability Standards program;
- Function as intermediary with the WECC for any Mandatory Reliability Standards compliance related matters, including data submittals, self-reports, mitigation plans and investigations;
- Provide a level of assurance that BC Hydro complies with the applicable Mandatory Reliability Standards. This includes developing and performing the

work outlined in the risk-based Compliance Assurance Plan, including preparation for the triennial WECC audits; and

- Sustain the Mandatory Reliability Standards Internal Compliance Program, associated Operational Procedures and compliance management system, including Mandatory Reliability Standards methods, practices, technology and training to increase effectiveness and ease of Mandatory Reliability Standards compliance.

5D.8.2 Overview of Operating Costs and FTEs

Table 5D-10 Reliability Standards Assurance KBU Fiscal 2022 Decision Operating Costs and FTEs by Department

	($ Millions)	Labour	Services - Other	Materials	Building & Equipment	Capitalized Overhead	External Recoveries	Total Operating	Total FTEs
1	Reliability Standards Assurance	3.9	4.2	0.0	0.0	0.0	0.0	**8.1**	22
2	**Total (Sch 5.4 L4, Sch 16.0 L27)**	**3.9**	**4.2**	**0.0**	**0.0**	**0.0**	**0.0**	**8.1**	**22**

Labour and consulting services are the largest drivers of operating costs for the Reliability Standards Assurance KBU. The number of FTEs in the Reliability Standards Assurance KBU is primarily driven by Mandatory Reliability Standards regulatory obligations. As described above, the Reliability Standards Assurance KBU is an integral part of BC Hydro’s compliance program to meet regulatory obligations for these standards.

For the fiscal 2022 Decision amounts the Reliability Standards Assurance KBU consisted of 22 FTEs. However, 11 of the 22 FTEs were subsequently transferred to other Business Groups to support their Mandatory Reliability Standards work activities. Additionally, three FTEs were added to Reliability Standards Assurance KBU from repurposed roles from within the Safety and Compliance Business Group. These 14 FTEs (fiscal 2022 Decision amount of 22 FTEs less 11 FTEs transferred outside Safety and Compliance Business Group plus three FTEs added from within the Safety and Compliance Business Group) have been organized into the following departments:

- **Office of the Director Compliance** – contains two FTEs. One FTE is the Director of Compliance and one FTE is the administrative support resource for the Reliability Standards Assurance KBU.
- Mandatory Reliability Standards **Critical Infrastructure Protection Compliance Assurance** – Four FTEs provide subject matter expertise and assurance activities for the enterprise across 11 currently effective CIP Standards which include 39 requirements. CIP standard requirements are complex to implement as they apply across multiple business groups.
- Mandatory Reliability Standards **Operations & Planning (O&P) Compliance Assurance** – Four FTEs provide subject matter expertise and assurance activities for the enterprise across 91 currently effective Operations & Planning Standards including 472 requirements. Operations & Planning Standards are higher in volume and have new and revised standards being introduced frequently.
- Mandatory Reliability Standards **Program Services** – Four FTEs provide support across the company for Mandatory Reliability Standards practices (i.e., processes, methods and tools). The group supports Mandatory Reliability Standards program level reporting, sustainment and training on methods and tools (e.g., causes analysis, risk and control analysis), maintenance and access management for Reliability Standards Assurance intranet site, SharePoint sites and repositories.

Non labour costs of $4.2 million are comprised of $4.1 million to fund consulting services, change and project management resources related to operations and process review work and audit support, and $0.1 million for employee travel, training and supplies.

5D.8.3 Fiscal 2023 to Fiscal 2025 Plan Operating Costs and FTEs

Table 5D-11 Reliability Standards Assurance KBU Operating Costs and FTEs

		Schedule Reference	F2021 Actual	F2022 Decision	F2023 Plan	F2024 Plan	F2025 Plan
			1	2	3	4	5
1	**Reliability Standards Assurance KBU**						
2	Operating Costs ($ million)	5.4 L4	8.0	8.1	8.3	5.9	5.2
3	FTEs	16.0 L27	9	22	19	22	22

As discussed in section 5D.2.2, the expansion of the Mandatory Reliability Standards and the evolving maturity of the Mandatory Reliability Standards compliance program are driving increased investment during the Test Period.

The Reliability Standards Assurance KBU plans to add an additional eight FTEs over the Test Period. As a result, after the transfer of 11 to other Business Groups to support their Mandatory Reliability Standards work activities, the Reliability Standards Assurance KBU from fiscal 2022 Decision amounts to fiscal 2023 Plan shows a decrease of three FTE. The eight additional FTE are comprised of the following:

- One FTE – new resource for the Mandatory Reliability Standards Critical Infrastructure Protection Compliance Assurance department to support the assurance component of the Mandatory Reliability Standards Internal Compliance Program and the expanded scope of the CIP Standards. The CIP Standards adopted by the BCUC continue to increase the scope of the program; for example, 133 low impact stations (131 stations plus two yet to go into service) will be subject to CIP Standards effective in fiscal 2023.
- Three FTEs – new resources for the Mandatory Reliability Standards Operations & Planning Compliance Assurance department. One FTE will support the assurance component of the Mandatory Reliability Standards Internal Compliance Program, and two FTEs will function as Project Compliance Advisors to support capital and maintenance programs and

projects (e.g., capital infrastructure projects, technology projects) to comply with both the Operations & Planning and CIP Mandatory Reliability Standards.

- Three FTEs – new resources for the Mandatory Reliability Standards Program Services department. Two FTEs will support the sustainment of the new compliance management system, which includes business analysis for new compliance workflows, configuration of simple compliance workflows, and provide support and training for users. One FTE will support Mandatory Reliability Standards assurance reviews and sustain the Mandatory Reliability Standards Operational Procedures related to the Mandatory Reliability Standards Internal Compliance Program, including Mandatory Reliability Standards awareness program, program process development and Compliance Assurance Plan development.
- One FTE – a new non-Mandatory Reliability Standards Compliance Specialist role for fiscal 2023 to provide assurance that BC Hydro has a consistent compliance framework to manage as regulatory, legislative and other compliance obligations continue to increase, including in respect of environmental regulations, Standards of Conduct, safety regulations and privacy legislation. It is important for BC Hydro to strengthen our enterprise compliance approach that outlines expectations and to conduct assurance activities to ensure controls are effective. The goal is to increase consistency, reduce risks, and strengthen our compliance with regulatory, legislative and other obligations across the organization. This dedicated resource will report to Director, Compliance to carry out this work and will focus on high-priority compliance areas across the enterprise.

In addition to the eight FTEs (seven Mandatory Reliability Standards FTEs and one non-Mandatory Reliability Standards FTE) and associated labour costs of $0.8 million increase for fiscal 2023 plan and a further increase of $0.6 million in for fiscal 2024, the Reliability Standards Assurance KBU requires $3.9 million one-time funding in fiscal 2023 and $0.8 million in fiscal 2024. This consists of three components:

1. Mandatory Reliability Standards improvements. In fiscal 2023, $3 million is required for external support regarding Operations & Planning Standards program improvements. This work improves the policies, procedures and controls for BC Hydro's compliance with the approximate 91 Operations & Planning Standards. The Operations & Planning Standards will be enhanced to mature the program to meet industry practice.
2. Other. In fiscal 2023, $0.5 million is required to complete Mitigation Plans, as discussed in Confidential Appendix JJ.
3. Mandatory Reliability Standards Assurance. In fiscal 2023, $0.4 million and fiscal 2024 $0.8 million is required to support assurance reviews. This assurance work will (a) review the consistent application of newly implemented processes and procedures coming out of the Mitigation Plans, (b) accelerate reviews to confirm compliance with the Mandatory Reliability Standards requirements not covered by Mitigation Plans, and (c) support preparation for the fiscal 2024 WECC triennial audit.

Internal Reliability Standards Assurance KBU labour, particularly the work of the Project Compliance Advisors, is expected to be used to support future capital and maintenance projects. A portion of this labour effort may be charged out to capital program and project work in the future.

5D.9 Business Unit Support KBU

5D.9.1 Responsibilities

The Safety Business Unit Support KBU holds the budget for the Office of the Senior Vice-President of Safety and Chief Compliance Officer.

5D.9.2 Overview of Operating Costs and FTEs

Table 5D-12 Business Unit Support KBU Fiscal 2022 Decision Operating Costs and FTEs by Department

	($ Millions)	Labour	Services - Other	Materials	Building & Equipment	Capitalized Overhead	External Recoveries	Total Operating	Total FTEs
1	SVP, Safety & Chief Compliance Officer	0.7	0.1	0.0	0.0	0.0	0.0	**0.8**	3
2	**Total (Sch 5.4 L5, Sch 16.0 L28)**	**0.7**	**0.1**	**0.0**	**0.0**	**0.0**	**0.0**	**0.8**	**3**

This departments planned costs are primarily labour for the Senior Vice-President of Safety and Chief Compliance Officer, one Strategic Business Advisor and an administrative assistant. The non-labour costs are for employee travel, training and miscellaneous services.

5D.9.3 Fiscal 2023 to Fiscal 2025 Plan Operating Costs and FTEs

Table 5D-13 Business Unit Support KBU Operating Costs and FTEs

		Schedule Reference	F2021 Actual	F2022 Decision	F2023 Plan	F2024 Plan	F2025 Plan
			1	2	3	4	5
1	**Business Unit Support KBU**						
2	Operating Costs ($ million)	5.4 L5	0.7	0.8	0.6	0.7	0.7
3	FTEs	16.0 L28	3	3	2	2	2

Operating costs are planned to remain relatively stable from fiscal 2022 Decision amount to the fiscal 2025 plan.

BC Hydro
Power smart

BC Hydro Fiscal 2023 to Fiscal 2025
Revenue Requirements Application

Chapter 5E

Operating Costs
Finance, Technology, Supply Chain
Business Group

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5E.1 Business Group

Chapter 5E details the composition of, and rationale for, the operating costs of the Finance, Technology, Supply Chain Business Group. The Finance, Technology, Supply Chain Business Group is one of six business groups in the organization and serves a Support function of the Plan-Build-Operate-Support model.

The Finance, Technology, Supply Chain Business Group budget was developed as part of the budgeting process outlined in Chapter 5, section 5.4, which the BCUC found to be reasonable in its decision on the Previous Application.[358] The budgeting approach continues to include both bottom-up and top-down elements and examines more than just incremental costs. The information provided in Chapter 5E demonstrates the basis for the entirety of the Business Group and KBU budgets, rather than focussing only on incremental cost requirements. This information is provided in a format and level of detail consistent to that presented in the equivalent chapter in the F2020-F2021 RRA.

Chapter 5E is organized as follows:

- Section 5E.2 provides an overview of the organization and responsibilities of the Finance, Technology, Supply Chain Business Group;
- Section 5E.3 provides the operating costs and FTE information for the Finance, Technology, Supply Chain Business Group as a whole;[359]
- Sections 5E.4 to 5E.7 provide more detailed information on the responsibilities, operating costs and FTEs for each KBU within the Finance, Technology, Supply

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358 BCUC Decision and Order No. G-187-21, Fiscal 2022 Revenue Requirements Application (June 17, 2021), p. 27: "The Panel considers BC Hydro's budgeting process involving top-down and bottom-up elements goes beyond the examination of incremental changes from the prior year and continues to be reasonable for forecasting operating costs. Therefore, for these reasons, the Panel finds the fiscal 2022 operating costs requested for recovery to be reasonable."

359 Please note the amounts presented in the tables in these sections may not add due to rounding.

Chain Business Group. The operating costs and FTE information for each KBU is broken out into two sections:[359]

- Overview of Operating Costs and FTEs – This section explains the starting operating costs and FTEs for the KBU based on the fiscal 2022 Decision amounts; and
- Fiscal 2023 to Fiscal 2025 Plan Operating Costs and FTEs – This section explains any incremental changes in the KBU between fiscal 2022 Decision amounts and fiscal 2023 to fiscal 2025 plan.

5E.2 Overview of Finance, Technology, Supply Chain Business Group Organization and Responsibilities

The Finance, Technology, Supply Chain Business Group's responsibilities include:

- Providing corporate financial and treasury services, financial support to all of BC Hydro's KBUs, internal audit services, and oversight to financial decisions to ensure they are consistent with BC Hydro's policies and controls;
- Facilitating the delivery of materials, vehicles and procurement services necessary for BC Hydro to provide service to customers; and
- Selecting, implementing and operating technology across BC Hydro. This includes managing information technology and operational technology systems to meet compliance and security requirements, sustain productivity, manage risks and enable business objectives.

The Finance, Technology, Supply Chain Business Group consists of the following KBUs:

Business Group	Key Business Unit
Finance, Technology, Supply Chain	Finance Technology Supply Chain Business Unit Support

There have been no material changes to the organization of this Business Group since the Previous Application.

5E.3 Fiscal 2023 to Fiscal 2025 Plan Operating Cost and FTE Summaries

This section addresses planned operating costs and FTEs for the Finance, Technology, Supply Chain Business Group. The following are some key points of note with respect to the information provided in Figure 5E-1, Table 5E-1 and Figure 5E-2, Table 5E-2 and Table 5E-3.

- The Technology KBU accounts for 51 per cent, or $157.9 million, of the total operating cost budget for the Finance, Technology, Supply Chain Business Group. All cross-organizational technology costs (e.g., licenses, maintenance fees, data center and end point devices) are managed on a consolidated basis within the Technology KBU.
- The Supply Chain KBU accounts for 474 FTEs, or nearly 48 per cent of the total FTEs for the Finance, Technology, Supply Chain Business Group. This is primarily to deliver fleet and materials management services, which account for nearly 300 FTEs, where a regional presence is required to support front line operations.
- From the fiscal 2022 Decision amounts to the fiscal 2025 Plan, the increases in the Finance, Technology, Supply Chain Business Group operating budgets are largely driven by Cybersecurity, Mandatory Reliability Standards, and software licensing and outsourcing agreements and infrastructure support, further discussed in section 5E.5.3.

Planned operating costs for this Business Group are approximately $308.4 million in fiscal 2023, approximately $314.9 million in fiscal 2024, and approximately $319.1 million in fiscal 2025 and are summarized by KBU in Figure 5E-1. Additional cost details are provided in Table 5E-1 below.

Figure 5E-1 Finance, Technology, Supply Chain Net Operating Costs by KBU (Fiscal 2023 Plan) ($ million)

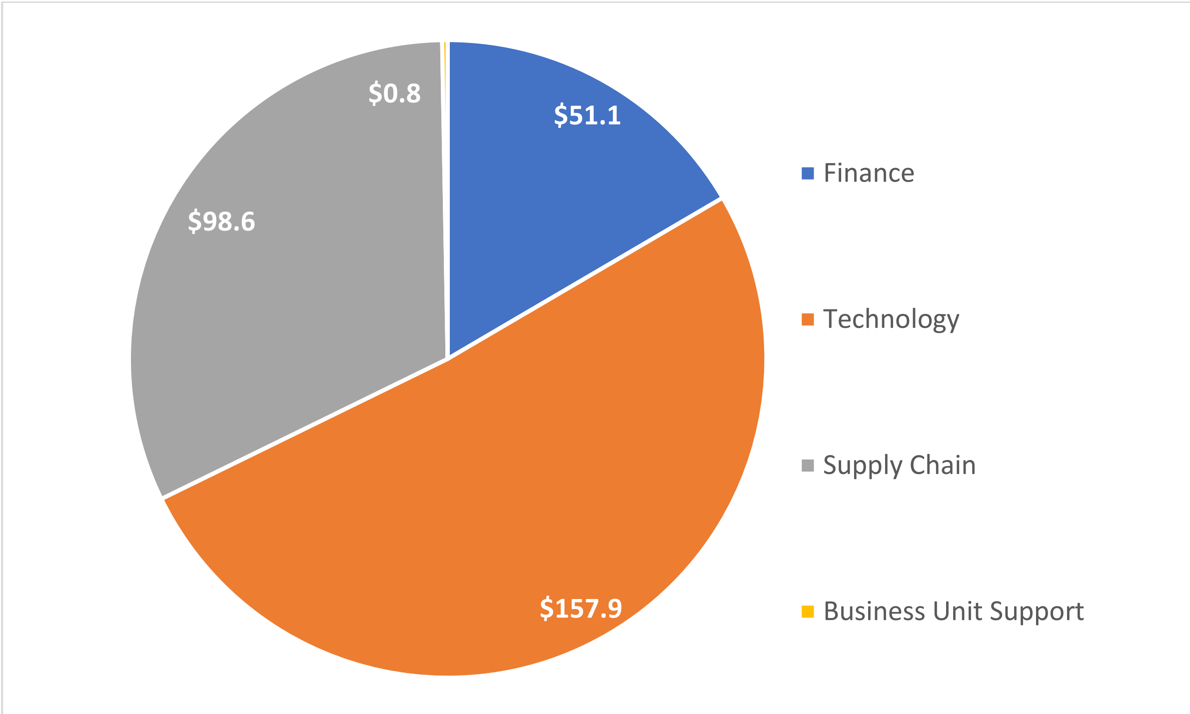

Table 5E-1 Finance, Technology, Supply Chain Net Operating Costs by KBU

	($ million)	Schedule Reference	F2021 Actual	F2022 Decision	F2023 Plan	F2024 Plan	F2025 Plan
			1	2	3	4	5
1	Finance	5.5 L1	46.0	51.0	51.1	52.5	54.0
2	Technology	5.5 L2	137.8	146.3	157.9	162.4	164.0
3	Supply Chain	5.5 L3	92.7	101.0	98.6	99.2	100.2
4	Business Unit Support	5.5 L4	0.8	0.9	0.8	0.9	0.9
5	Total	5.5 L10	277.3	299.1	308.4	314.9	319.1

The FTEs for the Finance, Technology, Supply Chain Business Group are summarized by KBU in Figure 5E-2. Additional details are provided in Table 5E-2 below.

Figure 5E-2 Finance, Technology, Supply Chain FTEs by KBU (Fiscal 2023 Plan)

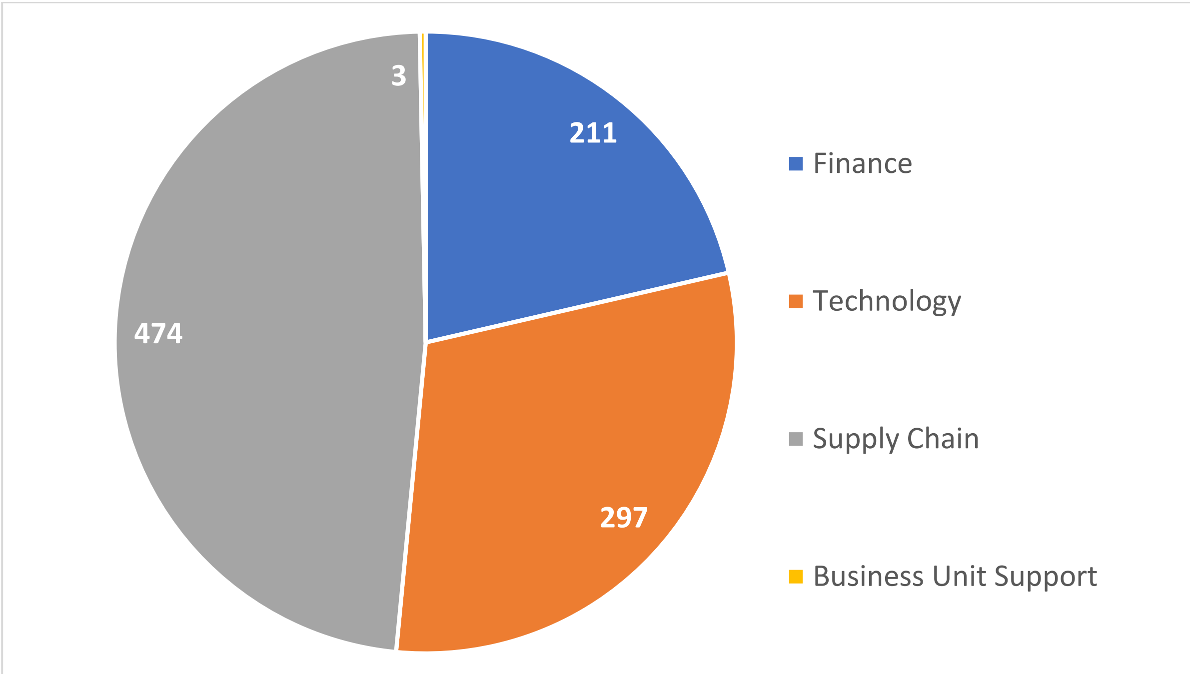

Table 5E-2 Finance, Technology, Supply Chain FTEs by KBU

	(FTEs)	Schedule Reference	F2021 Actual	F2022 Decision	F2023 Plan	F2024 Plan	F2025 Plan
			1	2	3	4	5
1	Finance	16.0 L30	209	211	211	211	211
2	Technology	16.0 L31	271	283	297	316	316
3	Supply Chain	16.0 L32	513	475	474	465	459
4	Business Unit Support	16.0 L33	3	3	3	3	3
5	Total	16.0 L34	996	972	985	995	989

Table 5E-3 below provides a continuity table which highlights changes to the Finance, Technology, Supply Chain Business Group from the Previous Application. An overall discussion of these changes, at a company-wide level, is provided in Chapter 5, section 5.5.3. Further details, by KBU, are provided in the sections below.

Table 5E-3 Finance, Technology, Supply Chain Operating Costs Continuity Schedule

	($ million)	Ref	F2023 Plan	F2024 Plan	F2025 Plan
1	**F2022 Revenue Requirement Application Plan**	a	**299.1**		
2	**Compliance Filing Adjustment**	b	**-**		
3	Reorganizational Impact	c	**-**		
4	**F2022 Decision (Schedule 5.5, line 10)**	d = Σ a to c	**299.1**		
5	Budget Transfers Between Business Groups	e	0.9		
6	**F2022 Forecast (Schedule 5.5, line 10)**	f = d+e	**300.0**	**308.4**	**314.9**
7	Current Year Budget Transfers Between Business Groups	g	-	-	-
8	**Test Period Net Cost Increase/Decrease**				
9	**Uncontrollable Cost Increases**				
10	Current Service Costs and Other Labour Costs		(2.5)	3.4	4.0
11	Technology licensing costs		4.1	-	-
12	Insurance		0.9	0.5	0.5
13		h	2.5	3.9	4.5
14	**Reliability Investments**				
15	Cyber Security		4.2	1.9	0.4
16	Mandatory Reliability Standards		2.0	1.6	-
17		i	6.2	3.5	0.4
18	**Site C**	j	-	-	0.2
19	**Net Cost Savings**				
20	Test Period Savings	k	(0.4)	(0.8)	(0.8)
21			(0.4)	(0.8)	(0.8)
22	**Total Test Period Net Increase/(Decrease)**	l = Σ h to k	**8.3**	**6.6**	**4.2**
23	**F2023 Net Operating Costs (Schedule 5.5, line 10)**	m= f+g+l	**308.4**	**314.9**	**319.1**

Table may not add due to rounding

5E.4 Finance KBU

5E.4.1 Responsibilities

The Finance KBU provides corporate-wide financial services and support to BC Hydro’s KBUs and overseeing financial decisions consistent with BC Hydro’s policies and controls. This includes budgeting, planning, forecasting, accounting, financial reporting, tax compliance and planning, cash management, debt and foreign exchange management, risk management, performance improvements through the Work Smart program, internal audit, and overseeing financial policy compliance.

The Finance KBU performs an important role in the financial stewardship of BC Hydro. To effectively manage an organization as complex as BC Hydro, stakeholders across the company require accurate, timely and insightful financial and management information throughout the annual business cycle and in forward planning. The Finance KBU provides this information through a robust system of controls. It also provides complementary services such as internal audit, change management, and Work Smart that add further value to the business and enable BC Hydro to deliver on our Service Plan and Five-Year Strategy commitments.

BC Hydro's business environment continues to grow in complexity each year, which results in increased demand for the services of the Finance KBU. For example, the Finance KBU leads or contributes to the many regulatory applications to the BCUC, including revenue requirements applications, Integrated Resource Plan, capital project filings such as CPCNs, and cost of capital proceedings. The Finance KBU is also very involved in work related to reliability investments (e.g., Mandatory Reliability Standards), including the related regulatory filings. While maintaining a relatively constant size and budget, the Finance KBU continues to lead and contribute to other activities, including:

- Planning – Finance coordinates the completion of annual business plans for each KBU, and creates the annual focus document, which provides clarity and alignment on BC Hydro's priorities across the company;
- Reporting – Finance produces a number of dashboards on either a monthly or quarterly basis on key performance indicators and targets critical to achieving business objectives that are used across the company to manage business performance. The Finance KBU is also a key contributor to the performance

metrics process, including the enhanced reporting of some discussed in Chapter 5, section 5.6;

- Business Support - Increased internal and external support required to meet project, policy and regulatory objectives. For example, increased levels of support required for polychlorinated biphenyl (**PCB**) and asbestos remediation programs, as well as regulatory and Mandatory Reliability Standards work as mentioned above;
- Debt Management – the Treasury and Financial Evaluations team now manages approximately $25 billion in total debt and $6.5 billion in outstanding derivative financial instruments, including those related to hedging under our debt management strategy to achieve increased cost certainty for ratepayers on long-term borrowings; and
- Work Smart – Work Smart is a key enabler in limiting our operating cost increases. We estimate that initiatives led by Work Smart, working in conjunction with teams across BC Hydro have resulted in more than 110,000 annual capacity hours gained. This enables the equivalent of nearly 70 FTEs' worth of effort to address increasing workload and to focus on higher-value work. During fiscal 2021 and fiscal 2022, as a result of the COVID-19 pandemic limiting the ability to carry out typical Work Smart activities, Work Smart team resources leveraged their process improvement skillsets to support emerging priorities such as compliance enhancements to meet Mandatory Reliability Standards.

There have been no material changes to the nature of the responsibilities of the Finance KBU since the Previous Application.

The Finance KBU consists of the following departments:

- Chief Accounting Officer Department;
- Treasury and Financial Evaluations Department; and

- Audit Services Department.

5E.4.1.1. Chief Accounting Officer Department

This department is made up of three teams:

Business Support Services provide an array of financial, consultation and decision support services to the business, including budgeting, forecasting and financial reporting as well as transaction processing and investment evaluation.

- Supporting business processes and initiatives through an understanding of the specific business needs of each department and assisting the business unit in achieving its goals from a financial perspective;
- Providing management consultation and decision support services to management teams, front line managers and staff. This includes financial evaluation, risk analysis, and recommendations on strategic issues, capital and initiative investment proposals, and day-to-day operational issues and decisions;
- Supporting business groups delivering capital projects by reviewing capital requests, providing input into the annual prioritization process, providing annual and long-term capital reporting and forecasting, converting projects into assets, preparing depreciation forecasts, completing due diligence reviews (e.g., financial reviews of business cases), preparing financial models, and preparing contract requisitions;
- Ensuring all employees are educated about, and following, corporate controls and policies;
- Facilitating the annual financial planning, work planning and resource allocation process at the KBU level;
- Applying BC Hydro's accounting and costing methodologies and systems to all financial transactions;

- Delivering management and cost accounting services to provide timely and accurate recording and reporting of cost information to support decision making;
- Providing budget support to the management teams of each KBU including reviewing overall budgets, cost pressures, cost savings and initiatives to develop a prioritized operating and capital budget;
- Preparing monthly reporting for business groups and individual KBUs including variance explanations, trends, emerging business issues and forecasts of year end results;
- Preparing non-energy and miscellaneous billing reports and issuing invoices in compliance with contracts; and
- Processing transactions including preparing and posting journal entries and completing general ledger reconciliations.

Controllership is responsible for consolidated financial and management reporting, including revenue and cost of energy reporting for both internal and external stakeholders, managing the quarterly review and annual external audit process, financial forecasting, taxation, accounting policy interpretation, pension costing, internal controls and policy compliance, and financial system and process support.

- **Financial Reporting:** this team is responsible for preparing and presenting BC Hydro’s consolidated internal and external financial reports. The team manages the external financial statement audit and review process, leads the planning, assessment and implementation of new and revised IFRS standards and provides accounting policy guidance, interpretations and assessments for complex accounting issues;
- **Forecasting, Revenue and Cost of Energy:** this team is responsible for preparing and updating BC Hydro’s consolidated financial forecast, which informs BC Hydro’s revenue requirements applications and annual Service

Plan. The forecast is used extensively by management in making both short-term and long-term financial decisions. In addition to regular forecast updates, this team is also involved in key initiatives and regulatory filings. This team also provides reporting, variance analysis and forecasting for revenue and cost of energy;

- **Internal Controls and Policy:** this team is responsible for maintaining and overseeing compliance with internal financial controls by ensuring financial policies are developed and updated, reviewing instances of control exceptions, providing business support for technology solutions, preparing and reviewing financial system access requests, and creating risk and control assessments for projects and initiatives across BC Hydro to support successful business outcomes;
- **Financial Processes:** this team is the conduit between Finance and Technology to ensure that our financial systems are configured to meet business requirements, are operating as designed, and are delivering data in a timely manner. This team also provides technical support to users and develops solutions to enhance the financial systems to meet reporting requirements;
- **Financial Accounting and Compliance:** this team provides back-office support for the Treasury and Financial Evaluations group and is directly responsible for the accounting, forecasting, and financial analysis of information pertaining to debt, derivatives, pension and other post-employment benefits; and
- **Taxation:** this team provides tax planning and advice throughout the company on property sales and purchases, procurement activities, sales transactions and employee benefits. The team also prepares and submits all the sales and income tax returns for the business and handles dispute resolution with suppliers, customers and tax authorities.

Business Planning, Risk and Performance consists of four functions that deliver the following services which drive decision making, focus and productivity throughout the organization:

- **Business Planning:** this team leads the corporate-wide annual business planning process, as well as the development of performance metrics and performance tracking related to business plans for each of BC Hydro's KBUs. The annual planning process involves the development of business plans and the annual focus document, which outlines the key priorities across BC Hydro and within the Business Groups. These business plans provide clarity on our priority work and help to measure progress towards achieving our objectives throughout the year. The annual focus document provides clarity to employees on the company-wide and Business Group objectives and key priorities and ensures alignment of work activities across the company. Dashboards and scorecards prepared by this team are a key performance tool to track progress on targets and help managers identify areas of concern and implement corrective action, if required, to bring performance back on track;
- **Enterprise Risk Management:** this team leads BC Hydro's approach to enterprise risk, including the annual refresh of the risk landscape, and ongoing monitoring and reporting of key risks and emerging risks to the Executive and Board of Directors. This team also works with Business Groups and KBUs throughout BC Hydro during the annual planning process to identify and understand key risks related to achieving business objectives so that these risks are considered in the development of each KBU's business plan as well as actively monitored throughout the fiscal year;
- **Work Smart:** this team leads BC Hydro's performance improvement initiatives through the Work Smart program, which uses practical tools and methods to improve processes; and

- **Change Management:** this team works on projects and initiatives across BC Hydro to understand what people need to do differently to achieve the benefits of the project. Communications, engagement, training and leadership plans are developed for specific groups so that that they have the appropriate knowledge, skills and abilities to perform their roles - both during and after the change. They also play a key role in ensuring leadership support and business ownership for the change to drive long term sustainment and achievement of benefits. This is a critical component to all projects where employee productivity is involved.

5E.4.1.2. Treasury and Financial Evaluations Department

The Treasury and Financial Evaluations department consists of several groups that provide financial management and commercial analysis services to BC Hydro. This department includes the following main functions:

- **Debt and Cash Management:** Treasury and Financial Evaluations is responsible for cash and foreign exchange management, banking and debt management. This involves ensuring that BC Hydro has sufficient financial resources to fund its operations and capital plan, maintaining credit facilities, managing finance charges and implementing debt management strategies;
- **Financial Risk Management:** Treasury and Financial Evaluations is responsible for key components of financial risk management, specifically BC Hydro's insurance program and credit risk management. This involves procuring and managing operational and construction insurance programs, and evaluating, monitoring and reporting credit exposures;
- **Pension Management:** Treasury and Financial Evaluations manages investments associated with BC Hydro's pension plan and non-pension post-retirement benefits;

- **Commercial Negotiations and Financial Analysis:** Treasury and Financial Evaluations manages commercial evaluations and structuring of complex projects and/or transactions with cross-business implications for BC Hydro. This team also develops standards for financial evaluation inputs and methodology for use across BC Hydro and a framework of controls to ensure these standards are followed.

5E.4.1.3. Audit Services Department

The purpose of Audit Services is to provide independent, objective assurance and consulting services to add value and improve BC Hydro's operations. Audit Services reports functionally to the Audit, Finance and Capital Committee of BC Hydro's Board of Directors and administratively to the Executive Vice President of Finance, Technology, Supply Chain and Chief Financial Officer.

Audit Services adheres to the Institute of Internal Auditors International Standards for the Professional Practice of Internal Auditing.

The Audit Services department develops and executes a two-year Audit Plan which incorporates operational, compliance and financial process audits to address BC Hydro's key risks and priorities.

5E.4.2 Overview of Operating Costs and FTEs

Table 5E-4 Finance KBU Fiscal 2022 Decision Operating Costs and FTEs by Department

	($ Millions)	Labour	Services - Other	Materials	Building & Equipment	Capitalized Overhead	External Recoveries	Total Operating	Total FTEs
1	Office of the Chief Accounting Officer	29.6	1.2	0.1	0.1	0.0	0.0	**31.0**	185
2	Treasury & Financial Evaluations	2.5	15.2	0.0	0.2	0.0	0.0	**17.8**	14
3	Audit Services	1.7	0.3	0.0	0.0	0.0	0.0	**2.1**	12
4	**Total (Sch 5.5 L1, Sch 16.0 L30)**	**33.9**	**16.8**	**0.1**	**0.2**	**0.0**	**0.0**	**51.0**	**211**

In the F2020-F2021 RRA, BC Hydro referred to a benchmarking report published by The Financial Executives Research Foundation, together with Robert Half, titled 2018 Benchmarking Accounting and Finance Functions. The report included analyses of the number of internal staff and the cost of staff for finance and accounting functions for companies of various sizes in North America. An additional report is referenced in this Application, entitled The PwC Finance Benchmarking Report 2019-2020. This report is UK-based and includes similar analysis as the Robert Half report.

The following table compares BC Hydro's FTEs and base operating cost budget to the benchmarks provided in these reports for both categories.

Table 5E-5 Benchmarking Accounting and Finance Functions

Benchmark	BC Hydro (Fiscal 2022)	Robert Half Report[360] Companies with annual revenue of $5 billion and higher	PwC Report[361] Power and Utilities Industry Companies
Number of internal staff in Accounting and Finance	182[362]	180 (median)	N/A
Cost of internal staff in Accounting and Finance as a percentage of overall revenues	0.54%[363]	0.5% (best) 0.8% (median)	0.63% (best) 0.81% (median)

As shown in the table above, the Finance KBU's FTE complement is comparable to the median for companies with revenues of $5 billion in the Robert Half Report. The Finance KBU's costs are slightly higher than the best result in the Robert Half Report and below the best in the PwC Report.

5E.4.2.1. Chief Accounting Officer Department

Approximately 95 per cent of this department's budget is related to labour. This represents 185 FTEs as follows:

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360 Link to Robert Half report: https://www.mercur.com/Filer/EN/PDF/RHI-Benchmarking-2018-FINAL.pdf?TS=637017980495948192.

361 Link to PwC report: https://www.pwc.co.uk/finance/assets/pdf/uk-finance-effectiveness-benchmarking-report-2019-2020.pdf.

362 The Finance KBU has 211 FTEs. However, this total includes 29 FTEs that perform business planning, change management and enterprise risk management functions which are not traditional finance and accounting functions. Excluding these FTEs, the total number of FTEs in the Finance KBU is 182.

363 The Finance KBU has a base operating cost budget of $36 million (excluding corporate insurance) which equates to approximately 0.54 per cent of BC Hydro's total fiscal 2022 revenues of $6.648 billion.

- Two FTEs for the Chief Accounting Officer and administrative assistant;
- 116 FTEs in Business Support Services, including:
  - Two Finance Directors and two administrative assistants;
  - 83 FTEs supporting all of the KBUs within BC Hydro. Each of these finance FTEs supports an average of 80 FTEs and $15 million in annual operating budgets;
  - 19 FTEs provide project reviews, evaluations, monitoring and reporting on over 500 capital projects or $1.4 billion in expenditures annually; analyse and convert over 2,500 projects and work orders into in-service assets; review 30 contracts and contract revisions for senior management and maintain asset records for $31 billion in capital assets; and
  - 10 FTEs are responsible for the annual preparation of 15,000 non-energy bills, processing of 7,800 journal entries and reconciliation of 150 general ledger accounts;
- 38 FTEs in Controllership, including:
  - Eight FTEs on the Financial Reporting team prepare over 110 internal and external financial reports and documents including monthly financial statements. In addition, this team is responsible for researching, analyzing, and drafting technical accounting memos relating to new accounting standards or supporting key initiatives and transactions across BC Hydro. It also provides financial support for the revenue requirements application process, including preparation of certain chapters and coordination and preparation of responses to BCUC and intervenor information requests and undertakings;
  - Seven FTEs provide monitoring and reporting services on BC Hydro’s revenues and cost of energy. These FTEs handle the payment, accounting,

forecasting, and budgeting for approximately 130 Electricity Purchase Agreements;

- Five FTEs on the Forecasting team support the preparation of the quarterly forecast update to the government and BC Hydro's Board of Directors. This team is also critical in supporting revenue requirement applications by preparing forecasts that determine rate increases (decreases) for BC Hydro customers;
- Four FTEs in the Financial Accounting and Compliance team provide back-office support for the Treasury and Financial Evaluations team including accounting, forecasting, reporting and financial analysis of information pertaining to financial instruments, pension and other post-employment benefit plans, and finance charges. The team also monitors and reports monthly on the Treasury and Financial Evaluations department's compliance with the Liability Risk Management Annual Strategic Plan and the Treasury Risk Management Policy. Best practices require the segregation of duties to an independent team to ensure that proper internal controls are in place for the safeguarding of assets and the accurate and timely recording of Treasury initiated transactions;
- 11 FTEs on the Internal Controls & Financial Processes teams maintain over 400 financial policy, procedure, and guideline documents, review business and travel expense compliance across BC Hydro, maintain approximately 30 Financial Process flow diagrams and review approximately 30 Technology projects each year. This team uses a risk and control framework to guide the design of financial controls, triage and support over 1200 technical issues per year, initiate an average of 12 financial system and reporting enhancements per year, conduct testing of system upgrades, and perform risk analysis to prevent financial system security role violations and unauthorized access; and

- Three FTEs in Taxation.

- 29 FTEs in Business Planning, Risk and Performance, including:
  - 12 FTEs on the Business Planning and Risk team lead BC Hydro's Enterprise Risk Management program, the development of annual business plans for each of BC Hydro's key business units, as well as the development of strategic plans. They also provide leadership in the areas of performance measurement at the corporate level and produce monthly and quarterly dashboards on key performance indicators and targets critical to achieving business objectives. These FTEs also work with the Board and Executive Team to develop and maintain an enterprise risk landscape, including guidelines around assessing risk likelihood and risk consequence, to help key business units identify and monitor risks which can impact BC Hydro across multiple aspects of the business. Additionally, they carry out risk and planning interviews and workshops to support BC Hydro's various risk management activities and report on enterprise risks to senior leaders, the Executive Team and the Board;
  - Four FTEs on the Work Smart team, which completes approximately 35 projects annually and has generated more than 110,000 annual capacity hours gained since the program's inception; and
  - 13 FTEs on the Enterprise Change Management team which supports approximately 50 change management projects per year.

The Chief Accounting Officer department has $1.4 million in non-labour expenditures which includes funding for external auditor and assurance services, consulting services, professional dues and fees, training and office supplies.

5E.4.2.2. Treasury and Financial Evaluations Department

There are 14 FTEs in Treasury and Financial Evaluations.

- Nine FTEs work in Debt Management, Financial Risk Management and Pension Management. These staff manage $25 billion in total debt, $6.5 billion in derivative financial instruments, $1.3 billion in letter of credit facilities, BC Hydro's insurance portfolio, and an approximate $4 billion pension plan; and
- Five FTEs on the Commercial Negotiations and Financial Analysis team. These staff provide commercial analysis services to groups across BC Hydro, including river system and capital project analysis for Project Delivery, Electricity Purchase Agreement analytics for the Generation System Operations KBU, and financial analysis for rate programs.

The Treasury Department has $15.4 million in non-labour expenditures including $15 million for corporate insurance and $0.4 million for professional fees, consultants, training, and specialized software.

5E.4.2.3. Audit Services Department

Approximately 81 per cent of the Audit Services department budget is related to labour. This represents 12 FTEs who complete approximately 15 audits per year and follow up on past audits to ensure recommendations are being addressed. This team is also responsible for investigating claimed control breaches that are reported via the company's hotline.

The department's services budget primarily provides funding for external subject matter experts, which supplement our teams where subject-matter specific expertise can add value, such as dam safety and cybersecurity.

5E.4.3 Fiscal 2023 to Fiscal 2025 Plan Operating Costs and FTEs

Table 5E-6 Finance KBU Operating Costs and FTEs

		Schedule Reference	F2021 Actual	F2022 Decision	F2023 Plan	F2024 Plan	F2025 Plan
			1	2	3	4	5
1	**Finance KBU**						
2	Operating Costs ($ million)	5.5 L1	46.0	51.0	51.1	52.5	54.0
3	FTEs	16.0 L30	209	211	211	211	211

Operating costs are increasing by approximately $0.1 million from the fiscal 2022 Decision amounts to the fiscal 2023 plan due to increased corporate insurance costs of $0.9 million, partly offset by a reduction in the Standard Labour Rate of $0.7 million and a reduction to the travel budget of $0.1 million. Operating costs are increasing by approximately $1.4 million from the fiscal 2023 plan to the fiscal 2024 plan due to Standard Labour Rate increases of $0.9 million and increased corporate insurance costs of $0.5 million. Operating costs are increasing by approximately $1.5 million from the fiscal 2024 plan to the fiscal 2025 plan due to Standard Labour Rate increases of $1.0 million and increased corporate insurance costs of $0.5 million. FTEs are planned to remain stable.

5E.5 Technology KBU

5E.5.1 Responsibilities

The Technology KBU is responsible for the planning, design, delivery, and operations of all information technology and several operational technology systems across the enterprise. It provides technology leadership and oversight across BC Hydro, is responsible for selecting appropriate technology solutions to deliver strong business outcomes and oversees and protects the company from cybersecurity risks. The Technology KBU works to ensure our systems are reliable, secure, and able to meet the growing needs of BC Hydro.

Primary responsibilities of the Technology KBU include:

- Planning and operating our complex technology environment;
- Protecting our systems and information;
- Ensuring the resilience of our systems;
- Enabling new business capabilities to meet business needs; and
- Optimizing technology operations by effectively managing resources and assets.

The nature of the responsibilities of the Technology KBU remain consistent with the Previous Application, although the cost and workload demands on the KBU are increasing.

Since the Previous Application, BC Hydro has restructured the Technology KBU to create a single Cybersecurity and Compliance department. Technology is now comprised of the following departments:

- Business Partner Services Department;
- Planning and Performance Department;
- Delivery Department;
- Operations Department; and
- Cybersecurity and Compliance Department.

5E.5.1.1. Business Partner Services Department

The Business Partner Services department works directly with BC Hydro KBUs to understand their business needs and develop technology solutions. The department assists with developing statements of objectives and business cases, initiating work, and meeting business objectives for all technology initiatives. The department also monitors issues, identifies and prioritizes enhancements, and oversees the delivery of sustainment programs for existing business systems and applications that are used by specific areas of the business. Enterprise wide systems and applications are supported by the Operations department, which is described further below.

5E.5.1.2. Planning and Performance Department

The Planning and Performance department consist of three teams that provide technology strategy development and strategic investment planning, portfolio and resource management, and business management functions for the Technology KBU.

- **Investment management:** this team manages demand for capital investment, selection and prioritization of investments, investment benefit realization, capital budgets, as well as regulatory and long-term capital planning.
- **Enterprise architecture:** this team develops and maintains technology roadmaps, reference architectures and technical standards, which are used to guide technology investment and design decisions.
- **Business management:** this team is responsible for all aspects of technology governance including business planning, budget management, vendor and contract management, performance reporting, policies and standards management, records and information management, risk management, software asset management, workforce planning and business continuity and disaster recovery planning.

5E.5.1.3. Delivery Department

The Delivery department is responsible for overseeing delivery of the technology capital investment portfolio including defining and ensuring compliance with project management standards, processes and procedures. The capital projects and work programs are described in Chapter 6, section 6.5.1. The delivery of capital initiatives typically includes operating expenditures related to early stage planning, project identification, analysis of alternatives, requirements analysis, change management, training, and data migration.

5E.5.1.4. Operations Department

The Operations department supports various technology applications that are enterprise-wide or used by multiple business groups. Activities carried out by this department include maintaining, sustaining, upgrading and optimizing enterprise applications such as customer support, financial, supply chain and human resource systems, project and portfolio management and smart metering applications.

This department is also responsible for the maintenance and sustainment of software and hardware related to data centres, including disaster recovery sites; personal computing and mobile devices; and networks and other telecommunications equipment and systems.

This department's responsibilities include the technology help desk for general user support as well as business application support and service management.

The Operations department also includes the Smart Metering and Network Operations team. This team is responsible for the day to day operation of the smart metering system, including data collection as well as device and network operations. This team also supports the meter to cash (e.g., billing) and energy conservation functions (by providing energy usage information), as well as energy loss and theft detection, power quality analysis, distribution grid use cases, and outage management functions.

5E.5.1.5. Cybersecurity and Compliance Department

The Cybersecurity and Compliance department has accountability for cybersecurity across all of BC Hydro, including the security of data, Information Technology and Operational Technology systems. It also has responsibility for supporting compliance with Critical Infrastructure Protection (**CIP**) Standards as they relate to digital systems.

5E.5.2 Overview of Operating Costs and FTEs

Table 5E-7 Technology KBU
Fiscal 2022 Decision Operating Costs
and FTEs by Department

	($ Millions)	Labour	Services - Other	Materials	Building & Equipment	Capitalized Overhead	External Recoveries	Total Operating	Total FTEs
1	Business Partner Services	6.4	11.6	0.0	4.9	0.0	0.0	**22.9**	44
2	Planning & Performance	7.4	1.5	0.3	0.1	0.0	0.0	**9.2**	48
3	Delivery	2.2	0.8	0.0	0.2	0.0	0.0	**3.2**	20
4	Operations	19.1	48.7	2.2	29.3	0.0	0.0	**99.3**	137
5	Cybersecurity and Compliance	5.7	4.9	0.0	1.0	0.0	0.0	**11.6**	34
6	**Total (Sch 5.5 L2, Sch 16.0 L31)**	**40.8**	**67.4**	**2.5**	**35.6**	**0.0**	**0.0**	**146.3**	**283**

As BC Hydro identifies opportunities to use technology to improve safety, reliability and productivity, the Technology KBU must manage the costs associated with these commitments while maintaining acceptable service levels. Primary technology cost drivers include:

- **Software Licensing and Maintenance:** Software licensing and maintenance costs continue to increase due to market pricing, changes in licensing models and increased use of digital technology to support business operations;
- **Sustainment and Maintenance Costs:** Higher application and infrastructure outsourcing, sustainment and maintenance costs are driven by capital investment in new and existing applications and increases in vendor pricing;
- **Cybersecurity:** Cost increases in this area are driven by heightened global cybersecurity risk from the growing complexity and volume of cyber attacks and the need to address recommendations from cybersecurity capability self-assessments and audits undertaken over the past two years.
- **Mandatory Reliability Standards:** The scope and complexity of the requirements under Mandatory Reliability Standards is increasing and the work that must be undertaken to strengthen our program and sustain new standards is increasing commensurately.

To date, the Technology KBU has managed to maintain an appropriate level of service by implementing cost optimization and reduction strategies to offset the cost drivers described above. These strategies have included, for example, deferring application maintenance as well as negotiating more favourable terms for contracts. However, the measures the Technology KBU has been using to mitigate the impacts of these pressures are no longer sufficient, resulting in an operating cost increase in the Test Period (for further information on the operating cost increases refer to section 5E.5.3 below).

Operating costs of the Technology KBU by department are as follows.

5E.5.2.1. Business Partner Services Department

The labour budget for the Business Partner Services department represents 44 FTEs. Employees in this department charge approximately 13 per cent of their time to capital projects. These FTEs are organized across five teams and support approximately 200 business-specific technology systems and applications.

The services budget in this department funds external service providers for business application maintenance and sustainment. These external service providers perform, evaluate and manage security, user-interface and platform stability improvements and upgrades across all business applications to maintain asset health and reliability.

This department also has a building and equipment budget for software licensing and support costs required for vendor support, security patches, and vendor-driven upgrades.

5E.5.2.2. Planning and Performance Department

Approximately 80 per cent of the Planning and Performance department budget is related to labour costs for 48 FTEs. Specifically:

- Five FTEs are responsible for strategic planning, investment benefits tracking, integrated investment planning, and portfolio planning for BC Hydro’s annual technology capital portfolio and five-year plan;
- Six FTEs in Enterprise Architecture are responsible for developing and maintaining technology roadmaps, reference architectures and technical standards that are used to guide technology investment and design decisions. Employees in this group charge approximately 27 per cent of their time to capital projects;
- Eight FTEs in the business management team are responsible for all aspects of technology governance including business planning, budget management, performance reporting, policies and standards management, risk management,

software asset management, workforce planning and business continuity and disaster recovery planning;

- 21 FTEs in the Records & Information Operations team manage a subset of BC Hydro's electronic and physical records; performing quality assurance, issuing approximately 52,000 drawings annually, providing corporate library services and circulating approximately 10,000 items per year; and
- Eight FTEs in the Vendor Management Office provide vendor relationship management and contract management, supporting a portfolio of approximately 80 vendors and a total average annual spend of approximately $160 million.

The non-labour budget for this department includes funding for research subscriptions and contractor resources providing subject matter expertise.

5E.5.2.3. Delivery Department

This department delivers the Technology capital portfolio, managing an average of over 130 active projects and work programs at any time and putting approximately 75 projects and work programs into service annually. The Delivery department workforce includes a mix of internal employees and external contractors. The labour budget for this department represents 20 FTEs. Employees in this department charge approximately 48 per cent of their time to capital projects.

The non-labour budget for this department is primarily for contractor resources to support Smart Metering Infrastructure end to end testing.

5E.5.2.4. Operations Department

The labour budget for the Operations department represents 137 FTEs. Employees in this department charge approximately 10 per cent of their time to capital projects. Specifically:

- Two FTEs in this department represent the Chief Information Officer and an Administrative Assistant;

- 46 FTEs on the Enterprise Applications teams operate and sustain approximately 100 enterprise-wide technology systems and applications used by BC Hydro employees and contractors;
- 29 FTEs on the Infrastructure, Network and Telecommunication Operations teams manage enterprise-wide and business-specific BC Hydro technology systems. This includes BC Hydro's approximately 2,500 data centre servers. This team also manages approximately 8,600 desktop and laptop computers and 5,700 mobile devices across BC Hydro;
- 39 FTEs on the Business Application Support and Service Management team respond to approximately 28,000 incidents, problems, change requests and service requests annually. Resourcing requirements for this team are driven by the continued need to operate, train and provide helpdesk support for critical technology systems and to establish and maintain service management processes and tools; and
- 21 FTEs on the Smart Metering and Network Operations team manage over 2 million meters, approximately 8,500 mesh network devices as well as over 370 million pieces of data per day (e.g., consumption data, power quality attributes, safety and security alarms, and operational exceptions).

This department's Services budget provides funding for the following costs:

- Enterprise application maintenance, sustainment and development;
- Data Centre services including maintenance and sustainment of servers, pooled storage, middleware, racks and cybersecurity devices; and
- End Point Device services including service desk support, desktops, laptops, mobile devices and video devices.

This department's materials budget provides funding for the lease and usage of approximately 500 printers/copiers located throughout BC Hydro.

This department's building and equipment budget provides funding for the following costs:

- Software license and maintenance fees for enterprise systems and applications; and
- Communications and utilities services across BC Hydro including mobile phones services, landline services, telecom services, internet services, satellite services and hardware maintenance and support.

5E.5.2.5. Cybersecurity and Compliance Department

The labour budget for this department represents 34 FTEs. Employees in this department charge approximately 3 per cent of their time to capital projects. Specifically, the FTEs have the following responsibilities:

- Three FTEs on the Cybersecurity Governance, Risk and Compliance team are responsible for cybersecurity governance, risk and performance encompassing the management of cybersecurity policy, enterprise risk management, training and awareness, metrics development and performance reporting across BC Hydro. The Cybersecurity Governance, Risk and Compliance team is also responsible for meeting or exceeding CIP compliance responsibilities for Technology;
- 11 FTEs on the CIP Compliance team manage implementation and sustainment of CIP Standards for IT systems and processes;
- Six FTEs on the Cybersecurity Planning team are responsible for cybersecurity strategic and investment planning for a capital portfolio of approximately $6 million annually; and
- 14 FTEs on the Cybersecurity Operations team are responsible for cybersecurity monitoring and incident response, including the management of end-point anti-malware controls, application controls, intrusion detection and prevention systems, firewalls and proxies. The Cybersecurity Operations team

receives over 13,000 cybersecurity alerts and blocks over 30 million emails annually.

The services budget in this department funds security infrastructure services, audit response, staff augmentation, 24/7 monitoring and response, external monitoring and threat intelligence, threat risk assessment, penetration testing and remediation, and security culture, training and awareness.

This department's building and equipment budget provides funding for security software licensing.

5E.5.3 Fiscal 2023 to Fiscal 2025 Plan Operating Costs and FTEs

Table 5E-8 Technology KBU Operating Costs and FTEs

		Schedule Reference	F2021 Actual	F2022 Decision	F2023 Plan	F2024 Plan	F2025 Plan
			1	2	3	4	5
1	**Technology KBU**						
2	Operating Costs ($ million)	5.5 L2	137.8	146.3	157.9	162.4	164.0
3	FTEs	16.0 L31	271	283	297	316	316

Operating costs are increasing by approximately $11.6 million from the fiscal 2022 Decision amounts to the fiscal 2023 plan due to:

- $4.2 million for cybersecurity (refer to Chapter 5, section 5.9),
- $2.0 million for Mandatory Reliability Standards (refer to Chapter 5, section 5.7),
- $4.1 million for software licensing and outsourced application and infrastructure support costs that are driven by market pricing, changes in licensing models and the increased use of and investment in digital technology to support business operations, and
- $2.1 million for budget that has been transferred from various KBUs as follows:
  - ▶ $1.8 million transferred from various KBUs (Supply Chain, Distribution Design and Customer Connections, Line Asset Planning, Learning and

Development and Properties) related to applications support and software licensing for in-service capital investments that will be managed by the Technology KBU, and

- $0.3 million for two FTEs that were transferred from the Reliability Standards Assurance KBU to Technology to establish the CIP Program Office; partially offset by,

- $0.8 million reduction due to Standard Labour Rate decreases.

Operating costs are increasing by approximately $4.5 million from the fiscal 2023 plan to the fiscal 2024 plan due to $1.9 million for cybersecurity, $1.6 million for Mandatory Reliability Standards and $1.0 million for Standard Labour Rate increases.

Operating costs are increasing by approximately $1.6 million from the fiscal 2024 plan to the fiscal 2025 plan due to $0.4 million for cybersecurity and $1.2 million for Standard Labour Rate increases.

FTEs are planned to increase by 33 from the fiscal 2022 Decision amounts to the fiscal 2025 plan. This is due to 4.5 FTEs required for cybersecurity and 7.0 FTEs required for Mandatory Reliability Standards in fiscal 2023, and 9.5 FTEs required for cybersecurity and 10.0 FTEs required for Mandatory Reliability Standards in fiscal 2024. In addition, since the Previous Application, two FTEs were transferred from the Reliability Standards Assurance KBU of the Safety and Compliance Business Group to Technology to establish the CIP Program Office, which supports the CIP Senior Manager in ensuring the consistent implementation of CIP requirements across BC Hydro. As noted in the Previous Application, the Technology KBU also internally repurposed $0.4 million for two FTE positions from Planning and Performance to Cybersecurity and Compliance to focus on cybersecurity governance, risk and compliance activities.

5E.6 Supply Chain KBU

5E.6.1 Responsibilities

The Supply Chain KBU continues to support the safe, cost-effective and timely work at BC Hydro through the delivery of materials, vehicles and procurement services to all KBUs.

There have been no material changes to the nature of the responsibilities of the Supply Chain KBU since the Previous Application.

Over the last decade, BC Hydro's work and annual spend with our external suppliers has increased by more than 300 per cent from $650 million to over $2 billion due mainly to BC Hydro's capital program. Supply Chain functions have become integral to delivering on key BC Hydro priorities such as capital plan delivery, ongoing reliable operations, safety and cost containment. BC Hydro uses suppliers to deliver equipment and materials such as transformers, generators, wire, electrical components and vehicles, as well as significant portions of work through services such as distribution line work, traffic management, vegetation management, security, information technology, engineering, vehicle maintenance and capital project construction.

In fiscal 2013, in response to the growing criticality of Supply Chain functions to BC Hydro, BC Hydro started a multi-year implementation of an updated Supply Chain and Fleet Services Business Model. Implementation of the business model includes changes to people, processes and technology. A significant portion of the people and process changes are well underway or complete. The implementation of the Supply Chain Applications Project in fiscal 2021, which provides information technology and other tools for Supply Chain, will achieve the remaining capabilities needed to fully operationalize the Supply Chain and Fleet Business Model. The Supply Chain Applications Project addresses the 13 identified capability gaps in BC Hydro's system and processes as described in BC Hydro's Supply Chain Applications Project Application filed in December 2016.

The ongoing operations and improved capabilities of Supply Chain are having a positive impact on performance across BC Hydro while helping to control costs. Some examples of how Supply Chain supports BC Hydro in maintaining its strong reliability ratings and delivering its capital, maintenance and operations plans on schedule and within budget include:

- Improved logistics support to other departments across BC Hydro on an ongoing basis for planned work as well as during emergency events ensuring that BC Hydro can safely and efficiently complete work and respond quickly during outages and emergencies. For example, Supply Chain's logistics support during storms and wildfires includes ensuring that the materials needed to restore power are available to field crews at outage sites across the province. It coordinates transportation and accommodation for goods and people who must be mobilized to respond, and emergency repairs of vehicles and equipment to keep staff operational throughout emergency events;
- Developing and implementing project supply chain strategies related to Stations, Lines and Interconnection projects to ensure materials and services required for these projects are available in a timely manner; and
- Developing and implementing category strategies such as:
  - The Contingent Labour Resource Augmentation category strategy where BC Hydro created consistent processes and tools across the organization for acquiring and managing contingent labour. It facilitates the use of competitive market-based rates, streamlined and standardized processes that reduce effort and mitigate risk. It also provides timely and reliable access to quality resources to support the broad variety of work across the organization; and
  - Several of BC Hydro's category strategies for services have included "unitizing" the service which means creating hundreds of individual work units that represent the full range of services that could be required. This

allows for more transparency into the costs of different work packages, supports market competitiveness and provides reliable information for work planning and budgeting to improve delivery of work.

The Supply Chain KBU is comprised of the following departments:

- Procurement Department; and
- Materials Management and Fleet Services Department.

5E.6.1.1. Procurement Department

Overall, the Procurement department has evolved in recent years to provide more strategic capabilities to respond to the needs of BC Hydro and to the increased complexities in the market. This includes more robust planning, analysis and supply market engagement.

The Procurement department is responsible for:

- Developing and executing supply chain related strategies, sourcing programs and project delivery strategies to support approximately $2 billion in annual enterprise capital construction, operational and maintenance needs;
- Developing and implementing category management processes and individual category strategic plans for BC Hydro’s key spend categories. The work incorporates strategy development, business process change, sourcing, and guidance on contract and supplier management. Examples of spend categories include power transformers, line services, vegetation management services, engineering services, security services, electrical components and distribution transformers;
- Leading Indigenous procurement policies and processes and working with the Indigenous Relations KBU to identify Indigenous procurement opportunities to meet commitments included in Impact Benefit Agreements and Relationship Agreements with Indigenous Nations;

- Developing, communicating and monitoring compliance with BC Hydro's procurement policies and guidelines which incorporate the obligations under trade agreements that BC Hydro is a party to such as the Canadian Free Trade Agreement and the New West Partnership Trade Agreement;
- Managing several enterprise-wide programs such as travel, credit card and the contingent labour resource augmentation solution; and
- Managing BC Hydro's Accounts Payable function.

5E.6.1.2. Materials Management and Fleet Services Department

The Materials Management and Fleet Services groups have been consolidated into one department reporting into a single Director who reports into the Chief Supply Chain Officer.

Materials Management

The Materials Management group provides the following services:

- Inventory forecasting and planning;
- Material distribution and transportation;
- Field warehouse operations;
- Disposition of assets at end of life from BC Hydro's systems; and
- Waste transformer oil management.

The Materials Management group has one main distribution centre located in Surrey, B.C. and services over 80 locations that cover the entire BC Hydro service area, requiring over 400,000 kilometers of travel each year. Over 50 per cent of our locations are serviced remotely from larger headquarters and require scheduled deliveries using complex transportation routes to replenish inventory levels over difficult terrain and remote islands.

Rigorous planning and inventory replenishment processes ensure that high service fill rates are achieved to support our crews performing restoration work and storm response. Our network provides business continuity with the management of spare parts and emergency inventories to ensure rapid response in the event of a system failure or natural disaster.

Materials Management is also required to procure inventory items that conform to unique specifications as a result of BC Hydro's system design. Achieving these objectives requires active contract management with key suppliers to realize on time delivery and quality specifications. Many of our materials (e.g., power poles) have long-lead times that require rigorous demand management to plan and distribute inventory for project work. Our Planning function manages inventory levels for approximately 39,000 inventory items that are situated across the BC Hydro network.

Materials Management also performs the pre-assembling of materials that involve staging, assembling, and kitting of inventory components to meet the needs of some capital projects.

Fleet Services

The Fleet Services group is responsible for the procurement and life-cycle management of approximately 3,500 fleet assets (including vehicles, trailers and other equipment such as forklifts). The life-cycle management of fleet assets includes:

- Asset planning and acquisition;
- Engineering;
- Registration and insurance;
- Maintenance and repair;
- Vehicle fueling;

- Asset transfers and disposal; and
- Fleet supplier and contract management.

Fleet Services operates five main garages and has mobile mechanics based out of 16 additional district offices.

5E.6.2 Overview of Operating Costs and FTEs

Table 5E-9 Supply Chain KBU Fiscal 2022 Decision Operating Costs and FTEs

	($ Millions)	Labour	Services - Other	Materials	Building & Equipment	Capitalized Overhead	External Recoveries	Total Operating	Total FTEs
1	Procurement	21.3	2.2	0.1	0.1	0.0	0.0	**23.6**	169
2	Materials Management	20.5	6.7	2.6	0.7	0.0	0.0	**30.5**	191
3	Fleet Management	14.6	13.4	16.9	0.4	0.0	0.0	**45.3**	109
4	Supply Chain Lead	0.7	0.9	0.0	0.0	0.0	0.0	**1.6**	7
5	**Total (Sch 5.5 L3, Sch 16.0 L32)**	**57.1**	**23.1**	**19.5**	**1.2**	**0.0**	**0.0**	**101.0**	**475**

5E.6.2.1. Procurement Department

Approximately 90 per cent of the Procurement department’s budget is related to labour. This represents 169 FTEs. Approximately 60 per cent of the Procurement department’s Services budget relates to contractor and supplemental labour to provide specialized expertise and resource augmentation for work peaks. The remainder of this budget relates to licence fees for program tools and external training fees.

The Procurement’s department operating cost budget has remained relatively flat from fiscal 2020 to fiscal 2022 despite the large volume, increasing complexity of work and improved strategic support.

The 169 FTEs are divided into the following teams which are described below:

- Category Management;
- Infrastructure Projects;
- Purchasing; and
- Supply Chain Central Services.

The Category Management, Infrastructure Projects and Purchasing teams consist of 117 FTEs and are comprised of the following:

- 59 FTEs on the Category Management team develop and implement category management strategies that will best meet BC Hydro requirements and optimize value. These FTEs focus on the approximately 50 spend categories that are critical to BC Hydro and represent the majority of BC Hydro's annual supplier spend.

  When developing and executing specific category strategies, BC Hydro sets high-level objectives in eight areas to reflect what good performance would be in that specific category to meet BC Hydro's needs. The eight areas are: reliability, responsiveness, safety, organizational productivity and efficiency, Indigenous Nations, compliance and control, supplier performance and relationships and total lifecycle cost. Category strategies are driving improved performance in all these areas which is helping individual areas of BC Hydro and the company deliver on their business priorities.

- 27 FTEs on the Infrastructure Projects team are responsible for developing and implementing project procurement strategies including Indigenous procurement participation for approximately 450 active projects related to Stations, Lines and Interconnection projects. Projects range in complexity and risk. Approximately 80 per cent of the labour costs for these FTEs are charged directly to the capital projects they support; and

- 31 FTEs on the Purchasing team are responsible for supporting the majority of the thousands of procurement related transactions annually, such as contract requests, releases and amendments that happen daily. They are also responsible for the smaller to medium sized and lower to medium complexity procurements, which mostly includes the sourcing of all materials over $25,000 as well as the sourcing of some short- to medium-term requirements for construction and other services. This team also develops and implements

Indigenous procurement participation strategies for these procurements where applicable.

Overall, the 117 FTEs on the Category Management, Infrastructure Projects and Purchasing teams conduct approximately 25,000 procurement transactions each year including 170 public sourcing competitions and 230 secondary sourcing processes for suppliers pre-qualified through public competitions. These FTEs also develop and implement project procurement strategies for approximately 450 active projects and develop and implement category strategies that will cover approximately 80 per cent of BC Hydro's supplier spend.

The Supply Chain Central Services team of 52 FTEs is also part of the Procurement department and is comprised of the following:

- Seven FTEs on the Procurement Policy, Compliance and Reporting team that develop, sustain, communicate and support compliance with procurement policies and guidelines across all of BC Hydro. This team provides training and interpretation guidance as well as reporting on Supply Chain metrics and data analysis. The team also maintains all policies, procedure and guidance documents and produces reports on an ongoing basis;
- 12 FTEs manage several enterprise-wide services, programs and contracts including:
    - The Bid Station which posts approximately a thousand procurement-related bids and amendments on BC Bid each year and provides central collection of all Bid submissions;
    - Vendor information maintenance to ensure supplier information required for sending orders and payments is accurate;
    - The credit card program with 5,500 card holders and approximately 3,500 change requests per year including new card requests, suspensions, lost and damaged cards and card limit changes; and

- The eCommerce program which allows for purchase orders and invoices to be sent electronically thereby reducing manual work for staff. This program also allows suppliers to choose earlier payment options on approved invoices in exchange for a sliding scale discount;

- 19 FTEs on the Accounts Payable team. The Accounts Payable function was repatriated to BC Hydro in May 2018 from Accenture. The Accounts Payable team processes approximately 140,000 invoices per year; and
- 14 FTEs in the Contingent Labour Solutions Office of which two FTEs manage BC Hydro's Contingent Labour Solution and 12 FTEs are part of an administrative/clerical pool. These 12 temporary employees provide short-term coverage for administrative support throughout the company and are only paid for their time while on assignment. Employees in this pool charge all their time to the individual cost centres they are assigned to for work.

5E.6.2.2. Materials Management and Fleet Services Department

The Materials Management and Fleet Services department is composed of the Materials Management group and the Fleet Services group. Of the departments total fiscal 2022 operating cost budget of $75.8 million and 300 FTEs, $30.5 million and 191 FTEs are for the Materials Management group and $45.3 million and 109 FTEs are for the Fleet Services group.

Materials Management

Materials Management is a critical support function to provide materials related services to over 1,500 BC Hydro field employees as well as approximately 80 contractor crews that perform work across the province. The Materials Management group manages approximately 350,000 transactions per year that include the issue, transfer and receipt of materials. It also manages approximately $300 million of inventory spread across the province.

Overall, the Material Management operating cost budget has remained relatively flat over the last three years after reflecting for the impact of the transfer of eight Stations Field Storekeepers to the Materials Management group from the Operations Business Group in fiscal 2021. This control on costs is being achieved by continually evaluating its delivery processes and finding improvements such as:

- Centralized contractor fulfillment for Lower Mainland contractor crews;
- Optimization of the main distribution centre labor pool to service multiple work streams at BC Hydro including project materials;
- Consolidation of Maintenance, Repair, Operations inventory at Field Stores to support crews and contractors; and
- Centralized concrete storage from suppliers.

The majority of this group's budget relates to labour costs for 191 FTEs. The number of Field Storekeepers at each location is aligned to BC Hydro's crew complements and transactional volumes to fulfill planned, emergent and maintenance work. The 191 FTEs are in the following functions:

- 27 FTEs are responsible for planning, acquiring and managing materials. These FTEs process an average of 225,000 inventory material requests each year, manage 39,000 catalogue items, process 18,000 purchase requisitions for catalogue and non-catalogue items each year. In addition, this team is responsible for managing approximately 130 contracts worth approximately $1.5 billion with over 100 suppliers;
- 87 FTEs in Regional Operations that support 60 regional field stores. This team manages 350,000 transactions each year related to the receipt of materials at the regional field stores and issuing materials to field crews across the province; and

- 77 FTEs in Central Operations that manage the delivery of materials to regional field stores with a monthly average of 80 scheduled runs via 16 routes to over 80 locations across the Province. This team also manages the disposal of materials and equipment, scrap materials recycling as well as oil management and wood recycling. BC Hydro processes between 1.5 million to 2 million pounds of salvage materials each month, generating $4.5 million per year from the sale of scrap materials and $300,000 per year from the sale of recycled oil. The recycling of transformer oil and materials results in approximately 94 per cent diversion from landfills and our transportation network is optimized to leverage backhauls from outbound routes to return materials for salvage processing.

This group's Services – Other budget of $6.7 million includes $3.9 million for third-party transportation costs to transport materials from the Main Distribution Centre to the regional field stores and $1.2 million for environmental contractors to handle used materials. The remainder of this budget funds travel for staff travelling between store locations to cover regional field stores that are not regularly staffed.

This group's Materials budget of $2.6 million is largely composed of the annual provision for obsolete materials.

Fleet Services

BC Hydro's fleet assets are relied on by diverse BC Hydro work teams, including over 1,500 operational crew members, doing planned and unplanned work (such as responding to storms and emergencies) safely and efficiently across the province. Almost 40 per cent of our fleet assets are located in smaller and remote locations and require use in off-road terrain such as transmission rights of way.

This groups labour budget represents 109 FTEs of which close to 85 per cent are union roles. These FTEs are in the following main functions:

- Nine FTEs are responsible for asset planning, acquisition, fleet engineering and supplier and contract management. This team develops and implements acquisition strategies, scans the market to keep abreast of new and green vehicle technologies, delivers on a Fleet capital spend of approximately $30 million per year, manages contracts and relationships with 35 suppliers (with an annual operating and capital spend of approximately $65 million), participates in sourcing events to select suppliers, performs fleet safety and maintenance engineering, manages manufacturer recalls, updates vehicle specifications, and manages fleet initiatives such as trials of new heavy hybrid vehicles; and
- 100 FTEs deliver maintenance operations across the province to keep our fleet assets and BC Hydro staff operational. Approximately 1,900 (54 per cent) of BC Hydro's 3,500 fleet assets are maintained and repaired in-house and the remaining lighter-duty assets are outsourced for repair and maintenance through a fleet management supplier.

BC Hydro's specialized and heavy aerial units are safety-critical vehicles operated in proximity to high-voltage power lines by our field crews. To ensure the availability of these specialized units and safety of our crews BC Hydro predominantly performs in-house maintenance/repair of heavier assets and equipment including maintenance scheduling and mandatory annual testing. This in-house maintenance/repair is performed by employees that are skilled, red-seal-journeyed tradespeople, and are supplemented by the use of external heavy-vehicle chassis dealers across the province. We also invest in specialized training for our mechanics in order for them to earn their Canadian Utility Fleet Mechanic certification and increase technical competency working on aerial equipment. To-date over 70 BC Hydro fleet staff have earned this certification, and another 15 mechanics and apprentices are presently at various stages in the Utility Fleet Mechanic training/certification process.

The FTEs in this group also manage the outsourced maintenance and repair of light and medium duty assets; operate a Fleet parts room; administer BC Hydro's vehicle pools, asset insurance/registration renewals, asset transfers and disposals; complete commissioning on new heavy vehicles, and manage fuel, lubricant and carbon offset costs.

Each year, Fleet Services purchases 200 to 350 new assets annually for diverse user groups across the organization, completes approximately 33,000 vehicle work orders and 8,000 parts orders, manages approximately 107,000 fuel transactions, and responds to approximately 150 accidents requiring repair coordination and cost recovery with ICBC.

In order to manage its budget and to support the objectives of its user groups Fleet Services continues to look for improvements to gain efficiencies. Examples include:

- Doubling the throughput in a mid-life maintenance inspection process;
- Working with the front-line crews to standardize heavy and medium specifications resulting in quicker delivery and commissioning time;
- Implementing manufacturers' new vehicle programs to gain access to a larger network of certified outfitting vendors (who install specialized equipment such as winches, safety equipment and storage on new vehicles) and gain shipping efficiencies; and
- Ensuring that our maintenance program, personnel and facilities meet provincial Commercial Vehicle Safety & Enforcement standards to save money and vehicle downtime. This enables us to complete one mandatory commercial inspection annually via internal staff at our own facilities versus the requirement for two inspections annually if vehicles had to go for external inspection.

This group's Services – Other budget of $13.4 million includes $7.6 million for the costs of outsourced maintenance and repairs on light and medium assets, $2.3 million for asset registration and insurance costs with ICBC, $0.9 million for mandatory vehicle testing services provided by BC Hydro's subsidiary Powertech and carbon offset costs of $0.5 million. The remainder of this budget relates to mobile mechanic travel costs to maintain and repair assets in their assigned territories including remote locations, and vehicle lease costs.

The groups Materials budget of $16.9 million primarily includes fuel costs of $10.4 million and parts costs of $6.0 million.

5E.6.3 Fiscal 2023 to Fiscal 2025 Plan Operating Costs and FTEs

Table 5E-10 Supply Chain KBU Operating Costs and FTEs

		Schedule Reference	F2021 Actual	F2022 Decision	F2023 Plan	F2024 Plan	F2025 Plan
			1	2	3	4	5
1	**Supply Chain KBU**						
2	Operating Costs ($ million)	5.5 L3	92.7	101.0	98.6	99.2	100.2
3	FTEs	16.0 L32	513	475	474	465	459

The changes in operating costs in the Test Period from the fiscal 2022 Decision are largely due to changes in the Standard Labour Rates, a transfer of budget to the Technology KBU for licence fees, and the realization of benefits from the Supply Chain Application project implementation. While these Supply Chain Application benefits will be realized in other KBUs during the Test Period, plans for implementation are currently being refined and therefore the operating cost and FTE savings have been included in the Supply Chain KBU in this application.

As shown in Table 5E-10 above, operating costs are decreasing by $2.4 million from the fiscal 2022 Decision amounts to the fiscal 2023 plan primarily due to:

- $1.2 million budget transfer to the Technology KBU for the Ariba licence fees;
- $0.9 million for a decrease in Standard Labour Rates; and
- $0.2 million in Supply Chain Application related benefits savings which will be realized in other KBUs during the Test Period once implementation plans are refined.

Operating costs are increasing by approximately $0.6 million from the fiscal 2023 plan to the fiscal 2024 plan primarily due $1.5 million for Standard Labour Rate increases partly offset by $0.8 million in Supply Chain Application related benefits savings which will be realized in other KBUs during the Test Period once implementation plans are refined.

Operating costs are increasing by $1.0 million from the fiscal 2024 plan to the fiscal 2025 plan due to $1.7 million for Standard Labour Rate increases partly offset by $0.8 million in Supply Chain Application related benefits savings which will be realized in other KBUs during the Test Period once implementation plans are refined.

FTEs are planned to decrease by 16 from the fiscal 2022 Decision amounts to the fiscal 2025 plan. This is primarily due to the reduction in FTEs expected as part of the Supply Chain Application benefits savings.

5E.7 Business Unit Support

5E.7.1 Responsibilities

The Finance, Technology, Supply Chain Business Unit Support KBU holds the budget for the Office of the Executive Vice President of Finance, Technology, Supply Chain and Chief Financial Officer.

5E.7.2 Overview of Operating Costs and FTEs

Table 5E-11 Business Unit Support KBU Fiscal 2022 Decision Operating Costs and FTEs

	($ Millions)	Labour	Services - Other	Materials	Building & Equipment	Capitalized Overhead	External Recoveries	Total Operating	Total FTEs
1	EVP, Finance, Technology, Supply Chain & CFO	0.8	0.1	0.0	0.0	0.0	0.0	**0.9**	3
2	**Total (Sch 5.5 L4, Sch 16.0 L33)**	**0.8**	**0.1**	**0.0**	**0.0**	**0.0**	**0.0**	**0.9**	**3**

5E.7.3 Fiscal 2023 to Fiscal 2025 Plan Operating Costs and FTEs

Table 5E-12 Business Unit Support KBU Operating Costs and FTEs

		Schedule Reference	F2021 Actual	F2022 Decision	F2023 Plan	F2024 Plan	F2025 Plan
			1	2	3	4	5
1	**Business Unit Support KBU**						
2	Operating Costs ($ million)	5.5 L4	0.8	0.9	0.8	0.9	0.9
3	FTEs	16.0 L33	3	3	3	3	3

Operating costs and FTEs are planned to remain stable during the Test Period compared to the fiscal 2022 Decision amounts.

BC Hydro
Power smart

Fiscal 2023 to Fiscal 2025

Revenue Requirements Application

Chapter 5F

Operating Costs

Customer and Corporate Affairs

Business Group

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5F.1 Introduction – Customer and Corporate Affairs Business Group

Chapter 5F details the composition of, and rationale for, the operating costs of the Customer and Corporate Affairs Business Group. The Customer and Corporate Affairs Business Group is one of six business groups in the organization and serves a Support function in the Plan-Build-Operate-Support model.

The Customer and Corporate Affairs Business Group budget was developed as part of the budgeting process outlined in Chapter 5, section 5.4, which the BCUC found to be reasonable in its decision on the Previous Application.[364] The budgeting approach includes both bottom-up and top-down elements and examines more than just incremental costs. The information provided in Chapter 5F demonstrates the basis for the entirety of the Business Group and KBU budgets, rather than focussing only on incremental cost requirements. This information is provided in a format and level of detail consistent to that presented in the equivalent chapter in the F2020-F2021 RRA.

Chapter 5F is organized as follows:

- Section 5F.2 provides an overview of the organization and responsibilities of the Customer and Corporate Affairs Business Group;
- Section 5F.3 provides the operating costs and FTE information for the Customer and Corporate Affairs Business Group as a whole;[365] and
- Sections 5F.4 to 5F.8 provide more detailed information on the responsibilities, cost and FTEs for each KBU within the Customer and Corporate Affairs Business

[364] BCUC Decision and Order No. G-187-21, Fiscal 2022 Revenue Requirements Application (June 17, 2021), page 27: "The Panel considers BC Hydro's budgeting process involving top-down and bottom-up elements goes beyond the examination of incremental changes from the prior year and continues to be reasonable for forecasting operating costs. Therefore, for these reasons, the Panel finds the fiscal 2022 operating costs requested for recovery to be reasonable."

[365] Please note the amounts presented in the tables in these sections may not add due to rounding.

Group. The operating costs and FTE information for each KBU is broken out into two sections:[365]

- Overview of Operating Costs and FTEs – This section explains the starting operating costs and FTEs for the KBU based on the fiscal 2022 Decision amounts; and
- Fiscal 2023 to Fiscal 2025 Plan Operating Costs and FTEs – This section explains any incremental changes in the KBU between fiscal 2022 Decision amounts and fiscal 2023 to fiscal 2025 plan.

5F.2 Overview of Customer and Corporate Affairs Business Group Organization and Responsibilities

The Customer and Corporate Affairs Business Group is responsible for serving our customers, conservation and energy management programs, communications, and regulatory affairs and rate design. The Business Group's role includes:

- Managing the experience of our four million residential, commercial and industrial customers as they interact with BC Hydro;
- Designing and implementing energy efficiency programs that enable and encourage all customer groups to conserve and manage the energy they use;
- Building relationships with the public, customers, external stakeholders, our regulator and our shareholder through ongoing communication and engagement opportunities; and
- Ensuring compliance with regulatory standards and developing customer rates.

The Customer and Corporate Affairs Business Group consists of the following KBUs:

Business Group	Key Business Unit
Customer and Corporate Affairs	Customer Service Conservation and Energy Management Communications and Community Engagement Regulatory and Rates Business Unit Support

Since the Previous Application, the People, Customer and Corporate Affairs Business Group has been renamed to the Customer and Corporate Affairs Business Group to reflect a change in reporting of the Chief Human Resources Officer. Effective November 2021, the Chief Human Resources Officer will report directly to the President and Chief Executive Officer. This shift reflects the significance of the human resources function in managing the programs that support, develop and shape our people and culture. The Human Resources KBU is, among other things, leading company-wide inclusion and diversity efforts.

In addition, the Ethics and Merit Office now reports under the Human Resources KBU. This move allows for greater alignment between the two groups as the Ethics Officer frequently collaborates with Human Resources on investigations, employee complaints and other conflict resolution situations.

Information on the Human Resources KBU is now included in Chapter 5G, section 5G.3.

5F.3 Fiscal 2023 to Fiscal 2025 Plan Operating Cost and FTE Summaries

This section addresses planned operating costs and FTEs for the Customer and Corporate Affairs Business Group. The following are some key points of note with respect to the information provided in Figure 5F-1, Table 5F-1, Figure 5F-2, Table 5F-2 and Table 5F-3.

- The Customer Service KBU comprises 70 per cent of the operating cost budget and 66 per cent of the total FTEs for the Customer and Corporate Affairs Business Group.

- Overall, labour costs make up over 65 per cent of the total operating costs for the Customer and Corporate Affairs Business Group; and
- Total operating costs are slightly increasing from fiscal 2022 Decision amounts to fiscal 2025 plan. Cost increases are primarily related to increases in standard labour rates.

Planned operating costs for this Business Group are approximately $96.6 million in fiscal 2023, approximately $98.6 million in fiscal 2024 and approximately $100.8 million in fiscal 2025.

The operating costs for the Customer and Corporate Affairs Business Group are summarized by KBU in Figure 5F-1 below.

Figure 5F-1 Customer and Corporate Affairs Net Operating Costs by KBU (Fiscal 2023 Plan) ($ million)

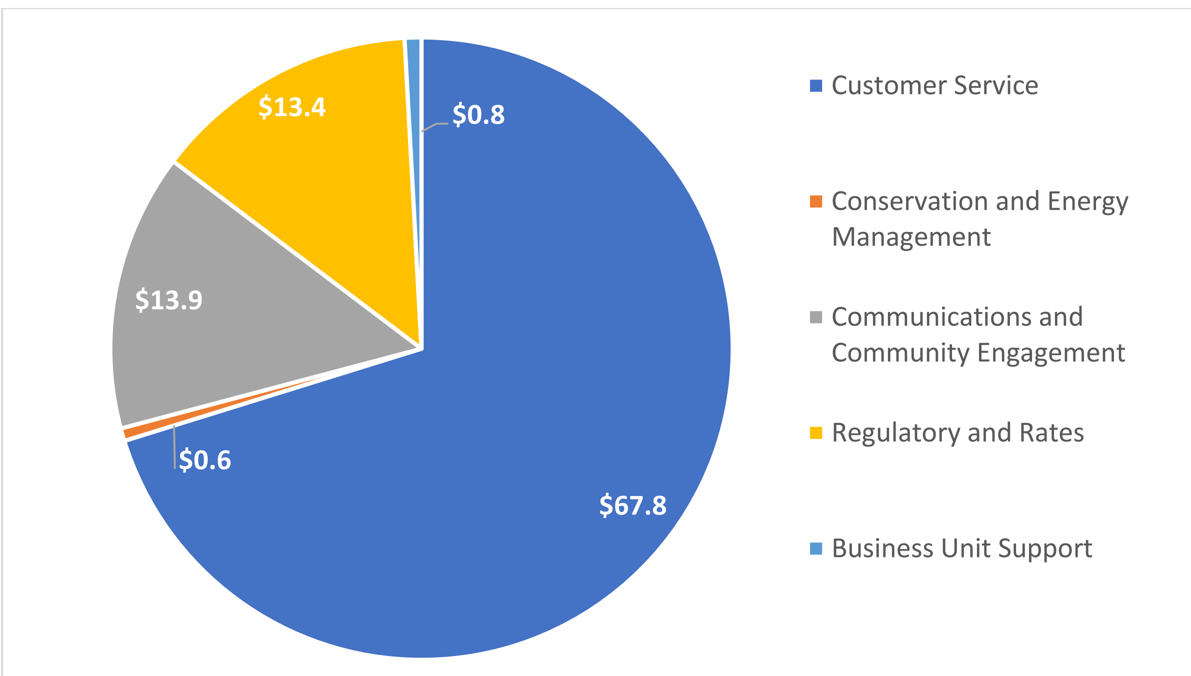

Table 5F-1 Customer and Corporate Affairs Net Operating Costs by KBU

	($ million)	Schedule Reference	F2021 Actual	F2022 Decision	F2023 Plan	F2024 Plan	F2025 Plan
			1	2	3	4	5
1	Customer Service	5.6 L1+L9	64.5	68.3	67.8	69.2	70.7
2	Conservation and Energy Management	5.6 L2	0.5	0.7	0.6	0.7	0.7
3	Communications and Community Engagement	5.6 L3	12.9	14.2	13.9	14.2	14.5
4	Regulatory and Rates	5.6 L4	13.7	13.1	13.4	13.7	14.0
5	Business Unit Support	5.6 L5	0.8	0.9	0.8	0.9	0.9
6	Total	5.6 L11	92.4	97.1	96.6	98.6	100.8

The FTEs for the Customer and Corporate Affairs Business Group are summarized by KBU in Figure 5F-2. Additional details are provided in Table 5F-2 below.

Figure 5F-2 Customer and Corporate Affairs FTEs by KBU (Fiscal 2023 Plan)

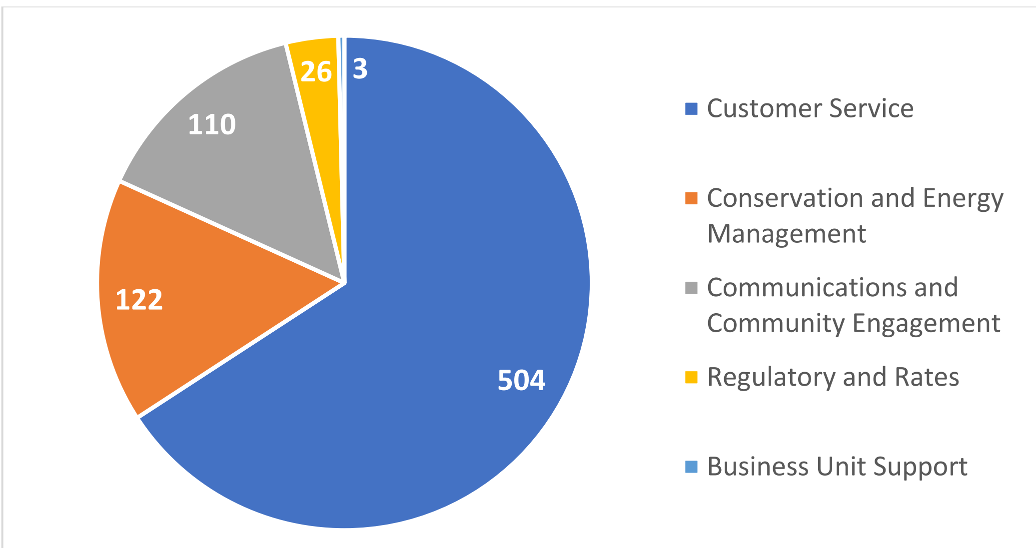

Table 5F-2 Customer and Corporate Affairs FTEs by KBU

	(FTEs)	Schedule Reference	F2021 Actual	F2022 Decision	F2023 Plan	F2024 Plan	F2025 Plan
			1	2	3	4	5
1	Customer Service	16.0 L35	507	492	504	504	504
2	Conservation and Energy Management	16.0 L36	119	116	122	122	123
3	Communications and Community Engagement	16.0 L37	97	108	110	110	110
4	Regulatory and Rates	16.0 L38	23	23	26	26	26
5	Business Unit Support	16.0 L39	3	3	3	3	3
6	Total	16.0 L40	749	742	765	765	766

Table 5F-3 below provides a continuity table which highlights changes to the Customer and Corporate Affairs Business Group from the Previous Application. An overall discussion of these changes, at a company-wide level, is provided in Chapter 5, section 5.5.3. Further details, by KBU, are provided in the sections below.

Table 5F-3 Customer and Corporate Affairs Operating Costs Continuity Schedule

	($ million)	Ref	F2023 Plan	F2024 Plan	F2025 Plan
1	**F2022 Revenue Requirement Application Plan**	a	**122.3**		
2	**Compliance Filing Adjustment**	b	(0.8)		
3	Reorganizational Impact	c	(24.4)		
4	**F2022 Decision (Schedule 5.6, line 11)**	d = Σ a to c	**97.1**		
5	Budget Transfers Between Business Groups	e	0.4		
6	**F2022 Forecast (Schedule 5.6, line 11)**	f = d+e	**97.5**	**96.6**	**98.6**
7	Current Year Budget Transfers Between Business Groups	g	(0.5)	-	-
8	**Current Year Incremental Adjustments:**				
9	Customer Crisis Fund Operating Costs		(0.5)	-	-
10		h	**(0.5)**	**-**	**-**
11	**Test Period Net Cost Increase/Decrease**				
12	**Uncontrollable Cost Increases**				
13	Current Service Costs and Other Labour Costs		(0.9)	1.7	1.9
14	BCUC and CER Cost Recovery Levies		0.2	0.2	0.2
15		i	(0.7)	1.8	2.1
16	**Strategic Initiatives**				
17	Electrification initiatives		0.2	0.1	0.1
18		j	0.2	0.1	0.1
19	**Net Cost Savings**				
20	Electric Vehicle Charging Infrastructure Costs		0.8	-	-
21	Test Period Savings		(0.2)	-	-
22		k	0.6	-	-
23	**Total Test Period Net Increase/(Decrease)**	l =∑ h to k	**0.1**	**1.9**	**2.2**
24	**F2023 Net Operating Costs (Schedule 5.6, line 11)**	m = f+g+h+l	**96.6**	**98.6**	**100.8**

Table may not add due to rounding

5F.4 Customer Service KBU

5F.4.1 Responsibilities

The Customer Service KBU is responsible for most of the key touchpoints for our residential, commercial, and industrial customers as they interact with BC Hydro, including the customer-facing activities related to revenue collection. Customer Service works with other groups across BC Hydro to design, implement, and operate services, processes, programs, systems, and tariffs that make it easy for customers to do business with us. With few exceptions (noted below), the functions and organization of this KBU have remained relatively consistent since the Previous Application.

In delivering our services, we strive to balance:

- Maximizing revenue, by growing existing load and pursuing new load opportunities, and by managing accounts receivables, reducing electricity theft and losses;
- Meeting customers’ service expectations, by understanding customer needs, removing barriers, and influencing the organization to incorporate customers’ perspectives; and
- Minimizing costs, by continuously improving our operational efficiency to realize persistent cost savings through the promotion of customer self-service and automation of manual tasks.

There have been two changes to the Customer Service KBU since the Previous Application. First, the Vice President, Customer Service Department was renamed Business Unit Support to better reflect its function. Second, a reorganization and renaming of the Customer Service Operations department to the Customer Relations and Customer Metering department resulted in some FTE transfers within Customer Service.

The Customer Service KBU is comprised of the following six departments:

- Contact Centre and Billing Operations Department;
- Customer Analytics, Revenue and Risk Management Department;
- Customer Relations and Customer Metering Department;
- Key Account Management Department;
- Large Customer Rate Operations Department; and
- Business Unit Support Department.

5F.4.1.1. Contact Centre and Billing Operations Department

This department is responsible for day-to-day management of core customer services processes including:

- Ensuring the accuracy of 1.3 million electricity bills sent to customers each month;
- Operating BC Hydro's primary customer contact centres, which receives over 2.6 million calls each year. Customer service representatives answer 1.3 million of these calls and the remainder are resolved within the Interactive Voice Response system;
- Processing payment exceptions when payments cannot be automatically applied to accounts (e.g., cheques with incorrect account numbers, outdated pre-authorized banking information, or Electronic Funds Transfer errors);
- Performing collections activities ("dunning") to maximize the recovery of revenues, such as issuing late payment reminders, disconnecting services for non-payment, assessing security deposits, and participating in bankruptcy proceedings;
- Providing day-to-day support to customers and planning for usability and transactional enhancements to the MyHydro web portal, which allows

customers to view and update account information online and enables more than 100,000 self-service transactions per month;

- Operating enhanced service channels such as the Business Account Services team and four in-person service offices;[366]
- Providing operational support and planning to the contact centre and billing teams by forecasting work volumes, developing staffing schedules that minimize labour costs while meeting wait and response time targets, managing training and process documentation, reviewing contact centre calls to enable coaching, and performing root cause analysis of escalations to understand how future issues can be avoided; and
- Developing, managing, and administering the Net Metering Program which continues to grow each year.

The department is responsible for planning the ongoing improvements to business practices and processes for the above functions to improve our customer service or reduce costs. It also leads customer engagement activities to bring customer perspectives to certain cross-organizational projects.

The Contact Centre and Billing Operations department is also responsible for the delivery of the Customer Crisis Fund Program which was established pursuant to Order in Council 365/2021 issued on June 21, 2021.[367]

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[366] BC Hydro operates four in-person locations, in Vancouver, Burnaby, Vernon and Prince George; however, those offices are currently closed because of COVID-19 restrictions. During the Test Period, BC Hydro plans to open two addition offices, in Surrey and Victoria.

[367] The Contact Center and Billing Operations Department was responsible for delivery of the Customer Crisis Fund Pilot Program, which ended on May 31, 2021 pursuant to BCUC Order No. G-166-17. Order in Council 365/2021 was issued to establish a new Customer Crisis Fund Program while the Government of British Columbia undertakes a policy review of options for a permanent customer crisis program, and to require that the program be funded from the surplus balance in the Customer Crisis Fund Regulatory Account attributed to the CCF Pilot Program, to a maximum of $5 million. The policy review is anticipated to take approximately 18 months. The BCUC approved the deferral of operating costs and customer grants on July 5, 2021 pursuant to Order No. G-203-21.

5F.4.1.2. Customer Analytics, Revenue and Risk Management Department

This department is responsible for the reduction of electricity theft and other non-theft revenue loss through distribution system metering and business intelligence tools including Smart Meter Infrastructure and a field inspection team. These activities include:

- Identifying, assessing and prioritizing analytics and human sourced leads for electricity theft, stolen meters, revenue losses and safety risks, and performing field inspections;
- Quantifying theft and other revenue losses from completed field inspections;
- Recovering funds from parties responsible for theft, including managing the involvement in civil litigation and criminal cases related to electricity theft;
- Conducting proactive distribution feeder inspections and utilizing the energy inventory balance approach enabled by smart meters to prevent recurrence of theft from grow-ops;
- Working with customers to address overloaded services and assist with customer safety and security related concerns;
- Identifying and resolving metering and billing errors; and
- Responding to local government requests for consumption information under the *Safety Standards Act*.

This department also manages the customer and energy analytics function. The volume of customer consumption and transaction data has increased significantly with the introduction of technologies such as smart meters and customer self-service capabilities. Analysis of this data allows us to make data-driven business decisions that improve customer service and reduce costs. These analyses include:

- Providing hourly load profiling and localized consumption information to assist with long-term business planning, such as load forecasts;

- Identifying detailed customer characteristics and consumption information to inform the Electric Tariff and rate designs;
- Providing data and analysis to support regulatory filings such as the evaluation of the Customer Crisis Fund Pilot, customer load and peak patterns for the Fully Allocated Cost of Service Study, Net Metering Evaluation, rate designs and the Integrated Resource Plan;
- Supporting operating groups by providing insights as well as self-service analytical tools that help improve or develop operational policies and business practices; and
- Supporting municipalities, customers and other external parties with a variety of initiatives related to CleanBC targets, electrification opportunities, and research studies through the provision of aggregated customer and energy data.

5F.4.1.3. Customer Relations and Customer Metering Department

This department is responsible for the day-to-day management of core field-related customer services including:

- Providing manual meter reading services for approximately 31,000 non-automated meters and other field customer service work;
- Supporting the Operations Business Group to coordinate and facilitate most meter exchanges and the planned outage notification processes;
- Operating the Underground Locate Centre in accordance with the BC One Call Ltd. membership agreement[368] in support of safety and damage prevention. This team responds to property owner or contractor requests by

[368] BC One Call Ltd. is a not-for-profit corporation that enables public and worker safety, as well as the reduction in damages, by providing a single point of contact for contractors and members of the public to identify the location of underground equipment. BC Hydro, FortisBC, Telus and more than 300 other utilities and municipalities are members. BC One Call pre-screens requests to locate underground equipment and notifies BC Hydro when digging will occur in the vicinity of our assets, based on mapping we provide. BC Hydro then provides the requestor with drawings that indicate the exact location of our equipment.

sending site plans showing the exact location of BC Hydro's underground facilities; and

- Proactively monitoring and issues management of BC Hydro's electric vehicle charging stations.

Customer Relations and Customer Metering is also responsible for the timely response and resolution of escalated customer issues and claims investigations against BC Hydro, and cost recovery of damages to BC Hydro plant and equipment. The team works with stakeholders across BC Hydro to investigate and find solutions and improve processes and customer service.

5F.4.1.4. Key Account Management Department

This department is responsible for managing relationships with BC Hydro's largest customers. Dedicated Key Account Managers support customers across all sectors of the B.C. economy including industrial, commercial, institutional, government and municipal customers.

Key Account Management supports approximately 753 customers with nearly 67,000 accounts, representing almost half (45 per cent) of BC Hydro's domestic energy sales and more than one-third (39 per cent) of BC Hydro's revenue.

Core customer service areas include new service connections, upgrades to existing service connections, capital project and program delivery, billing and rate inquiries, and outage scheduling and notification.

Key Account Management is the sales force responsible for promoting BC Hydro and government incentives and programs to our largest customers. The department works with customers to identify opportunities for growing existing load and pursuing new load opportunities, low carbon electrification and energy conservation projects. Key Account Management also oversees the contracts and deliverables of approximately 96 customer energy managers.

In addition, Key Account Management collects information on customers' business plans, market conditions, and other factors to inform BC Hydro's load forecast, and advances customer perspectives in rate and policy designs to remove barriers and attract or retain load.

5F.4.1.5. Large Customer Rate Operations Department

This department works primarily with BC Hydro's transmission customers to design, implement and administer BC Hydro's portfolio of rate schedules, tariff supplements and contracts for transmission voltage electricity supply. This includes overall management, governance and regulatory compliance for:

- Electric Tariff Supplement Nos. 5 and 87 – Electricity Supply Agreement;
- Rate Schedule 1823 Transmission Service – including maintenance of Tariff Supplement No. 74, Customer Baseline Load Determination Guidelines;
- Mining Customer Payment Plan and Industrial COVID-19 relief initiatives;
- Rate Schedule 1892 Transmission Service – Freshet Energy;
- Rate Schedule 1893 Transmission Service – Incremental Energy Rate; and
- Rate Schedule 1880 Transmission Service – Standby and Maintenance.

This department manages the stakeholder engagement and implementation of new and updated rate schedules and tariff supplements for BC Hydro's large industrial and other transmission service customers. It is also responsible for the negotiation and oversight of complex new business and commercial arrangements for large customer services.

5F.4.1.6. Business Unit Support Department

This department includes the Vice President, Customer Service who provides overall management to the Customer Service KBU. This department leads BC Hydro's efforts on growing new load and decarbonization. This includes:

- Overseeing the development and implementation of BC Hydro's Electrification Plan;
- Leading the development and implementation of proactive strategies to attract new industrial and large commercial customers;
- Working with government ministries as well as with internal and external stakeholders on the development and operation of electric vehicle charging station infrastructure; and
- Managing BC Hydro's participation in and compliance with the provincial Low Carbon Fuel Standard and the proposed federal Clean Fuel Standard.

In addition, the Business Unit Support department also oversees the compliance of the Electric Tariff and customer policy and participates in regulatory proceedings. This includes:

- Representing Customer Service in cross organizational initiatives such as Revenue Requirements Applications and Rate Design Applications to advance customer and operational perspectives;
- Ensuring electric vehicle charging stations comply with the requirements prescribed in the Greenhouse Gas Reduction Regulation;
- Leading the implementation of new rates or Electric Tariff amendments, including system development, process development and customer communications;
- Developing and managing operational policies and ensuring the compliance of the Electric Tariff for distribution service customers; and
- Managing the business planning and reporting functions for the Customer Service KBU.

5F.4.2 Overview of Operating Costs and FTEs

**Table 5F-4 Customer Service KBU
Fiscal 2022 Decision Operating Costs
and FTEs by Department**

	($ Millions)	Labour	Services - Other	Materials	Building & Equipment	Capitalized Overhead	External Recoveries	Total Operating	Total FTEs
1	Contact Centre & Billing Operations	24.8	14.9	0.1	0.2	0.0	0.0	**39.9**	301
2	Customer Analytics, Revenue & Risk Management	5.5	2.3	1.3	0.1	0.0	0.0	**9.2**	38
3	Customer Relations & Customer Metering	9.1	1.4	0.1	0.1	0.0	0.0	**10.6**	100
4	Key Account Management	2.8	0.3	0.0	0.0	0.0	0.0	**3.1**	29
5	Large Customer Rate Operations	0.9	0.1	0.0	0.0	0.0	0.0	**1.0**	5
6	Business Unit Support	3.0	1.4	0.0	0.0	0.0	0.0	**4.4**	19
7	**Total (Sch 5.6 L1+L9, Sch 16.0 L35)**	**46.1**	**20.4**	**1.4**	**0.4**	**0.0**	**0.0**	**68.3**	**492**

5F.4.2.1. Contact Centre and Billing Operations Department

Approximately 50 per cent of the Contact Centre and Billing Operations department budget relates to labour for operating BC Hydro’s contact centre, billing, payments, and collections teams. The department also incurs costs related to service contracts (primarily postage and printing costs for electricity billing and non-billing correspondence), and bad debt expense.

A portion of these costs is offset by revenue received through the Account Charge, Reconnection Charge, Returned Payment Charge and Late Payment Charge, which are cost-based Standard Charges assessed to the customers.

The Contact Centre and Billing Operations department also incurs the costs of administering the Customer Crisis Fund Program, as well as providing grants to eligible customers. These costs are deferred to the Customer Crisis Fund Regulatory Account and are not shown in Table 5F-4 above. See Chapter 7, section 7.3.3.5 for details on the Customer Crisis Fund Regulatory Account.

Labour

The Contact Centre and Billing Operations department requires 301 FTEs to operate the contact centre, billing, payment and collection functions.

Most labour requirements are directly linked to call and transactional volumes, as well as the desire to provide customers with timely and accurate services. For example, customers phoning the contact centre expect to speak with an agent without waiting for an extended period. Similarly, customers expect billing inquiries or payment issues to be resolved quickly and without a high level of effort. As there can be significant variations in call and transactional volumes, staffing levels are actively managed with the objective of meeting targeted and operational performance levels at the lowest cost.

These 301 FTEs can be categorized as follows:

- Two FTEs, the Director of the Contact Centre and Billing Operations department and an Administrative Assistant, provide overall management of this department;
- 191 FTEs are associated with the contact centre. Staffing consists primarily of Customer Service Representatives that are supervised by nine Team Managers and three Senior Managers. The span of control for Team Managers is approximately one manager for every 25 Customer Service Representatives. Contact centre staffing levels follow generally-accepted practices for contact centre management and are set predominately on the forecast volume and timing of in-bound customer calls, based on a target distribution of customer wait times. Schedules and staffing levels are then adjusted to provide consistent levels of service in all hours and to limit the number of customers that could be impacted by extended wait times;
- 50 FTEs are associated with the billing and payments functions. Billing and payments are highly automated. Most invoices are generated and issued to customers without manual intervention. Similarly, most payments are processed through systems integrations with financial institutions. However, manual intervention is required when payments are not successfully applied to customer accounts or when bills are stopped before being issued because control points are triggered (e.g., consumption is significantly higher than historical patterns or requires a change to a customer’s rate). Accordingly,

resource requirements are based on associated work volumes and customer response times. In calendar 2020, the billing team investigated and resolved 115,000 bills that were stopped because control limits were triggered;

- 16 FTEs are responsible for collections activities. Actively managing accounts with overdue balances is a key aspect of minimizing uncollectible revenue and avoiding bad debts;
- 29 FTEs are responsible for workforce planning, knowledge management, quality assurance, training, timesheet administration and other support to the operational teams;
- Six FTEs are responsible for operational reporting, process improvement and implementation of initiatives that improve revenue collection, reduce costs, improve customer service, or integrate new products and services (e.g., new or updated conservation programs) into the department's operations. Examples include leading an in-depth analysis and improvement of online move-in / move-out processes, which resulted in a 78 per cent increase in successful self-service move-in / move-out transactions between fiscal 2019 and fiscal 2021; developing a self-service option for customers wishing to create an Instalment Plan; and developing the transition plan to assist customers for the proposed termination of the RS 1755 Private Outdoor Lighting Service;
- Two FTEs manage the Net Metering Program. As work volumes are highly seasonal, resources are assigned from other teams in the Contact Centre and Billing Operations department when necessary to maintain response times for customer applications. In addition, the review of complex applications is undertaken by Distribution Asset Planning; and
- Five FTEs lead BC Hydro's initiatives to create a customer-centric work force and obtain customer feedback for BC Hydro's operations to improve our quality of service. This team also works with project teams across BC Hydro so that the customer perspectives are considered and incorporated early in the project

life cycle. Examples include customer engagement work undertaken for the net metering program and the street light replacement program, and engagement activities for BC Hydro's upcoming residential rate application.

In addition, employees within the Contact Centre and Billing Operations department are assigned to process applications for the Customer Crisis Fund Program. Labour requirements are based on the volume of applications received. Incremental hours worked are charged to the Customer Crisis Fund Regulatory Account.

Service Contracts

Service contracts for this department are budgeted at $9.0 million, the largest component being $7.1 million for postage, printing and paper. In addition, service contract costs include payment processing; credit checks; collection agency commissions; contact centre customer satisfaction surveys; and translation services.

The budget for postage, printing and paper is driven primarily by the number of customers that elect to receive paper bills. Other factors include the volume of non-billing correspondence, Canada Post's postage rates, and printing/paper costs. BC Hydro regularly promotes the adoption of paperless billing during telephone interactions with customers, as well as through online and social media channels. Campaigns and incentives are also used periodically. As a result of these efforts, as of June 2021, 61.7 per cent of accounts receive their bills electronically. This is the highest rate of paperless adoption amongst Canadian electric utilities participating in the Canadian Electricity Association's Customer Council.

BC Hydro estimates that paperless bill delivery saves BC Hydro customers over $8 million each year.

Costs for other service contracts are managed primarily by encouraging customers to use pre-authorized or electronic banking payments instead of cheques. 94 per cent of payments are currently made by pre-authorized or electronic payments. In addition, BC Hydro pays collection agencies by commission so that costs are not incurred unless agencies are able to recover unpaid bills, which provides a corresponding benefit to bad debt.

Bad Debt Expense

Bad debt expense was below the plan of $5.8 million in fiscal 2021, but is currently above plan in fiscal 2022, both being affected by the operational and economic impacts of the COVID-19 pandemic.[369] BC Hydro has maintained the plan at $5.8 million during the Test Period with the assumption that the impacts of the COVID-19 pandemic on bad debt expense will be limited to fiscal 2022. However, BC Hydro notes that bad debt expense is heavily influenced by external factors and, therefore, can vary year-to-year for reasons outside its control.

5F.4.2.2. Customer Analytics, Revenue and Risk Management Department

This department is managed by one senior manager who oversees three teams: Revenue Assurance, Field Inspection, and Customer and Energy Analytics. Approximately 60 per cent of this department's budget is related to labour costs. The remainder includes contractors, travel and materials required by the field staff as well as software, services, and warranty costs related to check meters.

Revenue Assurance and Field Inspection Teams

The Revenue Assurance and Field Inspection teams total 27 FTEs. These include:

- Seven FTEs that identify leads for field inspection;
- Three FTEs that are responsible for revenue recovery; and
- 17 FTEs that carry out all field activities associated with the revenue assurance program.

[369] The BCUC's COVID-19 moratorium on disconnections during the first half of fiscal 2021 resulted in most disconnections for non-payment occurring during the second half of fiscal 2021. As overdue accounts are expensed as bad debts 180 days after they are closed by the customer or following disconnection for non-payment by BC Hydro, the effect of the disconnection moratorium was to reduce uncollected accounts expensed as bad debt in fiscal 2021 and correspondingly increase bad debt expense in early fiscal 2022.

BC Hydro has dramatically reduced theft from marijuana grow-ops by leveraging the tools provided by the Smart Metering and Infrastructure program. Currently, most thefts occur from typical residential and commercial customers: fewer than 2 per cent of grow-ops are now believed to participate in electricity theft, compared to over 60 per cent of grow-ops prior to the installation of smart meters. Accordingly, BC Hydro has been able to reduce Field Inspection FTEs by approximately one-third since fiscal 2014.

BC Hydro continues to require a robust revenue assurance program to prevent recurrence of thefts from grow-ops, as well as to reduce theft and revenue leakage from normal residential and commercial customers. During fiscal 2021, approximately 3,200 investigations were performed related to suspected electricity theft, revenue loss and safety issues at individual premises. From these investigations, 65 thefts were identified and stopped. The Revenue Assurance team also identified and resolved 450 back-billings related to metering and billing errors.

The Revenue Assurance and Field Inspection teams now play key roles in identifying and mitigating public and employee safety risks as a result of unsafe electrical services. In fiscal 2021, BC Hydro conducted 481 investigations related to safety risks from potentially overloaded services. After being contacted by the Revenue Assurance team, 99 per cent of these customers voluntarily reduced load or obtained a service upgrade, while 1 per cent of overloaded service investigations resulted in a disconnection to mitigate safety risk. In the small number of cases where the customers’ electrical services were not found to be overloaded, investigations often still led to the resolution of safety issues or the identification of overloaded BC Hydro equipment.

Customer and Energy Analytics Team

The Customer and Energy Analytics team includes ten FTEs, comprised of one manager and nine data scientists and analysts.

In fiscal 2021, the Customer and Energy Analytics team fulfilled 266 Customer Data Requests. Two FTEs were dedicated to responding to Customer Data Requests to accommodate the increase in volume. This increase was predominantly driven by external customer requests for aggregated hourly load data to support CleanBC related initiatives and other research studies. In addition, the team completed 51 complex projects requiring analysis of customer and energy data, which supported data-driven decisions related to rate design, business practices, and allocation of operational resources.

5F.4.2.3. Customer Relations and Customer Metering Department

Approximately 86 per cent of this department’s budget is related to labour for 100 FTEs. This department is managed by one senior manager who oversees the following two main functions: field related customer services and customer escalations and claims.

The remaining budget includes travel and materials required by field services, payments to BC One Call, and claims against BC Hydro for damages.

Field Related Customer Services

This function consists of 85 FTEs as follows:

- Three field managers manage 50 FTEs located in 34 offices across the province. The span of control for field managers is approximately one manager for every 17 Field Service Representatives. In fiscal 2021, these FTEs conducted approximately 191,000 manual meter reads for meters that are not read automatically. In addition, they performed approximately 7,000 other field service orders for on-site investigation for billing inquiries, non-electrical meter maintenance, manual single-phase meter disconnections, reconnections, electric vehicle charging stations inspections and administration of customers’ keys so that employees and contractors can access BC Hydro equipment in buildings and behind locked gates. BC Hydro continues to find labour savings by leveraging this cost-effective field resource to perform more non-technical field customer service work.

The remaining 17 FTEs are responsible for management, planning, scheduling, dispatching, continuous optimization, training, safety, and reporting. This team also proactively monitors and manages issues of BC Hydro’s electric vehicle fast charging stations and supports the Operations Business Group to perform the coordination, facilitation, exception management and customer communications for 12,000 time-expired, failed, and compliance sampling meter exchanges each year.

- Nine FTEs support BC Hydro’s membership in the BC One Call organization to provide the locations of BC Hydro’s underground facilities to property owners and contractors with a required response time of 72 hours. The volume of BC One Call requests has increased from 153,703 in fiscal 2020 to 167,674 in fiscal 2021 to a forecast of approximately 190,000 for fiscal 2022. However, FTEs have remained constant as BC Hydro has been able to improve productivity through automation of certain aspects of the process. Payments to BC One Call are fixed based on request volumes from the prior year. BC Hydro’s annual charge for calendar 2021 was $375,575;
- Three FTEs are responsible for processing approximately 700 requests each year for customer-initiated vault maintenance disconnections and incentives for pad mounted transformer decoration. BC Hydro provides an incentive program to decorate pad mounted transformers to prevent graffiti on equipment and to blend in with surroundings. Vault maintenance disconnection work generates approximately $0.7 million per year in revenue to BC Hydro; and
- Three FTEs are responsible for engaging with commercial customers that may be significantly impacted by planned outages. Approximately 3,200 planned outages each year involve commercial customers.

Customer Escalations and Claims

This function consists of 14 FTEs as follows:

- Three FTEs manage approximately 640 complex escalations per year from the BCUC, government officials, Better Business Bureau, and the Office of the Ombudsperson. Our response time target for most escalations is five business days.[370] This team also provides quarterly reporting to the BCUC on escalation volume and response time;
- Three FTEs are responsible for resolving approximately 725 claims made against BC Hydro for damages; and
- Eight FTEs, including one manager, responsible for cost recovery against third parties for damage to BC Hydro plant and equipment. BC Hydro expects to recover approximately $5.8 million in fiscal 2022.

5F.4.2.4. Key Account Management Department

This department consists of 29 FTEs. Key Account Managers support customer participation in BC Hydro's conservation and energy management programs and approximately 50 per cent of the labour costs for these FTEs is funded by BC Hydro's DSM programs. In addition, Key Account Managers work with customers on opportunities for growing existing load, securing new load and low carbon electrification.

On average, each Key Account Manager supports approximately 31 customers. However, each portfolio varies depending on the complexity or volume of customer service needs.

[370] Complex issues that are dependent on subject matters experts have a target of ten business days.

5F.4.2.5. Large Customer Rate Operations Department

The Large Customer Rate Operations department is comprised of five FTEs.

Labour requirements are driven by the activities required to operate, maintain and ensure compliance with the complex rates and tariffs that define how BC Hydro's transmission customers pay for service. For example, each year this department reviews and establishes the Customer Baseline Load for approximately 100 transmission voltage customers taking service under the stepped rate provisions of Rate Schedule 1823. This effort requires direct interaction with each customer, in addition to preparing and supporting BC Hydro's annual application to the BCUC for Customer Baseline Load approval.

Labour requirements are also determined by the level of analysis and engagement necessary to develop and implement new rates and tariff supplements, as well as for the negotiation of new commercial agreements. These provide transmission customers with options to improve their competitiveness while benefitting all BC Hydro customers through the attraction and retention of load and revenue. Recent examples led by this department include the Mining Customer Payment Plan and Industrial COVID-19 relief initiatives. This department also prepares the required compliance filings to the BCUC, such as the Final Evaluation Report for the Freshet Rate Pilot.

5F.4.2.6. Business Unit Support Department

Approximately 70 per cent of this department's budget is related to labour costs for 19 FTEs. The remaining budget includes funding for strategic projects to improve the service we provide or to lower costs, dues and fees for industry associations and travel.

Two FTEs, the Vice President of Customer Service and an Administrative Assistant, provide overall management for the Customer Service KBU. The remaining 17 FTEs are allocated as follows:

- Six FTEs provide a single point of entry into BC Hydro for new prospective customers. This team helps identify suitable sites for energy-intensive customers. By the end of fiscal 2021, this team had identified over 1600 MW of prospective load from interested parties. To prepare for delivering its increased mandate as a result of the Electrification Plan, these FTEs will be separated from the Business Unit Support department and will be reported as the Business and Economic Development department starting in fiscal 2023. For further information on BC Hydro’s plan on load attraction, please refer to Chapter 10.
- Two FTEs oversee development of BC Hydro’s Electrification Plan and manage BC Hydro’s participation in and compliance with the provincial Low Carbon Fuel Standard and the proposed federal Clean Fuel Standard;
- Four FTEs are responsible for improving the overall electric vehicle customer service at the 97 fast charging stations owned and operated by BC Hydro. This team is also involved in electric vehicle related regulatory matters, and works with governments, businesses and other stakeholders to remove barriers to the adoption of electric vehicles in B.C.;
- Four FTEs provide policy instructions and directions to the customer operations teams. This includes setting up controls for compliance with the Electric Tariff and customer policies, advancing customer and operational perspectives in BC Hydro’s rate design applications, implementing rate and Electric Tariff changes, executing targeted customer communications, and maintaining customer service webpages; and
- One FTE provides monthly reporting on key performance indicators and targets for the Customer Service KBU.

5F.4.3 Fiscal 2023 to Fiscal 2025 Plan Operating Costs and FTEs

Table 5F-5 Customer Service KBU Operating Costs and FTEs

		Schedule Reference	F2021 Actual	F2022 Decision	F2023 Plan	F2024 Plan	F2025 Plan
			1	2	3	4	5
1	**Customer Service KBU**						
2	Operating Costs ($ million)	5.6 L1+L9	64.5	68.3	67.8	69.2	70.7
3	FTEs	16.0 L35	507	492	504	504	504

Operating costs are decreasing by approximately $0.5 million from fiscal 2022 Decision amounts to fiscal 2023 plan. This includes the following cost decreases:

- $0.5 million reduction to remove remaining funding for the Customer Crisis Fund Pilot Program. This is offset by an equivalent reduction to miscellaneous revenue for cessation on June 1, 2021 of the rate rider which was funding the program;
- $0.1 million reduction in Customer Service due to one FTE transferred to the Generation System Operations KBU in the Operations Business Group;[371]
- $0.2 million, including one FTE and associated budget from across multiple teams, will be transferred to the Regulatory and Rates KBU to accommodate increased work volumes;
- $0.5 million reduction in labour costs due to a reduction in Standard Labour Rates; and
- $0.1 million reduction for travel savings, as discussed further in Chapter 5, section 5.5.3.6.

[371] The Net Metering team (with three FTEs) was transferred from the Power Acquisitions and Contract Management KBU to the Customer Service KBU in fiscal 2021. In fiscal 2022, one FTE was transferred to the Generation System Operations KBU in the Operations Business Group. The remaining two FTEs are in the Contact Centre and Billing Operations department.

These cost decreases are partially offset by the following cost increases:

- $0.2 million funding as part of BC Hydro's Electrification Plan to support additional electric vehicle fast charging station operations and maintenance, including one incremental FTE; and
- $0.8 million funding for labour to support existing electric vehicle infrastructure. Costs related to performing these activities in fiscal 2022 were deferred.

Operating costs are increasing by approximately $1.4 million from fiscal 2023 plan to fiscal 2024 plan, and by approximately $1.5 million from fiscal 2024 plan to fiscal 2025 plan. This includes $0.1 million per year to support additional electric vehicle fast charging station operations and maintenance as part of BC Hydro's Electrification Plan. The remainder is due to Standard Labour Rate increases.

Customer Service FTEs are planned to increase by 12 from fiscal 2022 Decision amounts to fiscal 2023 plan due to:

- Ten incremental FTEs are planned in support of BC Hydro's Electrification Plan as discussed further in Chapter 10. Nine of these FTEs are funded by either Low Carbon Electrification or Load Attraction program budgets. One of the FTEs supports additional electric vehicle charging stations operations and maintenance and is funded by incremental operating cost budget as described above; and
- Four FTEs will be added to the Contact Centre and Billing Operations department due to higher work volumes. For example, additional resources are necessary to respond to customer inquiries in the Customer Support Centre, which BC Hydro launched in fiscal 2021 to provide customers with an authenticated email channel as an alternative to speaking with a customer service representative, and to provide additional support to Street Lighting Service customers in response to feedback provided through engagement related to BC Hydro's Street Light Rates Application. These four FTEs are

funded by savings from paperless billing and related initiatives; partially offset by,

- Two FTEs transferred out for re-organization transfers as described above.

Customer Service FTEs are planned to remain constant from fiscal 2023 plan to fiscal 2025 plan.

5F.5 Conservation and Energy Management KBU

5F.5.1 Responsibilities

The Conservation and Energy Management KBU is responsible for a range of activities that encourage customers to manage their energy consumption. These include DSM activities including energy efficiency and conservation, and capacity focused initiatives, and low carbon electrification activities which encourage customers to switch from higher carbon sources of energy to electricity.

There have been no material changes to the nature of the responsibilities of the Conservation and Energy Management KBU since the Previous Application.

FTEs are planned to increase over the Test Period to support the Electrification Plan as described in Chapter 10, section 10.4.

5F.5.2 Overview of Operating Costs and FTEs

Table 5F-6 Conservation and Energy Management KBU Fiscal 2022 Decision Operating Costs and FTEs by Department

	($ Millions)	Labour	Services - Other	Materials	Building & Equipment	Capitalized Overhead	External Recoveries	Total Operating	Total FTEs
1	Conservation & Energy Management	0.5	0.1	0.0	0.0	0.0	0.0	**0.7**	116
2	**Total (Sch 5.6 L2, Sch 16.0 L36)**	**0.5**	**0.1**	**0.0**	**0.0**	**0.0**	**0.0**	**0.7**	**116**

Employees in the Conservation and Energy Management KBU support BC Hydro's DSM and low carbon electrification activities. Therefore, the majority of labour costs are classified as deferred operating expenditures and are charged to the DSM

Regulatory Account (refer to Appendix A, Schedule 2.2 for DSM Regulatory Account additions). The deferred operating expenditures are not included Table 5F-6 above.

The operating budget shown above is primarily made up of labour costs totalling $0.5 million for overall management and administration of the KBU. In addition, the budget includes incidental expenses of $0.1 million that indirectly support DSM and low carbon electrification activities. This operating budget of $0.7 million has remained at the same general level since fiscal 2016.

FTE levels for this KBU have remained stable since they were assessed and reduced as part of the moderation strategy for DSM expenditures identified in the Fiscal 2017 to Fiscal 2019 Revenue Requirements Application. The KBU consists of 116 FTEs based on the fiscal 2022 Decision as follows:

- Two FTEs represent the Director of Conservation and Energy Management and an Administrative Assistant;
- Eight FTEs in the Strategic Planning Department. This department develops long-term DSM resource options to support BC Hydro's Integrated Resource Planning process, performs annual updates of the plans, provides modelling support and cost-effectiveness analysis for the KBU's governance and decision-making processes, prepares regulatory applications and supports other regulatory processes;
- 30 FTEs in the Residential and Commercial Marketing (Program Management) department. This department designs and manages offers targeting Residential, Commercial and Public Sector customers as well as supporting the development of new codes and standards. Staffing requirements for this department are determined by the number of offers in the marketplace and the complexity of those offers. Complexity is influenced by a number of factors including the barriers that exist to customer participation, the number of partnerships involved (e.g., market channels, FortisBC, installation contractors,

municipalities), and the number of technologies supported. Developing and managing offers requires gathering and assessing customer and industry feedback, design work, budgeting, partnership management, internal and external training, promotion as well as monitoring and reporting. The 30 FTEs in this department are divided as follows:

- ▶ 20 FTEs design and manage over 20 offers and partnerships within programs targeting BC Hydro's Residential, Commercial and Public Sector customers. Many of the offers in the marketplace have an increased level of complexity relative to historical program offers. For example, BC Hydro's Non-Integrated Areas offer has unique geographical and market barriers, relative to similar offers in the integrated area;
- ▶ Six FTEs focus on the development of policies, codes and standards including the B.C.'s Building Step Code, local government policy and offer support, New Construction Builder support, and Indigenous Communities Policy support;
- ▶ Three FTEs deliver marketing analytics, which provides customer targeting, marketing campaign and trial assessments, and reports and dashboards to help manage offers.; and
- ▶ One FTE represents the manager of the department;

- 19 FTEs in the Industrial Marketing (Program Management) department as follows:

  - ▶ 11 FTEs, predominantly program managers and engineers, are responsible for the design and management of offers within programs targeting BC Hydro's Industrial customers. Similar to the Residential and Commercial Marketing (Program Management) group, staffing requirements are determined by the number and complexity of offers in the marketplace. Currently, approximately ten industrial offers are being managed by this team, including incentive and energy study offers for transmission and distribution customers, strategic energy management offers and activity on demand response and localized DSM;

- Seven FTEs manage the training, quality control and accreditation of over 900 Alliance members across all customer segments. These members are qualified external service providers who supply goods and services to our customers; and
- One FTE represents the manager of the department;

- 39 FTEs in the Operations, Engineering and Quality Management department. Staffing levels in this department are driven by the number of customer applications submitted each year. These FTEs can be categorized as follows:
  - 20 FTEs on the operations team process 1,000 to 1,200 commercial and industrial applications and 32,000 to 48,000 residential applications each year. This includes applications for feasibility studies, plant-wide audits, energy managers, incentive projects and program enabled projects. Processing applications triggers further work such as carrying out credit reviews, reviewing and approving incentive payments and handling escalations. This work also includes quality management functions, such as developing and implementing business processes, implementing controls for business operations, verifying compliance with requirements, and oversight of the information technology systems used for application processing, tracking and reporting;
  - 18 FTEs on the engineering team, covering a range of specialized areas (e.g., lighting, HVAC, Pulp and Paper, Mining, etc.), perform technical reviews of custom projects to validate the viability of the projects and to estimate energy impacts and project costs. Engineering staff also advise Marketing and Industrial Marketing on the development of offers, and provide technical support to customers on their proposed projects; and
  - One FTE represents the manager of the department;

- 18 FTEs in the Evaluation, Measurement and Verification department as follows:
  - Nine FTEs on the Evaluation team. Staffing levels on this team are driven by the number of programs and initiatives in the market and by BC Hydro's evaluation criteria. Evaluation reports produce final estimates of the energy impacts of programs, rate structures and codes and standards, and identify opportunities for improvement. The number of these reports has remained similar at four to six per year since fiscal 2016. In addition to completing evaluation reports, this team also conducts between 16 and 19 data collection activities each year. Examples of these activities include Residential and Commercial End-Use Surveys; and
  - Nine FTEs on the Measurement and Verification team. While the Evaluation team estimates energy impacts at a program level, the Measurement and Verification team estimates energy savings at a project level. This information is used to adjust incentive levels for specific projects, inform individual Customer Baselines claims for rates related projects, inform program evaluations, and provide feedback to customers and BC Hydro staff on project performance. Staffing levels on this team are driven by the volume of projects implemented by commercial and industrial customers and by BC Hydro's measurement and verification criteria. The work resulting from these drivers involves on-site visits, installation of metering equipment on electrically energized equipment at customer sites and data analysis. The team produces between 50 and 70 measurement and verification reports each year, which document final estimates of the energy impacts of customer projects. This team also provides between 50 to 60 Customer Baseline reviews each year, depending on the number of transmission customers submitting a Customer Baseline claim. Lastly, the team completes between 40 to 60 measurement and verification plans each year, depending on the number of customers submitting project applications.

5F.5.3 Fiscal 2023 to Fiscal 2025 Plan Operating Costs and FTEs

Table 5F-7 Conservation and Energy Management KBU Operating Costs and FTEs

		Schedule Reference	F2021 Actual	F2022 Decision	F2023 Plan	F2024 Plan	F2025 Plan
			1	2	3	4	5
1	**Conservation and Energy Management KBU**						
2	Operating Costs ($ million)	5.6 L2	0.5	0.7	0.6	0.7	0.7
3	FTEs	16.0 L36	119	116	122	122	123

As shown in Table 5F-7 above, operating costs for the Conservation and Energy Management KBU are planned to remain relatively constant from fiscal 2022 Decision amounts through to the fiscal 2025 plan.

FTEs are planned to increase by six from the fiscal 2022 Decision amounts to the fiscal 2023 plan, and one additional FTE is planned in fiscal 2025. This includes one FTE transferred out to the Regulatory and Rates KBU in fiscal 2023, and eight additional resources needed to deliver the Electrification Plan, as described in Chapter 10.

As discussed above, nearly all labour costs for this KBU are classified as deferred operating expenditures and are charged to the DSM Regulatory Account.

5F.6 Communications and Community Engagement KBU

5F.6.1 Responsibilities

There have been no material changes to the nature of the responsibilities of the Communications and Community Engagement KBU since the Previous Application.

The Communications and Community Engagement KBU is responsible for the development and delivery of communications to key audiences, including customers, stakeholders, the Government of B.C., local governments, employees and the media. This includes information about BC Hydro's operations, capital projects, safety programs, conservation programs, emergency preparedness and customer service.

The Communications and Community Engagement KBU includes a number of functions not traditionally housed within a typical Communications department. In addition to marketing and media relations, and employee communications functions, the department includes community relations, policy and research. Grouping these teams under one umbrella allows BC Hydro to manage communication activities in an effective and collaborative manner.

The Communications and Community Engagement KBU consists of the following five departments:

- Marketing Communications Department;
- Communities and Capital Projects Department;
- Media Relations and Issues Management Department;
- Policy, Research and Strategic Communications Department; and
- Employee Communications Department.

5F.6.1.1. Marketing Communications Department

The Marketing Communications department provides both proactive and responsive communications to customers and stakeholders. The department supports a range of communications activities to build public awareness and understanding of energy conservation and management, customer service offerings, electrical safety and power outage preparedness. In addition, in the event of emergencies, the department supports incident response and restoration efforts through 24/7 communication and outreach to customers. Our customers expect BC Hydro to be online to share information, meet their service needs and hear about programs. As a result, marketing strategies, campaigns, programs and content are centred on creating digital experiences.

Moving forward, this team will also build and roll out a marketing communications strategy to support BC Hydro's Electrification Plan, helping current B.C. customers switch to clean electricity and encouraging new customers to locate in B.C.

The Marketing Communications department is comprised of three teams:

- Digital Communications;
- Customer Campaigns; and
- Brand Strategy.

The Digital Communications team leads BC Hydro's digital strategy and 24/7 social media strategy across all digital channels including bchydro.com, powersmart.ca, Hydroweb (employees' intranet site), customer email, e-newsletters and social platforms, developing content to engage customers, build followers and stand out in a crowded digital marketplace to convey important messages to customers. The team monitors social media channels closely for a range of topics related to customer feedback and issues. The team also plans campaigns to reach customers online at key points throughout the year and support customers' needs for information. We emphasize mobile communications, as 55 per cent of the nearly 24 million visits to bchydro.com each year are through mobile devices and these numbers continue to grow. The shift to digital communications also creates a need for data analytics to evaluate the effectiveness of our efforts and adapt accordingly.

The Customer Campaigns team leads the ongoing development of an annual integrated campaign strategy to provide information to customers. By using a combination of paid (advertising), owned (digital and face-to-face) and earned (media) communications strategies, the team designs campaigns that reach customers when they are most receptive to the information. Safety campaigns in the winter and late spring raise awareness of the hazards of electricity; conservation campaigns in the fall and spring encourage customers to save energy through actions in their homes and businesses; and customer service campaigns raise awareness of new offerings and updated services. The team develops strategies and messages to target a range of demographics and in a number of languages.

The Brand Strategy team leads BC Hydro's face-to-face outreach programs including a community marketing team and a K-12 Schools Program. Engaging with customers face-to-face allows for conversations and dialogue that spark an interest in energy, conservation, customer service and safety, leading to customers taking action at home, in businesses and in schools. The team is responsible for ensuring the BC Hydro brand is applied in a consistent and effective manner which is key to effective communications in an increasingly cluttered media environment. This team is also responsible for Creative Services, which supports brand management and standards as well as graphics services and support to KBUs across BC Hydro.

5F.6.1.2. Communities and Capital Projects Department

The Communities and Capital Projects department liaises with stakeholders across B.C. to facilitate approvals for operational imperatives, regional programs and capital projects. The department works to help resolve escalated issues between BC Hydro and its customers and helps to manage BC Hydro's relationships in communities where there is a concentration of assets and operational activities.

The Communities and Capital Projects department is comprised of four teams:

- Community Relations;
- Capital Projects Communications;
- Community Investment and Retiree Programs; and
- Visitor Centres.

The Community Relations team builds relationships with local governments in over 160 communities, including mayors, councillors, regional district officials and community leaders. Community Relations is the primary contact for the constituency offices for all 85 Members of the Legislative Assembly.

This team also provides communications support and coordinates with stakeholders on a range of matters including vegetation management, escalated customer issues, planned power outages, local construction projects, and the operations of our generation facilities. During significant emergency events such as storms and fires, Community Relations shares information with and acts as a conduit for dialogue between elected officials and the community.

The Capital Projects Communications team works closely with community stakeholders, leading consultation and communications work on BC Hydro’s capital projects. The team gathers local feedback from stakeholders to inform the decision-making process on projects. By conducting early and ongoing consultation and communications during all phases of a capital project, risks of delay or cost increases can be mitigated.

The Community Investment and Retiree Programs team administers the award of scholarships to select B.C. students, supports non-profit groups and registered charities through grants, and funds organizations and initiatives through sponsorships that support BC Hydro’s business objectives. This team also coordinates an annual charity workplace campaign to help BC Hydro employees give back to their community and supports BC Hydro retirees through the Power Pioneers Program.

The Visitor Centres team operates the Revelstoke Dam Visitor Centre, the W.A.C. Bennett Dam Visitor Centre in Hudson’s Hope and the Powerhouse at Stave Falls Visitor Centre in Mission. This work builds understanding of BC Hydro operations in communities. Visitor Centre staff provide information about our historic and current operations in the region as well as education on energy conservation and electrical safety. In addition, the Visitor Centres support reconciliation by including content from local Indigenous communities.

5F.6.1.3. Media Relations and Issues Management Department

This department is available 24 hours a day, seven days a week to provide information to the public through major and local media about BC Hydro's business and operations. This includes updates on damage caused by major storms and other emergency events, electrical safety information and tips for customers on how to conserve electricity. To build public awareness and understanding, the department also provides timely information to the media about various customer programs and capital projects that impact customers in communities across the province.

This department also provides communications training to dozens of senior leaders and subject matter experts in BC Hydro each year so that they are prepared to speak on behalf of BC Hydro when required.

Lastly, this department works with the Government of B.C. to keep them informed about our business and provide up-to-date information on key topics. This proactive approach mitigates the amount of time spent on escalated or emerging issues.

5F.6.1.4. Policy, Research and Strategic Communications Department

This department provides policy coordination and advice to support BC Hydro's priorities as well as the policy objectives of the Government of B.C. The department is comprised of the Policy team and the Corporate and Marketing Research team.

The Policy team works with the Ministry of Energy, Mines and Low Carbon Innovation to deliver on key reporting and legislated requirements, including the Budget Estimates Debate, the Annual Service Plan Report and the Service Plan. This involves providing information to the public about BC Hydro's performance, corporate governance and strategic priorities. The team also provides strategic advice and communications support, such as developing briefing materials with KBUs across BC Hydro, in response to emerging public and energy policy developments.

The Corporate and Market Research team supports a number of BC Hydro's KBUs, most notably the Conservation and Energy Management, Regulatory, Energy Planning and Customer Service. The team is responsible for tracking customer satisfaction (which is a BC Hydro Service Plan performance measure), assessing the effectiveness and awareness of core programs and gathering customer feedback to support regulatory applications on key initiatives such as the Integrated Resource Plan and rate design.

5F.6.1.5. Employee Communications Department

The Employee Communications department provides employees with information they need to enhance their work and support BC Hydro's strategic and operational initiatives. As a large number of BC Hydro employees work in the field, at BC Hydro facilities and district offices throughout the province, the department uses a variety of communications platforms to engage employees and meet a growing demand for information. These platforms include an employee intranet, newsletters, executive messages and company-wide conference calls. The department also provides members of BC Hydro's Executive Team with strategic communications support to promote employee engagement and enhance the visibility of senior leadership.

5F.6.2 Overview of Operating Costs and FTEs

Table 5F-8 Communications and Community Engagement KBU Fiscal 2022 Decision Operating Costs and FTEs

	($ Millions)	Labour	Services - Other	Materials	Building & Equipment	Capitalized Overhead	External Recoveries	Total Operating	Total FTEs
1	Chief Communications Officer	0.4	0.1	0.0	0.0	0.0	0.0	**0.5**	2
2	Marketing Communications	2.9	1.8	0.0	0.2	0.0	0.0	**4.9**	49
3	Communities and Capital Projects	3.9	1.3	0.1	0.1	0.0	0.0	**5.4**	38
4	Media Relations and Issue Management	0.6	0.0	0.0	0.0	0.0	0.0	**0.7**	5
5	Policy, Research and Strategic Comm	0.8	0.4	0.0	0.0	0.0	0.0	**1.2**	6
6	Employee Communications	1.5	0.1	0.0	0.0	0.0	0.0	**1.5**	9
7	**Total (Sch 5.6 L3, Sch 16.0 L37)**	**10.1**	**3.7**	**0.1**	**0.4**	**0.0**	**0.0**	**14.2**	**108**

5F.6.2.1. Chief Communications Officer Department

This department's budget consists of labour for two FTEs, which includes the Chief Communications Officer and an administrative assistant.

5F.6.2.2. Marketing Communications Department

This department consists of 49 FTEs. Many of these FTEs support BC Hydro's DSM programs and initiatives. Accordingly, 58 per cent of the costs associated with these FTEs are treated as deferred expenditures and are charged to the DSM Regulatory Account. These FTEs are divided into the following teams:

- Two FTEs represent the Director of Marketing Communications and an administrative assistant;
- 15 FTEs on the Digital Communications team. This team receives an average of 50,000 mentions, direct and private messages, and comments from customers each year, including significant activity during storms and other major emergencies and operational events. The team also delivers 26 million transactional emails annually including email bill delivery, newsletters, promotional emails and notifications related to customer accounts. Lastly, this team manages the employee intranet which receives approximately 4.5 million visits each year. To support this work, the Digital Communications operating budget includes $0.8 million for advertising, software licenses, specialized application support, content development, video production, and other incidental expenses;
- Seven FTEs on the Customer Campaigns team. This team delivers more than 20 conservation, safety and other customer information campaigns each year, including building awareness of electric vehicles and BC Hydro's charging station network. To support this work, the Customer Campaigns operating budget includes $0.8 million for advertising; and
- 25 FTEs on the Brand Strategy team, including:
  - ▶ Two FTEs supporting BC Hydro's Schools and Education Program which provides energy conservation and safety information to approximately 100,000 students each year. The program has substantially increased its reach with the launch of a new online platform which was completed with no

increase in budget. The program maintains a teacher mailing list with approximately 10,000 subscribers, 4,000 teacher user accounts and a web site which received 130,000 visits during the 2020/2021 school year (a 33 per cent increase compared to the previous year). The program's operating budget includes $0.2 million for advertising, supplies, application support and education consultants to support electrical safety awareness in schools;

- Seven FTEs on the Creative Services team responds to requests from across BC Hydro to create visual content (print, digital and video) to support consistent communication and customer understanding. From fiscal 2018 to fiscal 2020, this team completed approximately 2,200 requests each year. Depending on complexity, the average number of hours spent on each request ranges from two to 30 hours. The Creative Services operating budget includes $0.1 million non-labour for specialized software, application support and supplies;
- 14 FTEs on the Community Outreach team. This includes three FTEs on the core planning team, eight FTEs are a Team Lead, year-round outreach and retail representatives and two FTEs represent casual employees who support the spring and fall awareness campaigns for approximately ten weeks per year. This team visits 80 communities across the province and engages with over 50,000 customers a year both in-person, virtually and through digital channels in conversations about energy conservation and management as well as customer service priorities and electrification; and
- The remaining two FTEs represent the department manager and a brand standards lead who is responsible for the development, maintenance and enforcement of all brand assets for employees and suppliers.

5F.6.2.3. Communities and Capital Projects Department

The 38 FTEs in this department are divided into the following teams:

- 15 FTEs on the Community Relations team. Approximately 15 per cent of the cost for these FTEs are charged to capital projects that are supported by BC Hydro's community relations managers;
- Eight FTEs on the Capital Projects Communications team. The FTEs in this department charge approximately 80 per cent of their time to the capital projects they are supporting. In fiscal 2021, the team supported over 80 capital projects;
- Four FTEs on the Community Investment and Retirees Program team. The Community Investment operating budget includes $0.7 million for donations and sponsorships and $0.3 million for advertising. In fiscal 2016, BC Hydro revamped its sponsorships program, reducing the overall funding by 50 per cent and targeting sponsorships to areas that support BC Hydro's operations, such as building a skilled workforce, supporting safe and smart energy use and fostering strong relationships in the communities where our operations have the most impact; and
- 11 FTEs on the Visitor Centres team is comprised of three FTEs and multiple contract Tour Guides. In calendar 2019, there were more than 41,000 visitors to BC Hydro's Visitor Centres. The visitor centre's operating budget includes $0.5 million for materials and supplies (exhibits, interactives), advertising (signage, displays, ads), security and janitorial services and travel costs. Costs related to BC Hydro's Visitor Centres are partially offset by revenue from entrance fees, retail sales and audio tour rentals.

5F.6.2.4. Media Relations and Issues Management Department

The majority of this department's budget is related to labour for five FTEs.

The media landscape is constantly evolving, and timelines are getting tighter. Because they operate 24/7, our media relations team needs to be available at any time of the day to respond.

In addition, as storms and extreme weather have become more frequent over the past five years, so have the after-hours demands on the team. In fiscal 2021, BC Hydro responded to approximately 700 media requests.

This department also prepares dozens of earned media pieces each year ranging from news releases and information bulletins to operational updates and reports to provide customers with important information when and where they need it. Over the past three years, BC Hydro's earned media efforts have generated an average of 610 million media impressions and 3,600 stories per year.

5F.6.2.5. Policy, Research and Strategic Communications Department

The majority of this department's budget is related to labour for six FTEs:

- Three FTEs on the Policy team provide coordinated advice and information to Government so that the impacts of various policy decisions on ratepayers are understood and considered. In calendar year 2021, BC Hydro's communications with Government increased due to updates around the COVID-19 pandemic; and
- Three FTEs on the Research team support KBUs across BC Hydro by conducting surveys and focus groups. Feedback gained through this work provides valuable insights so that BC Hydro can better serve its customers and employees. The Research team uses an in-house polling tool called Your Power Poll to survey a group of over 4,000 customers. In fiscal 2021, BC Hydro completed over 80 surveys through Your Power Poll.

The department's operating budget includes $0.4 million for research services such as customer satisfaction surveys.

5F.6.2.6. Employee Communications Department

The majority of this department's budget is related to labour for nine FTEs. These FTEs support BC Hydro's KBUs and provide overall and targeted communications to BC Hydro's 6,500 employees, including approximately 2,000 field and stations-based workers with limited computer access.

There is a strong correlation between engaged and committed employees and employee retention, productivity and organizational effectiveness. Effective, directed and clear employee communication is essential to keeping employees informed and connected to their work.

Activities carried out by these FTEs include:

- The development of over 140 internal communications plans each year;
- Drafting over 100 Executive Team messages per year, researching and preparing responses to hundreds of employee e-mails and developing speaking notes and supporting visuals for internal and external presentations;
- Developing and executing between ten to 15 employee campaigns per year on monthly priorities as well as safety and workplace initiatives;
- Executing three all-employee safety conference calls per year as well as additional employee calls to respond to operational and emerging issues; and
- Managing six internal communications channels (an employee intranet, executive communications, 75 office and field TV screens, poster boards, all-employee calls and lobby displays).

The department's operating budget includes $0.1 million for promotional materials and supplies.

5F.6.3 Fiscal 2023 to Fiscal 2025 Plan Operating Costs and FTEs

Table 5F-9 Communications and Community Engagement KBU Operating Costs and FTEs

		Schedule Reference	F2021 Actual	F2022 Decision	F2023 Plan	F2024 Plan	F2025 Plan
			1	2	3	4	5
1	**Communications and Community Engagement KBU**						
2	Operating Costs ($ million)	5.6 L3	12.9	14.2	13.9	14.2	14.5
3	FTEs	16.0 L37	97	108	110	110	110

Operating costs are decreasing by approximately $0.3 million from fiscal 2022 Decision amounts to fiscal 2023 plan mainly due to a reduction in Standard Labour Rates. Operating costs are increasing by $0.3 million each year in fiscal 2024 and fiscal 2025 due to Standard Labour Rate increases.

FTEs are increasing by two from the fiscal 2022 Decision to fiscal 2023 plan. This includes an increase of three FTEs to support BC Hydro’s Electrification Plan, partly offset by a reduction of one FTE transferred to the Regulatory and Rates KBU. FTEs are planned to remain constant from fiscal 2023 plan to fiscal 2025 plan.

5F.7 Regulatory and Rates KBU

5F.7.1 Responsibilities

There have been no material changes to the nature of the responsibilities of the Regulatory and Rates KBU since the Previous Application.

This KBU is responsible for providing regulatory advice to KBUs across BC Hydro, developing regulatory strategies and managing applications and initiatives through the regulatory process. BC Hydro believes that an open and transparent regulatory process leads to better decisions and improved outcomes for our customers. This KBU supports this approach, acting as the main interface between the BCUC and BC Hydro and managing relationships with interveners during and outside regulatory proceedings.

This KBU is organized into the following three teams:

- Capital and Finance;
- Tariffs and Rate Design; and
- Assurance and Operations.

The Capital and Finance team is responsible for providing strategic planning, regulatory advice and support to KBUs regarding capital projects and Electricity Purchase Agreements as well as financial and revenue requirement regulatory matters. This includes leading BC Hydro's capital and finance-related regulatory applications (e.g., revenue requirements applications) and related compliance filings.

The Tariffs and Rate Design team is responsible for residential, general service, transmission service and Open Access Transmission Tariff rates; managing permits and reporting related to BC Hydro's international power lines, and resource planning. To support these responsibilities, the department carries out the following activities:

- Providing regulatory advice and research related to tariffs and rate design;
- Responding to external and internal tariff and rate queries;
- Managing Open Access Transmission Tariff applications, administration and technical issues; and
- Managing the Integrated Resource Plan application.

The Assurance and Operations team is responsible for leading filings and proceedings on assurance and operational issues, coordinating and implementing activities to meet regulatory requirements, and administering the Standards of Conduct program.[372] This includes:

[372] The Standards of Conduct Program is an internal program developed by BC Hydro to support compliance requirements for the management of non-public transmission function information in the provision of wholesale electricity sales.

- Preparation, review, quality control and tracking of regulatory materials;
- Research and training to support the development of applications;
- Coordination and preparation of public workshops and hearings; and
- Providing support and guidance for customer complaints, compliance filings and Mandatory Reliability Standards filings.

5F.7.2 Overview of Operating Costs and FTEs

Table 5F-10 Regulatory and Rates KBU Fiscal 2022 Decision Operating Costs and FTEs

	($ Millions)	Labour	Services - Other	Materials	Building & Equipment	Capitalized Overhead	External Recoveries	Total Operating	Total FTEs
1	Regulatory and Rates	4.5	8.5	0.0	0.0	0.0	0.0	**13.1**	23
2	**Total (Sch 5.6 L4, Sch 16.0 L38)**	**4.5**	**8.5**	**0.0**	**0.0**	**0.0**	**0.0**	13.1	**23**

Approximately 35 per cent of the Regulatory and Rates KBU budget is related to labour. This represents 23 FTEs as follows:

- A Chief Regulatory Officer and an Administrative Assistant;
- One Manager and five Regulatory Specialists in Capital and Finance;
- One Manager and eight Regulatory Specialists in Tariffs; and
- One Manager, one Regulatory Specialist, one Compliance Advisor and three Regulatory Coordinators in Assurance and Operations.

Over fiscal 2020 to fiscal 2021, BC Hydro submitted an average of approximately 350 filings to the BCUC each year. This equates to a ratio of approximately 21 filings each year for each manager or specialist in the KBU. The complexity of these filings ranges from recurring compliance reports with no or minimal process, to standard applications which may have an information request and argument phase, to major applications which may span multiple years with multiple rounds of information requests, intervener evidence, oral hearings and arguments. All of these filings, small to large, require regulatory oversight and expertise from employees in this

KBU. BC Hydro expects the number and complexity of filings to the BCUC to continue to increase going forward as a result of the Government of B.C.'s Comprehensive Review, which has enhanced the BCUC's regulatory oversight of BC Hydro.

The remaining 65 per cent of the Regulatory and Rates KBU budget consists of the following material costs in Services – Other:

- BCUC Hearing Room Rental Fee;
- BCUC and Canada Energy Regulator cost recovery levies;
- BCUC Fees and Participant Assistance / Cost Awards awarded by the BCUC to facilitate intervener participation in regulatory proceedings; and
- Consultant resources.

The BCUC Hearing Room Rental Fee is relatively constant and budgeted at $0.2 million annually. The remaining costs are driven by the number, type, complexity and length of regulatory proceedings in a given year and can vary.

BCUC and Canada Energy Regulator cost recovery levies are budgeted at $7.3 million which is consistent with the fiscal 2021 actual costs for these levies. These fees are amounts billed to BC Hydro by regulators to cover a portion of the regulators' budgets.

BCUC Fees and Participant Assistance / Cost Awards are budgeted at $0.6 million, however as these amounts are directly related to the number and complexity of regulatory proceedings, actuals can vary from one fiscal year to the next.

Consultant resources are retained to provide expertise in specialized subject areas during regulatory proceedings. They are budgeted at approximately $0.3 million. Potential applications during the Test Period, which will require consultant resources, include the Fiscal 2023 to Fiscal 2025 Revenue Requirements Application and the 2021 Integrated Resource Plan.

5F.7.3 Fiscal 2023 to Fiscal 2025 Plan Operating Costs and FTEs

Table 5F-11 Regulatory and Rates KBU Operating Costs and FTEs

		Schedule Reference	F2021 Actual	F2022 Decision	F2023 Plan	F2024 Plan	F2025 Plan
			1	2	3	4	5
1	**Regulatory and Rates KBU**						
2	Operating Costs ($ million)	5.6 L4	13.7	13.1	13.4	13.7	14.0
3	FTEs	16.0 L38	23	23	26	26	26

Operating costs are increasing by approximately $0.3 million from fiscal 2022 Decision amounts to fiscal 2023 plan due to expected increases in cost recovery levies from regulators, and increased labour costs driven by an addition of three FTEs to the Regulatory and Rates KBU as described below. Operating costs are increasing by approximately $0.3 million from fiscal 2023 plan to fiscal 2024 plan, and by $0.3 million from fiscal 2024 plan to fiscal 2025 plan due to expected increases on cost recovery levies from regulators and Standard Labour Rate increases.

FTEs are planned to increase by three in fiscal 2023 and remain constant over fiscal 2024 to fiscal 2025. The increase in FTEs is driven by an increase in the number and complexity of regulatory applications and compliance filings. These FTEs were transferred to the Regulatory and Rates KBU from other KBUs within the Customer and Corporate Affairs Business Group: one FTE from Customer Service; one FTE from Communications and Community Engagement; and one FTE from Conservation and Energy Management.

5F.8 Business Unit Support KBU

5F.8.1 Responsibilities

The Customer and Corporate Affairs Business Unit Support KBU holds the budget for the Office of the Senior Vice-President of Customer and Corporate Affairs.

5F.8.2 Overview of Operating Costs and FTEs

Table 5F-12 Business Unit Support KBU Fiscal 2022 Decision Operating Costs and FTEs

	($ Millions)	Labour	Services - Other	Materials	Building & Equipment	Capitalized Overhead	External Recoveries	Total Operating	Total FTEs
1	SVP, Customer & Corporate Affairs	0.8	0.1	0.0	0.0	0.0	0.0	**0.9**	3
2	**Total (Sch 5.6 L5, Sch 16.0 L39)**	**0.8**	**0.1**	**0.0**	**0.0**	**0.0**	**0.0**	**0.9**	**3**

5F.8.3 Fiscal 2023 to Fiscal 2025 Plan Operating Costs and FTEs

Table 5F-13 Business Unit Support KBU Operating Costs and FTEs

		Schedule Reference	F2021 Actual	F2022 Decision	F2023 Plan	F2024 Plan	F2025 Plan
			1	2	3	4	5
1	**Business Unit Support KBU**						
2	Operating Costs ($ million)	5.6 L5	0.8	0.9	0.8	0.9	0.9
3	FTEs	16.0 L39	3	3	3	3	3

Operating costs and FTEs are planned to remain relatively constant during the Test Period.

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Chapter 5G

Operating Costs

Other

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5G.1 Introduction – Other

Chapter 5G details the composition of, and rationale for the operating costs of the Other category.

The Other category includes three KBUs: Human Resources, the Office of the General Counsel, and the Office of the President and Chief Executive Officer.

Also included in this Other category are FTEs and operating costs related to:

- **Site C Project:** FTEs for the Site C Project are increasing in fiscal 2023 as the project staffs up to a full complement of resources for the peak construction period and decreasing over fiscal 2024 to fiscal 2025. Site C Project costs are charged to capital or the Site C Regulatory Account (discussed in Chapter 6, section 6.6 and Chapter 7, section 7.3.3.4. The first generating unit in-service is forecast for December 2024 and in advance of this milestone, operating costs will start to be incurred as resources prepare for the transition from the construction phase to the operating phase. These FTEs and operating costs will reside in the Business Groups supporting, operating and maintaining the Site C Generating Station. For further information, please refer to Chapter 5, section 5.10;
- **Corporate Costs:** Corporate Costs is used to manage the flow of payroll, benefits and current service pension costs to the business through Standard Labour Rates. It also includes certain general expenses that are not specifically related to any single Business Group or KBU and are captured centrally; and
- **Capitalized Costs:** This includes costs that are eligible for capitalization under IFRS IAS 16 Property, Plant and Equipment, which are recorded in operating expenses and allocated to capital projects using a capital overhead loading rate.

Since the Previous Application, the Human Resources KBU has been transferred to the Other category from the Customer and Corporate Affairs Business Group (previously the People, Customer and Corporate Affairs Business Group). This was done to reflect the Chief Human Resources Officer reporting directly to the President and Chief Executive Officer, effective November 1, 2021. This shift reflects the significance of the human resources function in managing the programs that support, develop and shape our people and culture. The Human Resources KBU is, among other things, leading the significant company-wide inclusion and diversity efforts. In addition, the Ethics and Merit Office (previously a separate KBU in the Customer and Corporate Affairs Business Group) now reports under the Human Resources KBU. This move allows for greater alignment between the two groups as the Ethics Officer frequently collaborates with Human Resources on investigations, employee complaints and other conflict resolution situations.

Chapter 5G is organized as follows:

- Section 5G.2 provides the operating costs and FTE information for the Other category as a whole; and
- Sections 5G.3 to 5G.8 provide more detailed information on the costs within the Other category.[373]

5G.2 Fiscal 2023 to Fiscal 2025 Plan Operating Cost and FTE Summaries

The operating costs for the Other category are summarized in Table 5G-1 below.

[373] Please note the amounts presented in the tables in these sections may not add due to rounding.

Table 5G-1 Other Net Operating Costs

	($ million)	Schedule Reference	F2021 Actual	F2022 Decision	F2023 Plan	F2024 Plan	F2025 Plan
			1	2	3	4	5
1	Human Resources	5.7 L1	21.0	24.4	23.6	24.1	24.6
2	Office of the General Counsel	5.7 L2	15.5	13.0	12.9	12.9	12.8
3	Office of the President and Chief Executive Officer	5.7 L3	0.8	0.9	0.9	0.9	0.9
4	Site C Project	5.7 L4	(0.0)	0.0	0.0	0.0	0.0
5	Corporate Costs	5.7 L5	(3.3)	0.5	0.5	0.5	0.5
6	Capitalized Costs (incl. IFRS Ineligible Cap. Costs)	5.7 L6+L8	(93.9)	(75.5)	(76.2)	(76.2)	(76.4)
7	Total	5.7 L12	(59.9)	(36.7)	(38.3)	(37.9)	(37.6)

FTEs in the Other category are summarized in Figure 5G-1. Additional detail is provided in Table 5G-2 below.

Figure 5G-1 Other FTEs (Fiscal 2023 Plan)

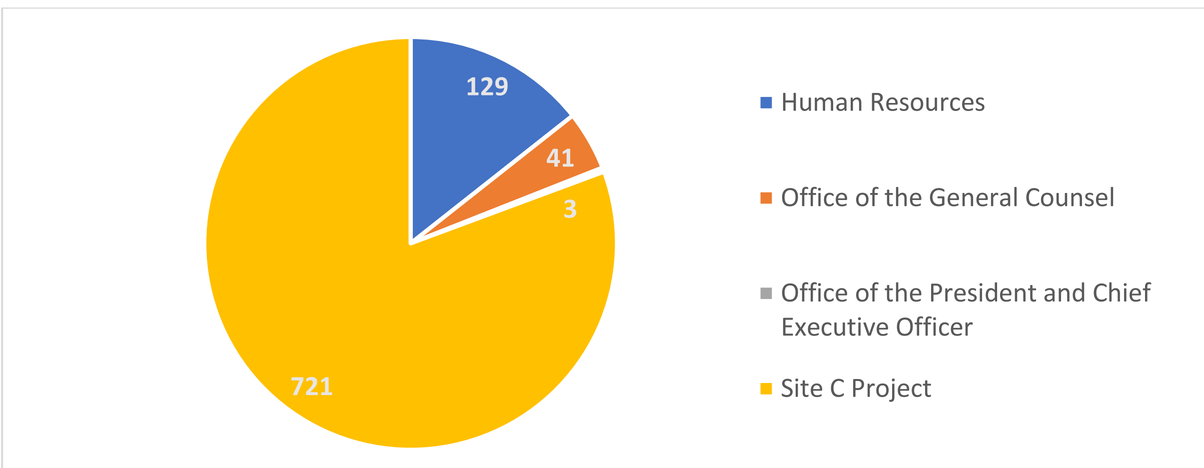

Table 5G-2 Other FTEs

	(FTEs)	Schedule Reference	F2021 Actual	F2022 Decision	F2023 Plan	F2024 Plan	F2025 Plan
			1	2	3	4	5
1	Human Resources	16.0 L41	126	131	129	129	129
2	Office of the General Counsel	16.0 L42	39	41	41	41	41
3	Office of the President and Chief Executive Officer	16.0 L43	3	3	3	3	3
4	Site C Project	16.0 L44	479	504	721	651	453
5	Total	16.0 L47	648	679	894	824	626

Table 5G-3 below provides a continuity table which highlights changes to the Other category from the Previous Application. An overall discussion of these changes, at a company-wide level, is provided in Chapter 5, section 5.5.3. Further details are provided in the sections below.

Table 5G-3 Other Operating Costs Continuity Schedule

	($ million)	Ref	F2023 Plan	F2024 Plan	F2025 Plan
1	**F2022 Revenue Requirement Application Plan**	a	**(61.1)**		
2	**Compliance Filing Adjustment**	b	**-**		
3	Reorganizational Impact	c	24.4		
4	**F2022 Decision (Schedule 5.7, line 12)**	d = Σ a to c	**(36.7)**	**(38.3)**	**(37.9)**
5	Budget Transfers Between Business Groups	e	(0.9)		
6	**F2022 Forecast (Schedule 5.7, line 12)**	f	**(37.6)**	-	-
7	Current Year Budget Transfers Between Business Groups	g	0.3	-	-
8	**Test Period Net Cost Increase/Decrease**				
9	**Uncontrollable Cost Increases**				
10	Current Service Costs and Other Labour Costs		(0.6)	0.7	0.8
11		h	(0.6)	0.7	0.8
12	**Reliability Investments**				
13	Mandatory Reliability Standards		0.1	(0.3)	(0.3)
14		i	0.1	(0.3)	(0.3)
15	**6. Net Cost Savings**				
16	Test Period Savings		(0.6)	-	(0.2)
17		j	(0.6)	-	(0.2)
18	**Total Test Period Net Increase/(Decrease)**	k = h+j	**(1.1)**	**0.4**	**0.3**
19	**F2023 Net Operating Costs (Schedule 5.7, line 12)**	l= f+g+k	**(38.3)**	**(37.9)**	**(37.6)**
20	Table may not add due to rounding				

5G.3 Human Resources KBU

5G.3.1 Responsibilities

The Human Resources KBU is responsible for employee attraction and retention programs as well as supporting the productivity and engagement of our workforce through:

- Employee development;
- Employee performance management;
- Career and succession planning;
- Compensation and total rewards programs;
- Health promotion and return to work programs; and
- Strong and effective relationships with our unions.

There is one notable change in responsibilities of this KBU since the Previous Application. As mentioned in section 5G.1, the Ethics and Merit Office, which was previously a separate KBU in the Customer and Corporate Affairs Business Group (previously People, Customer and Corporate Affairs Business Group), has moved into the Human Resources KBU.

The Human Resources KBU is organized into six departments:

- Employee Relations Department;
- Recruitment Department;
- People Development, Inclusion and Diversity Department;
- Total Rewards and Systems Department;
- Client Services Department; and
- Ethics and Merit Office Department.

5G.3.1.1. Employee Relations Department

The Employee Relations department is responsible for the overall labour relations strategy/management, collective agreement administration, union contract negotiations, policy development and governance, supporting managers/Human Resources with workplace issues, and dispute resolution (e.g., arbitrations).

5G.3.1.2. Recruitment Department

The Recruitment department is responsible for the internal and external recruitment of employees through direct sourcing and by maintaining relationships with professional associations and educational institutions. This department also includes Recruitment Services which provides services such as employee relocation, screening candidates, overseeing background checks and coordinating interviews.

5G.3.1.3. People Development, Inclusion and Diversity Department

The People Development, Inclusion and Diversity department is responsible for professional and leadership training and development, performance and talent management, coaching, onboarding, engagement and recognition programs. This department also leads inclusion and diversity initiatives to develop and support an inclusive and diverse workforce.

5G.3.1.4. Total Rewards and Systems Department

The Total Rewards and Systems department is comprised of the following teams: Total Rewards, Systems and Analytics, and Health and Recovery Services.

The Total Rewards team is responsible for the compensation, payroll, benefit, pension and time off programs that we provide to attract, retain, and support employees. This includes the management of third-party providers of benefits and pension services.

The Systems and Analytics team is responsible for human resources information systems, and providing reporting, and data and statistical analysis. This team also includes the Employee Service Center which fields employee questions and processes employee transactions such as setting up new hires in our system.

The Health and Recovery Services team is responsible for health promotion and supporting the return to work of employees. This includes preventative wellness programs, recovery and return to work programs, attendance management and WorkSafeBC claims.

5G.3.1.5. Client Services Department

The Client Services department works directly with managers and employees to provide human resources support. This includes activities such as supporting clients with human resources processes (e.g., performance management and succession planning), organizational design, leadership coaching, and addressing employee performance issues.

5G.3.1.6. Ethics and Merit Office Department

The Ethics and Merit Office department supports BC Hydro's efforts to provide a safe and respectful work environment, serving as a neutral party to support all BC Hydro employees. This department is responsible for BC Hydro's Code of Conduct, Contractor Standards for Ethical Conduct, Respectful Workplace, Ombudsperson and Merit Programs.

5G.3.2 Overview of Operating Costs and FTEs

Table 5G-4 Human Resources KBU Fiscal 2022 Decision Operating Costs and FTEs by Department

	($ Millions)	Labour	Services - Other	Materials	Building & Equipment	Capitalized Overhead	External Recoveries	Total Operating	Total FTEs
1	Chief Human Resources Officer	0.7	0.0	0.0	0.0	0.0	0.0	**0.8**	4
2	Employee Relations	1.1	0.1	0.0	0.0	0.0	0.0	**1.2**	7
3	Recruitment	2.9	2.2	0.0	0.0	0.0	0.0	**5.1**	22
4	People Development,Inclusion & Diversity	2.2	1.6	0.0	0.0	0.0	0.0	**3.8**	14
5	Total Rewards & Systems	5.7	1.6	0.0	0.0	0.0	0.0	**7.4**	47
6	Client Services	4.8	0.1	0.0	0.0	0.0	0.0	**5.0**	31
7	Ethics & Merit Office	0.8	0.3	0.0	0.0	0.0	0.0	**1.1**	5
8	**Total (Sch 5.7 L1, Sch 16.0 L41)**	**18.4**	**5.9**	**0.0**	**0.0**	**0.0**	**0.0**	**24.4**	**131**

Overall, BC Hydro has one Human Resources FTE for every 56 BC Hydro regular time FTEs. This is comparable to ratios at other organizations. According to a Human Resources Metrics Service report, the median rate for Canadian organizations is one Human Resources FTE for every 54 FTEs.[374] For comparison purposes, both ratios exclude payroll staff.

374 2017 HR Annual Metrics Report, HR Metrics Service, 2017.

The goal of the Human Resources KBU is to attract, retain and engage the employees required to operate our business. The operating costs allocated to this KBU have been effective in meeting this goal.

For example, BC Hydro's fiscal 2021 voluntary turnover rate was 1.0 per cent which is below the 3.8 per cent average for the Power and Utilities industry as reported by the Conference Board of Canada.[375] Minimizing turnover results in fewer replacement costs, and retains the specialized knowledge required to safely operate our system. In addition, our employee engagement score of 86 per cent exceeds the utilities industry average of 76 per cent.[376] A study by Gallup[377] found that businesses in the top quartile of employee engagement outperformed bottom quartile businesses by 10 per cent in customer loyalty and engagement, 21 per cent in profitability and 20 per cent in productivity.

5G.3.2.1. Chief Human Resources Officer Department

This department's budget is primarily related to labour comprised of four FTEs: one VP, People & Chief Human Resources Officer, one Strategic Business Advisor, one Administrative Assistant, and one Resource Strategy Management position.

5G.3.2.2. Employee Relations Department

This department's budget is primarily related to labour comprised of seven FTEs: one Manager, five Advisors, and one Administrative Assistant.

This group provides guidance and advice to the organization on managing complex and escalated labour relations issues, many of which take significant time to investigate and resolve over months or years. Average annual work volumes include approximately 115 corrective action investigations, 53 workplace accommodations

375 Coburn, Kelsey, and Allison Cowan. Compensation Planning Outlook 2020. Ottawa: The Conference Board of Canada, 2019.

376 Price Waterhouse Coopers – 2018 Employee Engagement Survey Results.

377 Gallup Q^{12}® Meta-Analysis Report, Gallup, https://news.gallup.com/reports/191489/q12-meta-analysis-report-2016.aspx.

and 85 grievances and arbitrations. This group is also responsible for daily collective agreement administration and interpretation, negotiating settlements and other forward-looking workplace agreements (e.g., Memorandums of Understanding), as well as leading collective bargaining negotiations.

5G.3.2.3. *Recruitment Department*

Approximately 57 per cent of this department's budget is related to labour comprised of 22 FTEs as follows:

- One Manager;
- Seven FTEs in Recruitment Services. This team is responsible for employee relocations, interview coordination and candidate scheduling. This group schedules over 3,800 interviews and conducts over 1,200 background checks (including over 250 Drug and Alcohol tests) on average per year; and
- 14 FTEs in Recruitment. This team is responsible for all internal and external hires and fills approximately 1,800 positions per year. Recruitments include filling existing positions vacated from employees leaving the position (i.e., internal movement, resignation, etc.), as well as new positions, some of which require specialized expertise (e.g., MRS and cybersecurity roles).

  On average each recruiter manages approximately 35 active vacancies at any point in time, which is a higher volume compared to other organizations. According to a Society of Human Resources Management report, recruiters in other organizations manage a median of 25 recruitment requisitions. [378]

The department's Services – Other budget relates to employee relocation expenses, background checks, external recruitment agencies, recruitment advertising and interview travel expenses. BC Hydro only utilizes external recruitment agencies for

[378] Mariotti, Andrew, *2017 Talent Acquisition Benchmarking Report*, Society for Human Resource Management, https://www.shrm.org/hr-today/trends-and-forecasting/research-and-surveys/Documents/2017-Talent-Acquisition-Benchmarking.pdf.

executive roles or hard to fill positions. All other recruitment is performed by in-house recruiters.

5G.3.2.4. People Development, Inclusion and Diversity Department

Approximately 58 per cent of this department's budget is related to labour comprised of 14 FTEs as follows:

- Two FTEs to lead and support the department - one Manager and one Administrative Assistant;
- Five FTEs in Leadership Development. This team provides enterprise-wide professional and leadership training and coaching for BC Hydro employees. Conducting this training in-house, and negotiating competitive pricing, results in lower costs than employees attending external training. For example, the cost per individual for most one-day professional training course delivered in-house is approximately \$200 to \$650, compared to the cost of a one-day professional training course at the University of British Columbia Sauder School of Business which can typically range from \$800 to \$1,000;
- Six FTEs in Talent and Performance Development, Employee Experience and Coaching. This team provides a range of talent management and employee experience and development programs. The primary focus of these programs is effective talent management and succession planning for various levels of management and critical roles to support business continuity. Programs such as talent management identify and prepare succession candidates for key positions that may be difficult to fill from the external market. This team also delivers employee recognition programs; and
- One FTE in Inclusion and Diversity who leads initiatives to support an inclusive and diverse workforce that reflects the diversity of B.C.'s available labour market.

The department's Services – Other budget relates to services provided for programs such as in-house leadership training, recognition and diversity programs, and the employee engagement survey. As an example of the benefit these services provide to BC Hydro, the employee engagement survey provides employees an opportunity to give feedback on what is working well and what could be improved. It also allows BC Hydro to take action to improve employee engagement and the effectiveness of our organization. This process is a key reason why our employee engagement exceeds the utilities industry average.

5G.3.2.5. Total Rewards and Systems Department

Approximately 77 per cent of this department's budget is related to labour comprised of 47 FTEs as follows:

- Three FTEs to lead and support the department - one Manager, one Administrative Assistant, and one Resource Strategy Management position;
- 15 FTEs in the Systems and Analytics team which includes the Employee Service Centre. Seven of the FTEs work in the Employee Service Center. They process employee transactions (e.g., new hires) and respond to approximately 18,000 employee inquiries per year. The remaining FTEs support the Human Resources systems platform and related applications and provide analytical support. In a typical year they handle more than 400 reporting requests and implement an average of 200 system fixes and enhancements;
- 17 FTEs in Total Rewards. This team develops, delivers, and administers all compensation, time off, benefit and pension programs. This team also oversees the services provided by external vendors for pension and benefit administration as well as group benefits which includes over 270,000 member benefit claim payments, and over 40,000 benefit and pension inquiries per year. Eight of the FTEs in this group are payroll staff who manage over 190,000 employee payments and 28,500 payroll inquiries per year. According

to a Deloitte report, this number of payroll FTEs is lower than the industry average of nine payroll FTEs for a company of BC Hydro's equivalent size;[379] and

- 12 FTEs in Health and Recovery Services. This team provides health promotion services, such as health education workshops and campaigns, to 3,600 employees per year. In addition, they manage 1,100 sick leave cases, 655 WorkSafe BC claims and 580 recovery services cases per year, of varying duration and complexity. Providing proactive health services and managing absences means that BC Hydro has a lower sick time usage than other public sector organizations. On average, employees have 7.0 sick days per year compared to the public sector average of 9.0 days according to a Conference Board of Canada report.[380] In addition, our return to work duration is less than four weeks compared to Sun Life's benchmark of 6.9 weeks.[381]

The department's Services – Other budget relates to vendors used to deliver pension and benefit administration, benefits and pension consulting and actuarial services, immunization clinics, Surges fitness management, the employee family assistance program, recovery programs and a WorkSafeBC claims management contractor.

5G.3.2.6. Client Services Department

This department's budget is primarily related to labour comprised of 31 FTEs: one Human Resources Lead, four Managers, two Human Resources Analysts, two Administrative Assistants and 22 Human Resources Business Partners. Client Services supports senior leaders, managers, and employees with annual Human Resources activities (e.g., performance management, succession planning),

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379 Deloitte Payroll Benchmarking Study, 2020 https://www2.deloitte.com/content/dam/Deloitte/us/Documents/human-capital/us-deloitte-payroll-benchmarking-survey-report.pdf.

380 Coburn, Kelsey, and Allison Cowan. *Compensation Planning Outlook 2020*. Ottawa: The Conference Board of Canada, 2019.

381 Sun Life Financial Canadian Benchmark for fiscal 2021.

strategic business needs (e.g., talent assessments, senior leader development, organizational changes, vacancy and headcount management) and individual employee matters (e.g., employee investigations). Overall, there is an average of one FTE in this department for every 223 regular time BC Hydro FTEs.

5G.3.2.7. Ethics and Merit Office Department

Approximately 73 per cent of this department's budget is related to labour comprised of five FTEs as follows: one Ethics Officer, one Senior Ethics Advisor, one Ethics Advisor, one Merit Advisor, and one Administrative Assistant.

Each year the department handles approximately 135 Code of Conduct inquiries and 150 Respectful Workplace cases.

The department's Services – Other budget includes funding for a secure confidential reporting line managed by a third-party service provider for individuals who prefer to report an incident anonymously. It also includes funding to retain independent subject-matter experts as required to provide independent investigations or to meet peak caseload and training volumes.

5G.3.3 Fiscal 2023 to Fiscal 2025 Plan Operating Costs and FTEs

Table 5G-5 Human Resources KBU Operating Costs and FTEs

		Schedule Reference	F2021 Actual	F2022 Decision	F2023 Plan	F2024 Plan	F2025 Plan
			1	2	3	4	5
1	**Human Resources KBU**						
2	Operating Costs ($ million)	5.7 L1	21.0	24.4	23.6	24.1	24.6
3	FTEs	16.0 L41	126	131	129	129	129

The number of the FTEs over the Test Period is reducing by two compared to the fiscal 2022 Decision amounts. This is due to a transfer out of two Resource Strategy Management positions from the Human Resources KBU to the Program and Contract Management KBU in the Operations Business Group.

The decrease in operating costs in fiscal 2023 plan of $0.8 million is largely driven by the two FTEs transferred to the Project and Contract Management KBU and a reduction in Standard Labour Rates. The increase of $0.5 million in fiscal 2024 plan and fiscal 2025 plan are driven by increases in Standard Labour Rates.

5G.4 Office of the General Counsel KBU

5G.4.1 Responsibilities

The Office of the General Counsel KBU reports directly to the President and Chief Executive Officer and provides guidance, expertise and oversight throughout BC Hydro on legal matters, corporate governance and freedom of information and privacy. Since September 2020, this KBU is also responsible for records management governance at BC Hydro.

There have been no material changes to the organization and responsibilities of the Office of the General Counsel KBU since the Previous Application.

The Office of the General Counsel KBU is comprised of the following three departments:

- Legal Services Department;
- Freedom of Information Coordinating Office Department; and
- Office of the Corporate Secretary Department.

5G.4.1.1. Legal Services Department

Legal Services is responsible for providing legal advice and support to the Board of Directors, the Executive Team, senior management, the Site C Project and all KBUs and departments across BC Hydro. BC Hydro operates in a complex and challenging legal environment, particularly given our significant presence across the province, increased regulatory compliance requirements and our status as both a regulated utility and a Crown Corporation.

5G.4.1.2. Freedom of Information Coordinating Office Department

The Freedom of Information Coordinating Office department is responsible for responding to, advising on, and addressing requests and issues related to access to information and privacy under the B.C. *Freedom of Information and Protection of Privacy Act* and other applicable legislation. Each year, the Freedom of Information Coordinating Office department responds to a large volume of direct requests as well as referrals from other agencies, working across BC Hydro to gather records and respond to requests within the time requirements in legislation. The work often involves detailed reviews of every record, which may involve hundreds or thousands of pages per request, to ensure responses are consistent with the *Freedom of Information and Protection of Privacy Act*. This department oversees the implementation of BC Hydro's privacy policies and undertakes required privacy impact assessments for programs, projects and initiatives. In addition, the department provides compliance training and advice to managers and employees across BC Hydro.

Since September 2020, the Freedom of Information Coordinating Office has assumed the responsibility for records management governance for all of BC Hydro, including policy development, overseeing the records management policy, records retention rules, training and compliance.

5G.4.1.3. Office of the Corporate Secretary Department

The Office of the Corporate Secretary department organizes, facilitates and records all meetings of the Board of Directors and responds to internal and external inquiries concerning Board decisions. This department also supports the Board of Directors, the Executive Team, management and employees on corporate governance.

5G.4.2 Overview of Operating Costs and FTEs

Table 5G-6 Office of the General Counsel KBU Fiscal 2022 Decision Operating Costs and FTEs by Department

	($ Millions)	Labour	Services - Other	Materials	Building & Equipment	Capitalized Overhead	External Recoveries	Total Operating	Total FTEs
1	Legal Services	5.1	5.9	0.1	0.0	0.0	0.0	**11.2**	34
2	Freedom of Information Coordinating Office	0.7	0.1	0.0	0.0	0.0	0.0	**0.8**	5
3	Office of the Corporate Secretary	0.3	0.7	0.0	0.0	0.0	0.0	**1.1**	2
4	**Total (Sch 5.7 L2, Sch 16.0 L42)**	**6.1**	**6.7**	**0.1**	**0.1**	**0.0**	**0.0**	**13.0**	**41**

The operating costs of the Office of the General Counsel KBU are largely comprised of labour costs for lawyers and external legal fees. This KBU is also responsible for fees and expenses for BC Hydro's Board of Directors.

Most of our in-house labour costs for lawyers are operating costs. The exception is lawyers who work on the Site C Project, other capital projects or other capitalized work, where their time is charged to the specific capital budget.

5G.4.2.1. Legal Services Department

The Legal Services department represents approximately 86 per cent of the General Counsel Office KBU operating costs and includes the General Counsel and a senior administrative assistant. Legal services are provided by a team of approximately 25 in-house lawyers, supported by a paralegal, an administrative manager and five support staff, as well as external lawyers.

In-house lawyers can be more cost-effective than external lawyers and provide the additional benefit of having broad knowledge of BC Hydro's business. In fiscal 2021, the weighted average hourly cost of external counsel was three times the cost of our in-house counsel. Given this cost difference, as well as the benefits of having an in-house legal team knowledgeable about BC Hydro's business, BC Hydro employs a team of in-house lawyers with the expertise to provide advice and support to all KBUs.

The department retains external counsel for large regulatory filings, transactions and projects, litigation, specialized legal expertise, and assistance during periods of higher than expected work volumes. The department manages law firm retainers, including costs and work scope, so that external counsel are used appropriately and cost-effectively in conjunction with in-house lawyers.

5G.4.2.2. Freedom of Information Coordinating Office Department

The Freedom of Information Coordinating Office department represents approximately 6 per cent of the Office of the General Counsel KBU's operating costs. The majority of costs in this department are related to labour. There are five FTEs in the department which consists of two information coordinators, one privacy specialist, one administrative assistant and one manager.

Over the recent fiscal years, there has been an approximate 80 per cent increase in Freedom of Information requests (168 requests in fiscal 2019, 216 requests in fiscal 2020, and 302 requests in fiscal 2021). This trend is expected to continue for fiscal 2022.

5G.4.2.3. Office of the Corporate Secretary Department

The Office of the Corporate Secretary department represents approximately 8 per cent of the operating cost of the Office of the General Counsel KBU, including labour costs for two FTEs as well as fees and expenses for BC Hydro's Board of Directors. Labour costs are for the Corporate Secretary and an administrative assistant, who also supports the Board Chair.

5G.4.3 Fiscal 2023 to Fiscal 2025 Plan Operating Costs and FTEs

Table 5G-7 Office of the General Counsel KBU Operating Costs and FTEs

		Schedule Reference	F2021 Actual	F2022 Decision	F2023 Plan	F2024 Plan	F2025 Plan
			1	2	3	4	5
1	**Office of the General Counsel KBU**						
2	Operating Costs ($ million)	5.7 L2	15.5	13.0	12.9	12.9	12.8
3	FTEs	16.0 L42	39	41	41	41	41

Operating costs are relatively consistent in fiscal 2023 plan compared to the fiscal 2022 Decision amounts with a decrease of $0.1 million in labour due to a decrease in Standard Labour Rates, which is offset by a $0.1 million increase in external legal fees to support Mandatory Reliability Standards, refer to Chapter 5, section 5.7. In fiscal 2024 and fiscal 2025 external legal fees are reduced by $0.3 million in each year due to reduced requirements for Mandatory Reliability Standards. This reduction is partially offset by Standard Labour Rate increases of $0.2 million in each of fiscal 2024 and fiscal 2025.

FTEs are planned to remain constant over the Test Period compared to the fiscal 2022 Decision amounts.

5G.5 Office of the President and Chief Executive Officer KBU

5G.5.1 Responsibilities

The Office of the President and Chief Executive Officer KBU includes the President and Chief Executive Officer, a strategic business advisor, and an executive assistant.

5G.5.2 Overview of Operating Costs and FTEs

Table 5G-8 President and Chief Executive Officer KBU Fiscal 2022 Decision Operating Costs and FTEs by Department

	($ Millions)	Labour	Services - Other	Materials	Building & Equipment	Capitalized Overhead	External Recoveries	Total Operating	Total FTEs
1	Office of the President & CEO	0.8	0.1	0.0	0.0	0.0	0.0	**0.9**	3
2	**Total (Sch 5.7 L3, Sch 16.0 L43)**	**0.8**	**0.1**	**0.0**	**0.0**	**0.0**	**0.0**	**0.9**	**3**

5G.5.3 Fiscal 2023 to Fiscal 2025 Plan Operating Costs and FTEs

Table 5G-9 President and Chief Executive Officer KBU Operating Costs and FTEs

		Schedule Reference	F2021 Actual	F2022 Decision	F2023 Plan	F2024 Plan	F2025 Plan
			1	2	3	4	5
1	**Office of the President and Chief Executive Officer KBU**						
2	Operating Costs ($ million)	5.7 L3	0.8	0.9	0.9	0.9	0.9
3	FTEs	16.0 L43	3	3	3	3	3

Operating costs are planned to remain relatively constant over the Test Period compared to the fiscal 2022 Decision amount.

FTEs are planned to remain constant over the Test Period compared to the fiscal 2022 Decision amount.

5G.6 Site C Project

5G.6.1 Responsibilities

Given its size, complexity and duration, the Site C Project has been set up as its own group with a complement of resources to support all components of successful project execution. Consistent with the Previous Application, this project team reports directly to the President and Chief Executive Officer through the Executive Vice President of the Site C Project. Construction began on the Site C Project in summer 2015. In February 2021, the Government of B.C. announced that the Site C Project will continue with a current cost estimate of $16 billion and a new expected final generating unit in-service date of 2025 (fiscal 2026), as a result of the delays and impacts of the COVID-19 pandemic.

The Site C Project team works closely with other departments in BC Hydro to align with financial, legal, procurement, environmental, contract management, engineering, safety and project delivery policies and practices. Further information on the Site C Project is provided in Chapter 6, section 6.6.

5G.6.2 Overview of Operating Costs and FTEs

Table 5G-10 Site C Project Fiscal 2022 Decision Operating Costs and FTEs by Department

	($ Millions)	Labour	Services - Other	Materials	Building & Equipment	Capitalized Overhead	External Recoveries	Total Operating	Total FTEs
1	Site C Project	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**	504
2	**Total (Sch 5.7 L4, Sch 16.0 L44)**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**504**

The Site C Project costs are charged to capital or to the Site C Regulatory Account. During fiscal 2020 and 2021, various substation and transmission related assets have been placed in-service and are currently being depreciated. The first unit in-service is forecast for December 2024 and in advance of this milestone, operating costs will start to be incurred as resources prepare for the transition from the construction phase to the operating phase. These FTEs and operating costs will reside in the Business Groups supporting, operating and maintaining the Site C Generating Station. For further information on these operating costs, please refer to Chapter 5, section 5.10.

5G.6.3 Fiscal 2023 and Fiscal 2025 Plan Operating Costs and FTEs

Table 5G-11 Site C Project Operating Costs and FTEs

		Schedule Reference	F2021 Actual	F2022 Decision	F2023 Plan	F2024 Plan	F2025 Plan
			1	2	3	4	5
1	**Site C Project KBU**						
2	Operating Costs ($ million)	5.7 L4	(0.0)	0.0	0.0	0.0	0.0
3	FTEs	16.0 L44	479	504	721	651	453

The Site C Project fiscal 2021 FTE actuals and fiscal 2022 to fiscal 2025 FTE plan amounts are provided in Table 5G-11 above.

The fiscal 2022 Decision FTE amount was based on the previous project budget of $10.7 billion. The fiscal 2023 to fiscal 2025 FTE plan amounts are based on the updated $16 billion project budget and thus the increase over the fiscal 2022 Decision FTEs.

The fiscal 2023 to fiscal 2025 plan was based on assumptions and estimates as part of the Site C Project budget re-baseline process. In addition, the FTE plan amounts include estimates for overtime. FTEs are charged to the project (i.e., are capitalized) and form part of the total project costs.

The peak construction periods are expected to be in fiscal 2023 and fiscal 2024. Overall, FTEs increases by fiscal 2023 are largely expected in the following areas:

- An increase in Construction Management resources needed to support Balance of Plant, Generating Station and Spillway, and Infrastructure construction activities;
- An increase in Engineering needed to support Balance of Plant and Main Civil Works activities; and
- An increase in professionals needed to support the areas of Contracts, Interface, Risk and Commercial Management.

5G.7 Corporate Costs

5G.7.1 Description

Corporate Costs is used to manage the flow of payroll, benefits and current service pension costs to the business through Standard Labour Rates as described in Chapter 5, section 5.12.2. In addition, Corporate Costs includes general expenses that are not specifically related to any single Business Group or KBU and are captured centrally.

5G.7.2 Overview of Operating Costs and FTEs

Table 5G-12 Corporate Costs
Fiscal 2022 Decision Operating Costs

	($ Millions)	Labour	Services - Other	Materials	Building & Equipment	Capitalized Overhead	External Recoveries	Total Operating	Total FTEs
1	Corporate Costs	0.0	0.4	0.0	0.1	0.0	0.0	**0.5**	-
2	**Total (Sch 5.7 L5, Sch 16.0 L45)**	**0.0**	**0.4**	**0.0**	**0.1**	**0.0**	**0.0**	**0.5**	**-**

The labour budget in Corporate Costs is zero as 100 per cent of the labour, benefit and current service pension costs planned are allocated out to the KBUs through Standard Labour Rates.

The fiscal 2022 Decision non-labour budget consists of various enterprise-wide memberships (e.g., Waterpower Canada, Western Energy Institute, Vancouver Board of Trade).

5G.7.3 Fiscal 2023 to Fiscal 2025 Plan Operating Costs

Table 5G-13 Corporate Costs Operating Costs

		Schedule Reference	F2021 Actual	F2022 Decision	F2023 Plan	F2024 Plan	F2025 Plan
			1	2	3	4	5
1	**Corporate Costs KBU**						
2	Operating Costs ($ million)	5.7 L5	(3.3)	0.5	0.5	0.5	0.5
3	FTEs	16.0 L45	0	0	0	0	0

Corporate Costs operating costs are planned to remain constant during the Test Period.

5G.8 Capitalized Costs

5G.8.1 Description

Capital overhead costs are costs that are eligible for capitalization under IFRS IAS 16, Property, Plant and Equipment. These costs are recorded in operating expenses and then allocated to capital projects using capital overhead loading rates (i.e., capitalized).

The approach to capitalized costs described below is unchanged since the Previous Application.

These costs are determined by multiplying the forecast eligible operating expenses by resource (e.g., materials, labour and services) by the eligible capital overhead percentages of each organizational group.

The capital overhead percentages for each organizational group are based on the IFRS Capital Cost Allocation study completed in 2012 with subsequent adjustments for changes in resourcing, work responsibilities and the cost distribution approach (e.g., direct charging to capital rather than allocating through capital overhead), that have occurred since the completion of the study. The study was reviewed by KPMG and was undertaken for the Fiscal 2012 to Fiscal 2014 Amended Revenue Requirements Application. The study's purpose was to determine the amount of costs eligible for allocation to capital under IFRS.

5G.8.2 Fiscal 2023 to Fiscal 2025 Plan Operating Costs

Table 5G-14 Capitalized Costs Operating Costs

	$ million	Schedule Reference	F2021 Actual	F2022 Decision	F2023 Plan	F2024 Plan	F2025 Plan
			1	2	3	4	5
1	Eligible Capital Overhead		(71.5)	(75.5)	(76.2)	(76.2)	(76.4)
2	Ineligible Capital Overhead		(22.4)	0.0	0.0	0.0	0.0
3	Total Overhead	5.7 L6+L8	(93.9)	(75.5)	(76.2)	(76.2)	(76.4)

Capitalized Costs are planned to remain relatively stable over the Test Period compared to fiscal 2022 Decision amounts. The change from fiscal 2021 actual to fiscal 2022 Decision amounts reflects the completion of the phase-in of IFRS ineligible capital overhead into operating costs in fiscal 2021.

BC Hydro Fiscal 2023 to Fiscal 2025
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Chapter 6

Capital Expenditures

PUBLIC

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6.1 Introduction

This chapter describes BC Hydro's well-established and robust capital planning and delivery processes, and our planned capital expenditures and additions from fiscal 2023 to fiscal 2025 (**Test Period**).[382] The capital forecasts in this chapter are derived from BC Hydro's fiscal 2022 to fiscal 2031 Capital Plan (**Capital Plan**) established based on a portfolio of multi-year project forecasts as of January 2021. The Capital Plan is based on the same planning processes described in the F2020-F2021 RRA and Previous Application, which the BCUC has determined to be reasonable in its previous two revenue requirements application decisions.

BC Hydro's project delivery practices remain consistent with the practices discussed in the F2020-F2021 RRA. Capital expenditures in the Test Period vary compared to both what was approved in the BCUC's Decision on our Previous Application and forecast largely due to the timing of major projects including the Site C project.

This chapter is organized around the following points:

- Section 6.1 describes the structure of this chapter and provides an overview of the capital expenditures and additions included in the Test Period. It also identifies how BC Hydro has responded to the BCUC's Decision on our Previous Application;
- Section 6.2 explains that we continue to use well-established and robust processes to plan and deliver our capital investments and can respond to new information so that changes are managed appropriately;
- Section 6.3 explains that our capital investments balance multiple objectives. It provides data on asset performance and project delivery to demonstrate that our investments are appropriate and that we continue to meet our performance target for delivering the capital projects;

[382] Capital "expenditures" reported in this chapter represent investments to add or replace existing assets, whereas capital "additions" represent when those assets are placed into service and included in rate base.

- Section 6.4 describes our Power System capital investments, which includes Generation, Transmission and Distribution assets, for the Test Period;
- Section 6.5 describes our Technology, Properties, Fleet and Business Support and Other capital investments for the Test Period;
- Section 6.6 describes the Site C Project expenditures and additions impacting the Test Period. The content aligns with the announcement by the Government of B.C. in February 2021 that the project will continue with a current cost estimate of $16 billion and includes a new expected final in-service date of 2025, as a result of the delays and impacts of the COVID-19 pandemic. This cost estimate was approved by the Government of B.C. as the revised project budget in June 2021; and
- Section 6.7 describes the capital investments that are driven by the Electrification Plan that are not included in the investments described in section 6.4.

6.1.1 Capital Appendices in the Application

The information in this chapter is supplemented by capital-related information in the following appendices:

- Appendix A, Schedule 13 provides decision and actual capital expenditures and additions for fiscal 2020, Decision and actual capital expenditures and additions for fiscal 2021, Decision and forecast capital expenditures and additions for fiscal 2022, and planned capital expenditures and additions for the Test Period;
- Appendix H provides a summary of BC Hydro's Capital Plan including major investments, related risks, and opportunities. It provides an overview of the capital investments that BC Hydro expects to undertake in the Test Period, within the context of BC Hydro's Capital Plan;
- Appendix I provides capital investment information for projects that are greater than $2 million for Technology projects, and greater than $5 million for other

projects, with planned capital expenditures or additions in the Test Period. Appendix I includes additional project-related information consistent with the 2018 Capital Filing Guidelines[383], such as the risk and value scores for individual projects;

- Appendix J provides capital project descriptions for 109 projects and programs of projects with planned total capital expenditures $10 million or greater for Technology projects, and $20 million or greater for other projects, with planned capital expenditures or additions in the Test Period. This information includes a project description, key drivers, issues addressed by the project, and where relevant, a discussion of project alternatives, implementation risks and risk treatment;
- Appendix K provides summaries of Strategies, Plans, and Studies. These documents do not create a financial commitment but are developed to seek potential solutions to upgrade the Power System and related infrastructure. These Strategies, Plans and Studies investigate and/or recommend broader regional, system, or business solutions or policies, supporting the need or justification for a future project or solution. The summaries provided in Appendix K provide context for the projects listed in Appendix I and J;
- Appendix L provides asset health indices for BC Hydro's generation assets. Compared to the Previous Application, the net asset health ratings have remained stable across BC Hydro's generation facilities;
- Appendix M provides asset health indices for BC Hydro's transmission and distribution assets. The asset health indices indicate that the majority of assets are in Good to Fair condition;

[383] The Capital Filing Guidelines were approved by BCUC Order No. G-313-19. Section 3.3 of the Decision provides direction on information included in an RRA. The decision is available online at: https://www.bcuc.com/Documents/Proceedings/2019/DOC_56448_2019-12-02-BCH-Review-of-BCH-Capital-Expenditures-Decision.pdf.

- Appendix N is a summary of BC Hydro's capital planning and delivery processes. BC Hydro has not made any significant changes to these processes since the Previous Application. The information in this appendix is consistent with our descriptions included in Chapter 6 of the F2020-F2021 RRA and Appendix S of the Previous Application;
- Appendix O provides BC Hydro's Technology Strategy and Five-Year Plan. This document provides guidance and direction for BC Hydro's future technology investments to manage compliance and security, manage risk and sustain productivity, and enhance business capability. The document is updated annually and was last updated in September 2020 and therefore remains the same as in the Previous Application;
- Appendix P provides a description of the expenditures that BC Hydro has deferred to the Project Write-off Costs Regulatory Account in fiscal 2021 and proposes to recover this amount from ratepayers over the Test Period in accordance with the approved recovery mechanism for the account;
- Appendix Q provides a copy of our annual reporting on reliability indices. BC Hydro's reliability metric results are similar to previous years;
- Appendix X, section 6 provides explanations for material variances between planned and actual capital expenditures and additions for fiscal 2021.[384] As discussed in the appendix, capital expenditures and capital additions in a fiscal year are impacted by a number of factors that may give rise to variances from plan, including project progression and timing, potential changes in scope due to as-found equipment conditions or other factors to meet business requirements, and cost changes due to market conditions or other factors; and

[384] This information was also provided in BC Hydro's Fiscal 2021 Annual Report to the BCUC. Variance explanations for fiscal 2022 will be provided in BC Hydro's Fiscal 2022 Annual Report to the BCUC.

- Appendix FF provides BC Hydro’s dam safety vulnerability index for all dams and its aggregate dam safety vulnerability index as well as BC Hydro’s long-term capital plan for ensuring the sustainable safety of all its dams as directed in Directive 12 of the Decision on the Previous Application.

6.1.2 Summary of BC Hydro’s Actual and Planned Capital Expenditures and Additions

BC Hydro’s capital investments generally fall into two broad categories – sustaining and growth:

- **Sustaining investments** address reliability, asset condition, regulatory, safety, security and environmental risks, issues and opportunities associated with existing assets. Sustaining investments also include all business support expenditures such as those related to Property, Technology and Fleet assets; and
- **Growth projects** help meet load and system growth through the addition of system capacity and by connecting new electricity supply. Growth projects may also add new infrastructure to the system to mitigate other risks such as reliability performance and/or allowing for the retirement of end-of-life assets. These investments are adding new assets to the Power System and reduce the need for continued sustaining investment in assets that are at or approaching end of life.

BC Hydro’s actual and planned capital expenditures and additions for fiscal 2021 to fiscal 2025 are provided in Table 6-1 and Table 6-2 below.

Table 6-1 Actual and Planned Capital Expenditures (Fiscal 2021 to Fiscal 2025)

($ millions)	F2021	F2022		F2023	F2024	F2025
	Actual	Decision	Forecast	Plan	Plan	Plan
Generation						
Growth (Schedule 13, Lines 1-2)	0.8	5.0	0.0	-	-	-
Sustaining (Schedule 13, Line 3)	299.2	383.4	376.6	300.9	311.0	500.4
Total Generation	300.0	388.4	376.6	300.9	311.0	500.4
Site C Project (Schedule 13, Line 8)	1,725.0	1,361.0	2,789.5	2,708.3	1,754.9	1,043.2
Transmission						
Growth (Schedule 13, Line 4)	121.9	142.9	79.7	125.2	151.5	117.2
Sustaining (Schedule 13, Line 5)	254.4	325.6	349.4	349.9	377.9	393.4
Total Transmission	376.3	468.5	429.1	475.1	529.4	510.7
Distribution						
Growth (Schedule 13, Line 6)	390.5	306.7	321.1	326.6	331.5	333.7
Sustaining (Schedule 13, Line 7)	204.1	219.3	217.7	193.8	190.9	182.4
Total Distribution	594.6	526.1	538.9	520.3	522.4	516.1
Business Support						
Technology (Schedule 13, Line 9)	90.8	69.2	107.1	109.4	88.2	86.6
Properties (Schedule 13, Line 10)	56.0	75.6	51.5	83.4	81.7	92.3
Fleet / Other (Schedule 13, Line 11)	54.8	70.3	60.7	80.1	76.1	57.6
Total	3,197.5	2,959.0	4,353.4	4,277.5	3,363.6	2,806.8
Less: Contribution in Aid	(195.7)	(214.2)	(158.7)	(188.1)	(186.1)	(177.4)
TOTAL	3,001.8	2,744.8	4,194.7	4,089.5	3,177.6	2,629.4
Electrification						
Transmission Load Interconnections - Growth	-	-	3.6	14.6	32.9	29.2
Transmission Regional System Reinforcement - Growth	-	-	2.0	8.0	18.1	16.1
Total Transmission Electrification (Schedule 13, Line 13)	-	-	5.5	22.6	51.1	45.3
Distribution System Expansion and Improvement - Growth (Schedule 13, Line 14)	-	-	1.0	4.0	9.1	8.0
Distribution Electric Vehicle Charging Infrastructure - Sustain (Schedule 13, Line 15)	-	-	-	2.0	2.0	2.0
Total Distribution Electrification	-	-	1.0	6.0	11.1	10.0
Total Electrification (Schedule 13, Line 16)	-	-	6.5	28.7	62.2	55.3
TOTAL	3,001.8	2,744.8	4,201.2	4,118.1	3,239.7	2,684.7

Table 6-2 Actual and Planned Capital Additions (Fiscal 2021 to Fiscal 2025)

($ millions)	F2021	F2022		F2023	F2024	F2025
	Actual	Decision	Forecast	Plan	Plan	Plan
Generation						
Growth	0.6	-	-	-	-	-
Sustaining	102.0	272.4	393.2	443.2	223.2	249.3
Total Generation (Schedule 13, Line 18)	102.6	272.4	393.2	443.2	223.2	249.3
Site C Project (Schedule 13, Line 22)	220.9	-	-	-	-	13,977.3
Transmission						
Growth	155.7	168.1	202.7	11.4	143.7	133.2
Sustaining	132.8	272.6	287.1	246.3	292.2	409.2
Total Transmission (Schedule 13, Line 20)	288.5	440.7	489.8	257.7	436.0	542.4
Distribution						
Growth	346.2	301.7	404.8	307.3	362.6	333.7
Sustaining	189.8	201.2	221.8	235.2	191.1	197.5
Total Distribution (Schedule 13, Line 21)	536.0	502.9	626.6	542.6	553.7	531.1
Business Support						
Technology (Schedule 13, Line 23)	164.9	94.3	79.3	130.6	119.5	78.6
Properties (Schedule 13, Line 24)	70.9	59.8	38.5	32.7	65.9	25.7
Fleet / Other (Schedule 13, Line 25)	49.5	75.2	63.3	70.3	90.9	56.8
Total	1,433.4	1,445.2	1,690.7	1,477.0	1,489.1	15,461.3
Less: Contribution in Aid	(180.7)	(187.2)	(213.3)	(170.1)	(176.6)	(209.4)
TOTAL	1,252.7	1,258.0	1,477.5	1,306.9	1,312.5	15,251.9
Electrification						
Transmission Load Interconnections - Growth	-	-	0.3	9.4	18.9	51.7
Transmission Regional System Reinforcement - Growth	-	-	0.2	5.2	10.4	28.4
Total Transmission Electrification (Schedule 13, Line 27)	-	-	0.5	14.6	29.2	80.1
Distribution System Expansion and Improvement - Growth	-	-	0.2	1.6	5.0	8.9
Distribution Electric Vehicle Charging Infrastructure - Sustain	-	-	-	1.6	2.0	2.0
Total Distribution Electrification (Schedule 13, Line 28)	-	-	0.2	3.2	7.0	10.9
Total Electrification (Schedule 13, Line 29)	-	-	0.7	17.8	36.3	91.0
TOTAL	1,252.7	1,258.0	1,478.2	1,324.8	1,348.8	15,342.8

The reasons for the changes across the Test Period compared to fiscal 2022 forecast are discussed in sections 6.4 to 6.6 for the specific portfolios.

6.1.3 We Have Responded to the Directives and Recommendations from the BCUC's Decision on the Previous Application

In its Decision on the Previous Application, the BCUC commented on certain aspects of BC Hydro's capital investments and made several directives and recommendations. We explain below how we have responded to these aspects of the Decision.

6.1.3.1 We Have Defined Resilience

In its Decision on the Previous Application, the BCUC encouraged BC Hydro to define the term "resilience" in this Application so that it could be considered by the BCUC as a factor in its deliberations.[385]

Resilience is the capacity to recover quickly from unexpected events. It means being setup to manage through challenges and prevent disruptions to the important services we provide. Being resilient enables reliability – something our customers count on – and gives us the space to be agile, while knowing our core functions continue to operate successfully.

One of the goals in our Five-Year Strategy is "Strengthen our resilience and agility". The Capital Plan includes funding for the successful implementation of version 7 of the Critical Infrastructure Protection (**CIP**) Mandatory Reliability Standards and physical security zone improvements at Key generation facilities which will support our goal to strengthen our resilience and agility. Further information on our plans to achieve this goal are provided in Appendix D.

6.1.3.2 The Application Includes Our Dam Safety Vulnerability Index and Long-Term Capital Plan

In its Decision on the Previous Application, the BCUC directed BC Hydro to file its dam safety vulnerability index for all dams and its aggregate dam safety vulnerability index. We have included the requested information in section 6.4.1.4 of this chapter. We have also included additional background on the methodology used to calculate this measure in Appendix FF.

385 BCUC Decision and Order No. G-187-21, BC Hydro Fiscal 2022 Revenue Requirements Application (June 17, 2021), page 57.

In addition, in the same Directive, the BCUC directed BC Hydro to file a long-term capital plan for ensuring the sustainable safety of all its dams by December 31, 2021. This information is also provided in Appendix FF and is derived from the Capital Plan.[386] As discussed further in Appendix FF, BC Hydro is investing extensively in the safety of its dams so that its overall dam safety risk profile is maintained.

6.1.3.3 We Have Provided an Updated Customer Satisfaction Index on Reliability

In its Decision on the Previous Application, the Panel noted that "BC Hydro's customer satisfaction index on reliability shows a continuous decline in reported satisfaction from industrial key accounts between F2014 and F2018" and directed BC Hydro "to provide updated figures for the customer satisfaction index on reliability in the Fiscal 2023 Revenue Requirements Application." [387] In Figure 6-8 we have included an update to the "Providing Reliable Electricity" scores in BC Hydro's Customer Satisfaction Index. The results indicate that customers continue to be satisfied with the level of reliability they are receiving and that there has been an increase in the reported satisfaction from industrial key accounts over the fiscal 2019 to fiscal 2021 period.

6.1.3.4 The Asset Investment Planning Project Has Been Cancelled and the Project Write-Off Costs are Prudent

In its Decision on the Previous Application, the BCUC requested clarity on the status of the Asset Investment Planning Tool project. [388] BC Hydro confirms that the project that was initiated in 2018 to address incremental improvements to our already robust capital planning process has been cancelled.

[386] Please refer to Appendix H of the Application.

[387] Directive 13; BCUC Decision and Order No. G-187-21, BC Hydro Fiscal 2022 Revenue Requirements Application (June 17, 2021), page 58.

[388] BCUC Decision and Order No. G-187-21, BC Hydro Fiscal 2022 Revenue Requirements Application (June 17, 2021), page 61.

Under International Financial Reporting Standards, a project can be placed into "on-hold" or "deferred" status for a period time while reconsideration of the project need or other alternatives occurs. If a project is not expected to be re-initiated within a reasonable timeframe or the work completed to date no longer has value, then the project must be cancelled and any capital costs to-date written off.

This was the case with the Asset Investment Planning Tool project. The project was placed into "on-hold" status in June 2019. In September 2020, BC Hydro determined that the project would not be re-activated until after June 2021 in light of new information on the expected total project cost and identification of a more prudent approach to align the project with the implementation of an Enterprise Asset Management software platform.[389] Accordingly, the project was cancelled in alignment with financial policy.

Once the Enterprise Asset Management Tool is in place and subject matter expertise resources are available, we will prioritize this initiative against other business improvement initiatives through our annual business planning process in alignment with BC Hydro's strategic objectives and focus areas. If BC Hydro decides to advance the investment to address the identified business requirements, a new project will be initiated.

BC Hydro has included the costs of the Asset Investment Planning Tool project in the Project Write-off Costs Regulatory Account for recovery from ratepayers. An explanation of the prudency of the project expenditures is included as Appendix P of this Application.

389 Refer to Appendix P, Asset Investment Planning Tool Project, where we explain that an Enterprise Asset Management software platform is necessary in order to integrate asset health information, asset life-cycle management and financial information, for the purpose of enabling asset investment planning. Implementation of an Asset Investment Planning Tool prior to an Enterprise Asset Management platform implementation would result in a standalone tool, without detailed asset information and reliant on manual data integration from multiple Information Technology systems.

6.1.3.5 The Capital Expenditures in this Application Are Based on Our Latest Capital Plan

In its Decision on the Previous Application, the BCUC stated "The Panel is concerned that the forecasts in BC Hydro's most-recently approved Capital Plan are no more current than April 2019 (July 2019 for technology capital). We acknowledge that this proceeding is a transitional RRA, but it appears that no capital plan had been approved between April 2019 and December 22, 2020, when the current Application was filed. The Panel expects BC Hydro to have its Capital Plan approved annually, and that the Capital Plan submitted with the Fiscal 2023 Revenue Requirements Application will have been updated and approved more recently than April 2019." [390]

The amount of time between the capital plan currency date and the Previous Application was an anomaly. BC Hydro was developing a capital plan in alignment with the timetable of our annual capital planning process but adjusted this schedule initially in response to the COVID-19 pandemic and subsequently, in order to allow the timing of future revenue requirements applications to be re-aligned.

The capital forecasts in this chapter are derived from BC Hydro's Capital Plan established based on a portfolio of multi-year project forecasts as of January 2021. The Capital Plan was approved by the Executive Team in May 2021 and presented to the Capital Projects Committee of the Board of Directors in June 2021. It was approved by the Board of Directors as part of the financial forecast that underpins this application. BC Hydro expects to present our next capital plan update to the Capital Projects Committee of the Board of Directors in November 2022 in alignment with the timetable of our annual capital planning process.

[390] BCUC Decision and Order No. G-187-21, BC Hydro Fiscal 2022 Revenue Requirements Application (June 17, 2021), page 61.

6.1.3.6 BC Hydro Continues to Maintain Strong Reliability Performance

In its Decision on the Previous Application, the BCUC expressed concern that BC Hydro's previous reduction in sustainment capital spending may be contributing to a reduction in system reliability. The BCUC recommended that it examine BC Hydro's system reliability statistics when fiscal 2021 data become available to determine whether a declining trend in system performance is emerging.[391]

BC Hydro's performance as measured by reliability metrics compares favourably to the Canadian Electricity Association benchmark and has been within acceptable thresholds of our Service Plan targets. While performance on specific metrics varies from year to year, all regions are generally maintaining their level of reliability. While these variations in regional performance are monitored, investments are identified and prioritized at an individual circuit level to ensure customers with lower reliability, compared to similar customers, are targeted for reliability improvements. Overall, BC Hydro is also increasing spending on sustainment capital year-over-year during the Test Period, as more assets reach end of life. Further discussion is provided in section 6.3.1below.

6.2 We Use Well-Established and Robust Processes to Plan and Deliver Capital Investments

This section explains that we continue to use well-established and robust processes to plan and deliver our capital investments. These processes allow us to respond to new information so that changes are managed appropriately.

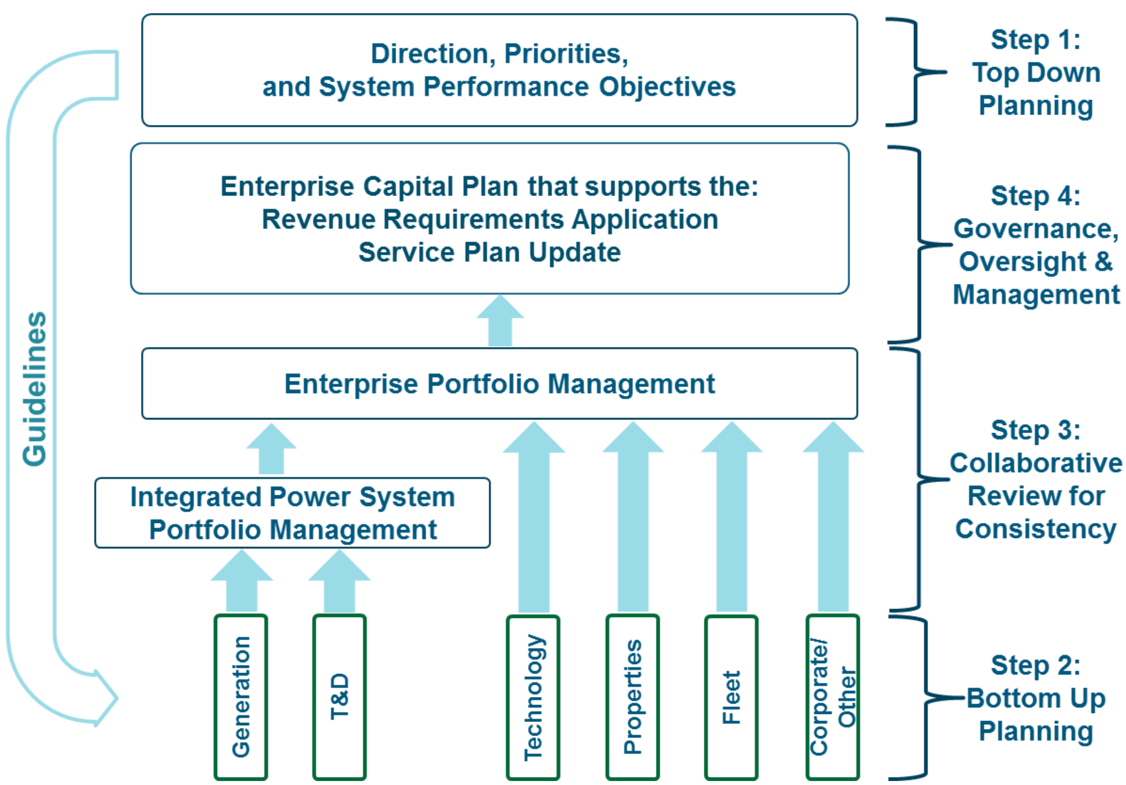
[391] Directive 13; BCUC Decision and Order No. G-187-21, BC Hydro Fiscal 2022 Revenue Requirements Application (June 17, 2021), page 58.

6.2.1 Enterprise-Wide Capital Planning Process Ensures Investments Are Appropriate and Focused on Key Strategic Priorities

Consistent with the F2020-F2021 RRA and the Previous Application, we used our Enterprise Capital Planning Process to develop the Capital Plan, from which the capital expenditures and additions included in this Application are derived.

Figure 6-1 below provides a simplified depiction of our capital planning process, which is described in detail in Appendix N. This top-down and bottom-up approach strives to ensure that we have the right balance of investment levels, system performance and risk and is consistent with BC Hydro's Five-Year Strategic goal to Control our Costs.[392]

Figure 6-1 Annual Enterprise Capital Planning Process



[392] Refer to Appendix D for BC Hydro's Five-Year Strategy.

The Capital Plan achieves key strategic objectives including investing to address compliance, addressing our highest safety risks and preserving the reliability of the Key generating facilities and the Bulk Electric System. Since the approval of the fiscal 2021 to fiscal 2030 Capital Plan (**Previous Plan**), changes in the portfolio include addressing increasing needs for the Technology, Properties and Fleet (**Supporting Portfolios**) in the near-term years of the Capital Plan and increases to the customer-driven capital expenditures net of contributions in aid. To address these changes while maintaining an appropriate level of risk within the Power System portfolio, there is a marginal increase to the rate impact of the Capital Plan in comparison to the Previous Plan equating to an additional $23.1 million or approximately one per cent in amortization and dismantling in the Test Period.

To balance our investment levels with system performance and risk, some investments were deferred in the near years of the Capital Plan. The retained risks associated with the deferrals were evaluated and considered to be manageable. These risks will be monitored, and adjustments will be made in the next capital planning cycle if appropriate.

For more detail on the Capital Plan, see BC Hydro's 10 Year Capital Plan memo in Appendix H.

6.2.2 Project Delivery Practices Remain Consistent

BC Hydro's project delivery practices remain consistent with the practices discussed in the F2020-F2021 RRA and Previous Application for the Power System[393] and the Supporting Portfolios[394].

Investments in the Power System make up approximately 90 per cent of BC Hydro's capital portfolio. Power System investments are generally delivered by three Key Business Units (**KBUs**) within BC Hydro: Project Delivery, Program and Contract

[393] A detailed discussion of those practices is provided in Appendix N, sections 2.7 to 2.9.

[394] A detailed discussion of those practices is provided in Appendix N Section 3.1 to 3.3

Management, and Distribution Design and Customer Connections. Each KBU uses a set of delivery processes suited to the types of investment for which they are responsible.

The Project Delivery KBU continues to use the Project and Portfolio Management System (**PPM**) to manage project risk, scope, schedule and cost when delivering larger, more complex projects.[395] BC Hydro's PPM processes are mature and stable, and BC Hydro continually seeks to identify opportunities for enhancements and updates. Recent enhancements have included:

- Further adoption of scaling methodologies that have demonstrated benefits in cost reductions and schedule acceleration. Project Delivery continues to focus on enhancements that leverage scaling opportunities leading to improved utilization and planning of resources, reduced deliverables, and overall accelerated schedules for projects that meet the scaling assessment criteria while still managing project risk; and
- Expanded application of historical data analytics to enable project teams to achieve more informed decisions when planning and forecasting projects including the duration, cost (including timing of expenditure) and resources.

We are also looking into key areas to enhance relevant PPM practices, including:

- BC Hydro is currently undertaking its third Organizational Project Management Maturity Model assessment. BC Hydro completed the first two assessments in 2010 and 2016. In 2016, BC Hydro completed its second Organizational Project Management Maturity Model Assessment, receiving the highest score among approximately 50 participating organizations from around the world. BC Hydro's score was 91 per cent, which represented a significant increase in maturity from our first assessment in 2010. In these OPM3™ assessments,

[395] PPM is described in more detail in Appendix N, section 2.7.

BC Hydro's practices are assessed against the Project Management Institute's Organizational Project Management Maturity Model, the globally recognized, industry-practice standard for assessing and developing capabilities in portfolio, program and project management. The third assessment is expected to be complete in the second quarter of fiscal 2022; and

- We are conducting a Project Risk Practices Review initiative to evaluate key risk management related practices (Risk Management, Estimating, and Scheduling), identify improvement opportunities and incorporate applicable external expertise and feedback.

Further discussion on delivery of supporting portfolio investments is included in section 6.5.

6.2.3 We Have Efficient Interconnection Processes to Respond to Customer Requests

Under BC Hydro's enterprise wide framework for capital prioritization[396], customer interconnection projects are considered Mandatory Investments, meaning those investments required to meet legal, regulatory or tariff compliance within the planning cycle. As such, BC Hydro allocates labour and budget resources to achieve required project timelines for customer interconnection. BC Hydro uses contract labour resources to supplement internal resources as required to manage fluctuations in the volume of customer requests and ensure that customer requests are managed efficiently.

Customer load interconnection requests are processed in two categories: one for transmission interconnections and one for distribution interconnections.[397] The subsections below describe how we manage requests that create constraints on our

[396] The enterprise wide framework for capital prioritization is described in Appendix N, section 1.1.

[397] Details on these process are provided on BC Hydro's website: https://app.bchydro.com/accounts-billing/electrical-connections/industrial-connections.html?WT.ac=ec_ec_industrial.

infrastructure, the processes for transmission and distribution load interconnections, and recent improvements to the interconnection process.

6.2.3.1 Interconnection Processes Manage Requests that Create Constraints on the System

Whether at the transmission or distribution level, our interconnection processes manage situations where increased load in a region causes strain on the existing infrastructure, as follows:

- BC Hydro assists customers to eliminate options that trigger expensive system upgrades at an early stage. It is in the best interest for both BC Hydro and the customer to avoid major system upgrades due to cost and schedule efficiencies. The Conceptual Review/Feasibility Study for transmission interconnections and Preliminary Investigation/Feasibility and Options Study for distribution interconnections are designed to provide information to assist the customers in selecting options that minimize the costs for both BC Hydro and the customers.[398] We may evaluate different locations, load levels, reliability levels, points of interconnections and other technical options so that customers can proceed to the next step with economically viable options; and
- BC Hydro mitigates any negative impacts to system reliability and existing customers. BC Hydro assess the impacts to existing customers and BC Hydro's system reliability in its interconnection studies, and then develops strategies to mitigate any impacts identified. The mitigation strategies may be a system upgrade to the BC Hydro system, a system upgrade to a customer's system, customer load curtailment or shedding if it is allowed under Mandatory Reliability Standards, or a combination of the above. In consultation with the customer BC Hydro selects the optimal solution to balance the customer's needs and costs, BC Hydro's cost, and system reliability. BC Hydro works

[398] Please refer to section 6.2.3.2 and 6.2.3.3 where we provide details on the Transmission and Distribution Interconnection processes.

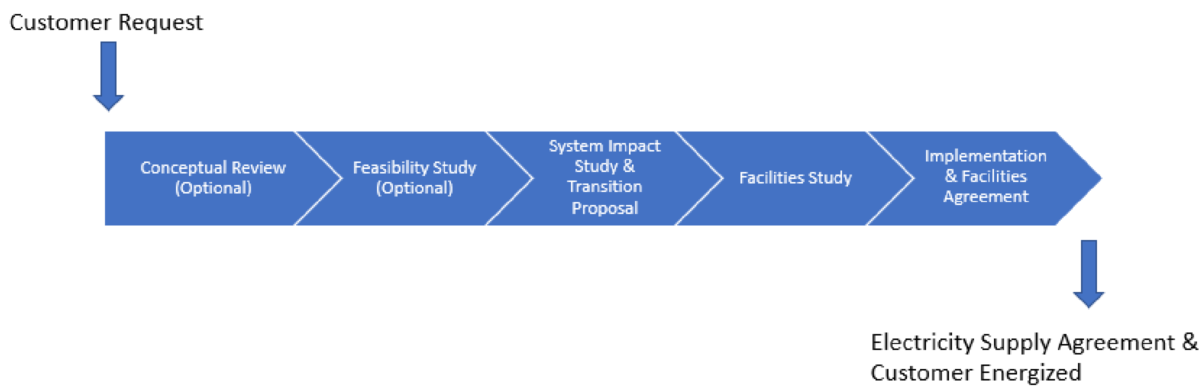
closely with the customer to assess whether changes to the customer's system or operation may be a more cost-effective solution than a change to BC Hydro's system or operation. In some cases, BC Hydro may implement a temporary solution at the customer's cost if the long-term solution required to maintain system reliability does not meet the customer's schedule.

BC Hydro system upgrades costs are allocated according to the terms of the applicable tariff. The Electric Tariff and the Electric Tariff Supplements No. 6 and No. 88 allow BC Hydro to recover the cost of system upgrades from the incremental customer revenue for large customer interconnections. For large customer interconnections, the customer provides a revenue guarantee toward the cost of system upgrades so that ratepayers are protected in case the customer terminates during implementation or the customer's expected revenue does not materialize. When the cost of system upgrades is too significant compared to the expected revenues from the customer, the tariff also has a safeguard which allows BC Hydro to collect a cash contribution from the customer above the threshold amount defined in the tariff for large customer interconnections.

6.2.3.2 Transmission Load Interconnections Follow a Staged Process

Transmission load interconnections typically follow a five-stage process, as shown in Figure 6-2 and described below. Compared to Distribution load interconnection, Transmission load interconnection typically requires reviews by more planning and engineering disciplines due to the nature of the interconnected electric system, follows more rigorous planning criteria driven by Mandatory Reliability Standards, and triggers higher costs and larger property or right-of-way requirements for system upgrades.

Figure 6-2 Transmission Load Interconnection Process



1. **Conceptual Review** – BC Hydro provides a high-level overview on available transmission capacity and methods to connect to the BC Hydro system, and the potential system modifications and upgrades involved, but no cost estimates or timelines.
2. **Feasibility Study** – BC Hydro provides a high level, limited technical assessment of potential impacts and required system modifications and upgrades for the proposed interconnection. This allows the customer to eliminate options prior to the System Impact Study, if there are multiple load, reliability or location scenarios.
3. **System Impact Study and Transition Proposal** – This study[399] identifies the facilities required, as well as a cost estimate, and may include comments on timelines for connection options. If the customer wants to proceed with a Facilities Study, BC Hydro prepares a transition proposal, which includes a plan and cost estimate to complete the Facilities Study.

[399] The study scope varies depending on where a customer is looking to connect, the complexity of system modifications and upgrades required, the number of connection options to be investigated, and the potential risks involved in implementing the project.

4. **Facilities Study** – The Facilities Study confirms the preferred interconnection option and identifies more detailed technical requirements. At completion, BC Hydro provides a project plan, which includes a refined implementation cost estimate and the customer's treatment under Electric Tariff Supplement No. 6 or No. 88, as applicable.[400]

5. **Implementation and Facilities Agreement** – BC Hydro prepares a Facilities Agreement identifying the facilities BC Hydro and the customer are each responsible to build, own, operate and pay for, as well as other terms and conditions. BC Hydro completes the interconnection work defined in the project plan, including detailed design and engineering, procurement of major equipment, construction and commissioning of facilities. An Electric Tariff Supplement No. 5 of No. 87 (Electricity Supply Agreement) is signed shortly before customer energization.

6.2.3.3 Distribution Interconnections Follow a Simplified Staged Process

Our typical process for distribution load interconnection requests follows a simplified process, as shown in Figure 6-3 and described below.

[400] Electric Tariff Supplement No. 6 applies to customers connecting directly to BC Hydro transmission system. Electric Tariff Supplement No. 88 applies to customers connecting to BC Hydro transmission system through a third-party owned transmission line or substation and referred as indirect interconnection customers.

Figure 6-3 Distribution Load Interconnection Process

1. **Preliminary Investigation, Feasibility and Options Study** – BC Hydro develops a high-level servicing proposal, including a preliminary estimate in accordance with the Electric Tariff, and a high-level project timeline.
2. **Detailed Design** – BC Hydro conducts detailed design and engineering for the project. The customer then receives a letter outlining the construction costs and detailed project deliverables for review and acceptance.
3. **Construction** – BC Hydro procures the major equipment, constructs and commissions the interconnection, installs revenue metering equipment, and completes required documentation including an Electric Service Agreement.

6.2.3.4 We Are Improving Our Interconnection Processes

As a part of the December 2020 and June 2021 compliance filings in response to the F2020-F2021 RRA Decision Directive 34 and 35, BC Hydro provided details on the initiatives completed in recent years to improve BC Hydro's ability to meet customer needs, demonstrated the progress BC Hydro has made on interconnection performance, and provided our plans for additional interconnection performance improvement initiatives[401]. In response to Directive 35, BC Hydro also conducted a workshop on March 11, 2021, with BCUC staff, potential interconnection customers, and current and potential Independent Power Producers.

Key improvements that BC Hydro has made to the interconnection process include:

- **Improved oversight and cross-company collaboration for customer-driven work** – An interconnection working group and executive steering committee was created in 2018 to strengthen internal coordination and governance. Similar coordination and oversight are also occurring at lower levels to provide better visibility and effective transition between different phases;
- **Streamlined processes** – Two Work Smart initiatives to shorten timelines of System Impact Study to Facilities Study transition and Low Complexity System Impact Study (for transmission interconnections) were implemented in 2016 and 2019 respectively. Interconnections & Shared Asset KBU and Project Delivery KBU improved coordination in releasing projects to the delivery organization which led to increased visibility, accelerated project setup, and faster onboarding of the project manager to understand customer expectation;
- **Benchmarked BC Hydro practice with peers** – 22 out of 23 recommendations identified in the 2016 Black and Veatch benchmarking study were implemented as described in BC Hydro's F2020-F2021 RRA Directive 34 compliance filing. The only recommendation that was not implemented in response to the benchmarking study was to increase BC Hydro staffing to complete interconnection studies. However, due to the expected increase in interconnection study work associated with the Electrification Plan,

[401] BC Hydro's December 2020 and June 2021 compliance filings to Fiscal 2020 to Fiscal 2021 Revenue Requirements Application Directive 34 and 35 are available on the BCUC's website at the link provided below. By providing this link, BC Hydro confirms that it considers the compliance filings to be on the record in this proceeding. https://www.bcuc.com/ApplicationView.aspx?ApplicationId=855.

additional BC Hydro resources are requested to implement the Electrification Plan, as discussed in Chapter 10;

- **Sought feedback from customers** – In fiscal 2021, BC Hydro launched interconnection customer surveys to assess customer satisfaction on our service and offer opportunities for customers to provide feedback on future improvements. The results indicate high levels of customer satisfaction, with an overall rating of 87 per cent. Although most customer responses were positive, we identified room for improvement in keeping customers up to date on the project status and understanding customer expectations better. We have incorporated the feedback from customer surveys to develop additional improvement measures identified in BC Hydro's F2020-F2021 RRA Directive 35 compliance filing and the Electrification Plan (see Chapter 10, section 10.3.4.1);
- **Interconnections Studies are largely delivered on time and additional measures were taken to accelerate the overall timeline** – BC Hydro's metric "studies delivered on time (%)" improved to 91.5 per cent in fiscal 2021 compared to 78.4 per cent in fiscal 2019 and 88.9 per cent in fiscal 2020. Multiple interconnection phases are paralleled to accelerate the overall interconnection timeline, and the customer's request may be split into multiple projects to meet customer's staged load requirements; and
- **Greater transparency on our interconnection performance** – In an effort to provide greater transparency into the volumes of interconnection studies and projects, the average timelines to complete the studies and project implementation, and the percentage of time we met our targets, BC Hydro started posting interconnection metrics on a quarterly basis on our external website at: https://app.bchydro.com/accounts-billing/electrical-connections/industrial-connections.html.

To ensure BC Hydro continues to manage load interconnection projects effectively and meet tariff requirements, the interconnection process underwent an independent internal process audit in fiscal 2021. Key findings of the audit include established and effective governance, good understanding of roles and responsibilities by an experienced team, effective monitoring and control of key risks, and consistent and frequent updates to the customers. The audit also identified recommendations for improvement, which are being implemented as additional initiatives, as discussed in BC Hydro's F2020-F2021 RRA Directive 35 compliance filing.

Although BC Hydro made progress in improving interconnection performance in recent years, there are further improvements to make so that BC Hydro and customer processes are better aligned, and additional cost and scheduling efficiencies can be achieved. As described in BC Hydro's F2020-F2021 RRA Directive 35 compliance filing, BC Hydro has identified additional initiatives and developed an interconnection plan to address the interconnections audit recommendations, customer feedback and to support BC Hydro's Electrification Plan.[402] We are implementing an interconnection plan to further streamline BC Hydro processes and support the expected increased volume of interconnection work.

6.2.4 BC Hydro Continues to Manage the Impacts of COVID-19

The COVID-19 pandemic has had a variety of impacts on the delivery of BC Hydro's capital investments. Projects and programs with construction or field work were required to incorporate new safety protocols which resulted in slowing or delaying some aspects of the work. Our updated Capital Plan incorporates any COVID-19 impacts on costs or schedule known as of January 2021 and are reflected in our capital expenditures within the Application. Further changes to projects and programs, beyond what is reflected in our Capital Plan, are expected to be minimal

[402] BC Hydro's Electrification Plan is discussed in Chapter 10.

and will be managed within the overall capital portfolio. Site C related COVID-19 impacts are discussed in section 6.6.

During the initial four months of the pandemic (April through July 2020) we implemented a COVID-19 prioritization process. This process determined which required construction activities, which were important to achieving system performance and risk mitigation objectives, could proceed under the COVID-19 safety protocols. A variation of this process was temporarily re-established in January 2021 with a focus on construction work at our higher density locations allowing for COVID-19 safety related work prioritization decisions to be made at a multi-project level.

BC Hydro is tracking all Project Delivery project schedule and cost impacts related to the COVID-19 pandemic using PPM Scheduling and Change Control practices, enabling portfolio level COVID-19 impact reporting. As of January 2021, the change control practice logged 67 projects that had COVID-19 related impacts with majority of them being schedule related. Of these 67 projects, 11 experienced a delay in their approved In-Service Date. The remainder of the schedule delays were on interim milestones that did not impact the approved In-Service Date.

BC Hydro also reviewed routine Power System and customer-driven work as part of the COVID-19 prioritization process. This type of work was typically not impacted by the COVID-19 safety protocols. Due to the short duration and low complexity of the investments, material ongoing impacts are not expected.

6.3 The Power System Is Performing Well and Our Delivery Processes Are Effective

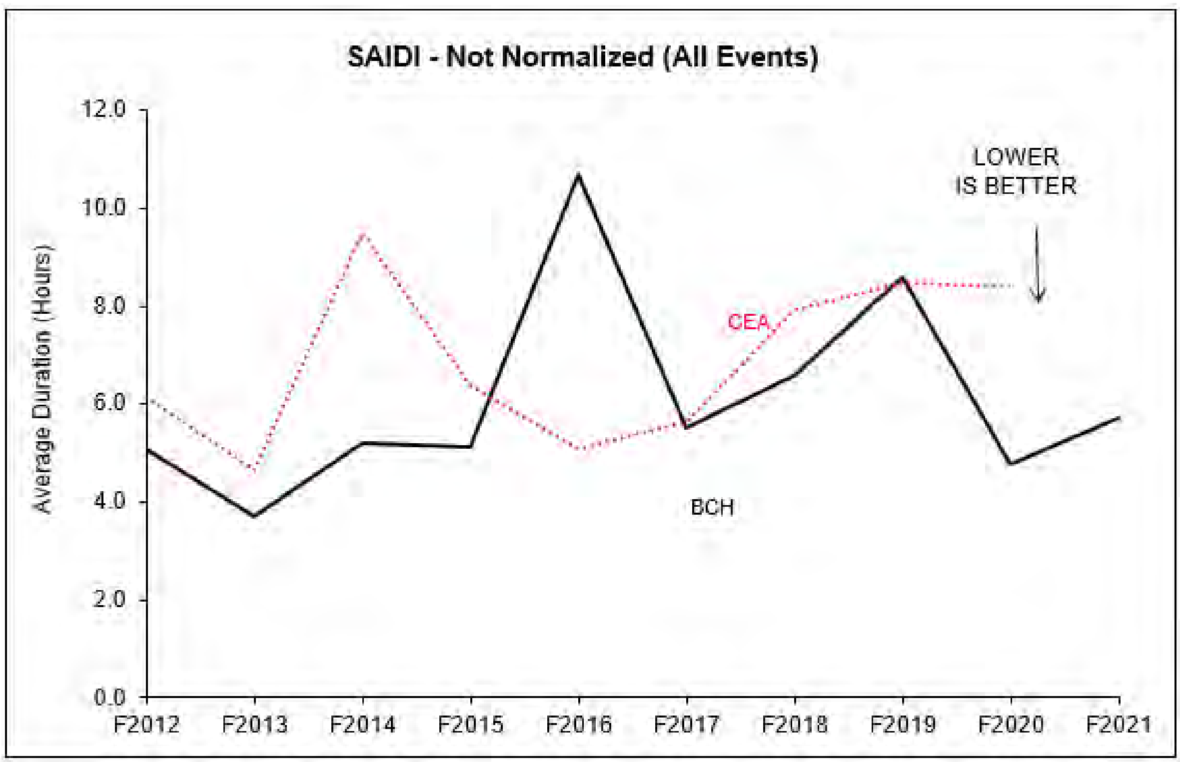
This section describes the performance of BC Hydro's Power System in terms of reliability and safety performance and the effectiveness of our delivery processes.

6.3.1 The Power System Continues to Perform Well, Is in Appropriate Condition and Customers Are Satisfied with Reliability Performance

BC Hydro continues to monitor the performance of the system and the health of our assets. Our most recent customer reliability and satisfaction indices indicate that we continue to have appropriate system performance.

Figure 6-4 below shows that, in the past decade, BC Hydro's unadjusted system average duration ("all-events" SAIDI) trend has performed as well as or better than the Canadian Electricity Association composite[403] with the exception of fiscal 2016 due to the August 2015 summer wind storm.

Figure 6-4 SAIDI (All Events, Not Normalized) Average Interruption Duration per Average Customer[404]



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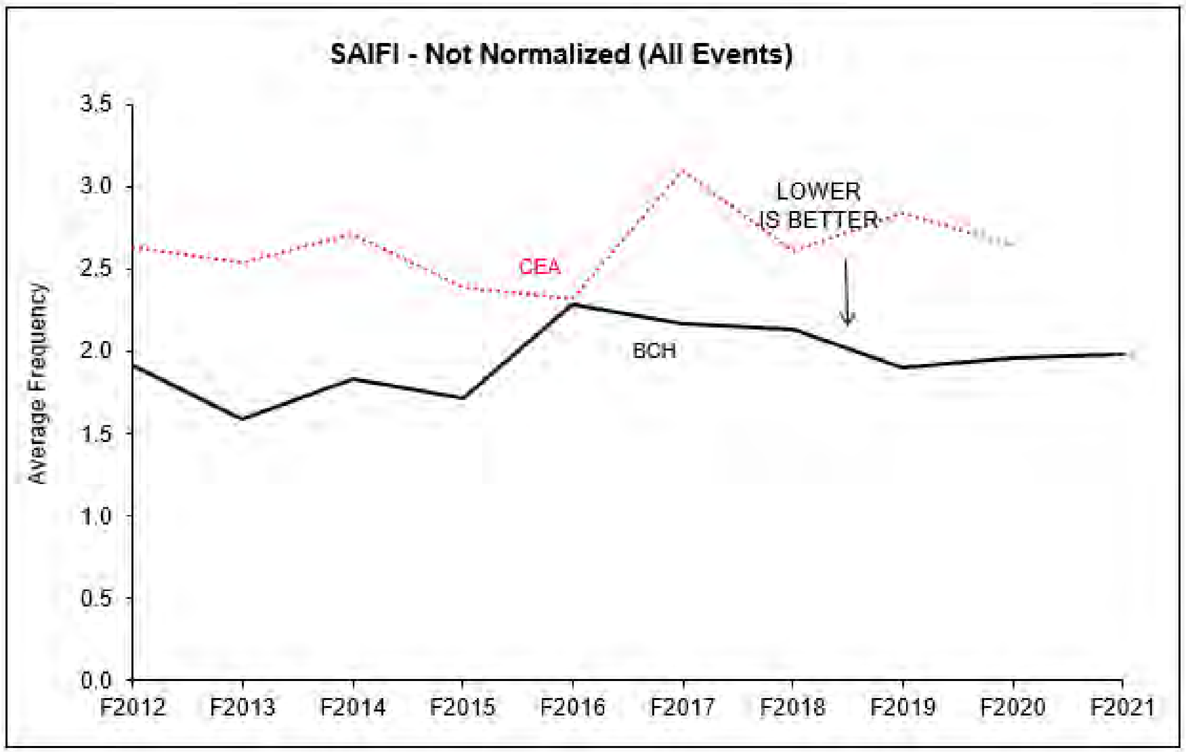
[403] BC Hydro is included in the Canadian Electricity Association composite.

[404] Canadian Electricity Association fiscal 2021 results are not available until approximately September 2021.

As shown in Figure 6-5 below, BC Hydro's unadjusted system average frequency ("all-events" SAIFI) trend has consistently out-performed the Canadian Electricity Association SAIFI composite.

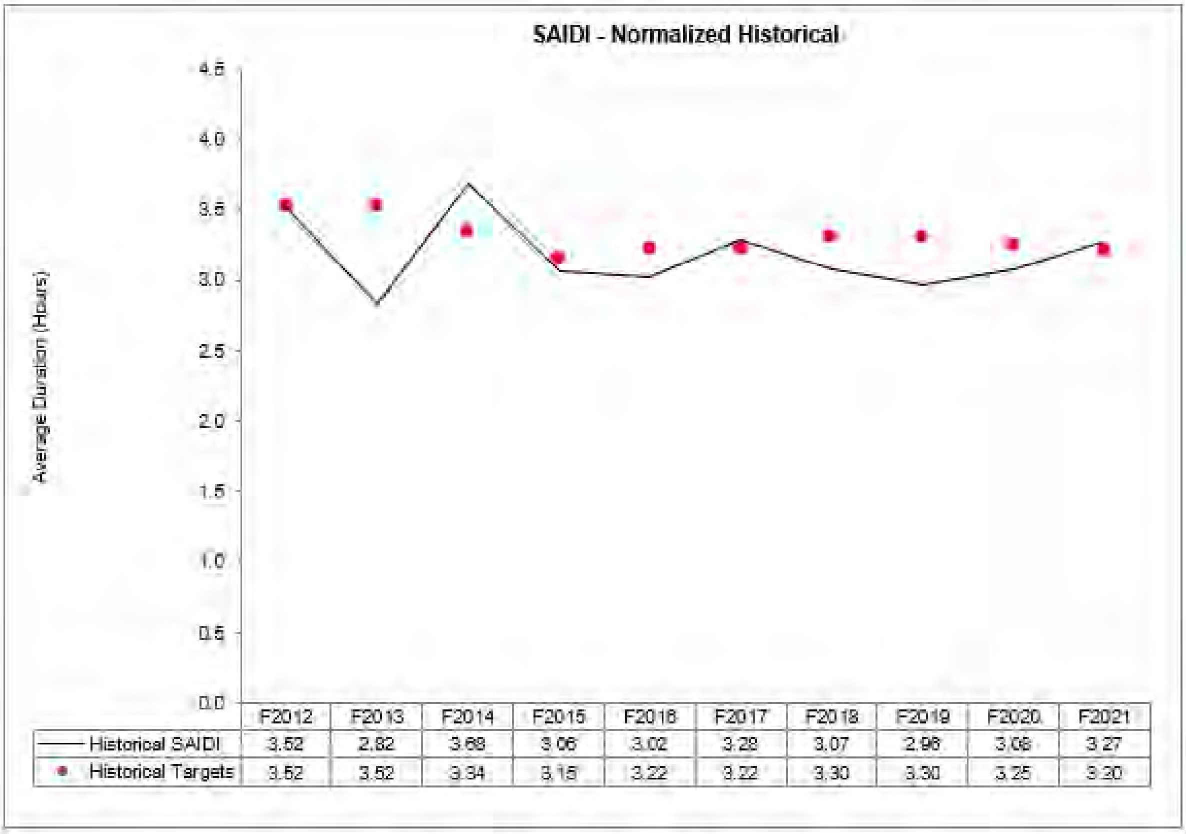
Figure 6-5 SAIFI (All Events, Not Normalized) Average Interruption Frequency per Average Customer[405]



As shown in Figure 6-6 below, normalized SAIDI (which measures the total outage duration experienced by an average customer in a year with adjustments for storm impacts) was better or within an acceptable range of our target over the past seven years. Targets are set as part of the development of the annual Service Plan based on historical performance and informed by the composition of the capital plan. Results within ten per cent of the target are considered acceptable.

[405] Canadian Electricity Association fiscal 2021 results are not available until approximately September 2021.

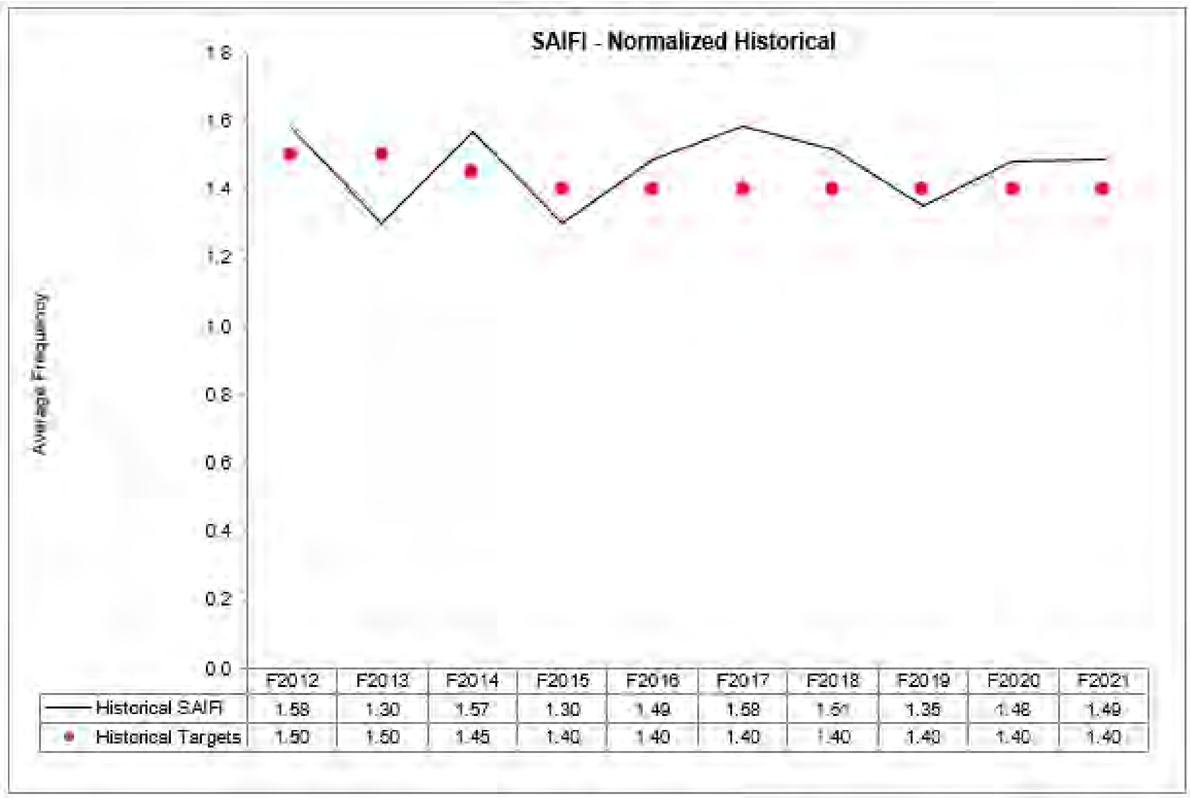
Figure 6-6 SAIDI (Normalized)



	F2012	F2013	F2014	F2015	F2016	F2017	F2018	F2019	F2020	F2021
Historical SAIDI	3.52	2.82	3.68	3.06	3.02	3.28	3.07	2.96	3.08	3.27
Historical Targets	3.52	3.52	3.34	3.15	3.22	3.22	3.30	3.30	3.25	3.20

As shown in Figure 6-7 below, normalized SAIFI, which measures the number of sustained disruptions per year excluding major events, was 1.48 disruptions in fiscal 2020, and 1.49 disruptions in fiscal 2021. In the last four years, SAIFI was better or within 10 per cent of the target which is considered acceptable performance.

Figure 6-7 SAIFI (Normalized)



BC Hydro also monitors reliability at the regional level. Table 6-3 below shows normalized historical SAIDI and SAIFI performance on a regional basis for the period fiscal 2017 to fiscal 2021.[406]

Table 6-3 Regional Historic SAIDI and SAIFI (Fiscal 2017 to Fiscal 2021)

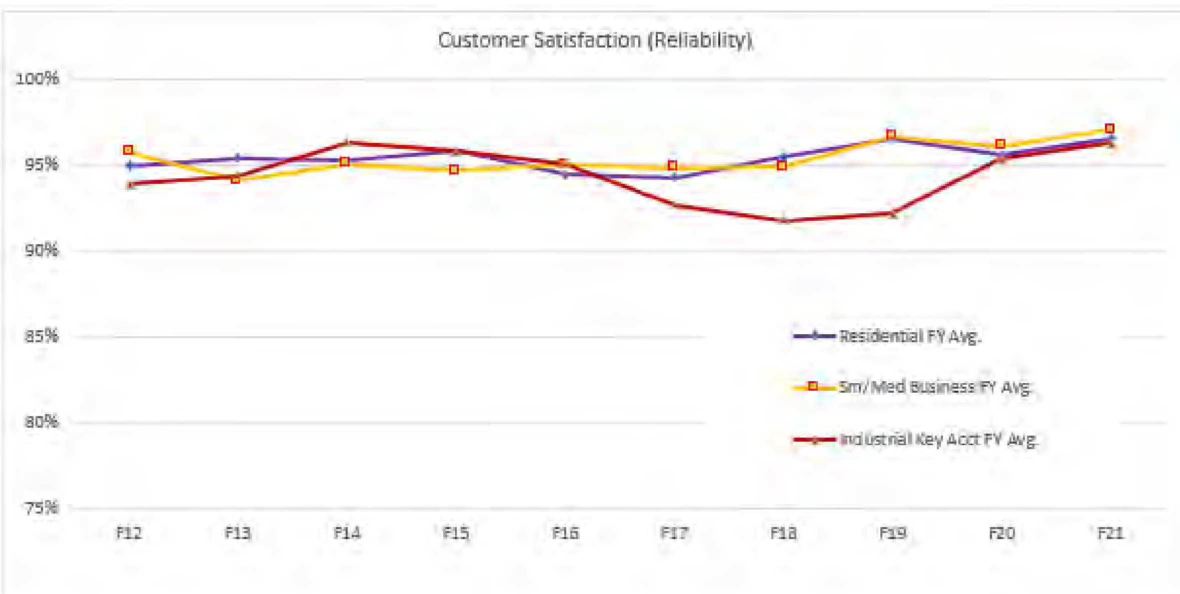
	Normalized SAIFI					Normalized SAIDI				
Fiscal Year	**LM**	**NI**	**SI**	**VI**	**NIA**	**LM**	**NI**	**SI**	**VI**	**NIA**
2017	1.02	3.73	2.32	1.73	11.98	1.82	7.90	4.85	4.43	19.98
2018	1.07	2.24	2.94	1.54	8.70	1.99	4.47	7.10	3.00	15.94
2019	0.96	2.41	2.30	1.42	6.39	2.00	5.72	4.68	3.44	13.98
2020	1.04	2.93	2.71	1.38	8.55	1.97	6.73	5.86	3.02	15.09
2021	1.03	2.65	2.45	1.63	11.60	1.98	7.75	5.21	3.74	28.99

[406] Lower Mainland (**LM**), Northern Interior (**NI**), Southern Interior (**SI**), Vancouver Island (**VI**), and Non-Integrated Area (**NIA**).

The SAIDI and SAIFI performance varies from year to year but all regions are generally maintaining their level of reliability. Regional differences in the number and duration of outages that customers may experience are due to factors such as geography, terrain, environmental conditions, vegetation, weather, and the variation in the BC Hydro system configurations supplying the individual circuits in the region. Impacts of weather-related events will also vary year to year. While these variations in regional performance are monitored, investments are identified and prioritized at an individual circuit level to ensure customers with lower reliability, compared to similar customers, are targeted for reliability improvements.

BC Hydro also monitors responses to the Providing Reliable Electricity scores in BC Hydro's Customer Satisfaction Index. As shown in Figure 6-8 below, the reliability scores in BC Hydro's Customer Satisfaction Index indicate that customers continue to be satisfied with the level of reliability they are receiving.[407]

Figure 6-8 Customer Satisfaction Index on Reliability



407 Figure 6-8 does not include data on customers in BC Hydro's Non-Integrated Areas. In response to Directive 25 from the F2020-F2021 RRA BC Hydro is now including customers from Non-Integrated Areas in the index of customer satisfaction with reliability.

The above discussed metrics are lagging indicators that reflect BC Hydro's historical investment decisions and they continue to indicate that BC Hydro is managing our service performance risks. BC Hydro also monitors the health of our assets and projects the impact of investments on future asset health. Currently, the overall condition of BC Hydro's Power System is appropriate. Approximately 71 per cent of major generating components at the Key and Strategic generating facilities are rated as Fair or Good. Similarly, approximately 90 per cent of the transmission, substation, and distribution assets are rated as Fair or Good. In each of the portfolios it is expected that a certain portion of BC Hydro's assets will be in Poor or Very Poor health at any point in time because, as the risks associated with the most critical and poorest health assets are addressed, other assets will continue to age and degrade.

At the level of capital investment in this Capital Plan, the impact on asset health is expected to vary across the system:

- BC Hydro's generation facilities are categorized as "Key", "Strategic" or "Available" according to the significance of the facility to BC Hydro's system.[408] Under the Capital Plan, the condition of BC Hydro's "Key" and "Strategic" generation facilities is expected to be stable. Investments planned for the Bridge River, Revelstoke and Kootenay Canal facilities, for example, will help maintain this stability;
- The condition of BC Hydro's transmission assets will remain stable, with only three to four per cent of transmission assets forecast to be in Poor or Very Poor condition; and
- The condition of some parts of the Power System are expected to continue to degrade. For example, over the next five years, the percentage of substation assets in Poor and Very Poor condition is expected to increase from 20 per cent to 22 per cent and the percentage of distribution assets in Poor and

[408] Refer to Appendix N, section 2.1.2 for the definition of the Key, Strategic and Available Facilities.

Very Poor condition is expected to increase slightly from 11 per cent to 12 per cent. The condition of the assets within BC Hydro's "Available" generation facilities, which provide less than one per cent of BC Hydro's annual energy, are expected to continue to deteriorate.

Allowing a marginal degradation in asset health is appropriate when considering the balance between investment levels, system performance and risk. The linkage between asset health and reliability is complex because a degradation in asset health may not lead to an impact on customer reliability. For example, most of BC Hydro's substations have built-in redundancy so that the failure of a single asset will not result in a customer outage. In addition, the installation of automated devices, such as circuit reclosers, on BC Hydro's distribution system, has mitigated the risk of declining reliability from deteriorating asset health.

As discussed above, BC Hydro monitors system performance at both a system and regional level. Changes in system performance are likely to materialize over time, rather than suddenly because of the factors described above like asset redundancy and automated devices. If system performance were to decline, BC Hydro has options to respond, including:

- Adjusting the level of asset condition driven replacements by redirecting funding from other parts of the BC Hydro capital investment portfolio;
- Bringing forward investments through our ex-plan governance process;[409] and
- Revisiting how our investment levels are balanced against our system performance and risk in the next capital plan update.

409 BC Hydro's ex-plan process is discussed in Appendix N, section 1.5.

6.3.2 We Are Managing the Safety Risks of Our Assets

BC Hydro monitors safety incidents that are caused by power system asset failure both in terms of injuries and near misses as an indication of how well we are managing the safety risks associated with our Power System assets.

Power System asset failures leading to injuries or near misses are a small percentage of BC Hydro's overall safety incidents. Over the period fiscal 2015 to fiscal 2021 asset failures have contributed to less than 0.05 per cent of total injuries and 1.5 per cent of reported near misses on an annual basis. We have not observed an increase in either injuries resulting from asset failures nor near misses as a percentage of the overall near misses reported.

Injuries and near misses may also be associated with failure of non-Power System assets such as tools, access gates, and elevators. These incidents are also a very low percentage of overall injuries and near misses. In recent capital plans, BC Hydro has increased funding to the Supporting Portfolios that maintain these assets in support of our safety objectives to ensure that workers have the right tools and equipment to safely complete their work.

In its Decision on the Previous Application, the BCUC stated "BC Hydro's [lost time] injury frequency increased between fiscal 2019 and fiscal 2020, but all-injury frequency has declined in the same period. However, the Panel is concerned that BC Hydro's results on both measures remain significantly above the Canadian Electricity Association average." The trend in these two specific metrics is not closely related to BC Hydro's asset management practices and capital investment decisions; however, some safety incidents may be linked to the overall delivery of BC Hydro's Capital Plan. Please refer to Chapter 5D, section 5D.2 where we explain our safety performance metrics and improvements that we have seen in our safety performance.

In Chapter 5D, section 5D.3 we respond to Directive 23 to the BCUC's Decision on the F2020-F2021 RRA Regarding Safety and explain that BC Hydro's most important safety performance measure is experiencing zero fatalities and serious disabling injuries, related to hazards such as electrical contact, fall from heights, mechanical or transportation. As such, over the Test Period, BC Hydro will prioritize reviewing and learning from incidents and near-miss incidents that had the potential to be fatalities or serious disabling injuries including where they are related to BC Hydro's assets and our capital investment decisions. Where there are safety risks associated with our assets, BC Hydro has options to mitigate these risks, including taking more planned outages so that work is safely completed with the assets de-energized, installing barriers and signage and/or advancing capital investments to replace equipment through our ex-plan process or in future capital plans.

6.3.3 We Continue to Deliver our Capital Program Within the Service Plan Target of +/- 5 Per Cent of Expected Cost

BC Hydro includes in its Service Plan a capital program metric[410] targeting aggregate Actual Costs falling within +5 per cent to -5 per cent of the aggregate Original Approved Expected Costs, excluding project reserve amounts. The metric is calculated using the results of generation[411] and transmission projects, as well as major distribution and properties projects.

Since 2014, when BC Hydro began using this metric, the performance results have been consistently within the targeted range. In the last five years, the aggregate Actual Costs have ranged from -3.64 per cent to +0.40 per cent of the Original Approved Expected Cost. Projects included in this metric for the five-year period, fiscal 2017 to fiscal 2021, had aggregate Actual Costs of $3,900 million, which is 3.64 per cent lower than the aggregate Original Approved Expected Cost of $4,047 million. Table 6-4 below summarizes the results of this metric over the past five reporting periods.

[410] Performance measure *3.d (Project Budget to Actual Cost)* in the BC Hydro Service Plan (Appendix C).
[411] The Site C Project is not included in the metric.

Table 6-4 Project Budget to Actual Cost Metric Results (Fiscal 2017 to Fiscal 2021)

($ millions)	F2013 to F2017	F2014 to F2018	F2015 to F2019	F2016 to F2020	F2017 to F2021
No. of Projects	540	493	426	377	281
Original Approved Expected Cost	6,363	6,936	8,000	7,182	4,047
Actual Costs	6,303	6,963	8,028	7,022	3,900
Cost Variance	-59.9	27.9	27.1	-160.2	-147.3
% Variance from Original Approved Expected Costs	-0.94	0.40	0.34	-2.23	-3.64

The F2017-F2021 Expected Costs and Actual Costs in aggregate are around three billion dollars lower than that of fiscal 2016 to fiscal 2020 because a few large projects were no longer included in the fiscal 2017 to fiscal 2021 dataset as their In-Service dates were in fiscal 2016. These projects include the Smart Metering Infrastructure project, Mica Unit 5 and Unit 6 project, and Interior to Lower Mainland project.

Of the 281 projects included in this analysis for the fiscal 2017 to fiscal 2021 five-year period, 70.1 per cent had an Actual Cost less than the Original Approved Expected Cost. The median project was 6.8 per cent below the Original Approved Expected Cost.

In fiscal 2021, BC Hydro completed a total of 39 projects with aggregate Original Approved Expected Costs of $308.3 million and aggregate Actual Costs of $321.9 million, which was a variance of $13.7 million (4.4 per cent).

6.4 Power System Forecast Capital Expenditures and Additions

BC Hydro’s planned capital expenditures and additions over the Test Period for the Power System are discussed in the following sub-sections. This includes the capital investments for BC Hydro’s Generation, Transmission and Distribution assets.[412] Throughout this section we comment on how the planned capital expenditures and additions in the Test Period compare to the fiscal 2022 forecast.

6.4.1 Generation Capital Expenditures and Additions

During the Test Period, capital investments in Generation assets include asset sustainment and Dam Safety investments. Generation capital expenditures represent approximately 25 per cent of the BC Hydro Capital Plan during the Test Period. Investment in the Generation hydro-electric portfolio represents 97 per cent of Generation capital expenditures during the Test Period. This is similar to the overall allocation of expenditures across Generation investments in the Previous Application.

The allocation of projects within the Generation hydro-electric portfolio has changed since the Previous Application. The Dam Safety portfolio now includes the full scope of water retention and conveyance assets in addition to the dams, reservoir slopes, spillways and dam instrumentation. Penstocks, power tunnels, intake gates and other water conveyance assets that were previously included under the Generation Hydro Sustaining portfolio are now included in the Dam Safety portfolio. The ability to convey water through and around the dam is a critical function when managing dam safety risks. This change to the Dam Safety portfolio was made to reflect the critical role of these assets in managing reservoir levels and outflows along with other dam safety risks.

6.4.1.1 Summary of Generation Capital Expenditures and Additions

Actual and planned capital expenditures and capital additions for Generation assets for fiscal 2021 to fiscal 2025 are presented in Table 6-5 and Table 6-6, below.

[412] Capital expenditures and additions related to the Site C Project and the Electrification Plan are excluded from the tables and discussion in this section. The Site C Project is discussed in section 6.6. The Electrification Plan capital expenditures are discussed in section 6.7 and Chapter 10.

Table 6-5 Generation Actual and Plan Capital Expenditures (Fiscal 2021 to Fiscal 2025)[413]

($ millions)	F2021	F2022		F2023	F2024	F2025
	Actual	Decision	Forecast	Plan	Plan	Plan
Hydroelectric Generation						
Growth	0.8	5.0	0.0	-	-	-
Redevelopment / Rehabilitation	9.3	-	0.7	0.3	-	-
Dam Safety	55.8	107.8	103.0	118.4	186.6	328.2
Sustaining - Other	222.1	287.2	270.3	174.6	135.3	197.7
Total Hydroelectric Generation	288.0	400.0	374.0	293.3	321.9	525.9
Non Integrated Areas						
Growth	-	-	-	-	-	-
Sustaining	4.7	4.7	6.8	10.2	6.2	6.3
Total Non Integrated Areas	4.7	4.7	6.8	10.2	6.2	6.3
Thermal Generation						
Growth	-	-	-	-	-	-
Sustaining	7.2	4.3	1.0	1.3	4.6	7.0
Total Thermal Generation	7.2	4.3	1.0	1.3	4.6	7.0
Total Gross Generation	300.0	409.0	381.8	304.8	332.8	539.1
Less: Portfolio Risk Adjustment	-	(20.7)	(5.2)	(3.9)	(21.8)	(38.7)
Total Generation	300.0	388.4	376.6	300.9	311.0	500.4
Less: Contribution in Aid	-	-	-	-	-	-
TOTAL	300.0	388.4	376.6	300.9	311.0	500.4

[413] Refer to Appendix N, section 2.11 for information on the Portfolio Risk Adjustment.

Table 6-6 Generation Actual and Plan Capital Additions (Fiscal 2021 to Fiscal 2025)[414]

($ millions)	F2021	F2022		F2023	F2024	F2025
	Actual	Decision	Forecast	Plan	Plan	Plan
Hydroelectric Generation						
Growth	0.6	-	-	-	-	-
Redevelopment / Rehabilitation	9.3	-	0.7	0.3	-	-
Dam Safety	34.1	30.6	66.7	103.6	87.2	149.4
Sustaining - Other	57.5	340.7	315.4	335.3	131.9	81.0
Total Hydroelectric Generation	101.4	371.3	382.8	439.2	219.1	230.4
Non Integrated Areas						
Growth	-	-	-	-	-	-
Sustaining	1.1	5.0	8.9	4.5	14.8	9.6
Total Non Integrated Areas	1.1	5.0	8.9	4.5	14.8	9.6
Thermal Generation						
Growth	-	-	-	-	-	-
Sustaining	0.1	3.1	9.1	0.6	0.6	12.5
Total Thermal Generation	0.1	3.1	9.1	0.6	0.6	12.5
Total Gross Generation	102.6	379.4	400.8	444.3	234.5	252.4
Less: Portfolio Risk Adjustment	-	(107.0)	(7.6)	(1.1)	(11.3)	(3.1)
Total Generation	102.6	272.4	393.2	443.2	223.2	249.3
Less: Contribution in Aid	-	-	-	-	-	-
TOTAL	102.6	272.4	393.2	443.2	223.2	249.3

6.4.1.2 The Site C Project Is the Only Generation Growth Project with Expenditures and Additions in Fiscal 2023 to Fiscal 2025

Generation growth projects are advanced to meet anticipated customer demand or are improvements at existing generating stations to increase supply side efficiency.[415] There are no Hydroelectric Generation Growth capital expenditures in fiscals 2023 to fiscal 2025 other than the Site C project, which is discussed in section 6.6.

[414] Refer to Appendix N, section 2.11 for information on the Portfolio Risk Adjustment.
[415] These projects are often referred to as Resource Smart projects.

6.4.1.3 There Are Minimal Hydroelectric Generation Redevelopment and Rehabilitation Projects Planned in Fiscal 2023 to Fiscal 2025

Generation redevelopment and rehabilitation projects are to redevelop facilities or significant elements of facilities that are at end of life. Actual and planned capital expenditures and capital additions for Generation redevelopment and rehabilitation programs and projects for the Test Period are presented in Table 6-7, below

Table 6-7 Generation Redevelopment and Rehabilitation – Plan Capital Additions and Expenditures (Fiscal 2023 to Fiscal 2025) ($ millions)

Planning ID	Name of Project	Capital Additions Plan F2023	Capital Additions Plan F2024	Capital Additions Plan F2025	Capital Expenditures Plan F2023	Capital Expenditures Plan F2024	Capital Expenditures Plan F2025
	Redevelopment / Rehabilitation						
	Programs and Projects Less than $5M	0.3	-	-	0.3	-	-
	TOTAL Redevelopment / Rehabilitation	**0.3**	**-**	**-**	**0.3**	**-**	**-**

Capital expenditures and additions in the Test Period are trailing costs associated with the John Hart Generating Station Replacement project.

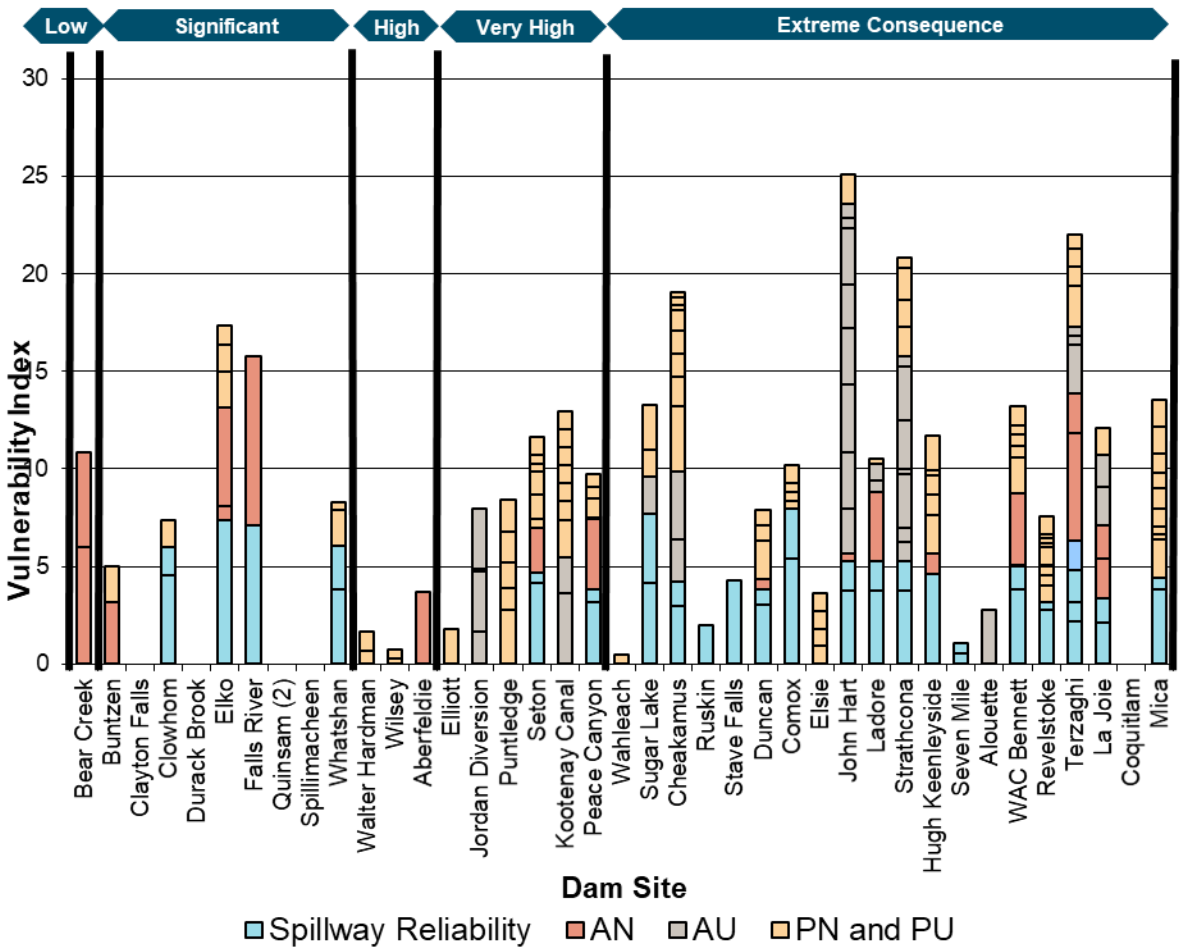
6.4.1.4 Dam Safety Expenditures Continue to Focus on Key Areas of Risk

Dam Safety projects are focused on mitigating safety risks associated with dams and other water conveyance or retention infrastructure within a hydroelectric setting, as well as addressing deterioration and loss of serviceability of those assets.

The Dam Safety Vulnerability Index Informs Capital Investment Decisions

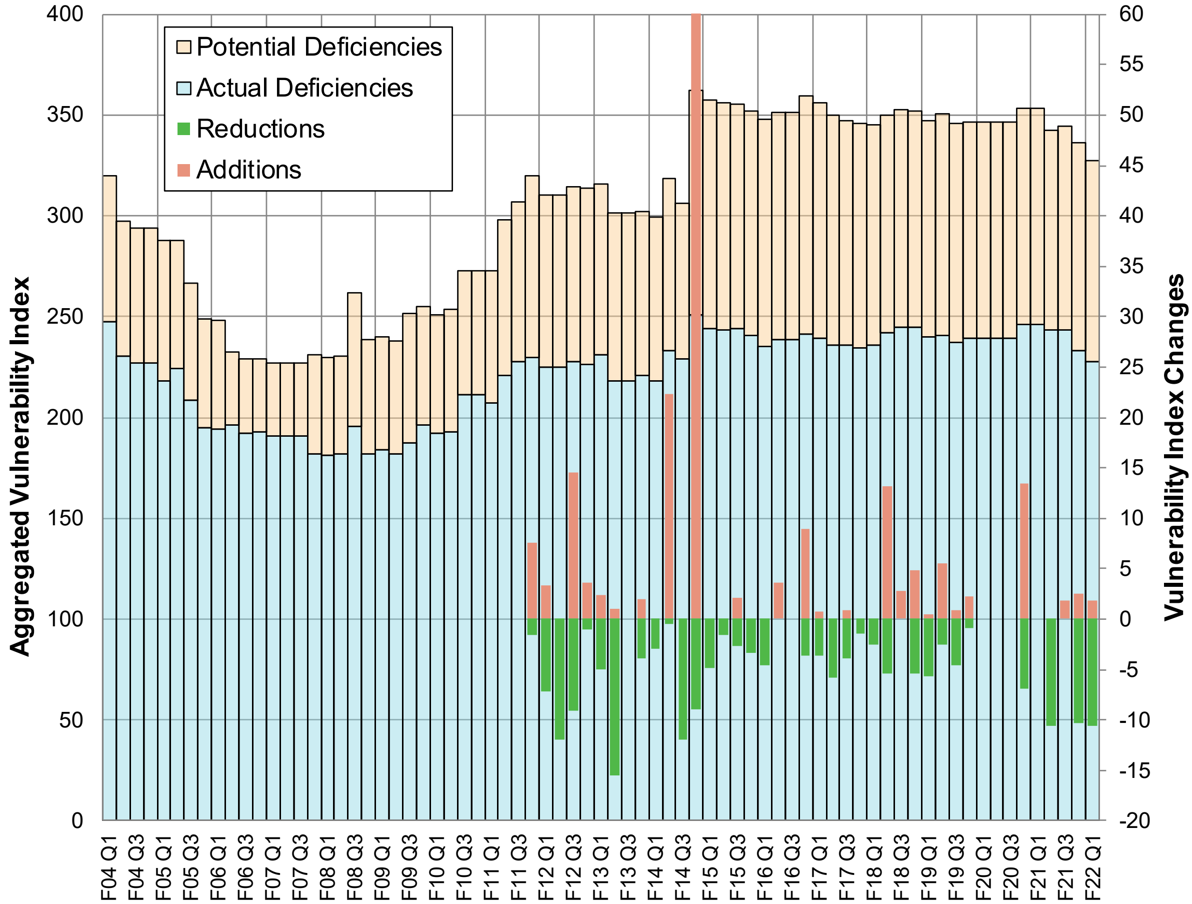
BC Hydro has a comprehensive and robust system for assessing the risks due to physical deficiencies in our dams. The most recent audit of BC Hydro's Dam Safety Program found that "BC Hydro has a well-established Dam Safety Program that is in line with international practices with some aspects operating at best practice levels" and that "BC Hydro continues to be a leader in risk assessment in the international dam safety community with a transparent, systematic and robust risk assessment process." When a deficiency in a dam is first identified, BC Hydro rates the associated level of concern using the Vulnerability Index that is described in greater detail in Appendix FF. The Vulnerability Index considers the gap between the actual performance capacity of the dam feature of concern and its required or minimum desired capacity per established norms of dam safety practice, the criticality of the feature to the safety of the dam, the frequency at which the capacity of the deficient feature is expected to be reached or exceeded, and the effectiveness of interim risk controls. For each dam, the Vulnerability Indices associated with all characterized deficiencies are aggregated and charted, as shown in Figure 6-9 below to provide an overall Vulnerability Index for the dam. Actual Deficiencies are broken out into Actual Normal (**AN**), Actual Unusual (**AU**), and Spillway Reliability Deficiencies, while Potential Normal (**PN**) and Potential Unusual (**PU**) Deficiencies are reported together. These types of deficiencies are described in more detail in section 2.3 of Appendix FF. As there is no factor relating to the consequences of failure, the Vulnerability Index is not a proxy for risk. Rather, risk is estimated by sorting the dams according to their consequence classifications within the Dam Safety Regulation, with risk inferred to be greater for vulnerabilities in higher consequence dams as one moves across the classifications from left to right in the chart. Since the Vulnerability Index for a dam is the aggregate of the vulnerabilities of individual components, features and functions, the relative importance of the individual vulnerabilities can be considered in decision-making.

Figure 6-9 Dam Safety Vulnerability Index Rating for BC Hydro Dams as at June 30, 2021



The Vulnerability Indices associated with all characterized deficiencies on all dams are aggregated and charted, as in Figure 6-10 below, to provide an overall Vulnerability Index for the dam fleet. The aggregate Vulnerability Index is plotted over time to show the relative risk position of BC Hydro's dam fleet. Also shown on Figure 6-10 are the values of Vulnerability Index reductions (green bars) achieved and Vulnerability Index additions (red bars) identified within each fiscal quarter since fiscal 2011. The notable increase in Vulnerability Index in fiscal 2014 arose from a revised understanding of seismic hazard at BC Hydro's dam sites with the completion of BC Hydro's Probabilistic Seismic Hazard Analysis model.

Figure 6-10 Aggregated Dam Safety Vulnerability Index as at June 30, 2021



The operation of large dams involves risk which is accepted for the benefits that accrue from relatively inexpensive and environmentally sustainable electricity and from flood control. To exclude risk altogether is impossible. BC Hydro’s aim is to manage the whole fleet of dams so there is no significant deterioration in the risk position and the overall level of risk is kept well within tolerable limits as guided by the Canadian Dam Association’s Dam Safety Guidelines and the International Commission on Large Dams’ Bulletin on Dam Safety Management. Increases to the Vulnerability Index are due to a combination of new knowledge regarding existing deficiencies coming out of investigations, observations and reviews, and new deficiencies due to generally deteriorating conditions. The rate of reduction to the

Vulnerability Index is dependent mainly on completion of capital projects, but also on favourable results from investigations or changes in reservoir management and facility operation.

Dam Safety projects are frequently complex, difficult to conceptualize, design and implement and, consequently, long in duration. The risks associated with a deficiency must therefore be managed even before a project is raised to address it. When a deficiency in a dam is first identified, the associated level of concern is rated to establish the priority and timing of the required treatment. Options for implementing interim controls to manage the risk until the deficiency can be addressed are considered next. If such controls are readily implemented, or if they are deemed necessary to reduce the interim risks to a tolerable level until dam improvements are completed, they are put into place by way of an Interim Dam Safety Risk Management Plan. In some cases, these controls include modifications or restrictions to how the reservoir is operated. Interim projects may also be undertaken to reduce the level of risk for the deficiency until a long-term risk reduction project can be developed and implemented. With these practices being followed, identified deficiencies in dams and their consequent risks are managed to a tolerable state through the course and duration of Dam Safety projects.

Dam Safety Capital Expenditures Are Increasing in the Test Period

Dam Safety represents 54 per cent of the Generation expenditures over the Test Period. Dam safety risks generally have a low probability of occurrence but, if realized, a high consequence. The key drivers of Dam Safety projects are described in Appendix N, section 2.1.3, and additional detail on the Dam Safety Long-Term Capital Plan is provided in Appendix FF.

Table 6-8 below provides a breakdown of the Dam Safety capital additions and capital expenditures in the Test Period that were summarized in Table 6-5 and Table 6-6 above.[416]

Table 6-8 Dam Safety Projects – Plan Capital Additions and Expenditures (Fiscal 2023 to Fiscal 2025) ($ millions)

Planning ID	Name of Project	Capital Additions Plan F2023	Capital Additions Plan F2024	Capital Additions Plan F2025	Capital Expenditures Plan F2023	Capital Expenditures Plan F2024	Capital Expenditures Plan F2025
	Dam Safety						
G000489	Bridge River 2 - Strip and Recoat Penstock 2 Interior	28.9	0.2	-	18.5	0.2	-
G000057	Cheakamus Recoat Units 1 and 2 Penstocks (Interior and Exterior)	29.2	0.0	-	12.2	0.1	-
G000640	Lake Buntzen 1 Coquitlam Tunnel Gates Refurbishment	17.5	1.2	-	3.0	0.2	-
G003129	Revelstoke Replace Downie Slide Instrumentation	15.0	-	-	0.2	-	-
G000657	Comox - Puntledge Flow Control Improvements	-	-	-	3.2	4.5	13.1
G000585	John Hart Dam Seismic Upgrade	-	-	-	10.9	32.3	91.4
G000668	Ladore Spillway Seismic Upgrade	-	-	-	3.2	10.0	17.2
G000195	Mica - Intake Gantry Crane Refurbishment	-	5.4	0.1	0.0	5.0	0.1
G000525	Strathcona Upgrade Discharge	-	-	-	6.5	4.4	65.7
G003555	W.A.C. Bennett Dam Seal Low Level Outlets	-	-	-	0.9	1.0	10.6
G000001	Alouette - Environmental Flow Discharge Upgrade and LLO Sealing	-	-	-	0.3	0.6	3.4
G000011	Alouette Improve Headworks & Surge Tower Seismic Stability	-	-	56.7	2.4	26.4	20.8
G000042	Ash River Extend Life of Steel Penstock	-	20.5	0.3	3.8	14.8	0.3
G003467	Bridge River 1 - Improve Slope Drainage	-	-	-	0.5	4.2	9.4
G000485	Bridge River 1 - Strip and Recoat Penstocks 1-4 Interior	-	-	-	0.6	0.5	1.0
G003133	GMS – Install Further Instrumentation for Monitoring Embankment Condition	-	-	-	0.6	1.1	3.7
G000556	Hugh Keenleyside - Spillway and Low Level Outlets Concrete Upgrade	-	-	-	0.5	0.4	9.5
G003723	Hugh Keenleyside - Fire Protection System Upgrade	-	-	8.6	0.5	3.1	4.4
G000459	La Joie - Dam Improvements	-	-	-	5.4	4.1	3.5
G003365	Mica - Discharge Facilities Seismic and Reliability Upgrades	-	-	-	1.5	2.0	2.2
G000467	Terzaghi - Spillway Chute Access Improvement	-	-	-	0.4	1.4	6.7
G003653	Various Sites - Reservoir Booms Replacement - F2020	-	9.8	9.9	8.6	9.1	0.6
G003554	W.A.C. Bennett Dam Recommission / Seal Spillway Sluice Gates	-	11.4	11.4	5.6	9.0	6.2

[416] More information on the projects listed can be found in Appendix I, page 1.

Planning ID	Name of Project	Capital Additions Plan F2023	Capital Additions Plan F2024	Capital Additions Plan F2025	Capital Expenditures Plan F2023	Capital Expenditures Plan F2024	Capital Expenditures Plan F2025
G004327	Bridge River 1 - Penstock Concrete Foundation Refurbishment	-	-	21.8	2.6	18.4	0.8
G000052	Cheakamus - Dam Improvements	-	-	-	-	-	4.7
G000131	G.M. Shrum - Intake Operating Gate and Intake Maintenance Gate Refurbishment	-	-	-	0.3	1.0	0.8
G003336	G.M. Shrum - Intake Operating Gate Hydraulic Upgrade	-	-	-	0.8	1.5	0.5
G002183	Hugh Keenleyside - Cranes Upgrade	-	-	-	-	-	0.6
G003811	Kootenay Canal - Canal Concrete Liner Joints Upgrade	-	-	-	-	-	1.0
G003234	Lake Buntzen 1 - Penstock Interior Restoration	-	-	-	-	1.7	7.0
G003131	Mica - Little Chief Inclinometers Installation	-	-	13.4	0.5	1.2	11.6
G004405	Ruskin - Left Abutment Slope Sinkhole Remediation	8.0	-	-	2.8	-	-
G000543	Seton - Canal Flow Control Structure Upgrade	-	-	-	-	-	1.8
G000295	Sugar Lake - Dam Abutments Upgrade	-	-	-	-	-	1.8
G000470	Terzaghi - Dam Instrumentation Upgrade	-	-	-	-	-	0.5
G000468	Terzaghi - Low Level Discharge Reliability Improvement	-	-	-	-	1.0	3.9
G004064	Various Sites - Probabilistic Seismic Hazard Model Update	-	-	-	0.6	1.2	2.4
G004172	Various Sites - Spillway Gate Standby Power Improvements	-	10.8	8.7	1.7	9.1	8.7
	Programs and Projects Less than $5M	5.1	27.9	18.5	19.8	17.0	12.3
	TOTAL Dam Safety	**103.6**	**87.2**	**149.4**	**118.4**	**186.6**	**328.2**

Capital investments in the Programs and Projects Less than $5 million line include projects to install, replace or rehabilitate instrumentation in dams and to implement miscellaneous upgrades of water conveyances and gates.

Dam Safety capital expenditures for the Test Period are higher compared to the fiscal 2022 forecast and show an increasing trend over the Test Period. This portfolio of capital expenditures consists mainly of large multi-year projects and, as a result, is subject to fluctuations in year-over-year spend.

A significant portion of the planned Dam Safety capital expenditures in the Test Period are driven by the detailed design and progression to implementation phase of a number of large projects, including: Alouette – Improve Headworks & Surge Tower Seismic Stability, Strathcona – Upgrade Discharge, Ladore – Spillway Seismic

Upgrade, John Hart Dam Seismic Upgrade, and Bridge River 1 – Improve Slope Drainage.

Dam Safety capital additions in the Test Period are expected to be higher than the fiscal 2022 forecast. The increased capital additions are being driven primarily by the following projects that are planned to be completed and put into service during the Test Period:

- Penstock recoating projects at Ash River, Bridge River, and Cheakamus;
- Alouette – Improve Headworks & Surge Tower Seismic Stability;
- Downie Slide and Little Chief slope instrumentation installations;
- Reservoir Boom Replacements;
- Spillway Gate Standby Power Improvements; and
- Bennett Dam – Seal Spillway Sluice Gates.

However, the majority of Dam Safety projects will be in various stages of design over the Test Period, with capital additions not expected until after fiscal 2025.

6.4.1.5 Other Hydroelectric Generation Sustaining Project Expenditures and Additions in the Test Period Target Key Risks

Generation sustaining investments classified as Other Projects are initiated to mitigate or resolve key risks identified with existing assets.[417] These investments can include:

- The replacement or upgrade of major generating equipment;
- The replacement or upgrade of auxiliary and balance of plant equipment such as: station service upgrades (e.g., 600 V circuit breaker projects), fire protection

[417] Further discussion of these risks is provided in Appendix N, section 2.1.

systems, Heating, Ventilating and Air Conditioning (**HVAC**) systems and piping systems;

- The replacement or upgrade of facility infrastructure;
- The replacement or upgrade of water passage and penstock related assets that were in the Implementation phase and not transitioned to the Dam Safety portfolio; and
- Projects to address safety and environmental risks or address regulatory compliance.

Table 6-9 below provides a summary of the capital additions and capital expenditures for Hydroelectric Generation Sustaining – Other Projects in the Test Period.[418]

[418] More information on the projects listed can be found in Appendix I, pages 1 and 2.

Table 6-9 Generation Sustaining – Other Projects – Plan Capital Additions and Expenditures (Fiscal 2023 to Fiscal 2025) ($ millions)

Planning ID	Name of Project	Capital Additions Plan F2023	Capital Additions Plan F2024	Capital Additions Plan F2025	Capital Expenditures Plan F2023	Capital Expenditures Plan F2024	Capital Expenditures Plan F2025
	Generation Sustaining - Other						
G000571	Cheakamus Replace Units 1 and 2 Turbine Inlet Valves	6.0	0.1	-	1.8	0.1	-
G000127	G.M. Shrum G1 to 10 Control System Upgrade	32.7	0.3	0.5	6.2	0.3	0.1
G000114	G.M. Shrum Upgrade HVAC System	-	19.3	0.8	9.3	7.2	0.8
G003035	Hugh Keenleyside Recoat Navlock Gates	6.2	0.0	-	2.5	0.0	-
G000747	Hugh Keenleyside Replace Service Water Piping	11.0	-	-	0.4	-	-
G000158	Jordan - Upgrade Governor & PRV Controls	11.9	0.5	-	4.0	0.5	-
G003211	Mica - Reactor 5RX3 Replacement	15.9	5.4	-	5.2	1.7	-
G000172	Mica Modernize Controls	15.4	15.4	-	8.1	3.4	-
G003207	Mica Replace Units 1 to 4 Generator Transformers	19.5	1.9	-	8.8	1.9	-
G003456	Mica Upgrade 600V Circuit Breakers	23.7	-	-	1.8	-	-
G000801	Mica Upgrade HVAC System	29.4	4.9	-	18.0	4.9	-
G000220	Peace Canyon - 600V Circuit Breaker Upgrades	5.1	3.4	-	4.9	2.5	-
G000241	Puntledge Recoat Interior and Exterior of Steel Penstock	11.6	-	-	2.6	-	-
G003373	Revelstoke Replace Fire Alarm System	7.1	-	-	0.1	-	-
G000834	Seven Mile - Replace T1 Transformer	-	10.1	-	5.4	0.7	-
G000822	Seven Mile Upgrade Powerhouse Crane Controls	9.7	-	-	0.5	-	-
G003515	Various - Water License Renewal	8.6	-	-	1.2	-	-
G000342	Wahleach Recoat Penstock (Interior and Exterior)	-	5.9	0.0	2.5	3.6	0.0
G000334	Wahleach Refurbish Generator	48.5	1.2	-	12.9	1.2	-
G001047	Waneta U3 Life Extension	30.4	-	-	-	-	-
G000776	Bridge River 1 Replace Units 1-4 Generators / Governors	-	-	-	2.5	11.4	19.4
G003338	Various Sites - Cutler Hammer Exciters Upgrade	2.3	2.0	2.0	2.0	2.0	2.0
G003584	Whatshan - Governor Replacement	-	5.4	-	2.5	2.2	-
G000031	Ash River - Upgrade Communication Systems	-	-	8.7	0.9	3.1	4.2
G000128	GMS - Unwatering System Refurbishment	-	-	6.2	0.6	1.7	5.0
G003058	Kootenay Canal - U1 - U4 Generators Refurbishment	-	-	-	0.4	0.8	3.1
G000952	Kootenay Canal Modernize Controls	-	-	-	1.4	0.7	7.6
G000168	Lake Buntzen 1 - Generator Replacement	-	-	-	1.1	3.3	3.7
G000519	LDR - Upgrade Communication Systems	-	-	7.4	1.8	3.5	1.3
G000181	Mica - U1 - U4 Circuit Breaker and Iso-phase Bus Replacement	-	-	15.0	4.2	11.5	12.5

Planning ID	Name of Project	Capital Additions Plan F2023	Capital Additions Plan F2024	Capital Additions Plan F2025	Capital Expenditures Plan F2023	Capital Expenditures Plan F2024	Capital Expenditures Plan F2025
G003835	Peace Canyon - U1 - U4 Exciter Replacement	-	-	-	0.4	0.8	0.6
G000252	Revelstoke - U1 - U4 Stator Replacement	-	-	-	1.2	2.9	5.6
G003026	Seton - Upgrade Unit	-	-	-	3.6	6.0	60.4
G003449	Various Facilities Replace Water Level Gauges	-	10.7	0.3	4.9	4.6	0.2
G000035	Ash River - Generator Replacement	-	-	-	0.4	0.7	0.9
G004409	Bridge River 2 - Transformer Replacement	-	7.9	-	6.5	0.8	-
G003826	G.M. Shrum - Pauwels Transformer Life Extension	-	-	-	0.3	0.8	2.2
G003302	G.M. Shrum - Physical Security Upgrade - Phase I	-	-	-	0.6	0.7	1.2
G003837	G.M. Shrum - U5 Generator Refurbishment	-	-	-	-	-	2.7
G000124	G.M. Shrum - U6 Generator Refurbishment	-	-	-	-	1.1	1.7
G000966	Kootenay Canal - Fire Detection and Alarm System Replacement	-	-	-	0.3	0.8	3.5
G001898	Ladore - Unit Transformer Upgrade	-	-	-	-	0.6	4.0
G002326	La Joie - Governor Pressure Regulating Valve Replacement	-	-	-	1.4	3.5	7.0
G004349	Mica - Crash-rated Gate Replacement	-	-	-	-	-	0.2
G003980	Mica - Nagle Creek Crossing Infrastructure Refurbishment	-	-	-	-	-	0.4
G000183	Mica - U1 - U2 Turbine Overhaul	-	-	-	-	1.2	3.6
G000231	Peace Canyon - High and Low Pressure Piping Replacement	-	-	-	0.3	0.5	0.5
G002413	Peace Canyon - Powerhouse, Intake and Tailrace Crane Upgrades	-	-	-	-	0.9	1.1
G004197	Revelstoke - Intake and Tailrace Gantry Crane Upgrades	-	-	-	-	1.1	4.7
G004155	Seven Mile - U1 - U3 Turbine Upgrade	-	-	-	-	-	1.3
G000436	Seven Mile - U1 - U4 Controls Upgrade	-	-	-	0.9	2.6	4.3
G004410	Various Sites - PCB Lighting Remediation (F2022-F2024)	-	9.4	-	3.4	3.5	-
	Programs and Projects Less than $5M	40.1	28.2	39.9	36.7	34.0	31.9
	TOTAL Generation Sustaining - Other	**335.3**	**131.9**	**81.0**	**174.6**	**135.3**	**197.7**

Sustaining - Other represents 43 per cent of the Hydroelectric Generation expenditures over the Test Period. These capital expenditures fluctuate year-over-year as investments progress through the phases of the project lifecycle. Capital additions also fluctuate as projects from the previous Test Period are put in service. Higher capital additions in fiscal 2023 and fiscal 2024 are driven by the following projects:

- G.M. Shrum G1 to 10 Control System Upgrade and HVAC System Upgrade;
- Mica Reactor 5RX3 Replacement, Modernize Controls, Units 1 to 4 Generator Transformers, Upgrade 600V Circuit Breakers, Upgrade HVAC System;

- Wahleach Refurbish Generator; and
- Waneta U3 Life Extension.

Capital investments in the Programs and Projects Less than $5 million line include a large number of smaller, less complex investments. In general, these are targeted sustaining investments for specific components or systems that support the generation of electricity. These investments generally follow the same classification as those described at the beginning of this section and include:

- The replacement or upgrade of auxiliary and balance of plant equipment such as: hoists, pumps, pressure vessels, back-up battery systems and instrumentation;
- The replacement of upgrade of building infrastructure and associated systems such as roofs and elevators within generating facilities; and
- Projects to address safety and security such as: fall arrest anchors, safe work platforms, and security system upgrades.

6.4.1.6 Non-Integrated Areas – Investments to Sustain Existing Assets

All expenditures in the Test Period in Non-Integrated Areas are to sustain existing assets. Non-Integrated Areas are separate self-contained areas. Each area has its own source of generation (usually diesel generators), associated switchyard, support buildings and distribution network. As the assets age and deteriorate they need to be replaced so that a safe and reliable level of service can be maintained to Non-Integrated Area customers. The sustaining investment projects and programs can be classified into the following categories:

- Generator replacements and overhauls;
- Fuel infrastructure upgrades;
- Switchgear and transformation upgrades;

- Communication and control upgrades;
- Station building and yard upgrades; and
- Line building replacements.

Table 6-10 below provides a summary of the Test Period capital additions and capital expenditures for Non-Integrated Areas Generation Projects.

Table 6-10 Non-Integrated Areas Generation Projects – Plan Capital Additions and Expenditures (Fiscal 2023 to Fiscal 2025) ($ millions)

Planning ID	Name of Project	Capital Additions Plan F2023	Capital Additions Plan F2024	Capital Additions Plan F2025	Capital Expenditures Plan F2023	Capital Expenditures Plan F2024	Capital Expenditures Plan F2025
	Non-Integrated Area						
	Programs and Projects Less than $5M	4.5	14.8	9.6	10.2	6.2	6.3
	TOTAL Non-Integrated Area	**4.5**	**14.8**	**9.6**	**10.2**	**6.2**	**6.3**

The forecast Test Period capital expenditures and additions are similar to the test period in the Previous Application.

BC Hydro shares an interest in reducing reliance on diesel in remote communities and is developing a strategy to address Non-Integrated Area community interests in reducing diesel generation. This strategy will align with CleanBC, BC Hydro's GHG Reduction Plan[419] and rely on recommendations from Phase Two of the Government of B.C.'s Comprehensive Review of BC Hydro; therefore, further details will be available once the review is complete. Renewable energy projects developed as part of this strategy are expected to be community-owned with an Independent Power Producer making the capital expenditure and with operations supported through an Energy Purchase Agreement with BC Hydro. Should the need for a capital expenditure arise to support this strategy, it would be initiated under our ex-plan governance process.

[419] Refer to Appendix BB for BC Hydro's GHG Reduction Plan.

6.4.1.7 Thermal Generation Sustainment Investments Expenditures and Additions Are Minimal in Fiscal 2023 to Fiscal 2025

Thermal Generation investments mitigate or resolve key risks identified with existing Thermal Generation assets. Table 6-11 below provides a summary of the capital additions and capital expenditures in the Test Period.[420]

Table 6-11 Thermal Generation Projects – Plan Capital Additions and Expenditures (Fiscal 2023 to Fiscal 2025) ($ millions)

Planning ID	Name of Project	Capital Additions Plan F2023	Capital Additions Plan F2024	Capital Additions Plan F2025	Capital Expenditures Plan F2023	Capital Expenditures Plan F2024	Capital Expenditures Plan F2025
	Thermal Generation						
G003189	Burrard - Modify for Post Generation Operations	-	-	4.9	0.6	3.6	0.2
G003760	Fort Nelson - U2 Steam Turbine Overhaul	-	-	-	-	-	0.4
	Programs and Projects Less than $5M	0.6	0.6	7.6	0.7	1.0	6.3
	TOTAL Thermal Generation	**0.6**	**0.6**	**12.5**	**1.3**	**4.6**	**7.0**

Expenditures related to the Burrard – Modify for Post Generation Operations project are focused on mitigating safety and environmental risks with equipment and infrastructure not required to support current synchronous condense operations. The option to sustain Burrard as a synchronous condense facility to meet the long-term power reinforcement needs for the Lower Mainland is under consideration as a part of the Lower Mainland - Capacitive and Reactive Power Reinforcement project.[421]

The Fort Nelson – U2 Steam Turbine Overhaul project is driven by the need to maintain reliable operation of the Unit 2 Turbine at Fort Nelson Generating Station.

The remaining Thermal Generation capital investments fall within the Programs and Projects Less than $5 million line.

[420] More information on the projects listed can be found in Appendix I, page 2..

[421] The Lower Mainland – Capacitive and Reactive Power Reinforcement Project has expenditures listed in Table 6-15.

6.4.2 Transmission Capital Expenditures and Additions

Transmission capital expenditures are approximately 30 per cent for growth and 70 per cent for sustain investments.[422,423] This represents an increase to sustain expenditures as a percentage of the portfolio compared to the overall allocation of expenditures across Transmission investments in the Previous Application. This percentage increase is related to decreases in growth driven investments and increases in investment in most sustain categories, in particular increases in Protection and Control, Stations Auxiliary Equipment, Other Power Equipment, and Overhead Life Extension.

The actual and plan capital expenditures and additions for fiscal 2021 to fiscal 2025 for Transmission, classified by Growth and Sustain categories, are provided in Table 6-12 and Table 6-13 below.

[422] Transmission capital investments continue to be driven by the needs described in Appendix N, section 2.3.

[423] Expenditures in this section do not include the investments associated with BC Hydro's Electrification Plan. Please refer to section 6.7 and Chapter 10 of this application for more detail on these capital expenditures.

Table 6-12 Transmission Actual and Plan Capital Expenditures (Fiscal 2021 to Fiscal 2025)[424]

($ millions)	F2021	F2022		F2023	F2024	F2025
	Actual	Decision	Forecast	Plan	Plan	Plan
Transmission Growth						
Regional System Reinforcement	38.0	80.6	25.5	25.6	37.2	61.3
Bulk System Reinforcement	(3.5)	17.0	5.4	4.0	8.7	35.5
Station Expansion & Modification	30.6	61.3	36.9	42.7	22.9	7.4
Feeder Positions / Section Additions	0.5	3.0	0.2	0.0	-	-
Generator Interconnections	4.7	5.3	10.7	1.0	2.2	2.1
Transmission Load Interconnections	51.6	28.7	28.6	59.7	84.5	42.6
Growth Total	121.9	195.9	107.4	132.9	155.5	148.9
Transmission Sustain - Stations						
Circuit Breakers	21.0	16.3	21.6	39.1	36.8	33.3
Other Power Equipment	99.9	87.6	119.1	121.4	122.2	118.7
Protection and Control	11.7	30.9	21.1	35.9	30.1	20.4
Stations Auxiliary Equipment	15.8	43.8	26.9	42.6	58.1	42.3
Stations Risk Mitigation	6.7	6.6	9.4	13.2	11.1	10.6
Telecommunications	18.2	33.5	25.8	22.0	27.9	43.1
Sustain Stations Total	173.2	218.8	224.0	274.2	286.2	268.3
Transmission Sustain - Lines						
Cable Sustainment	(2.7)	16.5	6.9	5.6	17.7	26.1
O/H Lines Life Extension	62.4	62.2	75.8	70.1	60.2	67.3
O/H Lines Performance Improvement	3.9	1.5	6.1	-	-	-
O/H Lines Risk Mitigation	6.4	5.6	7.5	9.1	8.6	10.4
ROW Sustainment	9.9	9.1	13.3	9.8	9.9	10.2
Third Party Requested Transmission Line Relocations	1.3	12.0	15.8	13.1	9.5	6.1
Sustain Lines Total	81.1	106.8	125.4	107.7	106.0	120.1
Less: Portfolio Risk Adjustment	-	(53.0)	(27.7)	(39.8)	(18.2)	(26.7)
Total Transmission	376.3	468.5	429.1	475.1	529.4	510.7
Less: Contribution in Aid	(9.0)	(14.0)	(8.9)	(29.7)	(26.6)	(16.2)
Total Net	367.3	454.5	420.2	445.4	502.7	494.4

424 Refer to Appendix N, section 2.11 for information on the Portfolio Risk Adjustment.

Table 6-13 Transmission Actual and Plan Capital Additions (Fiscal 2021 to Fiscal 2025)[425]

($ millions)	F2021	F2022		F2023	F2024	F2025
	Actual	Decision	Forecast	Plan	Plan	Plan
Transmission Growth						
Regional System Reinforcement	97.4	178.0	139.9	0.9	8.2	0.0
Bulk System Reinforcement	0.1	1.5	-	-	2.0	10.5
Station Expansion & Modification	0.8	1.3	1.4	0.0	89.3	64.8
Feeder Positions / Section Additions	-	4.8	0.9	0.0	-	-
Generator Interconnections	15.9	4.3	79.8	3.6	1.7	2.1
Transmission Load Interconnections	41.6	133.3	8.4	5.1	95.3	50.1
Growth Total	155.7	323.1	230.3	9.6	196.5	127.5
Transmission Sustain - Stations						
Circuit Breakers	19.0	13.9	15.7	12.6	41.5	50.7
Other Power Equipment	24.2	60.8	85.6	155.6	77.0	80.3
Protection and Control	2.8	8.3	1.6	10.8	61.5	14.6
Stations Auxiliary Equipment	6.9	39.9	29.4	25.8	41.0	66.1
Stations Risk Mitigation	6.4	16.3	6.5	10.4	10.6	8.1
Telecommunications	8.6	31.3	25.2	12.4	7.5	54.8
Sustain Stations Total	67.8	170.6	163.9	227.6	239.1	274.6
Transmission Sustain - Lines						
Cable Sustainment	(3.4)	2.8	3.3	3.9	1.2	23.3
O/H Lines Life Extension	49.3	68.1	79.6	58.8	92.5	58.1
O/H Lines Performance Improvement	1.7	1.5	10.7	-	-	-
O/H Lines Risk Mitigation	6.1	7.6	10.5	10.5	6.8	6.8
ROW Sustainment	10.8	9.1	16.2	10.4	9.9	10.1
Third Party Requested Transmission Line Relocations	0.5	13.0	2.9	18.5	19.6	6.0
Sustain Lines Total	65.0	102.0	123.1	102.1	130.0	104.3
Less: Portfolio Risk Adjustment	-	(155.0)	(27.6)	(81.6)	(129.6)	36.0
Total Transmission	288.5	440.7	489.8	257.7	436.0	542.4
Less: Contribution in Aid	(8.6)	(36.9)	(57.0)	(12.9)	(17.3)	(51.9)
Total Net	279.9	403.8	432.7	244.8	418.6	490.5

6.4.2.1 Transmission Assets Growth Capital Expenditures Are Increasing Slightly

In the Test Period, Growth capital expenditures for Transmission Assets are increasing compared to the fiscal 2022 forecast while additions are very low in fiscal 2023 but are increasing to match expenditures as projects are brought into service.

425 Refer to Appendix N, section 2.11 for information on the Portfolio Risk Adjustment.

The forecast Transmission Growth capital expenditures are based on the December 2020 System Peak Load Forecast and include partial funding for projects that support CleanBC, specifically, the North Montney Region – Electrification[426] and the Prince George to Terrace Capacitors[427] projects. Full funding for these projects will be included in future capital plans once firm load commitments are made by our customers.

Regional System Reinforcement

The regional transmission systems generally comprise a large portion of the 230 kV system and all of the 138 kV and 60 kV systems. Regional transmission systems include transmission facilities that service localized geographic areas. Transmission Growth projects at this level often involve the installation of additional regional capacity in order to support area load growth and to maintain area supply reliability. These projects can include upgrades of, and additions to, lines or substation equipment.

Table 6-14 below provides a summary of the capital additions and expenditures in the Test Period.[428]

[426] Refer to Table 6-14 in section 6.4.2.1, Appendix I, page 3 and Appendix J, page 136.

[427] Refer to Table 6-15 in section 6.4.2.1, Appendix I, page 3 and Appendix J, page 146. The partial funding included completion of the Feasibility stage in fiscal 2022 and the Capital Plan includes no capital expenditures in the Test Period for this project.

[428] More information on the projects listed can be found in Appendix I, page 3.

Table 6-14 Transmission Regional System Reinforcement Projects – Plan Capital Additions and Expenditures (Fiscal 2023 to Fiscal 2025) ($ millions)

Planning ID	Name of Project	Capital Additions Plan F2023	Capital Additions Plan F2024	Capital Additions Plan F2025	Capital Expenditures Plan F2023	Capital Expenditures Plan F2024	Capital Expenditures Plan F2025
	Regional System Reinforcement						
92423	Bridge River Transmission Project	-	-	-	2.5	13.8	29.5
901572	North Montney Region - Electrification	-	-	-	5.8	2.5	-
94034	West Kelowna Transmission and Westbank Upgrade Projects	-	-	-	6.9	9.7	10.4
900598	West End - Substation Construction and System Reinforcement	-	-	-	4.8	5.1	14.9
901858	Peace to Kelly Lake - Remedial Action Scheme Upgrade	-	8.1	0.0	4.4	3.4	0.0
900266	East Vancouver - Substation Construction	-	-	-	-	-	0.1
902126	Sunshine Coast - Transmission Reinforcement	-	-	-	0.5	2.6	6.4
	Programs and Projects Less than $5M	0.9	0.0	-	0.5	0.0	-
	TOTAL Regional System Reinforcement	**0.9**	**8.2**	**0.0**	**25.6**	**37.2**	**61.3**

Regional System Reinforcement capital expenditures are increasing across the Test Period due to increasing design and construction activities on the following projects:

- West Kelowna Transmission and Westbank Upgrade;
- West End - Substation Construction and System Reinforcement;
- Bridge River Transmission Project; and
- Sunshine Coast – Transmission Reinforcement.

Capital additions are minimal during the Test Period with no major projects coming into service until after the Test Period and are a significant decrease from fiscal 2022 when the Peace Region Electric Supply Project came into service.

Bulk System Reinforcement

The bulk system comprises high voltage transmission lines and related equipment that interconnect the large remote generating stations in the Peace River and Columbia River areas with the major load centres in the Lower Mainland and on Vancouver Island. The bulk system includes the 500 kV transmission system, the transmission connections to Vancouver Island, and interconnections with other utilities through interties to FortisBC, Rio Tinto Alcan, Alberta and the United States.

Table 6-15 below provides a summary of the capital additions and capital expenditures in Test Period.[429]

Table 6-15 Transmission Bulk System Reinforcement Projects – Plan Capital Additions and Expenditures (Fiscal 2023 to Fiscal 2025) ($ millions)

Planning ID	Name of Project	Capital Additions Plan F2023	Capital Additions Plan F2024	Capital Additions Plan F2025	Capital Expenditures Plan F2023	Capital Expenditures Plan F2024	Capital Expenditures Plan F2025
	Bulk System Reinforcements						
901562	Cranbrook 5L94 - Line Reactor Replacement	-	-	9.5	0.2	5.7	3.1
900992	Lower Mainland - Capacitive and Reactive Power Reinforcement	-	-	-	2.5	1.5	32.3
901574	Prince George to Terrace Capacitors Project	-	-	-	-	-	-
	Programs and Projects Less than $5M	-	2.0	1.1	1.2	1.5	0.1
	TOTAL Bulk System Reinforcements	**-**	**2.0**	**10.5**	**4.0**	**8.7**	**35.5**

Capital expenditures are increasing in fiscal 2024 and fiscal 2025 due to the Lower Mainland – Capacitive and Reactive Power Reinforcement project progressing through implementation.

Capital additions remain low but increasing through the Test Period until the Cranbrook 5L94 (Cranbrook substation intertie to Alberta) – Line Reactor Replacement project is brought into service in fiscal 2025.

Station Expansion and Modifications

Station expansion and modification projects replace, upgrade, or add capacity to existing substations to alleviate operational constraints or limitations resulting from local load growth. These projects impact transmission and distribution assets within the substation, and may involve installing additional transformer capacity, adding

429 Additional information on the projects listed is provided in Appendix I, page 3.

switchgear, converting to higher voltages, and reconfiguring existing facilities to accommodate increased capacity requirements.

Table 6-16 below provides a summary of the capital additions and capital expenditures in the Test Period.[430]

Table 6-16 Station Expansion and Modification Projects – Plan Capital Additions and Expenditures (Fiscal 2023 to Fiscal 2025) ($ millions)

Planning ID	Name of Project	Capital Additions Plan F2023	Capital Additions Plan F2024	Capital Additions Plan F2025	Capital Expenditures Plan F2023	Capital Expenditures Plan F2024	Capital Expenditures Plan F2025
	Station Expansion & Modification						
93788	Capilano Substation Upgrade	-	-	64.4	19.6	18.2	6.9
92910	Clayburn Substation Upgrade	-	30.0	0.4	9.8	2.8	0.4
92907	Mount Lehman Substation Upgrade	-	58.8	-	13.3	1.9	-
900268	Horne Payne - Feeder Section Addition	-	-	-	-	-	0.1
	Programs and Projects Less than $5M	0.0	0.5	-	0.0	0.0	-
	TOTAL Station Expansion & Modification	**0.0**	**89.3**	**64.8**	**42.7**	**22.9**	**7.4**

Capital expenditures in fiscal 2023 will increase over the fiscal 2022 forecast and decrease across the Test Period as the Mount Lehman Substation Upgrade, Clayburn Substation Upgrade, and Capilano Substation Upgrade projects progress into the later project stages. This is also driving the increase in capital additions in the last two years of the Test Period when these projects will be put in service.

Feeder Position/Section Additions

Feeder positions and feeder sections are located within substations and supply the interface between the substation and the distribution system for BC Hydro's distribution connected customers. These projects provide additional capacity for distribution customer load growth or for increased operational flexibility.

There are no feeder position/section additions investments within the Test Period.

[430] More information on the projects listed is provided in Appendix I, page 3.

Generator Interconnections

Generator Interconnections Projects continue to decrease, as there are no active calls for energy and the Standing Offer Program has been indefinitely suspended. Several projects that were previously accepted under the Standing Offer Program continue to proceed through the interconnection process. In addition to these Standing Offer Program projects, there is one First Nations generation project that is being advanced as a result of an Impact Benefit Agreement.

Until recently, the majority of new Independent Power Producers interconnections were facilitated by BC Hydro's Standing Offer Program. The program limited the funding that BC Hydro provided for network upgrades to a pre-determined threshold amount. The forecasts for interconnection costs for Independent Power Producer projects already in the program include only the estimated network upgrade costs up to the threshold. They do not include the costs of the network upgrade above the threshold which are funded by the Independent Power Producer.

Table 6-17 below provides the Generation Interconnections Projects forecast capital additions and expenditures in the Test Period. There are no projects with capital expenditures greater than $5 million.

Table 6-17 Generator Interconnection Projects – Plan Capital Additions and Expenditures (Fiscal 2023 to Fiscal 2025) ($ millions)

Planning ID	Name of Project	Capital Additions Plan F2023	Capital Additions Plan F2024	Capital Additions Plan F2025	Capital Expenditures Plan F2023	Capital Expenditures Plan F2024	Capital Expenditures Plan F2025
	Generator Interconnections						
	Programs and Projects Less than $5M	3.6	1.7	2.1	1.0	2.2	2.1
	TOTAL Generator Interconnections	**3.6**	**1.7**	**2.1**	**1.0**	**2.2**	**2.1**

Transmission Load Interconnections

BC Hydro continues to see a high volume of Transmission Load Interconnections requests, including requests from large loads in the Liquefied Natural Gas, Oil and Gas, Mining and Data Centres/Cryptocurrency segments. The volume of requests has increased significantly due to increases in electrification interests from the Oil and Gas sector and a combination of load growth and electrification interests from the Mining sector. This trend is expected to continue during the Test Period due to strong government support for electrification and load growth in these sectors which will result in higher capital expenditures compared to the fiscal 2022 forecast.

Table 6-18 below provides a summary of the capital additions and expenditures for Transmission Interconnection projects in the Test Period.[431]

[431] More information on the projects listed is provided in Appendix I, page 3.

Table 6-18 Transmission Load Interconnections Projects – Plan Capital Additions and Expenditures (Fiscal 2023 to Fiscal 2025) ($ millions)[432]

Planning ID	Name of Project	Capital Additions Plan F2023	Capital Additions Plan F2024	Capital Additions Plan F2025	Capital Expenditures Plan F2023	Capital Expenditures Plan F2024	Capital Expenditures Plan F2025
	Transmission Load Interconnections						
901580	Customer IPID – 901580 [redacted]	-	-	-	0.6	6.2	4.3
901573	Customer IPID - 901573 [redacted]	-	-	-	2.1	7.2	13.4
901851	Customer IPID - 901851 [redacted]	-	-	9.7	3.3	2.2	1.6
901581	Customer IPID - 901581 [redacted]	-	-	-	7.8	6.2	7.0
901940	Customer IPID - 901940 [redacted]	-	-	10.2	3.0	6.6	-
902121	Customer IPID - 902121 [redacted]	-	-	7.0	3.0	3.5	-
901943	Customer IPID - 901943 [redacted]	-	77.9	9.3	26.6	49.1	9.3
901938	Customer IPID - 901938 [redacted]	-	11.0	-	5.0	-	-
	Programs and Projects Less than $5M	5.1	6.4	14.0	8.3	3.6	7.1
	TOTAL Transmission Load Interconnections	5.1	95.3	50.1	59.7	84.5	42.6

[432] Customer driven interconnection projects include commercially sensitive information. Accordingly, the names of the specific Transmission Load Interconnection projects are filed in confidence with the BCUC.

The number of requests and the associated loads in a particular industry sector changes over time in response to market conditions and other factors including the implementation of BC Hydro's electrification plan and the government electrification funding availability influencing customer decisions.[433]

Capital investments to interconnect transmission customers are difficult to forecast. Due to uncertain timing, location and scope, only known transmission interconnection projects are included as specifically identified projects in the forecast capital expenditures for the Test Period. There will be changes in expenditures as customer requests move through the interconnection process and new projects are added, deferred or removed to respond to customer needs.[434]

6.4.2.2 Transmission Sustaining Capital Investment Is Increasing Within the Test Period

In the Test Period, Transmission Sustaining capital expenditures and additions are increasing in comparison to the fiscal 2022 forecast.

Circuit Breakers

Circuit breakers are used to isolate sections of the transmission and distribution system and to interrupt high currents under fault conditions. They are the primary protection device on the transmission and distribution system and must be capable of reliably interrupting both load currents and fault currents. The system currently has over 3,900 circuit breakers made up of a variety of different equipment in terms of voltage classes (from 4 kV to 500 kV).

The planned expenditures for the Test Period are for the replacement of circuit breakers as they reach end-of-life. The timing of the replacements is based on condition, failure rates and risk to the system. Refurbishment of circuit breakers is

[433] A discussion of the activities associated with Transmission Load Interconnection projects is provided in section 6.2.3.

[434] These changes are managed through on-going monitoring of the capital portfolio forecast as described in Appendix N, section 1.5.

considered but is usually not possible due to obsolescence. In addition, oil filled circuit breakers with Polychlorinated Biphenyl (**PCB**) levels at or above 50 ppm are being proactively replaced to ensure all units in the category are removed by the December 31, 2025 Federal PCB Regulation deadline.

Table 6-19 below provides a summary of the planned capital additions and capital expenditures in the Test Period.[435]

Table 6-19 Circuit Breaker – Plan Capital Additions and Expenditures (Fiscal 2023 to Fiscal 2025) ($ millions)

Planning ID	Name of Project	Capital Additions Plan F2023	Capital Additions Plan F2024	Capital Additions Plan F2025	Capital Expenditures Plan F2023	Capital Expenditures Plan F2024	Capital Expenditures Plan F2025
	Circuit Breakers						
900243	SPG Metalclad Switchgear Replacement	-	25.4	16.9	17.6	6.6	4.3
901248	Kimberley to Marysville - Substation Relocation	-	-	-	0.8	1.5	4.0
901612	Pemberton - Substation Rebuild	-	-	9.8	3.1	5.1	1.2
901613	Maple Ridge - Feeder Section 60 Series Refurbishment	-	-	-	0.5	1.1	6.4
	Programs and Projects Less than $5M	12.6	16.1	33.8	21.5	30.2	29.0
	TOTAL Circuit Breakers	**12.6**	**41.5**	**50.7**	**39.1**	**36.8**	**33.3**

Capital expenditures have increased over the fiscal 2022 forecast but remain consistent across the Test Period. Capital additions will increase in the later years of the Test Period when the SPG Metalclad Switchgear Replacement project is put in service. Capital investments included in the Programs and Projects Less than $5 million line include individual replacements that are delivered as part of an annual recurring capital program.

Other Power Equipment

Other power equipment expenditures are for the replacement or refurbishment of disconnect switches, surge arrestors, power transformers, instrument transformers, shunt reactors, shunt capacitors, synchronous condensers, high-voltage direct

[435] Additional information on the projects listed is provided in Appendix I, page 3.

current systems, series capacitor stations, cable terminations, and load tap changers. Some of the investments in this category include the replacement of oil filled equipment with PCB levels at or above 50 ppm that are being proactively replaced to ensure all units in the category are removed by the December 31, 2025 Federal PCB Regulation deadline.

Table 6-20 below provides a summary of the capital additions and capital expenditures in the Test Period.[436]

[436] Additional information on the projects listed is provided in Appendix I, page 4.

Table 6-20 Other Power Equipment – Plan Capital Additions and Expenditures (Fiscal 2023 to Fiscal 2025) ($ millions)

Planning ID	Name of Project	Capital Additions Plan F2023	Capital Additions Plan F2024	Capital Additions Plan F2025	Capital Expenditures Plan F2023	Capital Expenditures Plan F2024	Capital Expenditures Plan F2025
	Other Power Equipment						
92073	American Creek - Capacitor Protection Control Upgrade	16.1	0.3	-	5.3	0.3	-
900575	Barnard 50/60 Feeder Section Replacement	5.2	-	-	0.8	-	-
900564	Hundred Mile House T1/T2 EOL Replacement	15.5	0.0	-	2.1	0.0	-
93731	Jordan River - Switchyard Upgrade	30.4	0.6	-	8.2	0.6	-
92166	SC Excitation Systems Upgrade - VIT/KLY	-	12.5	0.1	3.1	1.2	0.1
900152	Natal Sub - NTL 60-138 kV Rebuild	-	-	42.4	8.6	10.8	17.7
94079	Sandspit Substation Replacement	12.7	0.4	-	5.1	0.4	-
94081	Ah-sin-heek - Substation Replacement	9.9	0.0	-	6.5	0.0	-
900247	Bridge River - T4 Transformer Replacement	26.6	0.4	-	17.6	0.4	-
901831	Kennedy - 5CX1 Controls Replacement (Emergency)	9.6	0.0	-	1.8	0.0	-
901224	Oldfield - Substation Feeder Section Upgrade	-	-	5.2	1.8	2.9	0.3
901821	Peace to Kelly Lake - Stations Sustainment	-	19.1	-	15.0	39.4	37.5
92618	VIT & KLY Hydrogen Gas Sys - Safety Upgrade	-	5.0	2.1	1.8	1.6	1.2
93705	Kl1 60Kv Renovation, 4Kv Decommission & Control Room	-	-	-	2.5	11.8	10.3
92478	Mainwaring Station Upgrade	-	-	25.1	6.8	9.3	17.6
92479	Newell Substation Upgrade	-	-	-	2.6	3.3	6.6
92759	Patricia - Substation Upgrade	-	-	-	3.9	3.1	5.1
900185	Peace Region to Kelly Lake - Reactor Replacement (Phase 2)	-	18.1	0.2	1.0	16.9	0.2
901618	Kelly Lake - Reactor Installation	-	-	-	1.8	3.8	1.5
901823	Norgate - Substation Bypass	-	-	-	1.1	2.2	1.7
900186	Peace Region to Kelly Lake - Reactor Replacement (Phase 3)	-	-	-	0.6	5.5	9.2
900187	Peace Region to Kelly Lake - Reactor Replacement (Phase 4)	-	-	-	-	-	0.8
94080	Telegraph Creek - Substation Replacement	-	-	-	-	-	0.1
	Programs and Projects Less than $5M	29.7	20.5	5.2	23.3	8.5	8.9
	TOTAL Other Power Equipment	**155.6**	**77.0**	**80.3**	**121.4**	**122.2**	**118.7**

Capital investments included in the Programs and Projects Less than $5 million line include smaller capital investments such as transformer life extension projects, and programs to address the replacement of disconnects, instrument transformers, metering kits and substation voltage regulators.

Capital expenditures are consistent across the Test Period and in line with the fiscal 2022 forecast. An increase in capital additions for fiscal 2023 is driven by the

Jordan River – Switchyard Upgrade and the Bridge River – T4 Transformer Replacement projects being put in-service.

Protection and Control

Protection and Control expenditures are for the replacement of end-of-life protective relaying and control systems at substations. Protection and Control assets are used to isolate transmission equipment from electrical faults, ensure stability and reliability of the Power System, and provide local and remote control and monitoring of the transmission system.

Table 6-21 below provides a summary of the capital additions and expenditures in the Test Period.[437]

Table 6-21 Protection and Control – Plan Capital Additions and Expenditures (Fiscal 2023 to Fiscal 2025) ($ millions)

Planning ID	Name of Project	Capital Additions Plan F2023	Capital Additions Plan F2024	Capital Additions Plan F2025	Capital Expenditures Plan F2023	Capital Expenditures Plan F2024	Capital Expenditures Plan F2025
	Protection and Control						
93687	GMS Substation - Control Systems Upgrade	-	13.0	0.1	5.3	2.6	0.1
900625	NERC CIP V5 Compliance at Medium Impact T&D Stations	-	-	-	4.7	5.0	4.1
900250	Control PLC984 and RTU Replacement (WSN)	-	-	-	1.7	2.0	4.0
901592	Various Sites - NERC CIP-003v7 Implementation	-	36.8	1.5	14.9	11.9	1.5
	Programs and Projects Less than $5M	10.8	11.6	13.0	9.3	8.6	10.8
	TOTAL Protection and Control	**10.8**	**61.5**	**14.6**	**35.9**	**30.1**	**20.4**

Capital expenditures in fiscal 2023 and fiscal 2024 are an increase compared to the fiscal 2022 forecast. The majority of these increases are related to the NERC CIP-003v7 and NERC CIP v5 Compliance projects. Capital additions in fiscal 2024 are attributable to work associated with NERC CIP-003v7.

[437] Additional information on the projects listed is provided in Appendix I, page 4.

Expenditures within the Programs and Projects Less than $5 million line include programs to replace end of life Protection and Control assets in substations including Protection Relays, Supervisory Control and Data Acquisition Remote Terminal Units and Digital Fault Recorders.

Stations Auxiliary Equipment

Auxiliary equipment expenditures are for the replacement of station equipment used to support the Power System, including station cables, bus work and insulators, steel and wood pole structures, equipment foundations, grounding systems, station power supplies, batteries and chargers, air compressors and dryers, buildings and HVAC equipment, perimeter fences, drainage systems, and gravel.

Table 6-22 below provides a summary of the capital additions and capital expenditures in the Test Period.[438]

Table 6-22 Stations Auxiliary Equipment – Plan Capital Additions and Expenditures (Fiscal 2023 to Fiscal 2025) ($ millions)

Planning ID	Name of Project	Capital Additions Plan F2023	Capital Additions Plan F2024	Capital Additions Plan F2025	Capital Expenditures Plan F2023	Capital Expenditures Plan F2024	Capital Expenditures Plan F2025
	Stations Auxiliary Equipment						
900726	Joseph Creek (JOE) Substation Upgrade	-	14.3	0.2	5.7	7.0	0.2
901045	Canal Flats - Substation Wood Pole Replacement	-	-	5.9	0.8	4.8	0.1
901049	Skookumchuck - Substation Wood Pole Replacement	-	-	6.0	0.8	4.9	0.1
901244	Cathedral Square - Substation HVAC Upgrade	-	-	16.0	3.0	6.1	6.1
901048	Lumby #2 - Substation Wood Pole Replacement	-	-	8.7	3.5	3.5	1.7
901040	Port Alberni - Substation Refurbishment	-	-	-	0.8	6.9	11.8
901090	Prevost - Substation Control Building Upgrade	-	-	-	-	-	0.0
900724	Woss - Substation Wood Pole Replacement	-	-	5.6	1.7	3.3	0.3
	Programs and Projects Less than $5M	25.8	26.7	23.7	26.3	21.6	22.0
	TOTAL Stations Auxiliary Equipment	**25.8**	**41.0**	**66.1**	**42.6**	**58.1**	**42.3**

438 Additional information is provided in Appendix I, page 4.

Capital expenditures for the Test Period have increased over the fiscal 2022 forecast, with a peak in fiscal 2024 primarily due to several of the projects moving into the later phases of the project lifecycle. A similar trend is observed across the capital additions as these projects reach their in-service date within the Test Period with a peak in fiscal 2025.

Capital investments in the Programs and Projects Less than $5 million line include program expenditures to replace substation wood poles, cables, insulators, fire protection, building roofs and battery banks.

Stations Risk Mitigation

Stations Risk Mitigation expenditures address safety, seismic, environment, severe weather and security risks. Each risk is evaluated based on business impact (e.g., reliability, financial, environmental, safety) and probability of occurrence to determine the appropriate magnitude and duration of investment that is required to mitigate the risk.

Table 6-23 below provides a summary of the capital additions and capital expenditures in the Test Period.[439]

[439] Additional information on the projects listed is provided in Appendix I, page 4.

Table 6-23 Stations Risk Mitigation – Plan Capital Additions and Expenditures (Fiscal 2023 to Fiscal 2025) ($ millions)

Planning ID	Name of Project	Capital Additions Plan F2023	Capital Additions Plan F2024	Capital Additions Plan F2025	Capital Expenditures Plan F2023	Capital Expenditures Plan F2024	Capital Expenditures Plan F2025
	Stations Risk Mitigation						
92158	Oil Spill Containment - F17/F18 (ALZ / MDN)	7.9	-	-	0.5	-	-
94052	Stations Seismic Upgrade -F16/17 (9 Stations)	-	-	-	1.6	2.0	1.7
900766	Project IPID - 900766 [redacted]	-	-	-	3.1	1.1	2.7
	Programs and Projects Less than $5M	2.5	10.6	8.1	8.0	8.1	6.2
	TOTAL Stations Risk Mitigation	10.4	10.6	8.1	13.2	11.1	10.6

The majority of the investments within the Test Period fall within the Programs and Projects Less than $5 million category, which includes programs for fire protection, security and seismic upgrades at various substations.

Capital expenditures and additions for fiscal 2023 have increased over the fiscal 2022 forecast but remain relatively stable over the Test Period.

Telecommunications

BC Hydro operates a telecommunications network to support operation of the transmission, distribution, and generation systems and to provide radio voice communications for staff in the field.

Telecommunications expenditures within the Test Period are for the replacement of telecommunication infrastructure including microwave radio, power line carrier, fibre optic cable, and VHF/UHF radio. The expenditures are optimized to address the replacement of assets with the poorest health where failure represents a risk to the safe operation of the Power System.

Table 6-24 below provides a summary of the capital additions and capital expenditures in the Test Period.[440]

Table 6-24 Telecommunications – Plan Capital Additions and Expenditures (Fiscal 2023 to Fiscal 2025) ($ millions)

Planning ID	Name of Project	Capital Additions Plan F2023	Capital Additions Plan F2024	Capital Additions Plan F2025	Capital Expenditures Plan F2023	Capital Expenditures Plan F2024	Capital Expenditures Plan F2025
	Telecommunications						
92183	Vancouver Island Radio System	-	-	49.7	9.6	6.1	0.6
900149	Various Sites - Mountain Top 1603 Replacement	5.1	0.2	-	0.5	0.2	-
900019	System Wide – Bulk Electric System Telecom Equipment Replacement	-	-	-	2.4	3.4	17.0
900709	Various Sites - Telecom Analog Private Line Replacement	-	-	-	0.5	1.0	3.8
93739	Fraser Valley - Telecom System Reliability Upgrade	-	-	-	0.5	2.1	3.8
900033	Various Sites - MPLS Core Router Upgrade	-	-	-	-	-	2.3
902241	Various Sites – Telecom Transport Network Resiliency Enhancement	-	-	-	0.4	7.0	6.2
	Programs and Projects Less than $5M	7.3	7.3	5.1	7.9	8.1	9.2
	TOTAL Telecommunications	**12.4**	**7.5**	**54.8**	**22.0**	**27.9**	**43.1**

Telecommunications capital expenditures will increase over the Test Period. This is primarily due to the concurrent execution of major projects to replace end of life telecommunications systems, particularly the Vancouver Island Radio System Replacement project and the System Wide – Bulk Electric System Telecom Equipment Replacement project. Similarly, capital additions are increasing in fiscal 2025 primarily due to the completion of the Vancouver Island Radio System Replacement project.

Capital investments in the Programs and Projects Less than $5 million line include programs to address microwave tower corrosion, and telecom battery, charger and power line carrier line matching unit replacements.

[440] Additional information on the projects listed is provided in Appendix I, page 4.

Cable Sustainment

Underground and submarine cables are generally used where overhead lines are not feasible or where there is a requirement to use cables. There are over 400 km of underground or submarine cables on the transmission system. Most of these circuits are located in Vancouver, Burnaby, Coquitlam and Victoria, and include 69 kV, 138 kV, 230 kV and 500 kV voltage levels. These circuits also include the Strait of Georgia crossings from the mainland to Vancouver Island. Cable sustainment expenditures are for the replacement of cables and ancillary equipment (e.g., pumping equipment and duct banks).

Table 6-25 below provides a summary of the capital additions and capital expenditures in the Test Period.[441]

Table 6-25 Cable Sustainment – Plan Capital Additions and Expenditures (Fiscal 2023 to Fiscal 2025) ($ millions)

Planning ID	Name of Project	Capital Additions Plan F2023	Capital Additions Plan F2024	Capital Additions Plan F2025	Capital Expenditures Plan F2023	Capital Expenditures Plan F2024	Capital Expenditures Plan F2025
	Cable Sustainment						
901002	2L146 - Cable Replacement	-	-	-	2.1	2.0	7.4
901623	Coquitlam - 2L51 Partial Replacement	-	-	9.7	2.0	5.2	1.4
94057	Gulf Islands - Transmission Reinforcement	-	-	-	-	-	0.2
93958	South Fraser Transmission Relocation Project	-	-	12.4	0.3	9.3	14.2
	Programs and Projects Less than $5M	3.9	1.2	1.2	1.1	1.2	2.8
	TOTAL Cable Sustainment	**3.9**	**1.2**	**23.3**	**5.6**	**17.7**	**26.1**

Capital expenditures are increasing over the Test Period due to increasing spending on the following projects:

- 2L146 (Goward substation to Horsey substation) – Cable Replacement;
- Coquitlam – 2L51 (Horne Payne substation to Como Lake substation cable) Partial Replacement; and

441 Additional information on the projects listed is provided in Appendix I, page 4.

- South Fraser Transmission Relocation Project.[442]

Capital additions are in line with fiscal 2022, until fiscal 2025 when assets on the Coquitlam – 2L51 Partial Replacement project and the South Fraser Transmission Relocation Project are forecast to be in-service. For the latter, an in-service date of fiscal 2025 was assumed at the time of the Capital Plan, however the recently-announced government decision and the alternative selected for the crossing will affect the in-service date.

Capital investments in the Programs and Projects Less than $5 million line include investments such as programs to address cable instrumentation upgrades and pumping plant refurbishments.

BC Hydro has recently been addressing an emergent issue on the 500 kV submarine cables to Vancouver Island. While immediate efforts are funded by maintenance, review of the long-term supply strategy for Vancouver Island may require additional capital investments. If required, these future investments will either be incorporated in future annual capital plan updates or initiated under BC Hydro's ex-plan governance process.

Overhead Lines Life Extension

The overhead transmission network consists of conductor systems, metal support structures, wood poles, and associated equipment which includes spacer dampers, aircraft warning markers, and disconnect switches. The overhead network has over 18,400 km of transmission lines. These circuits include approximately 23,000 metal support structures and approximately 116,000 wood poles. Life extension expenditures for overhead lines cover the replacement or refurbishment of line components.

[442] The South Fraser Transmission Relocation Project is currently in deferred status. Additional information on the project is provided in Appendix I, page 4, line 75 and Appendix J, page 148.

Table 6-26 below provides a summary of the capital additions and capital expenditures in the Test Period.[443]

Table 6-26 Overhead Lines Life Extension – Plan Capital Additions and Expenditures (Fiscal 2023 to Fiscal 2025) ($ millions)

Planning ID	Name of Project	Capital Additions Plan F2023	Capital Additions Plan F2024	Capital Additions Plan F2025	Capital Expenditures Plan F2023	Capital Expenditures Plan F2024	Capital Expenditures Plan F2025
	O/H Lines Life Extension						
94035	5L063 Telkwa Relocation	-	40.7	2.7	17.8	3.5	2.7
93729	Long Span Crossing Refurbishment - F17/F18 (1L37)	-	-	-	1.2	1.7	7.1
	Programs and Projects Less than $5M	58.8	51.8	55.4	51.1	54.9	57.4
	TOTAL O/H Lines Life Extension	**58.8**	**92.5**	**58.1**	**70.1**	**60.2**	**67.3**

The majority of the expenditures within the Overhead Lines Life Extension category fall within the Programs and Projects Less than $5 million line. These investments are mainly delivered as recurring work programs that target assets across all regions of the province. The programs include the replacement of transmission anchor rods, crossing markers, spacer dampers, line disconnect switches, and insulator replacements. The largest of these programs is devoted to wood structure and framing replacements, which includes pole replacements, bracing and crossarms. The capital expenditures in the Programs and Projects Less than $5 million remain consistent through the Test Period with slight increases each year but are lower than the forecast expenditures in fiscal 2022.

The total Overhead Lines Life Extension capital expenditures across the Test Period are consistent with the fiscal 2022 forecast but fluctuate primarily due to progression on the 5L063 (Skeena substation to Telkwa substation) Telkwa Relocation and the Long Span Crossing Refurbishment projects. Capital additions increase in fiscal 2024 as the 5L063 Telkwa Relocation project comes into service.

443 Additional information on the projects listed is provided in Appendix I, page 4.

Overhead Lines Performance Improvement

Investments in this category address transmission lines subject to localized weather conditions causing performance issues. This work is intended to bring the line back to its designed reliability level. Examples include local sections subject to unequal ice loading, high instances of lightning strikes, or salt fog.

There are no investments planned in this category over the Test Period.

Overhead Lines Risk Mitigation

Overhead Lines Risk Mitigation expenditures address issues and potential events which could put the system at risk of a prolonged outage or pose safety concerns. Currently, the focus is on reducing the risk to public safety and operating concerns associated with deficient transmission line to ground clearances. Civil protective work to protect transmission structures against flooding and slides are also addressed under this category.

Table 6-27 below provides a summary of the capital additions and capital expenditures in the Test Period.[444]

Table 6-27 Overhead Lines Risk Mitigation – Plan Capital Additions and Expenditures (Fiscal 2023 to Fiscal 2025) ($ millions)

Planning ID	Name of Project	Capital Additions Plan F2023	Capital Additions Plan F2024	Capital Additions Plan F2025	Capital Expenditures Plan F2023	Capital Expenditures Plan F2024	Capital Expenditures Plan F2025
	OH Lines Risk Mitigation						
901645	1X387AMX – Kitsault Transmission Line Hazard Mitigation	-	-	-	1.1	1.6	2.5
901474	2L003 and 2L049 – Transmission Line Crossing Seismic Upgrade (Second Narrows)	-	-	-	-	0.1	1.1
	Programs and Projects Less than $5M	10.5	6.8	6.8	8.0	6.9	6.9
	TOTAL OH Lines Risk Mitigation	**10.5**	**6.8**	**6.8**	**9.1**	**8.6**	**10.4**

444 Additional information on the projects listed is provided in Appendix I, page 4.

Capital investments in the Programs and Projects Less than $5 million line include programs to address the replacement of automatic splices, civil protective works, and the refurbishment of overhead guy wires.

Capital expenditures and additions are relatively consistent with the fiscal 2022 forecast and through the Test Period and overall show a slight increase due to forecast spending on 1X387 (decommissioned transmission circuit from Aiyansh substation to Amax Mine substation) – Kitsault Transmission Line Hazard Mitigation and the 2L003 (Walters substation to Horne Payne substation) and 2L049 (Meridian substation to Horne Payne substation) – Transmission Line Crossing Seismic Upgrade (Second Narrows) projects.

Rights-of-Way Sustainment

BC Hydro is responsible for managing the rights-of-way and infrastructure that allow access to the Power System, including over 16,000 km of resource roads. This includes roads located along BC Hydro's corridors where BC Hydro is the sole maintainer, and also includes industry-maintained roads leading to the Power System facilities where BC Hydro has shared obligations for road maintenance (such as forest service roads, telecom station roads, and other types of permit roads on Crown land). The Rights-of-Way Sustainment program restores roads in poor condition and replaces road structures if required (such as bridges, gates, culverts, and retaining walls). The program also acquires and renews legal status of rights-of-way for overhead transmission lines throughout the province.

Table 6-28 below provides a summary of the capital additions and capital expenditures in the Test Period.

Table 6-28 ROW Sustainment – Plan Capital Additions and Expenditures (Fiscal 2023 to Fiscal 2025) ($ millions)

Planning ID	Name of Project	Capital Additions Plan F2023	Capital Additions Plan F2024	Capital Additions Plan F2025	Capital Expenditures Plan F2023	Capital Expenditures Plan F2024	Capital Expenditures Plan F2025
	ROW Sustainment						
	Programs and Projects Less than $5M	10.4	9.9	10.1	9.8	9.9	10.2
	TOTAL ROW Sustainment	**10.4**	**9.9**	**10.1**	**9.8**	**9.9**	**10.2**

All of the Rights-of-Way Sustainment investments within the Test Period are included in the Programs and Projects Less than $5 million line. These investments include programs for access repairs and rights acquisition. Capital expenditures and additions for access related investments across the Test Period are consistent with fiscal 2022 forecast. Small fluctuations within this category are largely due to rights acquisitions.

Third-Party Requested Transmission Line Relocations

Third-party requested line relocations are expenditures initiated when BC Hydro enters into an agreement with a third-party whose work requires our transmission lines to be modified or relocated. With the exception of relocations requested by the Ministry of Transportation and Infrastructure for highway rerouting or improvement projects, the third-party will pay for all costs incurred, resulting in offsetting Contributions in Aid for the capital expenditure. For relocations requested by the Ministry of Transportation and Infrastructure, BC Hydro recovers costs based on a protocol agreement. Under this protocol agreement, BC Hydro recovers approximately 50 per cent of the costs incurred for the relocation of 69 kV transmission lines. This cost sharing arrangement recognizes the benefit of rights-of-way provided to BC Hydro by the Ministry of Transportation at no cost. Costs for the relocation of transmission lines greater than 100 kV are recovered from the Ministry at full direct cost. BC Hydro may also relocate transmission lines where legally or contractually obligated.

Table 6-29 below provides a summary of capital additions and capital expenditures in the Test Period.

Table 6-29 Third-Party Requested Transmission Line Relocations – Plan Capital Additions and Expenditures (Fiscal 2023 to Fiscal 2025) ($ millions)

Planning ID	Name of Project	Capital Additions Plan F2023	Capital Additions Plan F2024	Capital Additions Plan F2025	Capital Expenditures Plan F2023	Capital Expenditures Plan F2024	Capital Expenditures Plan F2025
	Third Party Requested Transmission Line Relocations						
901563	Customer IPID - 901563 [redacted]	-	5.7	-	2.0	2.9	-
901807	Customer IPID - 901807 [redacted]	-	7.9	-	2.6	0.5	-
	Programs and Projects Less than $5M	18.5	13.9	6.0	11.1	6.6	6.1
	TOTAL Third Party Requested Transmission Line Relocations	18.5	19.6	6.0	13.1	9.5	6.1

Most of the Third-Party Requested Transmission Line Relocations investments during the Test Period are included in the Programs and Projects Less than $5 million line. As a result of the uncertainty in the number of requests from third-parties, the majority of the planned capital expenditures included in the Capital Plan are based on historical average levels of requests.

Contributions in Aid

Contributions in Aid are periodic or lump-sum payments or consideration received from customers or third-parties to provide funding towards the cost of construction or acquisition of an asset where the ownership, operation and maintenance responsibilities remain with BC Hydro.

Transmission Contributions in Aid amounts vary across the Test Period due to the timing of expected payments associated with Transmission Load Interconnection projects[445] and Third-Party Requested Transmission Line Relocation projects.

6.4.3 Distribution Capital Expenditures and Additions

Distribution capital investments in the Test Period are approximately 60 per cent for growth and 40 per cent for sustain investments.[446,447] This is similar to the overall allocation of expenditures across Distribution investments in the Previous Application.

The Distribution actual and planned capital expenditures and additions for the Test Period are provided in Table 6-30 and Table 6-31, below.

[445] Including those listed in Appendix I, page 3.

[446] Distribution capital expenditures and additions continue to be driven by the needs described in Appendix N, section 2.3.

[447] Expenditures in this section do not include the investments associated with BC Hydro's Electrification Plan. Please refer to section 6.7 and Chapter 10 for more detail on these capital expenditures.

Table 6-30 Distribution Actual and Plan Capital Expenditures (Fiscal 2021 to Fiscal 2025)

($ millions)	F2021	F2022		F2023	F2024	F2025
	Actual	Decision	Forecast	Plan	Plan	Plan
Distribution Growth						
Customer Driven						
Customer Connections	260.5	213.5	213.5	220.6	221.4	223.2
Major Customer Connections	54.4	29.0	61.8	33.4	30.2	38.2
IPP	0.9	2.2	3.4	1.5	1.1	1.1
Customer Driven Total	315.8	244.8	278.7	255.4	252.8	262.5
System Expansion and Improvement	74.7	61.2	41.7	70.8	78.4	70.8
Uneconomic Extension Assistance	-	0.7	0.7	0.4	0.4	0.4
Growth Total	390.5	306.7	321.1	326.6	331.5	333.7
Distribution Sustain						
System Expansion and Improvement	46.3	62.0	39.8	37.8	53.2	47.0
Asset Replacement						
Poles	48.7	63.2	48.1	51.5	51.1	54.2
Overhead Equipment	30.1	43.0	52.7	35.6	17.4	13.5
Underground Equipment	51.0	30.0	49.7	39.1	39.4	37.5
Trouble	20.5	20.2	20.8	21.2	21.6	22.1
Asset Replacement Total	150.3	156.3	171.4	147.4	129.6	127.3
Electric Vehicle Charging Infrastructure	2.9	(0.2)	5.3	3.7	3.2	3.3
Beautification	4.5	1.2	1.2	4.8	4.8	4.9
Sustain Total	204.1	219.3	217.7	193.8	190.9	182.4
Total Distribution	594.6	526.1	538.9	520.3	522.4	516.1
Less: Contribution in Aid	(186.7)	(200.2)	(149.8)	(158.4)	(159.4)	(161.2)
Total Net	407.9	325.9	389.1	362.0	362.9	354.9

Table 6-31 Distribution Actual and Plan Capital Additions (Fiscal 2021 to Fiscal 2025)

($ millions)	F2021	F2022		F2023	F2024	F2025
	Actual	Decision	Forecast	Plan	Plan	Plan
Distribution Growth						
Customer Driven						
Customer Connections	217.2	213.3	216.8	219.9	221.4	223.0
Major Customer Connections	55.2	20.2	76.3	29.5	31.5	46.4
IPP	0.8	2.2	1.4	3.9	1.1	1.1
Customer Driven Total	273.1	235.7	294.5	253.2	254.0	270.6
System Expansion and Improvement	72.9	65.3	109.7	53.7	108.3	62.8
Uneconomic Extension Assistance	0.2	0.7	0.7	0.4	0.4	0.4
Growth Total	346.2	301.7	404.8	307.3	362.6	333.7
Distribution Sustain						
System Expansion and Improvement	52.3	46.2	46.8	76.9	49.4	56.6
Asset Replacement						
Poles	45.9	62.6	45.2	50.6	51.2	53.6
Overhead Equipment	22.1	40.4	48.4	39.1	21.1	19.2
Underground Equipment	44.4	30.4	50.7	39.5	39.3	37.9
Trouble	20.4	20.1	20.6	21.1	21.6	22.0
Asset Replacement Total	132.9	153.5	164.9	150.3	133.1	132.7
Electric Vehicle Charging Infrastructure	(0.5)	0.3	8.6	3.6	3.7	3.2
Beautification	5.1	1.2	1.5	4.4	4.8	4.9
Sustain Total	189.8	201.2	221.8	235.2	191.1	197.5
Total Distribution	536.0	502.9	626.6	542.6	553.7	531.1
Less: Contribution in Aid	(172.1)	(150.4)	(156.2)	(157.2)	(159.3)	(157.5)
Total Net	363.9	352.5	470.4	385.4	394.5	373.6

6.4.3.1 Distribution Growth Capital Expenditures and Additions Are Increasing over the Test Period

Customer Driven Expenditures

Distribution Growth Customer Driven capital expenditures and additions are increasing over the Test Period. Fiscal 2021 actuals for Distribution Growth Customer Driven capital expenditures and additions exceeded plan and customer activity trends in the first two quarters of fiscal 2022 have not indicated any slowdown in activity.

Within the Customer Driven category, the majority of planned capital expenditures are for Programs and Projects Less than $5 million. These expenditures include residential and commercial load customer connections (approximately 5,500 design connections and 36,500 simple “express” connections annually). The level of residential and commercial development economic activity in the province is the single largest driver of these customer capital expenditures.

COVID-19 impacts caused a slow down in new customer service requests in April and May 2020, but requests subsequently increased above normal for the remainder of fiscal 2021. Customer development investments are not projected to slow down in fiscal 2022 – home sales are strong and presales for multi-residential and commercial developments also continue to show a normal level of activity.

There are five projects greater than $5 million with expenditures in the Test Period. These projects are listed in Table 6-32 below.[448]

[448] Additional information on the projects listed is provided in Appendix I, page 6.

Table 6-32 Customer Driven – Plan Capital Additions and Expenditures (Fiscal 2023 to Fiscal 2025) ($ millions)

Planning ID	Name of Project	Capital Additions Plan F2023	Capital Additions Plan F2024	Capital Additions Plan F2025	Capital Expenditures Plan F2023	Capital Expenditures Plan F2024	Capital Expenditures Plan F2025
	Customer Driven						
DY-1545	Customer IPID DY-1545 - [redacted]	-	-	20.4	1.5	0.4	0.1
DY-0347	Customer IPID DY-0347 - [redacted]	-	-	16.3	2.3	4.7	0.1
901955	Customer IPID 901955 - [redacted]	-	-	-	0.8	1.5	4.9
902127	Customer IPID 902127 – [redacted]	-	-	-	0.6	1.1	2.2
902128	Customer IPID 902128 - [redacted]	-	-	-	0.8	1.5	4.9
	Programs and Projects Less than $5M	253.2	254.0	234.0	249.6	243.7	250.4
	TOTAL Customer Driven	253.2	254.0	270.6	255.4	252.8	262.5

System Expansion and Improvement - Growth

Growth driven system expansion and improvement expenditures address existing capacity constraints and anticipated load growth. BC Hydro is undertaking several projects to increase the capacity and transfer load at the highest risk locations, including projects related to the Downtown Vancouver Redevelopment to convert the downtown core from a 12 kV dual-radial system to a 25 kV open loop system over the next 30-plus years.

Table 6-33 below provides a summary of the capital additions and capital expenditures in the Test Period.[449]

Table 6-33 System Expansion and Improvement – Plan Capital Additions and Expenditures (Fiscal 2023 to Fiscal 2025) ($ millions)

Planning ID	Name of Project	Capital Additions Plan F2023	Capital Additions Plan F2024	Capital Additions Plan F2025	Capital Expenditures Plan F2023	Capital Expenditures Plan F2024	Capital Expenditures Plan F2025
	System Expansion and Improvement						
900316	LOH 12F56, 12F62 Voltage Conversion Preparation (LM-BBY-082)	4.9	-	-	3.5	-	-
901518	Mount Lehman New Feeder to Offload Balfour, Mount Lehman and Gloucester Feeders (FV-ABT-042)	5.0	-	-	0.6	-	-
93650	Two new CBN Feeders to Offload SMW (LM-FVE-606)	-	5.5	-	1.4	-	-
92802	Glenmore Voltage Conversion (LM-NSC-088)	-	5.1	-	4.8	0.0	-
901355	Norgate - Offload NOR loads to NVR feeders (LM-NSH-074)	-	12.3	-	11.3	0.3	-
901356	North Vancouver - Offload NVR loads to LYN new feeders (LM-NSH-075)	-	6.3	-	5.8	0.2	-
900431	Oldfield (OFD) Voltage Conversion 12 to 25kV (NI-NEW-273)	-	-	5.6	2.3	2.2	0.1
901132	Three Fleetwood feeders to offload McLellan (FV-FVW-723)	-	11.9	-	7.9	0.1	-
93669	Three new MLE Feeders to offload CBN (LM-FVE-607)	-	9.1	-	1.0	-	-
901891	Downtown Vancouver - Voltage Conversion Preparation for Customer Vaults (LM-VAN-210)	-	-	-	1.7	1.7	1.7
901890	Fleetwood - Distribution Feeder Ductbank and Feeder Insallation (FV-FVW-023)	-	-	16.4	2.8	10.5	2.5
901949	Fleetwood - Distribution Feeder Ductbank and Feeder Installation (FV-FVW-805)	-	-	9.4	2.3	7.1	-
901950	Langley - MLN 25F32 and MLN 25F33 Offload (FV-FVW-741)	-	-	5.8	1.7	4.1	-
901820	Tofino - New LBH 25F54 Feeder Installation To Offload LBH 25F52 (VI-PAL-010)	-	7.5	-	2.4	-	-
900541	Vancouver Island - Saltspring 25F61 Cable Extension to North Pender Island (VI-GUL-005)	-	-	-	1.5	5.4	14.7
	Programs and Projects Less than $5M	43.8	50.6	25.5	19.7	46.7	51.9
	TOTAL System Expansion and Improvement	**53.7**	**108.3**	**62.8**	**70.8**	**78.4**	**70.8**

This category of investments is subject to year-over-year fluctuations as a result of the prioritization of work to adjust to changes in the forecast load growth. The majority of capital additions and expenditures in the growth System Expansion and

[449] More information on the projects listed is provided in Appendix I, page 6.

Improvement category, including Programs and Projects Less than $5 million, are made up of the following:

- **New Feeders** - These are projects to construct new feeders and infrastructure to offload heavily loaded existing feeders or to supply distribution customer load growth. The significant areas of new feeder projects include Abbotsford, Gulf Islands, Surrey, and North Vancouver. BC Hydro is forecasting capital expenditures of $30.1 million in fiscal 2023, which decrease to $23.2 million in fiscal 2025, and capital additions of $16.3 million in fiscal 2023 which increase to $37.0 million in fiscal 2025.
- **Voltage Conversions** - These are projects to convert the distribution primary voltage from 4 kV to 12 kV or from 12 kV to 25 kV. The objective of these investments is to increase existing distribution infrastructure capability to:
  - Increase system capacity to supply distribution customer load growth;
  - Increase operating flexibility for restoration and planned outages aligned with substation and transmission plans;
  - Increase system efficiency by reducing electrical system losses and improving customer service voltages;
  - Reduce congestion in heavily populated corridors;
  - Minimize equipment additions and its environmental footprint; or
  - Enable transmission and substation plans for expansion or redevelopment requiring feeder loads to be transferred to other feeders or substations.

  The significant areas of voltage conversion within the Test Period include Vancouver, Burnaby, North Vancouver, and Prince Rupert. BC Hydro is forecasting capital expenditures of $28.3 million in fiscal 2023 which decrease to $26.2 million in fiscal 2025, and capital additions of $26.2 million in fiscal 2023 which decrease to $6.5 million in fiscal 2025.

- **Downtown Vancouver Redevelopment** - The Downtown Vancouver Redevelopment Plan is a long-term strategic plan, aligned with the Downtown Vancouver Electric Supply plan[450] to convert the downtown core from a 12 kV dual-radial system to a 25 kV open loop system over the next 30-plus years. The Cathedral Square transformer failure in 2007, the maintenance hole fire in 2008, and the Murrin transformer failure in 2013 have demonstrated the considerable supply risk and vulnerability of the aging and congested distribution system in the Downtown Vancouver area. This initiative addresses the risk of long, high consequence outages in the downtown area. The plan replaces assets in poor condition with equipment that meets current standards and introduces automation to provide operational flexibility, reduce congested circuits and reduce outage restoration times. In conjunction with the Downtown Vancouver Redevelopment, BC Hydro will continue with the H-Frames Elimination safety initiative in Downtown Vancouver to eliminate potential hazards to the public. The replacement circuits will be an underground automated open loop system to align with the overall redevelopment initiative. The safety initiative is nearing completion which results in a decrease in sustain spending over the Test Period. BC Hydro is forecasting capital expenditures of $1.4 million in fiscal 2023 which increases to $12.8 million in fiscal 2025, and capital additions of $1.8 million in fiscal 2023 which increases to $10.9 million in fiscal 2025.

Uneconomic Extension Assistance

The Uneconomic Extension Assistance program is a legislated fund in the Electric Tariff[451] which provides financial assistance towards the cost of uneconomic distribution overhead electrical extensions requested by new connection customers to serve farms, principal residences, and irrigation loads.

[450] See Appendix K, Pages 77 and 78.
[451] Refer to section 8.8 of the Electric Tariff.

Table 6-34 below provides a summary of the Test Period capital additions and capital expenditures.

Table 6-34 Uneconomic Extension Assistance – Plan Capital Additions and Expenditures (Fiscal 2023 to Fiscal 2025) ($ millions)

Planning ID	Name of Project	Capital Additions Plan F2023	Capital Additions Plan F2024	Capital Additions Plan F2025	Capital Expenditures Plan F2023	Capital Expenditures Plan F2024	Capital Expenditures Plan F2025
	Uneconomic Extension Assistance						
	Programs and Projects Less than $5M	0.4	0.4	0.4	0.4	0.4	0.4
	TOTAL Uneconomic Extension Assistance	**0.4**	**0.4**	**0.4**	**0.4**	**0.4**	**0.4**

Capital additions and expenditures for Uneconomic Extension Assistance are forecast at approximately $0.4 million per fiscal across the Test Period, which is consistent with the fiscal 2022 forecast.

6.4.3.2 Distribution Sustaining Capital Expenditures and Additions Are Decreasing Compared to Fiscal 2022

System Expansion and Improvement - Sustain

System expansion and improvement sustaining expenditures maintain and improve distribution system performance including addressing customer reliability, safety risks and regulatory and legal requirements. The forecast level of capital expenditures and additions for System Expansion and Improvement is higher in the Test Period compared to fiscal 2022. The increase is primarily due to the timing of smaller sustaining Programs and Projects less than $5 million and due to higher forecast expenditures for the H-Frames Elimination projects, the Mission 25F51 Feeder Tie project and the 100 Mile House Line Relocation project.

Table 6-35 below provides a summary of the capital additions and capital expenditures in the Test Period.[452]

[452] Additional information on the projects listed is provided in Appendix I, page 6.

Table 6-35 System Expansion and Improvement – Plan Capital Additions and Expenditures (Fiscal 2023 to Fiscal 2025) ($ millions)

Planning ID	Name of Project	Capital Additions Plan F2023	Capital Additions Plan F2024	Capital Additions Plan F2025	Capital Expenditures Plan F2023	Capital Expenditures Plan F2024	Capital Expenditures Plan F2025
	System Expansion and Improvement						
900391	Downtown Vancouver - Underground Murrin Feeders to Eliminate H-Frames in Gastown	18.1	-	-	1.7	-	-
900557	H-Frame Elimination - Chinatown	20.4	-	-	-	-	-
901822	Mission - Feeder 25F51 Tie (FV-ABT-039)	-	-	12.1	1.5	8.3	2.0
901892	100 Mile House - Relocate Sections of Transmission along Hendrix Road (SI-HMH-002)	-	-	5.4	2.3	2.3	-
901081	Gwillim Microwave - Power Supply Upgrade	-	7.4	-	3.2	2.2	-
	Programs and Projects Less than $5M	38.4	42.0	39.2	29.2	40.5	45.0
	TOTAL System Expansion and Improvement	**76.9**	**49.4**	**56.6**	**37.8**	**53.2**	**47.0**

Year-over-year fluctuations are the result of the prioritization of work with the timing of lower priority work being adjusted. The majority of the sustaining System Expansion and Improvement investments are captured in the Programs and Projects Less than $5 million line and are for small projects that relate to the following areas:

- **Customer Reliability** - The objective of customer reliability expenditures is to improve reliability on targeted distribution circuits that are performing poorly. The scope of customer reliability projects may include new standby feeders, feeder ties, as well as circuit undergrounding or reconfiguration, line relocations and protection upgrades. BC Hydro is forecasting capital expenditures of $5.8 million in fiscal 2023 and increasing to $9.3 million in fiscal 2025 and capital additions of $3.6 million in fiscal 2023 and increasing to $20.3 million in fiscal 2025. The increase is primarily due to the Mission – Feeder 25F51 Tie (FV-ABT-039) project and an increase in Projects Less than $5 million; and
- **Distribution Automation** - Automation of distribution devices provide operating personnel with remote monitoring and visibility of system parameters and system status, facilitate remote operability, and enable greater flexibility to efficiently operate the system. Specific assets such as capacitors, voltage regulators and underground switchgear targeted for automation involve many

existing assets that are approaching end of life. Therefore, the automation capability for these assets is being integrated with the Asset Replacement programs to ensure that end-of-life asset replacement decisions appropriately consider automation benefits. The costs associated with these programs are captured under Asset Replacement. The remaining assets such as reclosers, lateral reclosers, and communicating line monitors are mostly newer assets being added to the distribution system and therefore remain funded under the Distribution Automation program. Expenditures in the Test Period are focused on installation, replacement and automation of reclosing, switching and monitoring devices to enable faster fault isolation and outage restoration in order to enhance service reliability, and on voltage management devices to improve power quality. BC Hydro is forecasting capital expenditures of $7.0 million in fiscal 2023 which increases to $8.3 million in fiscal 2025, and capital additions of $9.4 million in fiscal 2023 which decrease to $8.3 million in fiscal 2025.

Asset Replacement

Distribution asset replacements expenditures address equipment that has reached end of life. The forecast level of capital expenditures and additions for Asset Replacements is lower in the Test Period than in the fiscal 2022 forecast. The decrease is primarily due to the planned completion of the Various Sites – LED Street Light Conversion project, as well as PCB contaminated equipment phase-out replacements which are decreasing during the Test Period.

Table 6-36 below provides a summary of the capital additions and capital expenditures in the Test Period.[453]

[453] Additional information on the projects listed is provided in Appendix I, page 6.

Table 6-36 Asset Replacement – Plan Capital Additions and Expenditures (Fiscal 2023 to Fiscal 2025) ($ millions)

Planning ID	Name of Project	Capital Additions Plan F2023	Capital Additions Plan F2024	Capital Additions Plan F2025	Capital Expenditures Plan F2023	Capital Expenditures Plan F2024	Capital Expenditures Plan F2025
	Asset Replacement						
900556	Various Sites - LED Street Light Conversion	21.7	7.4	5.8	20.3	4.2	-
	Programs and Projects Less than $5M	128.6	125.8	126.9	127.2	125.4	127.3
	TOTAL Asset Replacement	**150.3**	**133.1**	**132.7**	**147.4**	**129.6**	**127.3**

The majority of capital additions and expenditures in this category consist of recurring capital programs in the Programs and Projects less than $5 million line to address the replacement of assets in the following four categories:

- **Poles** - This category covers wood poles as well as elevated platforms. Poles and platforms at end of life pose a significant risk to crews and the general public and may cause outages on the system. An increasing number of BC Hydro's approximately 900,000 distribution system wood poles are reaching end of life. More than 114,000 poles are currently greater than 50 years of age compared to 67,000 units that were greater than 50 years of age in fiscal 2014. Wood pole end of life is identified by a series of inspection programs that run throughout the fiscal year. BC Hydro is forecasting expenditures of $51.5 million in fiscal 2023, $51.1 million in fiscal 2024, and $54.2 million in fiscal 2025 after recoveries from TELUS;[454]
- ***Overhead System*** **-** Overhead system assets include transformers, voltage regulators, capacitors, conductor, and switches including porcelain fuse cut-out switches. BC Hydro also manages a fleet of streetlights as part of the distribution overhead system. A three-year deployment of light-emitting diode streetlights began in fiscal 2021 to replace the current fleet of existing high pressure sodium and mercury vapour units. Equipment on the overhead

[454] Approximately 86 per cent of the poles on the distribution system are jointly owned by TELUS and BC Hydro. TELUS pays 40 per cent of pole-in-place replacement costs for jointly owned poles.

system with PCB levels at or above 50 Parts Per Million (**ppm**) is being proactively replaced to ensure all units in the category are removed by the December 31, 2025 Federal PCB Regulation deadline. BC Hydro is forecasting capital expenditures of $35.6 million in fiscal 2023, $17.4 million in fiscal 2024, and $13.5 million in fiscal 2025 to address end-of-life replacements on the overhead system, including replacement of assets considered under the automation program;

- **Underground System -** Underground system assets include feeder cables, submarine cables, residential distribution cables and equipment, transformers and switchgear. Underground systems typically supply densely populated areas. Equipment in poor condition can pose a significant risk to system reliability and to public and worker safety. Detailed condition assessments combined with risk assessments are used to identify when replacements of underground system assets are required. Older Paper Insulated Lead Sheathed Cables are at or reaching end of life and need to be replaced to mitigate reliability and worker safety issues. Transformers and other oil filled equipment with PCB levels at or above 50 ppm are being proactively replaced to ensure all units in the category are removed by the December 31, 2025 Federal PCB Regulation deadline. BC Hydro is forecasting capital expenditures of $39.1 million in fiscal 2023, $39.4 million in fiscal 2024, and $37.5 million in fiscal 2025 to address end-of-life replacements on the underground system, including replacement of assets considered under the automation program; and
- **Trouble** - Trouble capital expenditures are for equipment replacements that meet capitalization rules and resulting from: routine trouble calls, which are day-to-day restoration of power outages; storms, which are events causing outages over a large geographic area or affecting a large number of customers or of extended duration; or damage to plant, which are events where a third party may be liable for the cost of the system repairs. BC Hydro and contractor crews respond to between 40,000 and 60,000 dispatched calls per year

regarding the distribution system. The forecast expenditures are based on historical levels. BC Hydro is forecasting expenditures of $21.2 million in fiscal 2023, $21.6 million in fiscal 2024, and $22.1 million in fiscal 2025 to respond to trouble calls.

Electric Vehicle Charging Infrastructure

BC Hydro's forecast expenditures on Electric Vehicle (**EV**) charging infrastructure are for installing and sustaining a network of EV direct current fast charging (**DCFC**) stations. For the Test Period, BC Hydro is including costs related to EV DCFC infrastructures that meet the requirements for a prescribed undertaking under section 5 of the Greenhouse Gas Reduction (Clean Energy) Regulation, as discussed in Chapter 10, section 10.3.2. Under section 18 of the *Clean Energy Act*, BC Hydro recovers in rates its costs incurred with respect to the prescribed undertakings.

Table 6-37 below provide the capital expenditures and additions for EV charging infrastructure in the Test Period that are included in BC Hydro's Capital Plan[455].

Table 6-37 Electric Vehicle Charging Infrastructure – Plan Capital Additions and Expenditures (Fiscal 2023 to Fiscal 2025) ($ millions)

Planning ID	Name of Project	Capital Additions Plan F2023	Capital Additions Plan F2024	Capital Additions Plan F2025	Capital Expenditures Plan F2023	Capital Expenditures Plan F2024	Capital Expenditures Plan F2025
	Electric Vehicle Charging Infrastructure						
	Programs and Projects Less than $5M	3.6	3.7	3.2	3.7	3.2	3.3
	TOTAL Electric Vehicle Charging Infrastructure	**3.6**	**3.7**	**3.2**	**3.7**	**3.2**	**3.3**

455 BC Hydro has also included incremental capital expenditures and additions for electric vehicle charging infrastructure in the Test Period as part of the Electrification Plan. Refer to section 6.7 and Chapter 10, section 10.4.3.2.

Annual capital expenditures and additions are net of contributions from the Government of B.C. and National Resources Canada. The expenditures will vary between fiscal years based on the timing of receipt of those contributions.

Beautification Program Provides Benefits to Municipal Governments

BC Hydro's Beautification Fund provides financial assistance to municipal governments to relocate BC Hydro equipment on public property. BC Hydro contributes one-third of the estimated project costs to relocate overhead lines and poles to underground duct banks. Previous projects have included high traffic areas and community venues such as town centres, parks, commercial districts, civic facilities, and bike lanes.

The purpose of the fund is to help municipal governments achieve their environmental and community improvement objectives such as:

- Enhance the use of public spaces;
- Improve visual aesthetics of public areas; and
- Support community redevelopment projects.

Two-thirds of the forecast expenditures will be offset by contributions from the municipalities.

Table 6-38 Beautification – Plan Capital Additions and Expenditures (Fiscal 2023 to Fiscal 2025) ($ millions)

Planning ID	Name of Project	Capital Additions Plan F2023	Capital Additions Plan F2024	Capital Additions Plan F2025	Capital Expenditures Plan F2023	Capital Expenditures Plan F2024	Capital Expenditures Plan F2025
	Beautification						
	Programs and Projects Less than $5M	4.4	4.8	4.9	4.8	4.8	4.9
	TOTAL Beautification	**4.4**	**4.8**	**4.9**	**4.8**	**4.8**	**4.9**

Annual capital expenditures and additions are driven by the number of projects submitted to the program by municipalities. Capital expenditures and additions are below $5 million per fiscal year across the Test Period. This is an increase from the $1.2 million forecast for fiscal 2022 due to increases in the value of projects submitted by municipalities.

Contributions in Aid

Contributions in Aid are periodic or lump-sum payments or consideration received from customers or third parties to provide funding toward the cost of construction or acquisition of an asset, where the asset ownership, operation and maintenance responsibilities remain with BC Hydro. Distribution Contributions in Aid are mostly received under the Customer Driven Program for new connection requests in accordance with the Electric Tariff and payments are made in advance of costs being incurred. Contributions in Aid are also received under the Beautification and Uneconomic Extension Assistance programs. All three programs are discussed above.

In the Test Period, the Distribution Contributions in Aid is forecast to increase slightly over the fiscal 2022 forecast. These increases are associated with customer driven investments.

6.5 Supporting Portfolios

6.5.1 Technology

The Technology KBU is responsible for the planning, design, delivery and operation of BC Hydro’s Information Technology (**IT**) systems and several Operational Technology (**OT**) systems. IT assets or systems are tools for commercial decision making, planning, business process management, and resource allocation. OT assets or systems provide operational monitoring and/or control of assets in the electric network in real time (or near real time).

6.5.1.1 BC Hydro's Operations Depend on Technology Capital Assets

BC Hydro's operations rely on IT and OT for power system operations, workforce mobility, business process support, decision support, communications, security and services to customers.

Our operations are enabled by an extensive technology asset portfolio that includes data centres, software platforms, applications and computing and communications devices. We operate a wide range of software platforms including enterprise and business applications, geographic information systems, document and collaboration systems, data analytics solutions, and web portals for our customers and workforce. We also provide workstations, laptops and other mobile devices to access and share information and work across our integrated network.

6.5.1.2 Strategic Drivers Impact Technology Capital Investments

Appendix O provides BC Hydro's Technology Strategy and 5-Year Plan. The document is updated annually and was last updated in September 2020.

The Technology Strategy and 5-Year Plan reflects the Capital Plan. Investment priorities are driven by our increasing use of information technology, our growing cybersecurity and compliance requirements, investments in our systems that support business operations and end-of-life asset replacements.

Key expenditures planned for the Test Period include projects to address cybersecurity risk and support Mandatory Reliability Standards compliance, and continuation of the Contact Centre Technology Foundation, Energy Management System Upgrade, and Advanced Distribution Management System projects.

BC Hydro will also focus within the Test Period on a series of projects related to decommissioning Passport and upgrading our enterprise system, SAP, to the future supported platform of S/4HANA.[456] This is in line with the Technology Plan (Appendix O) and entails three major workstreams:

1. The “Stations Work Management” work stream focuses on migrating stations assets from Passport to SAP and utilizing SAP’s built-in Enterprise Asset Management functionality to configure work management workflows in SAP. The addition of a work planning and scheduling tool will complete the scope of work and allow for the full realization of benefit from the rationalization of Stations Field Operations resources.
2. The “Distribution Design Modernization” work stream migrates distribution design workflows and calculators from Passport to a new portal for initiating customer connections. The work includes configuring the workflows in SAP and implementing a modern, commercial design tool capable of integrating directly with SAP and eliminating the current ‘swivel chair’ approach between Passport and the existing, custom design tool. This project is expected to increase the productivity and efficiency of the Distribution Design resources as well as remove the last functionality from Passport. This will be the final stage of the major transformation to SAP, BC Hydro’s integrated Enterprise Resource Planning system.
3. The “SAP to S/4HANA Migration” work stream includes projects required to migrate functionality from BC Hydro’s current version of SAP to the newer S/4HANA version. SAP S/4HANA runs on an in-memory database capable of improved performance and data access. The upgrade must be completed by 2027 in order to keep BC Hydro on a fully supported version of SAP.

[456] SAP is BC Hydro’s primary IT system and enterprise resource planning software. Enterprise Resource Planning software is designed to help manage and integrate the functions of core business processes like finance, HR, supply chain, project management and plant maintenance as a single system. After 2027, SAP will no longer support versions of SAP that are not migrated to S/4HANA, SAP’s next generation Enterprise Resource Planning software.

6.5.1.3 Technology KBU Continues to Monitor Project Delivery Performance

The Technology KBU is responsible for delivery of BC Hydro's IT and OT investments. The KBU uses the Information Technology Delivery Standard Practices methodology. The Information Technology Delivery Standard Practices provides assurance that BC Hydro is effectively managing scope, schedule, cost and risk in delivering IT and OT projects.

Table 6-39 below provides a summary of BC Hydro's performance in delivering technology capital projects by comparing total approved First Full Funding[457] (FFF) for projects to total actual project costs.

Table 6-39 Technology Projects Completed Within Total Approved First Full Funding Amount (Fiscal 2016 to Fiscal 2021)

Fiscal Year	No. of Projects Completed	Percentage of Projects Completed Within FFF Amount	Cumulative Project Cost ($ million)		Variance	
			[A] FFF Amount ($ million)	[B] Actual Final Cost ($ million)	[A – B] ($ million)	[(A -B)/A] (%)
2016	34	68	42.0	41.0	1.0	2.4
2017	37	81	59.6	61.1	(1.5)	(2.5)
2018	23	91	33.5	32.4	1.1	3.3
2019	20	95	48.4	40.7	7.7	16.0
2020	18	89	29.8	25.5	4.3	14.4
2021	20	95	46.5	37.6	8.9	19.1
Total	**152**		**259.8**	**238.3**	**21.5**	**8.3**

From fiscal 2016 to fiscal 2021, a total of 152 projects were completed, with total approved first full funding of $259.8 million and total actual costs of $238.3 million – a favourable variance of $21.5 million or 8.3 per cent. Recurring capital programs and capital purchases are excluded.

[457] First Full Funding is the Original Approved Authorized Cost at the Implementation phase.

These results compare favourably to the Project Management Institute 2021 Pulse of the Profession global project management survey which reported that 64 per cent of technology projects are completed on budget. In fiscal 2021, 20 BC Hydro Technology projects were completed and 19 (95 per cent) of those were completed within their total approved First Full Funding amount.

6.5.1.4 Technology KBU Continues to Monitor Benefits Realization

The benefits realization process monitors investments in the delivery phase and assets in service to facilitate identification and achievement of expected results. The timeline for monitoring benefits is the entire asset life cycle with positive intermediate outcomes being leading indicators of benefits.

Table 6-40 below provides a summary of BC Hydro's benefits realization portfolio for planned, active and completed Technology projects over $2 million in the Enhanced Business Capability investment category.

Table 6-40 Technology Benefits Realization Portfolio

Planning ID	Project Name	Project Status
T001196	Enterprise Billing Infrastructure	Complete
T000524	Fleet / Garage Management System	Complete
T000563	Field Access to Safety Information	Complete
T001611	Autodesk Substation Design Suite	Complete
T000601	Customer Mobile	Complete
T001035	Dam Safety Information System	Active
T001856	Legal Information Management System	Active
T001127	Supply Chain Applications	Active
T001841	Contingent Labour Management System	Active
T001723	Customer Connect Web Enablement	Active
T002004	Enterprise Hydroweb Redesign	Active
T000625	Vehicle and Equipment Telemetry	Active
T002016	Advanced Distribution Management System	Active
T001397	Contact Centre Technology Foundation	Active
T002122	Stations Work Management	Planned

Benefits realization work is limited to projects that enhance business capability. where the achievement of benefits is necessary to meet business objectives for the investment.

The benefits realization process has increased the focus on benefits identification in Technology business cases and produced cause-and-effect models that help maintain focus on benefits during project delivery and operations.

6.5.1.5 Technology Capital Expenditures and Additions

Technology capital expenditures and capital additions for the Test Period are presented in Table 6-41 and Table 6-42 below.

Table 6-41 Technology Actual and Plan Capital Expenditures by Investment Category (Fiscal 2021 to Fiscal 2025)

($ millions)	F2021	F2022		F2023	F2024	F2025
	Actual	Decision	Forecast	Plan	Plan	Plan
Manage Compliance and Security	9.0	9.9	22.1	15.1	10.4	11.0
Manage Risk and Sustain Productivity	68.5	60.6	69.1	71.9	55.8	56.5
Enhance Business Capability	12.2	8.5	32.6	38.1	30.0	19.1
Total Gross	89.6	79.0	123.7	125.2	96.2	86.6
Portfolio Adjustment	-	(10.0)	(21.9)	(16.0)	(8.0)	-
Total Net	89.6	69.0	101.8	109.2	88.2	86.6

Table 6-42 Technology Actual and Plan Capital Additions by Investment Category (Fiscal 2021 to Fiscal 2025)

($ millions)	F2021	F2022		F2023	F2024	F2025
	Actual	Decision	Forecast	Plan	Plan	Plan
Manage Compliance and Security	12.8	9.9	17.2	23.8	10.4	9.2
Manage Risk and Sustain Productivity	67.0	79.2	73.2	86.1	68.6	45.2
Enhance Business Capability	85.1	8.5	6.9	28.1	54.6	30.2
Total Gross	164.9	97.6	97.3	138.0	133.5	84.6
Portfolio Adjustment	-	(10.0)	(18.0)	(19.0)	(14.0)	(6.0)
Total Net	164.9	87.6	79.3	119.0	119.5	78.6

As shown in the tables above, BC Hydro's forecast Technology capital investments are grouped into the following three categories:

- **Manage compliance and security:** This category includes investments that address regulatory requirements, periodic foundational cybersecurity improvements, cybersecurity hardware replacements and software license renewals, and growing cybersecurity threats;

- **Manage risk and sustain productivity:** This category includes investments that address asset failure risk and new investments to help manage operational and business risks and expand information technology services as needed; and
- **Enhance business capability:** This category includes investments for new or improved business capabilities.

The primary investment drivers in each investment category are shown in Table 6-43 below.

Table 6-43 Technology Investment Categories and Investment Drivers

Category	Investment Driver
Manage Compliance and Security	**Regulatory compliance risk** Investment toward achieving Mandatory Reliability Standards, WorkSafe BC, or other compliance outcomes.
	Cybersecurity risk Investment driven by cybersecurity threats, vulnerabilities and incidents.
Manage Risk and Sustain Productivity	**Asset risk** Investment to address declining asset health (including supportability), which increases the likelihood of asset failures including outages, declining performance and loss of capacity. The risk to business systems, capabilities, production and services are considered in a business-as-usual environment.
	Sustainment of productivity Investment to maintain the efficiency of IT assets, asset systems and the downstream business functions that rely on them. This includes recurring capital work programs (excluding enhancements), and software license purchases.
Enhance Business Capability	**Enhancement of capability** Investment to enable new or enhance existing business capabilities, to expand capacity, or to manage operational, financial, and reputational risks.

The tables below provide a breakdown of the Test Period Technology capital expenditures and additions by investment category.

Table 6-44 below describes the planned capital additions and expenditures in the Manage Compliance and Security category.[458]

Table 6-44 Technology Capital Expenditures and Additions – Manage Compliance and Security (Fiscal 2023 to Fiscal 2025)

Planning ID	Name of Project	Capital Addition Forecast F23	Capital Addition Forecast F24	Capital Addition Forecast F25	Expenditure Forecast F23	Expenditure Forecast F24	Expenditure Forecast F25
	Manage Compliance and Security						
	Projects Over $2 million						
T002623	NERC CIP-13	3.5	-	-	1.1	-	-
T002718	Enterprise MRS Compliance Management System	2.9	-	-	2.5	-	-
T001744	Time Based Rates	4.4	-	-	2.6	-	-
T001935	Privileged Access Management	3.0	-	-	2.3	-	-
T002612	SIEM Subscription License Acquisition	-	-	3.4	-	-	3.4
T002613	Network Product License Acquisition	-	4.3	-	-	4.3	-
T001930	Corporate Firewalls Refresh	2.5	-	-	0.2	-	-
	Subtotal - Projects over $2 million	16.3	4.3	3.4	8.5	4.3	3.4
	Programs over $2 million (Recurring Capital)						
	Subtotal - Programs over $2 million	2.0	2.0	-	1.0	2.0	-
	Projects and Programs less than $2 million	5.6	4.1	5.8	5.6	4.1	7.6
	Subtotal - Management Compliance and Security	**23.8**	**10.4**	**9.2**	**15.1**	**10.4**	**11.0**

As shown in the table above, there are seven projects over $2 million in this category:

- The NERC CIP-13 project is to implement standards to mitigate cybersecurity risks to the reliable operation of the Bulk Electric System by implementing security controls for supply chain risk management of Bulk Electric System Cyber Systems;
- The Enterprise MRS Compliance Management System project is to establish a single source for reliability compliance management and oversight by way of enhancements and standardization in our current solution. This will help ensure BC Hydro's reliability compliance management and governance process are aligned with industry best practices;

[458] Further information on projects over $2 million is provided in Appendix I and projects over $10 million in Appendix J.

- The Time-based Rates project is to implement foundational technology to enable voluntary, time-of-use rate options for residential and commercial customers;
- The Privileged Access Management project is to improve BC Hydro's cybersecurity software solution that securely manages the user accounts of administrators, applications, and devices, having elevated permissions to critical corporate resources;
- The SIEM Subscription License Acquisition is to comply with the software usage agreement for BC Hydro's Security Information and Event Management software, which analyzes alerts generated by applications and network hardware;
- The Network Product License Acquisition is to extend software maintenance and licensing for the use of BC Hydro’s network and security products and services; and
- The Corporate Firewalls Refresh project is to replace or upgrade network security equipment to maintain full vendor support and to reduce cybersecurity risk.

Table 6-45 below describes the planned capital additions and expenditures in the Manage Risk and Sustain Productivity category, Projects over $2 million.[459]

[459] Further information on projects over $2 million is provided in Appendix I and projects over $10 million in Appendix J.

Table 6-45 Technology Capital Expenditures and Additions – Manage Risk and Sustain Productivity (Fiscal 2023 to Fiscal 2025) – Projects Over $2 million

Planning ID	Name of Project	Capital Addition Forecast F23	Capital Addition Forecast F24	Capital Addition Forecast F25	Expenditure Forecast F23	Expenditure Forecast F24	Expenditure Forecast F25
	Manage Risk and Sustain Productivity						
	Projects over $2 million						
T001379	SAP S/4HANA Upgrade	-	-	-	-	-	7.0
T002360	Human Capital Management (HCM) Foundation	2.8	-	-	2.4	-	-
T002061	SAP Business Warehouse (BW) Upgrade	4.5	-	-	0.5	-	-
T001397	Contact Centre Technology Foundation Refresh	-	23.6	-	13.3	4.5	-
T001877	Primary GIS Platform Upgrade	3.9	-	-	1.2	0.1	-
T002258	SAP Customer Front End Replacement	-	8.7	-	4.0	4.0	-
T002085	Advanced Metering System Software Upgrade	-	2.9	-	2.2	0.7	-
T002036	Energy Management System (EMS) Upgrade	12.4	-	-	2.5	-	-
T002321	Primary Data Centre Network Refresh	8.0	-	-	5.2	-	-
T002317	Backup Data Centre Network Refresh	-	4.0	-	2.0	2.0	-
T002324	Operations Data Centre Network Refresh	-	2.0	-	1.0	1.0	-
T002483	Windows Server Upgrade	2.0	-	-	2.0	-	-
T001072	Data Centre Backup	4.3	-	-	4.3	-	-
T002678	Data Centre Backup Sustainment	2.2	-	-	2.2	-	-
T002679	Data Centre Backup Sustainment	-	1.6	-	-	1.6	-
T002692	Physical Security Network Transition	-	4.0	-	2.0	1.8	-
T002073	EAS Hardware Upgrade	-	3.0	-	0.2	2.6	0.3
T002202	Corporate Telephony Replacement	-	-	-	2.3	-	-
T002669	Corporate Telephony Replacement	0.8	0.8	0.8	0.8	0.8	0.8
T002318	Regional Site Infrastructure Refresh	2.5	-	-	1.0	-	-
T002676	Meter Data Management System Upgrade	-	2.9	-	-	2.9	-
	Subtotal - Projects over $2 million	43.2	53.6	0.8	49.0	22.1	8.1
	Programs over $2 million (Recurring Capital)						
	Subtotal - Programs over $2 million	30.3	20.9	17.5	19.2	20.2	17.5
	Projects and Programs less than $2 million	19.9	17.7	26.9	19.9	18.1	31.0
	Subtotal - Manage Risk and Sustain Productivity	**93.4**	**92.2**	**45.2**	**88.1**	**60.3**	**56.5**

As shown in the table above, there are 18 projects over $2 million in this category:

- The SAP S/4HANA Upgrade project is to update BC Hydro's primary Enterprise Resource Planning system and solutions from SAP ECC to SAP S/4HANA, to maintain vendor support after 2027;
- The Human Capital Management Foundation project is to implement a modern software platform capable of more effectively enabling learning management, workforce management, recruitment and other HR functions. This foundational solution will allow for the future implementation of modern, integrated Human Capital Management solutions while eliminating existing, outdated BC Hydro

solutions. This project is one in a sequence of projects to assure the continuing operation of critical IT solutions on vendor-supported platforms;

- The SAP Business Warehouse (BW) Upgrade project is to replace the existing SAP Business Warehouse solution with the new HANA Business Warehouse solution. The project will address current performance and functional issues in SAP reporting, minimize continued development on the existing solution, and improve readiness for the SAP S/4HANA Upgrade project. This project is one in a sequence of projects to assure the continuing operation of critical IT solutions on vendor-supported platforms;
- The Contact Centre Technology Foundation Refresh project is to address end-of-life Contact Centre IT assets. The project will implement modern contact centre technologies to provide a stable and capable IT platform for all of BC Hydro's contact centres. The project forecast includes $9.6 million in enhanced business capability funding;
- The Primary GIS Platform Upgrade project is to upgrade BC Hydro's primary Geographic Information System platform supporting a suite of software applications required for operation of the transmission and distribution system. The current Geographic Information System versions are no longer vendor-supported, resulting in increasing risk of unplanned outages for these solutions;
- The SAP Customer Front End Replacement project is to replace BC Hydro's SAP Customer Interaction Center solution which is used by Contact Centre & Billing Operations and other groups as a front-end to manage customer lifecycle activities. This project is one in a sequence of projects to assure the continuing operation of critical IT solutions on vendor-supported platforms;
- The Advanced Metering System Software Upgrade project is to upgrade the end-of-life solution to comply with the vendor agreement and maintain full

vendor support. Advanced metering system software is used to manage BC Hydro's smart meter configurations and communications;

- The Energy Management System (EMS) is a critical IT system used by Transmission Distribution System Operations to operate the Bulk Electric System in the province of B.C. The Energy Management System (EMS) Upgrade project is to upgrade the EMS solution to the latest version to ensure reliable infrastructure and application availability;
- The Primary Data Centre, Secondary Data Centre, and Operations Data Centre network refresh projects are to replace end-of-life network equipment;
- The Windows Server Upgrade project will upgrade the operating systems of BC Hydro servers running Windows 2008 or 2012, to Windows 2016 or 2019;
- The Data Centre Backup projects will improve BC Hydro's data backup systems and technologies to safeguard against data loss. The improved data backup solution will help ensure the protection of BC Hydro's data and provide new capacity for increasing data volumes and sources;
- The Physical Security Network Transition project is to refresh the physical security network and transition its ongoing management to the Technology KBU;
- The EAS (Energy Analytics Solution) Hardware Upgrade project is to upgrade of the end-of-life EAS Data Computing Appliance, which hosts BC Hydro's Energy Analytics Solution;
- The Corporate Telephony Replacement projects are to replace the end-of-life corporate telephony system with a fully supported system having improved capability;
- The Regional Site Infrastructure program is to replace end-of-life server infrastructure across approximately 15 regional sites; and

- The Meter Data Management System Upgrade project is to upgrade the end-of-life system including associated hardware and database.

As shown in the table above, there are also Recurring Capital Programs over $2 million to sustain BC Hydro's IT hardware and software assets. Hardware capital programs provide data centre equipment including servers, storage and load balancers; facility equipment such as Surrey Campus network; field equipment including vehicle mobile access to the data network; and personal computing equipment such as PCs, Windows software and personal mobile devices. Software capital programs provide software updates and tools to maintain efficient project delivery and business operations; and ongoing application improvements to manage asset performance and risk, and to keep up with business changes.

Table 6-46 below describes the planned capital additions and expenditures in the Enhance Business Capability category in the Test Period.

Table 6-46 Technology Capital Expenditures and Additions – Enhance Business Capability (Fiscal 2023 to Fiscal 2025)

Planning ID	Name of Project	Capital Addition Forecast F23	Capital Addition Forecast F24	Capital Addition Forecast F25	Capital Expenditure Forecast F23	Capital Expenditure Forecast F24	Capital Expenditure Forecast F25
	Enhance Business Capability						
	Projects over $2 million						
T001035	Dam Safety Information System (DSIS)	3.3	-	-	1.1	0.3	-
T00625	Vehicle and Equipment Telemetry	-	2.5	-	0.9	0.9	-
T002016	Advanced Distribution Management System (ADMS)	11.0	-	-	2.3	0.1	-
T002122	Stations Work Management	-	22.0	-	8.0	9.0	-
T002549	Distribution Design Modernization	-	-	23.0	3.0	10.0	10.0
	Subtotal - Projects over $2 million	14.3	24.5	23.0	15.3	20.2	10.0
	Programs over $2 million						
	Subtotal - Programs over $2 million	-	-	-	-	-	-
	Projects and Programs less than $2 million	6.5	6.6	7.2	6.6	5.2	9.1
	Subtotal - Enhance Business Capability	**20.8**	**31.0**	**30.2**	**21.9**	**25.5**	**19.1**

As shown in the table above, there are five projects over $2 million in this category:

- The Dam Safety Information System project is to consolidate data from many sources and provide a single interface for Dam Safety Surveillance Engineers to view the conditions of BC Hydro dams;
- The Vehicle and Equipment Telemetry project is to implement a vehicle telematics system that will help to manage capital and operating costs, availability, utilization and safety related to all BC Hydro vehicles;
- The Advanced Distribution Management System project is to assist Real-Time Operations and field operating personnel with the monitoring and control of the electric distribution system. This project will replace the end-of-life Distribution Management System acquired from Schneider Electric in 2010;
- The Stations Work Management project is to consolidate stations assets, work orders, and maintenance programs into SAP, and implement an integrated, enterprise level, job planning and scheduling tool to replace the existing Excel-based solution. The project will enable efficiencies in Stations work management and facilitate the retirement of Passport; and
- The Distribution Design Modernization project will implement a new IT platform for distribution design and electric connections work management. The existing work management capabilities will be migrated from Passport to SAP and the current Distribution Analysis and Design application will be replaced by a modern graphical design tool. The project is required for the retirement of Passport.

6.5.2 Properties Capital Investments

The Properties KBU is responsible for the supply, operations and maintenance of BC Hydro’s headquarters and field offices, which total 105 facilities, comprising approximately three million square feet of office and industrial space. These facilities house field crews as well as a wide range of critical functions including system operations, telecommunications, emergency operations, customer contact, materials management, fleet management, and security command centres. BC Hydro's headquarters and field offices provide critical services to B.C. communities and local industry and must be operational for 24-hour response in all conditions, similar to other emergency services facilities (e.g., fire halls). Facilities managed by the Properties KBU do not include Generation plant buildings or Transmission and Distribution substations, which are included in the Power System Capital Plan. As discussed below, Properties regularly assesses the health of the 14,000 individual assets managed by the Group. All risks associated with these assets are reviewed based on BC Hydro's standard approach

6.5.2.1 Properties Portfolio Investments Address Risks and Issues with Existing Assets

The investments in the Properties portfolio are driven by the need to address the issues and risks associated with the existing physical assets and infrastructure. Properties capital investments fall into two general categories, distinguished by the scope and size of the projects:

- **Building Development** - projects include the major refurbishing or rebuilding of field buildings in areas where BC Hydro's existing facilities are at end of life and/or inadequate to meet operational needs; and
- **Building Improvement** - projects at existing facilities to address operational deficiencies as well as end-of-life replacements of aging building components and systems.

Properties capital planning focuses on assessing the health of existing assets and determining operational requirements that cannot be met by the existing assets, to establish an effective long-term capital plan.

Aging Assets

Facilities managed by Properties are, on average, 35 years old, with more than 45 per cent of the facilities being greater than 40 years old. Continued investment in these assets in the Test Period and beyond is required to maintain efficient and effective operation of BC Hydro's building assets, to limit costly and disruptive failures and to achieve the organization's objectives. All Properties projects are classified as Sustaining Capital.

Asset Health

Properties assesses the health of nearly 14,000 individual assets at the 105 BC Hydro facilities managed by Properties (including each facility's seismic withstand), based on each asset's current condition remaining life expectancy, likelihood of failure, and impact of failure. These assets include building envelopes, roofs, HVAC systems, elevators, etc. The results of these assessments identify assets that are at or near end of life. Investments in these assets are considered for inclusion in the capital plan.

Operational Requirements

Properties seeks feedback from key occupant groups in order to capture each group's building-related requirements across the portfolio. These occupants assess their facilities for their ability to meet their operational priorities. This feedback results in proposed investments to address specific operational demands including, for example, inadequate office and operational space, insufficient material storage space, and undersized truck bays.

6.5.2.2 Properties Capital Investment Delivery Aligns with BC Hydro's Standard Approach

BC Hydro has applied a Portfolio Risk Adjustment to its planned capital expenditures and additions in the Test Period to account for uncertainty in the schedule and cost of projects. The accuracy of planned capital expenditures and additions increases with the level of analysis and information on project scope, schedule and cost. Therefore, the largest uncertainties are associated with projects that are currently in early stages of the project lifecycle, as their scope, schedule and cost are not as well defined as projects that are in later stages. A Portfolio Risk Adjustment of minus 10 per cent is applied to the plan for projects in Identification, Definition, and Implementation.

6.5.2.3 Properties Capital Expenditures and Additions

The following capital expenditures and additions for Building Development and Building Improvement are outlined Table 6-47 and Table 6-48 below.

Table 6-47 Properties Actual and Plan Capital Expenditures (Fiscal 2021 to Fiscal 2025)

($ millions)	F2021	F2022		F2023	F2024	F2025
	Actual	Decision	Forecast	Plan	Plan	Plan
Properties						
Building Development	14.4	53.8	14.4	55.3	62.7	73.1
Building Improvements and Other	41.6	21.8	37.1	28.2	19.0	19.2
Total	56.0	75.6	51.5	83.4	81.7	92.3

Table 6-48 Properties Actual and Plan Capital Additions (Fiscal 2021 to Fiscal 2025)

($ millions)	F2021	F2022		F2023	F2024	F2025
	Actual	Decision	Forecast	Plan	Plan	Plan
Properties						
Building Development	23.5	38.0	2.4	6.6	44.9	6.6
Building Improvements and Other	47.4	21.8	36.1	26.1	21.0	19.1
Total	70.9	59.8	38.5	32.7	65.9	25.7

Properties capital expenditures in the Test Period are planned to be higher than fiscal 2022 primarily due to the delay in commencement of several Building Development projects previously planned to commence in earlier years. Building Development capital expenditure actual forecast and capital additions were lower than planned in fiscal 2021 and fiscal 2022 due to delays in commencement of implementation for multiple projects associated primarily with permit approvals and sourcing suitable land. Building Improvements actual forecast expenditures and additions were higher than planned in fiscal 2021 and fiscal 2022 due to a reprioritization of projects for assets requiring upgrade. Properties' approach is to manage the Building Improvements projects and Building Development projects as a combined Building Projects portfolio. As some projects are delayed, others are advanced, based on changing priorities which may include asset condition or operational requirements.

6.5.2.4 Building Development Projects

The planned capital expenditures and additions for Building Development projects in the Test Period are provided in Table 6-49 and Table 6-50 below.

Table 6-49 Building Development Projects Plan Capital Expenditures for (Fiscal 2023 to Fiscal 2025) ($ millions)

Planning ID	Name of Project	Capital Expenditure Plan F23	Capital Expenditure Plan F24	Capital Expenditure Plan F25
P202103	Prince Rupert Field Building Redevelopment	5.1	-	-
P201704	Materials Classification Facility Building Redevelopment	24.9	6.2	-
P202201	Queen Charlotte City Field Building Redevelopment	2.0	4.6	-
P202102	Mica Staff Accommodations Building Redevelopment	2.0	8.0	3.5
P201703	Chilliwack Field Building Redevelopment	10.0	5.0	11.0
P202001	Campbell River II Field Building Redevelopment	4.5	13.5	14.0
P201902	North Vancouver Field Building Redevelopment	9.0	18.5	13.0
P202102	Cranbrook Field Building Redevelopment	1.0	5.3	11.5
P202101	Duncan Field Building Redevelopment	6.0	4.0	6.5
P201901	Kamloops Field Building Redevelopment	2.5	3.5	19.5
P202401	Fort St. John Field Building Redevelopment	-	1.0	2.0
	Portfolio risk adjustment	(11.7)	(6.9)	(7.9)
	Total Building Development	**55.3**	**62.7**	**73.1**

Table 6-50 Building Development Projects Plan Capital Additions for (Fiscal 2023 to Fiscal 2025) ($ millions)

Planning ID	Name of Project	Capital Addition Plan F23	Capital Addition Plan F24	Capital Addition Plan F25
P202103	Prince Rupert Field Building Redevelopment	6.6		
P201704	Materials Classification Facility Building Redevelopment		44.6	
P202201	Queen Charlotte City Field Building Redevelopment		7.1	
P202102	Mica Staff Accommodations Building Redevelopment	-	-	14.5
P202101	Duncan Field Building Redevelopment	5.0		
	Portfolio risk adjustment	(5.0)	(6.9)	(7.9)
	Total Building Development	**6.6**	**44.9**	**6.6**

Annual capital expenditures on Building Development projects are higher than the fiscal 2022 forecast, as projects in Definition or Identification advance into construction.

6.5.2.5 Building Improvement Projects

The planned capital expenditures and additions for Building Improvement projects in the Test Period are provided in Table 6-51 and Table 6-52 below. There are approximately 35 individual projects planned over the Test Period, at locations across the province. These are grouped below by project type based on the asset categories the individual projects are addressing. Many of these projects are less than $2 million.

Table 6-51 Building Improvement Projects Plan Capital Expenditures (Fiscal 2023 to Fiscal 2025) ($ millions)

Name of Project Type	Capital Expenditure Plan F23	Capital Expenditure Plan F24	Capital Expenditure Plan F25
Building Improvements			
Building Envelope	0.3	0.8	1
Elevators	-	-	-
HVAC	5.6	2.4	4.2
Interiors	7.9	6.3	2.8
Life/Safety	2.9	1.7	0.3
Roof	0.4	3.1	5.6
Storage Buildings	1.8	2.4	3.2
Yard	6.9	2.3	2.1
Portfolio risk adjustment	2.4	0	0
Total Building Improvements and Other	**28.2**	**19.0**	**19.2**

Table 6-52 Building Improvement Projects Plan Capital Additions (Fiscal 2023 to Fiscal 2025) ($ millions)

Name of Project Type	Capital Addition Plan F23	Capital Addition Plan F24	Capital Addition Plan F25
Building Improvements			
Building Envelope	0.3	0.6	0.9
Elevators	-	-	-
HVAC	6.4	3.4	3.7
Interiors	8.6	6.8	3.9
Life/Safety	3.5	2.0	0.7
Roof	1.8	2.3	4.9
Storage Buildings	2.4	2.2	2.9
Yard	7.4	3.7	2.1
Portfolio risk adjustment	(4.3)	0.0	0
Total Building Improvements and Other	**26.1**	**21.0**	**19.1**

Annual capital expenditures on Building Improvements projects are consistent with fiscal 2022 Decision amount, but lower than actual amounts in the F2020-F2021 RRA and Previous Application.

6.5.3 Fleet

Fleet is responsible for the acquisition, maintenance and disposal of BC Hydro's 3,500 vehicle, trailer and equipment assets relied on by field crews and staff across the province to complete the organization's maintenance and capital work programs and support system reliability. The safety, reliability, and availability of vehicles and equipment are critical to ensure BC Hydro employees can safely and efficiently complete diverse types of planned and unplanned work, including restoration work during storms and emergencies.

6.5.3.1 Fleet Investments Are Managed Using Established Industry Principles and Practices

BC Hydro manages the lifecycle of diverse vehicle and equipment assets using established fleet industry principles and practices. These vehicle and equipment assets include light vehicles (cars, SUVs, pickups and compact vans), medium vehicles (flat deck trucks, service body trucks, walk-in and heavy vans), heavy vehicles (bucket trucks, digger derricks, cranes, heavy flat decks, highway tractors, fire trucks, and dump trucks), trailers, forklifts, and other types of equipment (all referred to here as Vehicles and Equipment). The present average age of fleet assets is 6.9 years, with expected planned Vehicle and Equipment lifespans ranging from 10 to 16 years, depending upon asset class. Fleet investments in the Test Period reflect a long-standing approach that accounts for asset condition and aligns to industry standards.

6.5.3.2 Fleet Portfolio Investments

Investments in fleet assets are made to sustain reliable operations across the province, minimize total asset lifecycle costs, ensure fitness of given assets for evolving work purposes, and limit safety and operational risks by meeting safety and other regulatory requirements.

Fleet investments can be of two major types:

- Replacement of end-of-life Vehicles and Equipment to reduce financial risks, control lifecycle costs and address age-related mechanical, safety and reliability issues. These sustaining investments form much of the Fleet capital plan and seek to avoid financial risk of increasing maintenance costs as assets age, including the higher likelihood of costly unplanned maintenance events. It is important to continually maintain the composition of the fleet from the standpoint of average age in order to limit the build-up of high cost, older vehicles and equipment; and
- Providing additional or upgraded fleet assets to improve operational productivity, flexibility and safety. This represents a very small portion of fleet capital investments and includes value-based vehicle and equipment purchases via the upgrading or the addition of new assets in response to changing business needs and work methods.

6.5.3.3 Fleet Assets Capital Planning Has Balanced Affordability and Operational Needs

Fleet Investment Capital Planning for the Test Period was guided by the principle of balancing affordability and vehicle reliability, while providing support to operate our system safely. In its capital planning process, BC Hydro identifies and ranks Vehicles and Equipment for replacement using asset information (asset age/remaining life, mileage, maintenance costs, utilization rates, observed downtime frequency), input from fleet maintenance staff and end-users on asset condition, criticality and operational requirements. End-users also can identify requirements for upgraded or additional fleet assets. This information is used to assemble a list of Vehicles and Equipment for acquisition planning. The process is initiated in advance of the expected end-of-life replacement criteria (i.e., for a vehicle with a 10-year life replacement planning is started at approximately the seven-year mark). The general fleet replacement criteria are established based on historical data, as well as the suggested useful life in a commercial application as determined by BC Hydro fleet data, industry benchmarks and vehicle manufacturers. In addition, the work application and the environmental conditions in which the assets are operated are considered as they have an impact on the actual life of the vehicle.

6.5.3.4 Fleet Capital Expenditures and Additions

Fleet's actual and planned capital expenditures and additions for fiscal 2021 to fiscal 2025 are provided in Table 6-53 and Table 6-54 below.

Table 6-53 Fleet - Vehicle and Equipment Actual and Plan Capital Expenditures (Fiscal 2021 to Fiscal 2025)

($ millions)	F2021	F2022		F2023	F2024	F2025
	Actual	Decision	Forecast	Plan	Plan	Plan
Fleet	31.4	27.2	27.4	42.0	39.6	27.5

Table 6-54 Fleet - Vehicle and Equipment Actual and Plan Capital Additions (Fiscal 2021 to Fiscal 2025)

($ millions)	F2021	F2022		F2023	F2024	F2025
	Actual	Decision	Forecast	Plan	Plan	Plan
Fleet	26.7	27.2	27.4	42.0	39.6	27.5

During the Test Period, Fleet capital expenditures and additions are increasing compared to the fiscal 2022 forecast. This increase reflects the need to mitigate the aging asset base. Fleet will be focusing on end-of-life medium and heavy vehicle replacements, given their criticality to the reliability of the Power System and worker safety.

The planned investment levels are reasonable, based on the age and condition of the fleet assets, expected requirements and mitigation plans.

6.5.4 Business Support and Other Technology Capital Expenditures and Additions

Business Support and Other Technology includes capital expenditures and additions related to oil management operating infrastructure upgrades, Field Operations tools and equipment, Control Centre system upgrades, and workforce training equipment. The individual plans for these different areas except for the upgrades to the oil management operating infrastructure are generally less than $5 million per year.

Business Support and Other Technology Capital actual and planned capital expenditures and additions for fiscal 2021 to fiscal 2025 are provided in Table 6-55 and Table 6-56 below.[460]

Table 6-55 Business Support and Other Technology Actual and Plan Capital Expenditures (Fiscal 2021 to Fiscal 2025)

($ millions)	F2021	F2022		F2023	F2024	F2025
	Actual	Decision	Forecast	Plan	Plan	Plan
Business Support - Other	23.4	43.1	33.3	38.1	36.5	30.1
Other Technology	1.2	0.2	5.3	0.2	-	-

Table 6-56 Business Support and Other Technology Actual and Plan Capital Additions (Fiscal 2021 to Fiscal 2025)

($ millions)	F2021	F2022		F2023	F2024	F2025
	Actual	Decision	Forecast	Plan	Plan	Plan
Business Support - Other	22.7	48.0	35.9	28.3	51.3	29.3
Other Technology	-	6.7	-	11.6	-	-

The Test Period capital expenditures and additions for Business Support include the Materials Management - Oil Management Operating Infrastructure project, which is forecast to start the Implementation Phase in mid-fiscal 2022 and be in-service in fiscal 2024.

[460] Additional information on the projects listed is provided in Appendix I, page 9.

When excluding the Materials Management - Oil Management Operating Infrastructure project, the planned Business Support and Other Technology capital expenditures and additions for the Test Period are comparable to the fiscal 2022 forecast.

The fiscal 2022 capital expenditures and additions forecasts were lower than the fiscal 2022 Decision. This was primarily due to the Materials Management - Oil Management Operating Infrastructure project schedule change and implementation costs forecast being shifted out by one fiscal year, as well as the cancellation of the Learning & Development - Energized Training Substation project as a result of shifting priorities and uncertainty with regard to the site location.

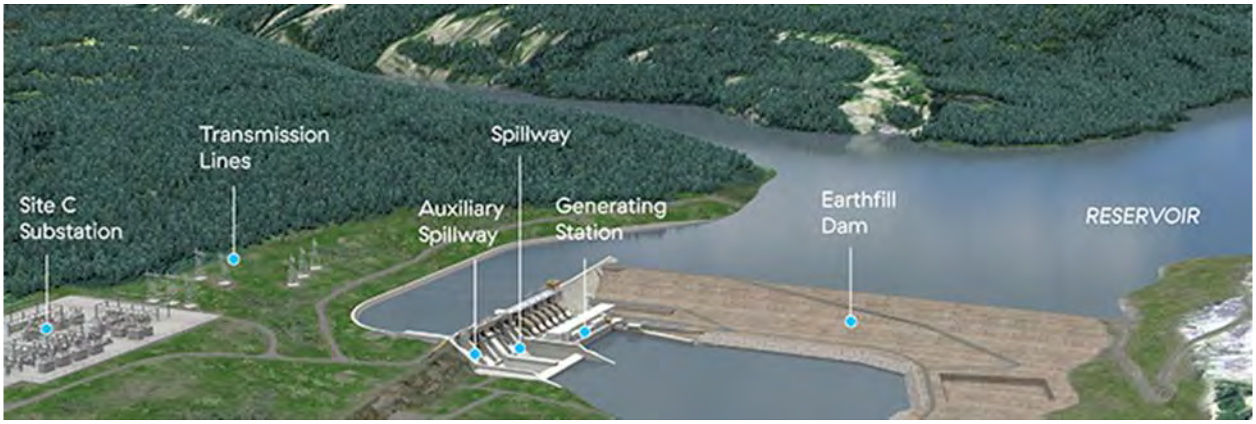
6.6 Site C Project

In this section we provide background information on BC Hydro's Site C Clean Energy Project (**Site C**) and set out the Site C expenditures and capital additions in the Test Period. Site C capital additions planned in this Test Period only begin to affect rates in fiscal 2025.

6.6.1 Project Overview

Site C will be a third dam and hydroelectric generating station on the Peace River in northeast B.C. It will provide 1,100 megawatts (**MW**) of capacity, and produce approximately 5,100 gigawatt hours of electricity each year — enough energy to power the equivalent of about 450,000 homes per year in B.C. As the third project on one river system, Site C will gain significant efficiencies by taking advantage of water already stored in the Williston Reservoir. This means that Site C will generate approximately 35 per cent of the energy produced at W.A.C. Bennett Dam, with only 5 per cent of the reservoir area. Figure 6-11 below provides a high-level overview of the key project components.

Figure 6-11 Site C Key Components



The key components of the Site C project include:

- An earthfill dam, approximately 1,050 metres long and 60 metres high above the riverbed;
- A generating station with six 183 MW generating units;
- An 83-kilometre-long reservoir that will be, on average, two to three times the width of the current river
- Two large diversion tunnels, approximately 750 metres long and 11 metres in diameter, to temporarily reroute the Peace River around the dam site;
- Construction of two temporary cofferdams across the main river channel to allow for construction of the earthfill dam;
- Worker accommodation at the dam site, with other workers being housed off site and in the region;
- The realignment of six segments of Highway 29 over a total distance of 30 kilometres;
- Shoreline protection at Hudson's Hope;
- Two new 500 kilovolt AC transmission lines that will connect the Site C facilities to the existing Peace Canyon Substation, along an existing right-of-way;

- An 800-metre roller-compacted-concrete buttress to enhance seismic protection; and
- Access roads in the vicinity of the site and a temporary construction access bridge across the Peace River at the dam site.

Additional information on the Project can be found on the Site C Clean Energy Project website (sitecproject.com) which was created to provide the public with information regarding Site C including:

- A project overview;
- Updates on construction activities;
- Environmental programs;
- Jobs and business opportunities;
- Our work with Indigenous peoples;
- Voluntary progress reports to the BCUC; and
- News and other information.

6.6.2 Previous Project Approval History

In December 2014, the Project received approval from the Government of B.C. to proceed to construction. In 2017, a BCUC Site C Inquiry was commenced to review the Project. On November 1, 2017, the BCUC issued its final report on the Site C Project. This led to a decision from the Government of B.C., which announced its approval to proceed with the Site C Project on December 11, 2017. As part of this announcement, BC Hydro provided a revised cost estimate of $10.7 billion, consisting of a BC Hydro project budget of $9.992 billion and a project reserve of $0.708 billion subject to Treasury Board control. The total project budget of $10.7 billion was approved in February 2018.

6.6.3 There Have Been Project Cost and Schedule Pressures

Prior to the COVID-19 pandemic, and since the $10.7 billion budget was approved in February 2018, the Project was managing significant financial pressures as reported in the Site C progress reports to the BCUC, due to:

- Amendments to the main civil works contract;
- Additional labour resource requirements;
- First Nations treaty infringement claims and an injunction application;
- Increased costs associated with reservoir clearing, transmission line construction and highway re-alignment work; and
- Additional significant scope and design enhancements to the foundations of the structures on the right bank.

The COVID-19 pandemic, along with the need for foundation enhancements on the right bank to deal with unanticipated geotechnical conditions, has significantly added to these cost pressures. Nonetheless, prior to the COVID-19 pandemic, the project remained on schedule for the first generating unit to go into service in late 2023 and the final unit in 2024.

The COVID-19 pandemic, which started in March 2020, created significant pressures on the project budget and schedule primarily due to BC Hydro not being able to restart and accelerate certain work that was restricted due to the pandemic. This impacted construction activities on Site C as the work was scaled back to only those activities that were critical to achieve river diversion and essential services, such as site safety and security and environmental protection. This decision resulted in a reduction of the work force staying at site by approximately 50 per cent. In May 2020, BC Hydro began safely increasing construction activities at Site C in a gradual phased approach.

In addition, an identified project geological risk materialized on the right bank. Towards the end of December 2019, investigations and analysis of geological mapping and monitoring activities completed during construction identified that foundation enhancements would be required to increase the stability below the powerhouse, spillways and future dam core areas. By early 2020, BC Hydro had determined that significant foundation enhancements were required to increase the stability under the structures on the right bank, including the powerhouse, spillways and future dam core area.

BC Hydro commenced work to re-baseline the project budget starting in July 2020. This process included performing a detailed bottom-up review of both the budget and schedule, which included an updated and revised Cost Risk Analysis and Schedule Risk Analysis, and reviews of the remaining project risks. This re-baseline process included working collaboratively with Ernst & Young Canada as the Independent Project Oversight Advisor.

The Site C Project Assurance Board also commissioned an independent due diligence review to assist it in its evaluation of the technical integrity of the proposed mitigation measures for the right bank foundation issues and to ensure they meet the Canadian Dam Association dam safety guidelines. A second report was also commissioned to review the design of the earthfill dam. These reports concluded the right bank foundation enhancement solutions are appropriate and sound, and will make the right bank structures safe and serviceable over the long operating life of Site C. The report on the earthfill dam concluded this structure can be built safely and meet all Canadian Dam Association dam safety and reliability guidelines.

6.6.4 Revised Site C Project Budget and Schedule

On February 26, 2021, the Government of B.C. announced that the Site C Project would continue with a current cost estimate to complete the Project of $16 billion and includes a new expected final in-service date of 2025 (fiscal 2026), as a result of the delays and impacts of the pandemic. The Government of B.C. approved the current cost estimate of $16 billion in June 2021 as the updated project budget.

The one-year delay due to the COVID-19 pandemic and other costs associated with COVID-19 are the single largest driver to the increase in the cost estimate followed by the additional costs for the foundation enhancement measures. In addition, as noted above, the Project was managing significant financial pressures prior to the COVID-19 pandemic due to other cost drivers. See Table 6-57 below for a comparison between the previously approved Project budget and the revised approved Project budget.

Table 6-57 Previous Project Budget compared to Revised Project Budget ($ millions)

Description	Previous Budget	Revised Project Budget	Change
Dam, Power Facilities and Associated Structures and Transmission (Note 1)	4,548	8,258	3,710
Offsite Works, Direct Construction Supervision and Site Services (Note 2)	1,845	2,895	1,050
Total Direct Construction Cost	**6,393**	**11,153**	**4,760**
Indirect Costs (Note 3)	1,456	2,082	626
Total Construction and Indirect Costs	**7,849**	**13,235**	**5,386**
Interest During Construction	1,285	2,028	743
Contingency / Reserve	1,566	737	(829)
Total	**10,700**	**16,000**	**5,300**

Note 1: Key items included are river diversion infrastructure, earthfill dam and related works, spillways, powerhouse, generation equipment and transmission and substation work.

Note 2: Key items included are highway re-alignment and reservoir related work, direct construction supervision, and site services such as workers accommodation.

Note 3: Key items included are mitigation and compensation programs, development and regulatory costs, project management, engineering and other support services such as project controls, contracts management, environmental, and Indigenous relations.

In February 2021, the Government also released the Site C Project Review, led by Peter Milburn (**Milburn Review**), which included 17 recommendations aimed at improving oversight, governance, risk management, and construction and claims management. BC Hydro accepted all the recommendations and started to implement them as soon as they were received. As of July 2021, 17 of the

17 recommendations are either fully complete (15) or substantially complete (two), and remaining actions will be fully completed in September 2021. Despite the COVID-19 pandemic, the project achieved significant construction milestones. In fall 2020, the Peace River was diverted around the construction site, and the first of two 500 kV transmission lines and the substation were placed into operation. In spring 2021, the upstream and downstream cofferdams were completed which created a dry area for earthfill dam construction across the Peace River.

The project continues to manage significant risks which include: the ongoing COVID-19 pandemic and the potential impacts to on-site construction activities; continued commercial negotiations with contractors; design finalization, procurement and execution of the foundation enhancements; the procurement for the balance of plant contracts; and the ability of the project to attract and retain sufficient skilled workers. The Site C Project continues to work with Mr. Milburn, Ernst & Young Canada, the Technical Advisory Board, the external independent dam experts, and the Project Assurance Board to manage these risks. Despite these risks, our objective is to complete the Project within the approved budget and are actively managing the project to that cost.

6.6.5 Capital Expenditures and Additions

The Site C Project actual and planned capital expenditures and capital additions for fiscal 2021 to fiscal 2025 are provided in Table 6-58 and Table 6-59 below. The Fiscal 2022 Decision amounts in the two tables below were based on forecasts provided prior to the approved budget of $16 billion. The Fiscal 2022 Forecast and Test Period Plan amounts are based on the revised $16 billion budget. More information can be found in Appendix I, page 10, and Appendix J, page 201.

Table 6-58 Site C Actual and Plan Capital Expenditures (Fiscal 2021 to Fiscal 2025)

($ millions)	F2021	F2022		F2023	F2024	F2025
	Actual	Decision	Forecast	Plan	Plan	Plan
Deferred Capital	15.0	27.4	18.5	25.5	26.7	18.3
Construction Capital	1,725.0	1,361.0	2,789.5	2,708.3	1,754.9	1,043.2
Total	1,740.0	1,388.4	2,808.0	2,733.9	1,781.6	1,061.4

Table 6-59 Site C Actual and Plan Capital Additions (Fiscal 2021 to Fiscal 2025)

($ millions)	F2021	F2022		F2023	F2024	F2025
	Actual	Decision	Forecast	Plan	Plan	Plan
Deferred Capital						612.3
Construction Capital	220.9	-	-	-	-	13,977.3
Total	220.9	-	-	-	-	14,589.6

Planned construction capital expenditures of $2.7 billion, $1.8 billion and $1.1 billion are included in the Test Period. Deferred capital costs consist of pre-implementation construction expenditures and other costs not eligible for capitalization.

As noted in Table 6-59 above, there are $14.0 billion construction capital additions planned for fiscal 2025 which are primarily due to the following key assets planned to be in-service:

- First generating unit;
- Earthfill dam and related assets;
- Powerhouse and spillways related assets;
- 2.6-kilometre shoreline protection berm in Hudson's Hope;
- Remaining transmission related assets (including the second, 75 kilometre - 205 tower, 500 kilovolt line); and
- Second generating unit.

Having the first generating unit in-service in December 2024 means that the project would have the ability to start generating electricity for customers and amortization of the above noted key assets and related direct costs and allocations of the infrastructure, indirect and interest-during-construction costs will commence. As the first generating unit is planned to be in-service in December 2024, amortization of these costs in fiscal 2025 are only for a partial year and not for the full year. The useful life of these assets to be placed in-service range from 15 years to 100 years, with a weighted average useful life currently forecasted to be approximately 84 years.

All remaining generating units are planned to be in-service between February 2025 and November 2025 as shown in the Table 6-60below, and amortization will commence on these remaining units as they are placed in-service. The project is on track to meet these in-service dates.

Table 6-60 Planned In-service Dates for All Generating Units

Generating Units	Planned In-service Dates
Unit 1 (first power)	December 2024
Unit 2	February 2025
Unit 3	May 2025
Unit 4	July 2025
Unit 5	September 2025
Unit 6	November 2025

See Chapter 7, section 7.3.3 for the proposed commencement of recovery of the Deferred Capital Additions starting in fiscal 2025.

6.6.6 Key Activities Required Prior to Capital Additions

Prior to the first generating unit coming into service in December 2024, there are several construction activities that need to be substantially completed both on the dam site and off the dam site prior to December 2024.

Activities required on the dam site include completing the earthfill dam, approach channel, powerhouse and spillways; having the first generating unit ready for commissioning; removing the right bank cofferdam; and watering up of the powerhouse and spillway tailraces and converting the diversion tunnels.

Activities required to be completed off the dam site include clearing the reservoir, realignment of Highway 29, and connecting the powerhouse to the substation via transmission lines.

6.7 We Are Investing to Support Electrification

The capital investments in BC Hydro's Capital Plan, as described above within this chapter, and in Appendix I and Appendix J, are aligned with the System Load Forecast dated December 2020. BC Hydro's is also investing capital to support our Electrification Plan as described in Chapter 10. As part of the Electrification Plan, BC Hydro developed a forecast of the incremental capital expenditures and additions required to support the increased loads associated with the Electrification Plan which are not included in the December 2020 System Load Forecast. These incremental capital expenditures and additions are presented in Table 6-61 and Table 6-62 below.

Table 6-61 Electrification Actual and Plan Capital Expenditures (Fiscal 2021 to Fiscal 2025)

($ millions)	F2021	F2022		F2023	F2024	F2025
	Actual	Decision	Forecast	Plan	Plan	Plan
Transmission Growth						
Transmission Load Interconnections - Growth	-	-	3.6	14.6	32.9	29.2
Transmission Regional System Reinforcement - Growth	-	-	2.0	8.0	18.1	16.1
Total Transmission Electrification	-	-	5.5	22.6	51.1	45.3
Distribution Growth						
Distribution System Expansion and Improvement - Growth	-	-	1.0	4.0	9.1	8.0
Distribution Sustain						
Distribution Electric Vehicle Charging Infrastructure - Sustain	-	-	-	2.0	2.0	2.0
Total Distribution Electrification	-	-	1.0	6.0	11.1	10.0
Total Electrification	-	-	6.5	28.7	62.2	55.3

Table 6-62 Electrification Actual and Plan Capital Additions (Fiscal 2021 to Fiscal 2025)

($ millions)	F2021	F2022		F2023	F2024	F2025
	Actual	Decision	Forecast	Plan	Plan	Plan
Transmission Growth						
Transmission Load Interconnections - Growth	-	-	0.3	9.4	18.9	51.7
Transmission Regional System Reinforcement - Growth	-	-	0.2	5.2	10.4	28.4
Total Transmission Electrification	-	-	0.5	14.6	29.2	80.1
Distribution Growth						
Distribution System Expansion and Improvement - Growth	-	-	0.2	1.6	5.0	8.9
Distribution Sustain						
Distribution Electric Vehicle Charging Infrastructure - Sustain	-	-	-	1.6	2.0	2.0
Total Distribution Electrification	-	-	0.2	3.2	7.0	10.9
Total Electrification	-	-	0.7	17.8	36.3	91.0

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

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

Section 10.4.2.4 of Chapter 10 describes these incremental investments and explains the methodology and assumptions for the capital expenditures included in the Electrification Plan. Chapter 10 also describes how these investments are cost effective and will benefit ratepayers.

These investments were not included in BC Hydro's Capital Plan that was presented to the Capital Projects Committee in June 2021, however they are included in the financial forecast that underpins this application. According to BC Hydro's governance for adding investments to the Capital Plan, these investments will either be initiated as ex-plan investments[461] or added to future capital plans, with an adjustment to the budget, as part of BC Hydro's annual capital planning process. We

[461] BC Hydro's ex-plan process is described in Appendix N, section 1.5.

will not be displacing capital investments in the Capital Plan to facilitate these incremental investments to support electrification.

BC Hydro Fiscal 2023 to Fiscal 2025

Revenue Requirements Application

Chapter 7

Regulatory Accounts

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7.1 Introduction

This chapter describes BC Hydro's use of deferral and regulatory accounts (collectively referred to as regulatory accounts) and our proposals to change or close those accounts or to establish new regulatory accounts.

The general purpose of a regulatory account is to defer costs or revenues for future recovery or refund. In the absence of rate-regulated accounting, these costs or revenues would be recognized in the current accounting period. Regulatory accounts can either be regulatory assets (amounts to be recovered from ratepayers) or regulatory liabilities (amounts to be refunded to ratepayers). Regulatory accounts are not debt, though BC Hydro has often incurred debt to fund the expenditures in regulatory accounts that have not yet been recovered from ratepayers.

BC Hydro's use of regulatory accounts is in accordance with International Financial Reporting Standards (**IFRS**) and in compliance with BCUC Orders and government guidelines. Rate-regulated accounting is permitted under IFRS 14, *Regulatory Deferral Accounts*.

As shown in Figure 7-1 below, BC Hydro's total regulatory account balance has been on a downward trend since peaking in fiscal 2016. It is forecast to continue downward over the Test Period.

Figure 7-1 Regulatory Account Balances Fiscal 2020 to Fiscal 2021 Actual and Fiscal 2022 to Fiscal 2030 Forecast

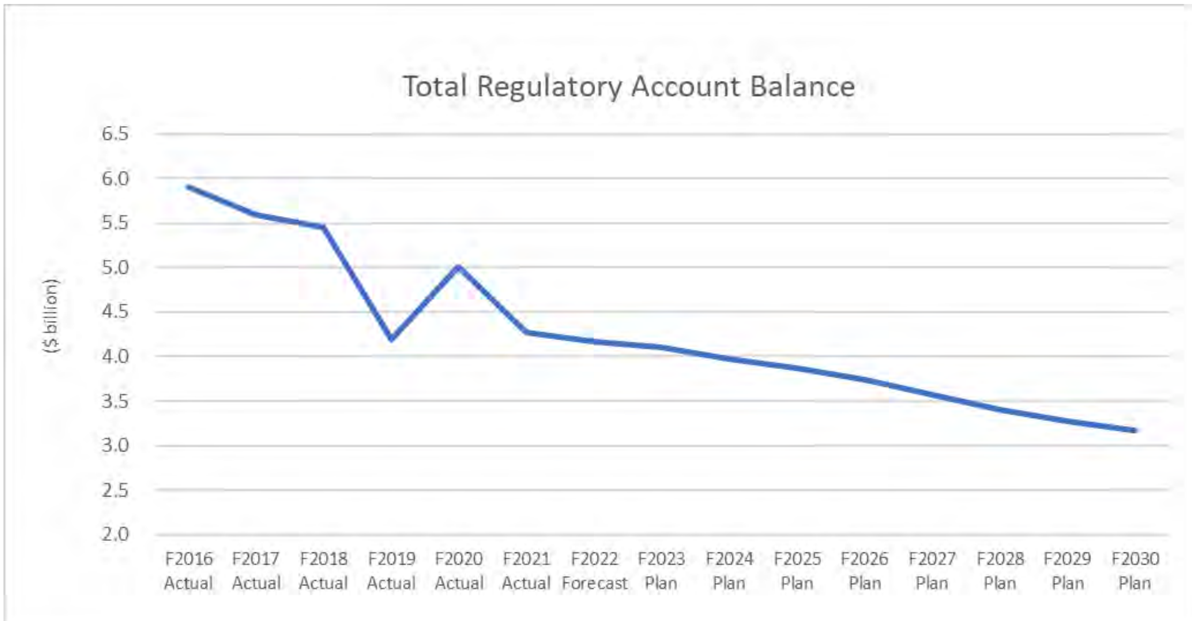

Figure 7-1 above shows BC Hydro's total net regulatory account balance is forecast to be reduced to $4.2 billion at the end of fiscal 2022 (a reduction of $1.7 billion or 30 per cent from the peak) and to $3.2 billion at the end of fiscal 2030. In addition, with this application, BC Hydro has or has proposed regulatory mechanisms to recover the balances of all of its regulatory accounts in rates.

This chapter is organized around the following points:

- Section 7.2 summarizes BCUC Directives in respect of regulatory accounts and references where we have addressed each Directive in the Application;
- Section 7.3 describes BC Hydro's requests related to regulatory accounts in the Application, which are limited, and outlines the reasons for each request;
- Section 7.4 explains that BC Hydro's use of regulatory accounts is in accordance with IFRS and in compliance with BCUC Orders;

- Section 7.5 presents our actual and forecast regulatory account balances from fiscal 2021 to fiscal 2025 and our plan to manage the balances. Our plan shows that we are forecasting a significant decrease in the regulatory account balances; and
- Section 7.6 discusses the impacts of the COVID-19 pandemic on BC Hydro's regulatory accounts. For example, COVID-19 resulted in reduced customer load, the impact of which was deferred.

BC Hydro provides a description of each of its existing regulatory accounts, types of regulatory accounts and the application of interest to existing regulatory accounts in Appendix R of the Application. Additional information on the balances in the regulatory accounts is also provided in Appendix A, Schedules 2.1 and 2.2.

7.2 BC Hydro is Responding to BCUC Directives on Regulatory Accounts

Table 7-1 below provides a summary of BCUC Directives (from the Previous Application and F2020-F2021 RRA (F2020-F2021 RRA) Decisions) and references where we have addressed each Directive in the Application.

Table 7-1 Summary of BCUC Directives from the Previous Application and F2020-F2021 RRA

No.	Directive/Recommendation	Reference
Applicable Directives from BCUC's Decision on the Previous Application and Order No. G-187-21		
14	Therefore, the Panel approves the recovery of the balances in the Cost of Energy Variance Accounts through the proposed DARR table mechanism for F2022 only. Using this approach, the DARR percentage is set at 0 % as of April 1, 2021 for F2022.	Section 7.3.3.3
15	Therefore, the Panel directs BC Hydro to establish a new regulatory account to capture the variances arising in F2022 as a result of any changes to the depreciation expense determined in the depreciation study, with interest charges being on the same basis as previously approved for the Amortization of Capital Additions Regulatory Account. The Panel further directs BC Hydro to propose a recovery mechanism for this new regulatory account in its F2023 RRA.	Section 7.4 and Appendix R, section 3.4

No.	Directive/Recommendation	Reference
16	The Panel approves the following requests with respect to BC Hydro's regulatory accounts: To continue to defer any variances between forecast and actual dismantling costs in F2022 to the Dismantling Cost Regulatory Account; continue to apply interest to the balance of the account each year based on BC Hydro's current weighted average cost of debt; continue to recover the forecast interest charged to the account each year from the account each year; and, continue to recover the forecast account balance at the end of a test period over the next test period. To recover amounts deferred to the Project Write-off Costs Regulatory Account in respect of completed fiscal years over the next test period, starting in F2022 and on an ongoing basis, subject to BCUC review and approval of the recovery of these amounts; apply interest to the balance of the account based on BC Hydro's current weighted average cost of debt; and, recover actual interest charged to the account for amounts related to any completed fiscal years over the next test period.	Section 7.3.3.2 and Appendix R, section 3.8 Reflected in account description in Appendix R, section 3.11
17	The Panel approves the closure of the Rock Bay Remediation Regulatory Account at the end of F2022, or a subsequent fiscal year, when the account balance is zero.	Section 7.4
20	The Panel directs BC Hydro to provide in its F2023 RRA a discussion of whether Low Carbon Electrification (**LCE**) expenditures deferred to the Demand Side Management (**DSM**) Regulatory Account should be recovered only from the beneficiaries of these expenditures, and if so by what methods this could be accomplished.	Section 7.3.3.9 and Chapter 10, section 10.3.2
24	Therefore, the Panel approves the establishment of the Electric Vehicle (**EV**) Costs Regulatory Account to defer any actual operating costs, depreciation, and cost of energy amounts related to BC Hydro's EV charging stations that meet the definition of a prescribed undertaking under the GGRR for F2020 and F2021. The Panel also approves BC Hydro's request to apply interest to the balance of the account based on BC Hydro's current weighted average cost of debt. However, the Panel denies BC Hydro's request to recover from the account each year the forecast interest charged to the account each year. Further, the Panel also denies BC Hydro's request to, starting in F2022, recover the forecast account balance at the end of a test period over the next test period. BC Hydro is directed to apply for a recovery mechanism for the account in its F2023 RRA. The Panel also directs BC Hydro to remove from its revenue requirement all F2022 costs related to its EV charging stations that meet the definition of a prescribed undertaking under the GGRR and defer these costs to the Electric Vehicle Costs Regulatory Account.	Section 7.3.3.8

No.	Directive/Recommendation	Reference
Applicable Directives from BCUC's F2020-F2021 RRA Decision and Order No. G-246-20		
41	Therefore, the Panel disallows BC Hydro's forecast of $10 million net gains in each of fiscal 2020 and fiscal 2021 and instead allows forecast net gains of $0 in the Test Period from the sale of surplus real property. Given the Panel's concern with the balance that has already accumulated in the Real Property Sales regulatory account, if a balance recoverable from ratepayers is still expected to exist in this account at the end of the next test period, the Panel directs BC Hydro to provide in its Fiscal 2023 RRA, a proposal on how it plans to recover the balance from ratepayers.	Section 7.3.3.7
48	Therefore, we approve BC Hydro's request to defer low carbon electrification expenditures up to the undertaking costs to the DSM Regulatory Account. Since the DSM Regulatory Account will now include non-traditional DSM expenditures, the Panel sees value in increasing the transparency of the regulatory account and therefore, directs BC Hydro to separately track these expenditures in the DSM Regulatory Account.	Appendix A, Schedule 2.2
55	Therefore, the Panel directs BC Hydro to provide in all future RRAs an updated Debt Management Regulatory Account Annual Status Report as provided in its Annual Report to the BCUC.	Appendix S

7.3 BC Hydro's Proposed Changes to Regulatory Accounts

BC Hydro is requesting approval for the following changes to regulatory accounts and is providing information on other accounts currently under review in separate applications as follows:

- Section 7.3.1- The establishment of one new regulatory account – the Load Attraction Costs Regulatory Account;
- Section 7.3.2 - Changes to two existing regulatory account – the Mandatory Reliability Standards Costs Regulatory Account and the Dismantling Cost Regulatory Account;
- Section 7.3.3 – The establishment of a recovery mechanism for eight regulatory accounts – Low Carbon Fuel Credit Regulatory Account, Fiscal 2022 Depreciation Study Impact Regulatory Account, the Cost of Energy Variance Accounts, the Site C Regulatory Account, the Customer Crisis Fund Regulatory

Account, the Mining Customer Payment Plan Regulatory Account, the Real Property Sales Regulatory Account, and the Electric Vehicle Costs Regulatory Account. This section also confirms that BC Hydro proposes no changes in respect of the recovery of the DSM Regulatory Account and references a discussion in section 10.4.3 of Chapter 10 that responds to the BCUC direction on this topic; and

- Section 7.3.4 – Account currently under review - BC Hydro also recently filed a separate application proposing an additional new regulatory account - the Mandatory Reliability Standards Costs Regulatory Account.[462]

The sections below provide the rationale for the one proposed new regulatory account and changes to existing regulatory accounts. A description of each regulatory account that existed and was approved by the BCUC prior to this application can be found in Appendix R.

7.3.1 BC Hydro Is Proposing Only One New Regulatory Account

7.3.1.1 Load Attraction Costs Regulatory Account

BC Hydro is proposing the establishment of the Load Attraction Costs Regulatory Account as a new benefit matching account for Load Attraction costs. As described below, the new account aligns with the BCUC's Regulatory Account Checklist criteria for benefit matching accounts.

Load Attraction is one of three components of the Electrification Plan described in Chapter 10. As discussed in Chapter 10, section 10.3, Load Attraction includes the BC Hydro Load Attraction Program and the Brownfield and BC Hydro Owned Asset Optimization Program. These Load Attraction programs aim to attract new load to BC Hydro's system, with a focus on industries such as mining, data centres, crypto-currency, carbon capture, synthetic fuel production and hydrogen.

[462] This account is being reviewed in the Application for Approval of Mandatory Reliability Standards Costs Regulatory Account for fiscal 2022 filed on August 31, 2021

Load Attraction contributes to the benefits of the Electrification Plan discussed in Chapter 10, section 10.2, by reducing rate increases to customers by attracting new electrical load while BC Hydro has an energy surplus. Specifically, projects that proceed and connect to BC Hydro's grid will produce a positive Net Present Value (**NPV**) as shown in Appendix U, Table 8 and favourable benefit cost ratio over both the surplus period and over the effective measure life of the program. The projects will provide benefits over the average load weighted life of the projects, which is estimated at 22 years as presented in Chapter 10, section 10.4.3.3.

Although Load Attraction provides future benefits to customers over a weighted average load-weighted life of 22 years, the expenditures for Load Attraction do not meet the IFRS criteria for capitalization as Intangible Assets under IAS 38, *Intangible Assets.* Therefore, the Load Attraction expenditures would be required to be expensed as incurred operating expenses under IFRS in the absence of regulatory accounting treatment under IFRS 14. If these Load Attraction costs are expensed as incurred, it would create a misalignment between the rate impacts (felt by current ratepayers) and the benefits of the projects (the expected benefit period of 22 years). Therefore, BC Hydro is proposing the establishment of a new benefit matching accountfor these costs named the Load Attraction Cost Regulatory Account.

Benefit matching: The BCUC Regulatory Account Filing Checklist identifies benefit matching accounts as an appropriate type of regulatory account that defers recovery of costs that under Generally Accepted Accounting Standards would otherwise be required to be expensed in the current accounting period to a future period (when the benefits of those costs are realized), if they provide long-term benefits to current and future ratepayers. BC Hydro currently uses benefits matching accounts as described in Appendix R, section 1.2, including the DSM Regulatory Account.

Section IV of the BCUC Regulatory Account Filing Checklist includes the following criteria for assessing whether a regulatory account is appropriate:

(a) Whether, or to what extent, the item is outside of management's control;

(b) The degree of forecast uncertainty associated with the item;

(c) The materiality of the costs; and

(d) Any impact on intergenerational equity.

With respect to BCUC criteria (a) and (b), the majority of the Load Attraction costs will be linked to potential customer projects. For example, Load Attraction incentives will not be authorized until the customer has made a decision to proceed. While BC Hydro has the power to influence whether projects proceed, due to geopolitical or macroeconomic influences (e.g., global commodity prices) there is a risk that projects will not proceed. Therefore, whether a customer project proceeds is ultimately not within management's control. Given this ultimate lack of control and consequent uncertainty, it is appropriate to defer Load Attraction costs to a regulatory account.

With respect to BCUC criteria (c), materiality, the forecast Load Attraction costs over the Test Period and over the five-year term of the program are $27 million and $52 million, respectively. As such, BC Hydro believes the costs are material, which favours deferral.

With respect to BCUC criteria (d), impact on intergenerational equity, the Load Attraction costs are expected to be incurred over a period of five years but provide benefits to ratepayers over an estimated 22 years. Therefore, the expensing of the costs as incurred would cause intergenerational inequity, while the deferral and amortizing of the costs would increase intergenerational equity.

Types of costs included in account: The forecast Load Attraction expenditures over the term of the program are in the following categories:

- Opportunity and feasibility assessments;

- Incentives to offset customer costs of interconnection studies (transmission) and detailed design and engineering (distribution);
- Incentives to offset customer costs (contributions) for BC Hydro interconnection capital;
- Incentives to offset customer costs of electrification (interconnection costs on customer side of meter, other on-site upgrades); and
- Public awareness.

BC Hydro proposes to defer to the Load Attraction Costs Regulatory Account actual incremental labour and contractor costs to deliver the load attraction program, advertising costs, and incentives to offset customer costs in the categories listed above. Load Attraction costs eligible for capitalization will be capitalized and will not be captured in this account.

Amortization period of 20 years: Although the load-weighted average expected benefit period is 22 years, BC Hydro is proposing to use a 20-year amortization period for each year of expenditures to be conservative and to account for the uncertainty of these new loads. BC Hydro proposes that the forecast expenditure by fiscal year (vintage balance) be amortized over 20 years commencing the year following the forecast expenditures. As actual expenditures will differ from forecast expenditures in a test period, the forecast account balance at the end of a test period related to the difference between the amortization of the forecast annual expenditures and the calculation of amortization based on the actual annual expenditures during that test period, will be recovered over the next test period to ensure that ratepayers pay the actual costs over time.

Financing costs: As cash expenditures will be deferred to this account that BC Hydro is required to finance, BC Hydro proposes that interest at the weighted average cost of debt rate apply to the account consistent with BC Hydro's approach for application of interest as described in Appendix R, section 2. Forecast interest charged to the account is proposed to be amortized from the account each year and the forecast account balance at the end of a test period related to the difference between the forecast interest recovered and the actual interest charged to the account during that test period be recovered over the next test period.

Therefore, BC Hydro requests BCUC approval to establish a new Load Attraction Costs Regulatory Account to:

- Defer actual load attraction operating costs to this account each year beginning in fiscal 2023 and ending in fiscal 2027;
- Apply interest to the balance of the account based on BC Hydro’s current weighted average cost of debt;
- Amortize forecast interest charged on the account each year from the account each year;
- Amortize the forecast annual operating cost amount from the account, starting the fiscal year following the expenditures, into rates over the benefit period of 20 years;
- Recover over the next test period, the forecast account balance at the end of a test period related to the difference between the amortization of the forecast annual load attraction operating cost amount and the calculation of the amortization based on the actual annual load attraction operating cost amounts; and
- Recover over the next test period, the forecast account balance at the end of a test period related to the difference between the forecast interest recovered and the actual interest charged to the account during that test period.

7.3.2 BC Hydro Is Proposing Changes to the following Regulatory Accounts

7.3.2.1 Mandatory Reliability Standards Costs Regulatory Account

In the Application for Approval of Mandatory Reliability Standards Costs Regulatory Account for fiscal 2022 filed on August 31, 2021, BC Hydro applied for BCUC approval of a new MRS Costs Regulatory Account for fiscal 2022 to capture certain actual unplanned costs expected to be incurred in fiscal 2022 associated with MRS, recover the forecast balance over the Test Period, and to apply interest to the account.

MRS will continue to evolve, and we expect that there will continue to be unplanned costs to implement and maintain compliance with MRS requirements for the foreseeable future. Therefore, BC Hydro is seeking BCUC approval in this application for the continued use of the MRS Costs Regulatory Account for fiscal 2023 and future years. Effective starting in fiscal 2023, BC Hydro proposes that the scope of the MRS Costs Regulatory Account include costs associated with the following items, as required:

- Unplanned costs related to the implementation of new or revised MRS adopted as a result of a future Assessment Report filed with the BCUC where the BCUC's adoption of such new or changed MRS occurred too late to be reflected in our forecast for the test period; and
- Unplanned costs incurred in a test period to address possible non-compliances with MRS, if and as required, where the work related to such possible non-compliances was identified too late to be reflected in our forecast for the test period. BC Hydro notes that this does not include any penalties assessed against BC Hydro, which are to the account of the shareholder.

At present, BC Hydro is aware of one item, which was determined to be required subsequent to the completion of the forecast for this application, meeting the criteria above, that is expected to result in unplanned work and costs in fiscal 2023.

Specifically, BC Hydro expects to incur unplanned compliance-related costs during fiscal 2023 as a result of certain mitigation activities discussed in confidential Appendix JJ of the Application. While the specific nature of costs is confidential, our preliminary estimate of these costs is approximately $5 million. Consistent with the above proposal, we would defer actual amounts incurred (not forecast amounts) to the MRS Costs Regulatory Account.

Regarding recovery of any balance in the MRS Costs Regulatory Account, BC Hydro proposes to provide the total actual MRS costs deferred, including supporting details, in a subsequent revenue requirements application to enable the BCUC to determine the extent of cost recovery. BC Hydro would reflect the costs, attributable to completed fiscal years, in proposed rates for that future test period, but recovery would be subject to BCUC review of the details provided. BC Hydro notes that some information may be confidential.

Therefore, BC Hydro requests BCUC approval to:

- Defer actual unplanned MRS costs to the MRS Costs Regulatory Account, effective in fiscal 2023 and on an ongoing basis,
  - Related to the implementation of new or revised MRS adopted as a result of a future Assessment Report filed with the BCUC where the BCUC's adoption of such new or revised MRS occurred too late to be reflected in the forecast for the test period; and
  - Incurred in a test period to address possible non-compliances with MRS, if and as required, where the work related to such possible non-compliance was identified too late to be reflected in the forecast for the test period. BC Hydro notes that this does not include any penalties assessed against BC Hydro, which are to the account of the shareholder.
- Recover amounts deferred to the MRS Costs Regulatory Account in respect of completed fiscal years, including any under/over recovered balance from

fiscal 2022, over the next test period, starting in fiscal 2026 and on an ongoing basis, subject to BCUC review and approval of these amounts;

- Apply interest to the balance of the account based on BC Hydro's weighted average cost of debt; and
- Recover actual interest charged to the account for amounts related to any completed fiscal years over the next test period.

7.3.2.2 Dismantling Cost Regulatory Account

In its Decision G-246-20 on BC Hydro's F2020-F2021 RRA, the BCUC directed BC Hydro to provide in its Previous Application an assessment of whether its current practice of expensing dismantling costs as they occur would result in intergenerational inequity and to provide options on how to better promote intergenerational equity. The BCUC also directed BC Hydro to include in its upcoming depreciation study a net salvage study and, in the RRA immediately after the completion of the depreciation and net salvage studies, report on the results and recommendations, as well as BC Hydro's plan to implement those recommendations.

In its Decision on BC Hydro's Previous Application, the BCUC accepted BC Hydro's view that a net salvage report was required to analyze and compare the different approaches to recovering forecast dismantling costs and accepted that the net salvage report would be filed in this application.

In Chapter 8, section 8.4, BC Hydro provides the result of the net salvage study and the recommendations of its depreciation consultant for recovery of dismantling costs in rates. As discussed in Chapter 8, BC Hydro proposes to adopt net salvage using a phase-in approach beginning in the next test period.

Until BC Hydro implements net salvage rates in the next test period, BC Hydro proposes to continue to defer variances between forecast and actual dismantling costs to the Dismantling Cost Regulatory Account for fiscal 2023 to fiscal 2025.

Therefore, BC Hydro requests BCUC approval to:

- Continue to defer any variances between forecast and actual dismantling costs in fiscal 2023 to fiscal 2025 to the Dismantling Cost Regulatory Account;
- Continue to apply interest to the balance of the account each year based on BC Hydro's current weighted average cost of debt;
- Continue to recover the forecast interest charged to the account each year from the account each year; and
- Continue to recover the forecast account balance at the end of a test period over the next test period.

7.3.3 Recovery Mechanisms

BC Hydro is proposing recovery mechanisms for the accounts listed in this section and, with this application, BC Hydro has or has proposed recovery mechanisms to recover the balances of all of its regulatory accounts in rates. This section also confirms that BC Hydro proposes no changes in respect of the recovery of the DSM Regulatory Account and references a discussion in Chapter 10, section 10.4.3, that responds to the BCUC direction on this topic.

7.3.3.1 Low Carbon Fuel Credits Regulatory Account

In Order No. G-248-21, the BCUC approved the establishment of the Low Carbon Fuel Credits Regulatory Account to capture, on an ongoing basis, the difference between forecast and actual miscellaneous revenue from low carbon fuel credits, and apply interest on the balance of the account based on BC Hydro's current weighted average cost of debt. In Order No. G-248-21, the BCUC also directed BC Hydro to include in this application for review by the BCUC, a discussion of the Low Carbon Fuel Credits Variance Regulatory Account balance and a request for an amortization method for the account balance. There is no forecast balance in the account for the Test Period.

As the low carbon fuel credit revenues recognized by BC Hydro are a result of transfers to Powerex based on a transfer pricing agreement, low carbon fuel credit variances experienced by BC Hydro are offset by variances in Trade Income. Trade Income variances are deferred to the Trade Income Deferral Account and recovered using the DARR mechanism. BC Hydro proposes to classify the Low Carbon Fuel Credits Regulatory Account as a Cost of Energy variance account and recover the Low Carbon Fuel Credits Regulatory Account balance using the DARR mechanism. This treatment will ensure the BC Hydro and Powerex variances are both recovered/refunded to ratepayers over the same term. BC Hydro is requesting a return to the DARR table mechanism in section 7.3.3.3 below.

Therefore, BC Hydro requests BCUC approval to:

- Recover the balance of the Low Carbon Fuel Credits Regulatory Account through the DARR mechanism.

7.3.3.2 Fiscal 2022 Depreciation Study Impact Regulatory Account

In its Decision on the Previous Application, Directive 15,[463] the BCUC directed BC Hydro to establish a new regulatory account to capture the variances arising in fiscal 2022 as a result of any changes to the depreciation expense determined in the depreciation study and to apply interest to this account based on BC Hydro's weighted average cost of debt.

As directed by the BCUC, BC Hydro is requesting a recovery mechanism for the account. BC Hydro proposes to recover the forecast balance of the account at March 31, 2022 over the Test Period. If there is a balance remaining at the end of the Test Period, as a result of actual amounts being different than the forecast amount, BC Hydro proposes to recover the remaining balance over the following test period.

[463] BCUC Decision on Previous Application, June 17, 2021, pages 68 to 69.

Therefore, BC Hydro requests BCUC approval to:

- Recover the forecast March 31, 2022 balance for the Fiscal 2022 Depreciation Study Impact Regulatory Account over the Test Period;
- Apply interest to the balance of the account each year based on BC Hydro's current weighted average cost of debt; and
- Recover the forecast interest charged to the account each year beginning in fiscal 2023; and
- Recover any remaining balance at the end of the Test Period, as a result of actual amounts being different than the forecast amount, over the following test period.

7.3.3.3 Cost of Energy Variance Accounts

BC Hydro has six[464] Cost of Energy Variance Accounts that capture the differences between forecast and actual revenues and costs for recovery or refund to ratepayers in future periods: the Heritage Deferral Account, the Non Heritage Deferral Account, the Load Variance Regulatory Account, the Biomass Energy Program Variance Regulatory Account, the Low Carbon Fuel Credits Variance Regulatory Account and the Trade Income Deferral Account.

In the Previous Application, BC Hydro proposed to return to the DARR table mechanism to recover the balances in the Cost of Energy Variance Accounts going forward, but also proposed to determine the level of the DARR based on the forecast net balance of the Cost of Energy Variance Accounts at the end of the preceding fiscal year. In its Decision on the Previous Application, Directive 14,[465] the BCUC approved the recovery of the balance of the Cost of Energy Variance Accounts through the DARR table mechanism for fiscal 2022 only, but noted that the

[464] Includes Low Carbon Fuel Credit Variance Regulatory Account.
[465] BCUC Decision on Previous Application, June 17, 2021, page 67.

streamlined manner in which the Application was reviewed meant that not all of the significant issues related to the mechanism could be examined fully.

Therefore, in this application, BC Hydro is proposing to return to the DARR table mechanism to recover the balances in the Cost of Energy Variance Accounts going forward. The DARR table mechanism continues to provide a principled and structured approach to clearing the net balances in the Cost of Energy Variance Accounts in a reasonable and transparent manner. The DARR continues to meet the following objectives set out for the DARR in the Fiscal 2009 to Fiscal 2010 Revenue Requirements Application which BC Hydro considers remain valid:

1. Minimize intergenerational inequity by being responsive to the changing net balance in the Cost of Energy Variance Accounts;
2. Maintain rate stability for customers to the extent practicable; and
3. Be administratively simple and transparent.

The estimated amortization period for the balance in the Cost of Energy Variance Accounts using the DARR table mechanism typically remains between four to six years. This is consistent with minimizing intergenerational inequity while maintaining rate stability.

BC Hydro performed an evaluation of the mechanism and alternatives during the Fiscal 2009 to Fiscal 2010 Revenue Requirements Application and Fiscal 2012 to Fiscal 2014 Revenue Requirements Application and concluded in the Fiscal 2012 to Fiscal 2014 Revenue Requirements Application that the alternatives were either not a satisfactory way to clear the balances, created more volatility or were more administratively complex than the proposed mechanism. In BC Hydro’s response to BCSEA IR 1.13.1 in the Previous Application, BC Hydro’s modelling showed that the proposed DARR table mechanism clears balances of $250 million, $500 million and $750 million within four to six years and that an atypical balance of $1 billion clears in seven years. Considering the previous analysis performed, BC Hydro considers that the DARR table mechanism continues to meet the objectives noted above and provides a structured and transparent approach to clearing the balances in the Cost of Energy Variance Accounts.

In its Decision on the Previous Application, the BCUC commented as follows:

> The Panel is not persuaded that the 5 percent cap proposed in the DARR table mechanism is necessary to avoid the potential for rate shock. While the Panel recognizes that the proposed cap could provide some certainty to ratepayers, it is nonetheless concerned that the proposed cap could result in significant Cost of Energy Variance Account balances not being cleared quickly enough.

BC Hydro considers that capping the DARR percentage at +/- 5 per cent achieves a reasonable balance between maintaining rate stability, avoiding potential rate shock and minimizing intergenerational inequity. As noted above, BC Hydro modeling shows that a balance of $750 million clears in six years and an atypical balance of $1 billion clears in seven years which BC Hydro considers to achieve a reasonable balance between maintaining rate stability, avoiding potential rate shock and minimizing intergenerational inequity. BC Hydro considers that having a higher (or no) cap to clear the balances faster could lead to volatility and even rate shock and would outweigh any benefits in terms of intergenerational equity.

BC Hydro notes that if the BCUC agrees with the proposed DARR table mechanism, BC Hydro is still required to seek BCUC approval for its proposed rate increases and specifically requested DARR percentages in its revenue requirements applications. The BCUC may choose to approve, deny or alter BC Hydro's DARR proposal and/or the DARR mechanism in any such application. The need to seek approval of the DARR percentage in a case where the forecast net balance is expected to exceed $500 million (as posed in the BCSEA IR 1.13.1 from the Previous Application proceeding) would involve essentially the same process.

The DARR table mechanism is shown in Table 7-2.

Table 7-2 Deferral Account Rate Rider Table Mechanism

Forecast Net Balance at the end of the Preceding Fiscal Year		% Rate Rider Effective Following April 1
> $ million	<= $ million	
-	(500)	(5.0)
(500)	(450)	(4.5)
(450)	(400)	(4.0)
(400)	(350)	(3.5)
(350)	(300)	(3.0)
(300)	(250)	(2.5)
(250)	(200)	(2.0)
(200)	(150)	(1.5)
(150)	(100)	(1.0)
(100)	(50)	(0.5)
(50)	0	0.0
0	50	0.0
50	100	0.5
100	150	1.0
150	200	1.5
200	250	2.0
250	300	2.5
300	350	3.0
350	400	3.5
400	450	4.0
450	500	4.5
500	-	5.0

As shown in Table 7-5 in section 7.5, the forecast net balance in the Cost of Energy Variance Accounts is as follows:

- ($220) million at the end of fiscal 2022;
- (121) million at the end of fiscal 2023; and
- ($72) million at the end of fiscal 2024.

Applying the DARR table mechanism, the DARR would be set at (2.0) per cent for fiscal 2023, (1.0) per cent for fiscal 2024 and (0.5) per cent for fiscal 2025.

Therefore, BC Hydro requests BCUC approval to:

- Recover the balances in the Cost of Energy Variance Accounts through the DARR using the DARR table mechanism as described in this section: specifically, starting in fiscal 2023 and on an ongoing basis, set the DARR percentage effective April 1 of a given year based on the percentage in the DARR table mechanism corresponding to the forecast net balance of the Cost of Energy Variance Accounts at the end of the preceding fiscal year; and
- To refund the balances in the Cost of Energy Variance Accounts through the DARR using the DARR table mechanism and set the DARR at:
  - (2.0) per cent for fiscal 2023;
  - (1.0) per cent for fiscal 2024; and
  - (0.5) per cent for fiscal 2025.

7.3.3.4 Site C Regulatory Account

The Site C Regulatory Account was created to match the recovery of Site C costs not eligible for capitalization with the benefits that the project will produce over its useful life. As discussed in Chapter 6, section 6.6.5, BC Hydro expects Unit 1 of the Site C project to come into service in December 2024 and Unit 2 in February 2025. There are $14.0 billion in Site C capital additions forecast during fiscal 2025 that are identified in Chapter 6, Table 6-59 and described following that table. Thus, ratepayers will begin to receive benefits of Site C at that time.

Accordingly, BC Hydro proposes to commence recovery of the forecast balance of $613 million in the Site C Regulatory Account on January 1, 2025. BC Hydro proposes to recover the balance over 84 years, which is the forecast weighted average expected useful life of the Site C assets. More information regarding the basis for the 84-year useful life can be found in Chapter 6, section 6.6.5.

In order to ensure that ratepayers will ultimately be charged the actual costs deferred to the Site C regulatory account, on an ongoing basis BC Hydro proposes to amortize the forecast balance in the Site C Regulatory Account at the end of the prior test period over the remaining weighted average useful life. For example, the forecast balance at the end of fiscal 2025 as determined for the test period beginning fiscal 2026 will be amortized over the remaining average useful life of 83.75 (being 84 less the 0.25 years of amortization taken in the fiscal 2023 to fiscal 2025 Test Period). As the Site C project will be fully in-service during the test period beginning fiscal 2026, the actual balance in the Site C regulatory Account will be known for future test periods and will be appropriately amortized.

Pursuant to existing BCUC orders, BC Hydro will continue to defer any costs related to the Site C Project that are not able to be capitalized under IFRS and apply interest at BC Hydro's weighted cost of debt until all Site C units are placed in-service.

BC Hydro's proposed approach of leaving the Test Period rates interim at the conclusion of this proceeding pending the BCUC's future consideration of the recoverability of Site C capital and deferred costs will ensure that final rates in the Test Period will reflect the appropriate amortization irrespective of the approval of this proposed Site C Regulatory Account recovery mechanism. Customers will be kept whole.

Therefore, BC Hydro requests BCUC approval to:

- Commence recovery of the forecast balance in the Site C Regulatory account as at December 31, 2024 on January 1, 2025 over the forecast weighted average life of the Site C assets of 84 years; and
- On an ongoing basis commencing in the test period beginning in fiscal 2026, amortize the forecast balance in the Site C Regulatory Account at the end of the prior test period over the remaining weighted average useful life.

7.3.3.5 Customer Crisis Fund Regulatory Account

The Customer Crisis Fund Regulatory Account captures amounts deferred attributable to the following two programs:

- The Customer Crisis Fund Pilot Program; and
- COVID Relief Fund for Residential Customers.

By Order No. G-166-17, the BCUC approved the Customer Crisis Fund pilot program on a three-year basis. In Decision and accompanying Order No. G-144-21 dated May 7, 2021, the BCUC found that continuation of the Customer Crisis Fund Pilot Program could not be justified and ordered BC Hydro to terminate the Customer Crisis Fund Pilot Program effective May 31, 2021. By Order No. G-162-21 dated May 27, 2021, the BCUC approved BC Hydro's application to rescind the Customer Crisis Fund Rate Rider, effective June 1, 2021. By Order No. G-179-21A dated June 7, 2021, the BCUC granted approval allowing BC Hydro to amend its Electric Tariff to remove language that enables on-bill credits for the Customer Crisis Fund Pilot Program grants and removing all references to the COVID-19 Relief Fund for Residential Customers, effective September 1, 2021.

As required by the Government of B.C.'s Direction to the British Columbia Utilities BCUC respecting COVID-19 Relief (Order in Council (**OIC**) No. 159 issued on April 2, 2020), the BCUC approved[466] BC Hydro's application to amend BC Hydro's Electric Tariff in order to implement BC Hydro's COVID Relief Fund and allow amounts credited to residential customers to be deferred to the Customer Crisis Fund Regulatory Account. The COVID Relief Fund for Residential Customers was a temporary program available until June 30, 2020.

The forecast balance of the Customer Crisis Fund Regulatory Account at the end of fiscal 2022, and the components comprising that balance, are provided in Table 7-3 below.

[466] BCUC Order No. G-79-20.

Table 7-3 Summary of Customer Crisis Fund Forecast Balance at March 31, 2022

($ million)	Customer Crisis Fund Pilot Program Balance	COVID Relief Fund for Residential Customers Balance
Rate Rider Revenue	(11.1)	n/a
COVID-19 Bill Credits	n/a	37.3
Internal Costs	5.7	1.2
Interest	(0.5)	2.3
Total	(5.9)	40.8

As the COVID-19 Relief program is complete, BC Hydro is proposing to recover the forecast balance associated with the COVID Relief Fund for Residential Customers (i.e., $40.8 million) over the Test Period. BC Hydro proposes this recovery period because these costs relate to the past, and BC Hydro considers that there are no future benefits for ratepayers associated with these costs. As such, this recovery period promotes intergenerational equity. BC Hydro notes that section 4 of OIC 159 indicates that the recovery period for this account from all ratepayers is to be determined by BC Hydro.

BC Hydro is not proposing to recover the $(5.9 million) forecast portion of the balance related to the Customer Crisis Fund Pilot Program. The reason for this is that OIC 365, issued on June 21, 2021, directs the BCUC to enable BC Hydro to defer up to $5 million to this account related to grants issued to customers and BC Hydro internal costs to administer the program. Amounts deferred will reduce the balance in this portion of the account such that the expected balance following such deferrals would be minimal. On July 5, 2021, the BCUC issued Order No. G-203-21 that confirmed the direction of OIC 365. The BCUC directed BC Hydro to include an update regarding the Customer Crisis Fund Pilot Program in any revenue requirement applications filed with the BCUC while the Customer Crisis Fund Pilot Program remains active, including advising of the balance of the Customer Crisis Fund Regulatory Account and the expected duration of the Customer Crisis Fund Pilot Program. It directed BC Hydro to provide notice to the BCUC when the

Deferred Amounts included in the Customer Crisis Fund Regulatory Account reach $5 million.

BC Hydro notes that the $5.9 million portion of the balance of the account relates to residential ratepayers. The up to $5 million that will be deferred to the account pursuant to OIC 365 also relates to residential ratepayers. In its application in respect of OIC 365, BC Hydro noted that Government is considering whether a permanent program should be implemented. Accordingly, BC Hydro considers it preferable to retain the $5.9 million so that it may be possible to flow the benefits to residential ratepayers. If that portion of the balance were to be returned now, pursuant to OIC 159 it would flow to all ratepayers, instead of just residential ratepayers. As necessary, BC Hydro will propose a mechanism for recovery or return of any balance remaining in the account in its next revenue requirements application.

Therefore, BC Hydro requests BCUC approval to:

- Recover the forecast March 31, 2022 balance for COVID Relief Fund for Residential Customers in the Customer Crisis Fund Regulatory Account over this Test Period;
- Continue to apply interest to the balance of the account each year based on BC Hydro's current weighted average cost of debt, and
- Recover the forecast interest charged to the account attributable to the COVID Relief Fund for Residential Customers balance each year from the account each year beginning in fiscal 2023.

7.3.3.6 Mining Customer Payment Plan Regulatory Account

The Mining Customer Payment Plan Regulatory Account captures deferred amounts attributable to the following two programs:

- Mining Customer Payment Plan amounts (specifically, any impaired amounts related to participating customers in Tariff Supplements (**TS**) 90, 97, 98, 99); and
- COVID-19 Relief measures for commercial customers.

In accordance with section 3(2) of OIC No. 123, issued on February 29, 2016, BCUC Order No. G-34-16 authorized BC Hydro to establish the Mining Customer Payment Plan Regulatory Account for the original TS 90. This program closed on March 14, 2021 with no balance in the regulatory account. In the Previous Application,[467] BC Hydro noted that Government indicated that the program may continue in the future. As at the Application date, Government has not announced anything further in this regard. BC Hydro has not proposed the closure of the account in this application pending any further forthcoming information regarding the program.

In accordance with OIC No. 319, issued on June 19, 2020, BC Hydro announced new COVID-19 relief measures, including three new Industrial Customer Payment Plan tariff supplements (TS 97, TS 98, TS 99) that allowed certain industrial customers to temporarily defer a portion of their bills, with repayment plus interest following the payment deferral period. The ability for participating customers to defer bill payments under these tariff supplements closed during fiscal 2021.

As required by the Government of B.C.'s Direction to the British Columbia Utilities BCUC Respecting COVID-19 Relief (OIC No. 159 issued on April 2, 2020), the BCUC approved[468] BC Hydro's application to waive charges for eligible commercial

[467] Fiscal 2022 Revenue Requirements Application, BCUC IR 1.59.3.
[468] BCUC Order No. G-79-20.

customers during the period from the date that is the later of April 1, 2020 and the date on which an eligible commercial customer ceased operating until June 30, 2020 and defer the waived charges and BC Hydro's cost of administering this relief for eligible commercial and industrial customers to the Mining Customer Payment Plan Regulatory Account and apply interest at BC Hydro's weighted average cost of debt.

The forecast balance of the Mining Customer Payment Plan Regulatory Account at the end of fiscal 2022, and the components comprising that balance, are provided in Table 7-4 below.

Table 7-4 Summary of Mining Customer Payment Plan Regulatory Account Forecast Balance at March 31, 2022

($ million)	Industrial Customer Impairment Losses (TS 90, 97, 98, 99)	COVID-19 Relief Measures for Commercial Customers
Impaired Receivables	0.1	n/a
COVID-19 Bill Credits	n/a	6.9
Internal Costs	0	n/a
Interest	0	0.5
Total	0.1	7.4

As the COVID-19 Relief measures for commercial customers is complete, BC Hydro is proposing to recover the forecast balance associated with that program at March 31, 2022 (i.e., $7.4 million) over the Test Period. BC Hydro proposes this recovery period because these costs relate to the past, and BC Hydro considers that there are limited future benefits for ratepayers associated with these costs. As such, this recovery period promotes intergenerational equity. BC Hydro notes that section 4 of OIC 159 indicates that the recovery period for this account from all ratepayers is to be determined by BC Hydro.

BC Hydro is not proposing to recover the $0.1 million forecast portion of the balance related to the mining and industrial customer tariff supplements. The reason for this is that the impaired amount, while required under accounting standards, relates to amounts owing by industrial customers under these tariff supplements which are currently being repaid as required. BC Hydro expects full repayment from these customers by September 30, 2021 as required under the tariff supplements and thus does not expect any impaired amount will remain that would require collection from ratepayers.

Therefore, BC Hydro requests BCUC approval to:

- Recover the forecast March 31, 2022 balance for COVID-19 Relief measures for commercial customers in the Mining Customer Payment Plan Regulatory Account over this Test Period;
- Continue to apply interest to the balance of the account each year based on BC Hydro's current weighted average cost of debt; and
- Recover the forecast interest charged to the account attributable to COVID-19 Relief measures for commercial customers each year from the account each year beginning in fiscal 2023.

7.3.3.7 Real Property Sales Regulatory Account

By Order No. G-48-14, the Real Property Sales Regulatory Account was established on March 24, 2014 on the basis of Direction 7 of OIC 097 to defer the variances between BC Hydro's actual and forecast real property gain/loss from real estate sales, with interest to be applied to the account based on BC Hydro's weighted average cost of debt.

The timing of completion of real estate transactions is difficult to forecast accurately. The Real Property Sales Regulatory Account was intended to smooth the recognition of gains and losses from real property sales (that could otherwise impact rates in a particular year) while ensuring that ratepayers receive the benefits from the sales, regardless of the years in which the sales occurred.

Since fiscal 2015, BC Hydro has been preparing surplus properties for sale. Activities have included market value appraisals and estimates, investigation and remediation of environmental contamination, working with municipalities on subdivision requirements, and consultation with First Nations.

The 2013 10 Year Rates Plan included a target of $50 million of net gains from real property sales over the first five years (i.e., fiscal 2015 through fiscal 2019) of the plan. Consistent with this target, beginning in fiscal 2015, BC Hydro included $10 million in forecast net gains from real property sales in each fiscal year. In the F2020-F2021 RRA, BC Hydro increased the net gains target from $50 million to $100 million and extended the timeframe to achieve this target to the end of fiscal 2024.

However, BC Hydro's actual net gains were less than forecast as sales have taken time to occur, resulting in an accumulated balance in the account. Consequently, in the F2020-F2021 RRA Decision, the BCUC directed BC Hydro to reflect forecast net gains of $0 in fiscal 2020 and fiscal 2021 and allowed BC Hydro to record only actual net gains realized on the sale of properties.

Consistent with the BCUC's direction provided in the F2020-F2021 RRA Decision, BC Hydro recorded only actual net gains realized on the sale of properties in fiscal 2020 and fiscal 2021 and included interest on the balance. The actual balance in the Real Property Sales Regulatory Account at the end of fiscal 2021 was $47 million. Any net gains occurring in fiscal 2022 will similarly be included in the account.

In its Decision on the F2020-F2021 RRA, the BCUC stated:

> "Given the Panel's concern with the balance that has already accumulated in the Real Property Sales regulatory account, if a balance recoverable from ratepayers is still expected to exist in this account at the end of the next test period, the Panel directs BC Hydro to provide in its fiscal 2023 RRA, a proposal on how it plans to recover the balance from ratepayers".[469]

[469] Directive 41; BCUC Decision and Order No. G-246-20, BC Hydro Fiscal 2020 to Fiscal 2021 Revenue Requirements Application (October 2, 2020), page 127.

BC Hydro's proposal for recovery of the $47 million balance in the Real Property Sales Regulatory Account is to continue to recover the balance through realization of actual net gains over the Test Period. BC Hydro continues to make progress in its active property sales. For example, this fall, BC Hydro expects to remove its subject conditions and complete the sale of one property with net gains of $15 million. BC Hydro also expects to complete other sales by end of the fiscal 2024, consistent with the target presented in the F2020-F2021 RRA, totaling a net gain of $100 million. Over the Test Period, BC Hydro expects these sales to result in realized net gains in excess of the current balance of $47 million at March 31, 2021. As such, the account could be in a liability balance (i.e., amount owing to ratepayers) by the end of the Test Period and BC Hydro proposes to refund the balance in the account to ratepayers over the next test period. However, if the balance at the end of the Test Period remains in an asset position (i.e., amount recoverable from ratepayers), BC Hydro proposes to recover the balance in the account from ratepayers over the next test period.

7.3.3.8 Electric Vehicle Costs Regulatory Account

In the Previous Application, BC Hydro requested BCUC approval to establish an Electric Vehicle Costs Regulatory Account to defer any actual operating costs, amortization, and cost of energy amounts related to electric vehicle charging stations that meet the definition of a prescribed undertaking under the GGRR for fiscal 2020 and fiscal 2021; apply interest to the balance of the account based on BC Hydro's current weighted average cost of debt and recover the forecast interest charged to the account each year from the account each year; and, starting in fiscal 2022, recover the forecast balance at the end of a test period over the next test period, until such time that the actual amounts deferred to the account for fiscal 2020 and fiscal 2021 are recovered in rates.

In its Decision on the Previous Application, Directive 24, the BCUC approved the establishment of the Electric Vehicle Costs Regulatory Account to defer any actual operating costs, depreciation, and cost of energy amounts related to BC Hydro's EV charging stations that meet the definition of a prescribed undertaking under the GGRR for fiscal 2020 and fiscal 2021 and approved BC Hydro's request to apply interest to the balance of the account based on BC Hydro's current weighted average cost of debt. The BCUC denied BC Hydro's request to, starting in fiscal 2022, recover the forecast account balance and forecast interest at the end of a test period over the next test period. It directed BC Hydro to remove all fiscal 2022 costs related to its EV charging stations that meet the definition of a prescribed undertaking under the GGRR and defer these costs to the Electric Vehicle Costs Regulatory Account. The BCUC also directed BC Hydro to apply for a recovery mechanism for the account in this application.

As directed by the BCUC, BC Hydro is requesting a recovery mechanism for the account. As no further transfers are expected to be made to this account after March 31, 2022, BC Hydro proposes to recover the forecast balance of the account at March 31, 2022 over this Test Period and recover any balance remaining at the end of this Test Period, as a result of actual fiscal 2022 costs varying from forecast, over the next test period. Under section 18 of the *Clean Energy Act*, the BCUC must set rates that allow BC Hydro to collect sufficient revenue to recover costs incurred for implementing prescribed undertakings.

As the account captures amounts attributable to fiscal 2020 to fiscal 2022 only, BC Hydro is not forecasting the deferral of any further costs, other than interest, to this account over the Test Period. However, as actual fiscal 2022 costs may vary from forecast fiscal 2022 costs, a balance may remain in the account at the end of this Test Period which BC Hydro proposes would be recovered over the next test period. Therefore, BC Hydro expects to close the Electric Vehicle Costs Regulatory in the next test period when the balance will be fully amortized into rates and transfer any residual interest remaining in the account to the Total Finance Charges Regulatory Account.

Therefore, BC Hydro requests BCUC approval to:

- Recover the forecast March 31, 2022 balance for the Electric Vehicle Costs Regulatory Account over this Test Period and recover any balance remaining at the end of this Test Period over the next test period;
- Continue to apply interest to the balance of the account each year based on BC Hydro's current weighted average cost of debt; and
- Recover the forecast interest charged to the account each year beginning in fiscal 2023.

7.3.3.9 DSM Regulatory Account

In Directive 20 in its Decision on the Previous Application, the BCUC directed BC Hydro to provide in this application a discussion of whether LCE expenditures deferred to the DSM Regulatory Account should be recovered only from the beneficiaries of these expenditures, and if so by what methods this could be accomplished.

BC Hydro proposes no change to the recovery of the LCE component of the DSM Regulatory Account. Please refer to Chapter 10, section 10.4.3.1 for our explanation as to why this is appropriate.

7.3.4 Account Currently Under Review in Another Proceeding

7.3.4.1 Mandatory Reliability Standards Costs Regulatory Account

In an application filed on August 31, 2021, BC Hydro applied for BCUC approval of a new MRS Costs Regulatory Account in fiscal 2022 to capture unplanned costs incurred in fiscal 2022 associated with MRS. We also sought approval to apply interest to the account and recover the forecast ending balance of the account at the end of fiscal 2022 over this Test Period including forecast interest charged to the account each year.

We are seeking approval in this application to continue the use of this account after fiscal 2022. Refer to section 7.3.2.1.

7.4 BC Hydro's Use of Regulatory Accounts is in Accordance with IFRS and BCUC Orders

BC Hydro's use of regulatory accounts is in accordance with IFRS and is compliant with BCUC Orders and government directions. BC Hydro applies rate-regulated accounting in accordance with IFRS 14, *Regulatory Deferral Accounts*.

As discussed in Chapter 8, section 8.13, the International Accounting Standards Board (**IASB**) has published the exposure draft of a new standard 'Regulatory Assets and Regulatory Liabilities' that is intended to replace the interim standard IFRS 14 'Regulatory Deferral Accounts'. Based on the current IASB timeline, the accounting standard for Rate Regulated accounting may be in effect for fiscal 2025 or earlier if BC Hydro elects to early adopt the standard which is permitted in the exposure draft. BC Hydro will assess the impacts of the new standard when it is finalized and may seek BCUC approval for new or revised regulatory accounts to defer the impacts at adoption and for collection in a future revenue requirement.

Regulatory accounts are commonly used in the utility industry in North America. The general purpose of a regulatory account is to defer costs or revenues for future recovery or refund. For example, regulatory accounts are used to defer differences between forecast and actual costs or revenues, or to better match costs and benefits for customers. In the absence of rate-regulated accounting, these costs or revenues would be recognized in the current accounting period.

BC Hydro's regulatory accounts are subject to BCUC review and approval,[470] and have been scrutinized in detail in recent BCUC proceedings as more of BC Hydro's regulatory accounts have become subject to the BCUC's jurisdiction. In particular, in its Fiscal 2017 to Fiscal 2019 RRA, BC Hydro provided a detailed discussion of each

[470] Subject to applicable directions or legislation.

of its regulatory accounts, including a description of the account, its history and the existing or proposed recovery mechanism or period of the account balance. In its Decision on that RRA, the Panel took no exception to the treatment of the regulatory accounts for which BC Hydro did request any change, and approved BC Hydro's proposed changes subject to certain directions in that decision. BC Hydro's subsequent RRAs, and subject BCUC decisions, have been built on that foundation and now can appropriately focus on any circumstances that warrant changes to a regulatory account, the creation of a new account, or the closing of an account.

In its Decision on the Previous Application, the BCUC maintained our existing regulatory accounts and the amortization periods associated with them. The BCUC also approved the closure of one regulatory account (Rock Bay Remediation Regulatory Account) and directed the establishment of the following two new regulatory accounts:

- Fiscal 2022 Depreciation Study Impacts Regulatory Account, to capture the variances arising in fiscal 2022 as a result of any changes to the depreciation expense determined in the depreciation study, with interest charges being on the same basis as previously approved for the Amortization of Capital Additions Regulatory Account;[471] and
- Electric Vehicle Costs Regulatory Account, to defer any actual operating costs, depreciation, and cost of energy amounts related to BC Hydro's EV charging stations that meet the definition of a prescribed undertaking under the GGRR for fiscal 2020, fiscal 2021 and fiscal 2022 and to apply interest to the balance of the account based on BC Hydro's current weighted average cost of debt.[472]

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[471] Directive 15; BCUC Decision and Order No. G 187 2021, BC Hydro Fiscal 2022 Revenue Requirements Application (June 17, 2021), pages 68, 69.

[472] Directive 24; BCUC Decision and Order No. G 187 2021, BC Hydro Fiscal 2022 Revenue Requirements Application (June 17, 2021), page 102.

In Appendix R to the Application, BC Hydro describes each of its approved regulatory accounts including the BCUC Orders that have approved their scope, recovery mechanisms, and application of interest where appropriate.

7.5 Plan to Manage Regulatory Account Balances

This section outlines our plan to manage our regulatory account balances. At the end of fiscal 2021, BC Hydro had a total of 29 regulatory accounts, with a total net balance of $4.3 billion. Based on existing approved recovery mechanisms and those proposed in this application, BC Hydro is forecasting that the total net balance in the accounts will be reduced to $3.9 billion at the end of fiscal 2025 and to $3.2 billion by the end of fiscal 2030. Almost all of the remaining forecast balance in fiscal 2030 is in accounts that are recovered over long terms and BC Hydro has or has requested recovery mechanisms for all of its regulatory accounts.

Table 7-5 below presents the fiscal 2021 actual, fiscal 2022 Decision and fiscal 2022 Forecast, fiscal 2023 to fiscal 2025 Plan, and fiscal 2026 to fiscal 2030 forecast balances of BC Hydro's regulatory accounts.

Table 7-5 Regulatory Account Balances Fiscal 2021 Actual, Fiscal 2022 Forecast, Fiscal 2022 to Fiscal 2025 Plan and Fiscal 2026 to Fiscal 2030 Forecast

	End of Year Balance ($ million)	Schedule Reference	F2021 Actual	F2022 Decision	F2022 Forecast	F2023 Plan	F2024 Plan	F2025 Plan	F2026 Plan	F2027 Plan	F2028 Plan	F2029 Plan	F2030 Plan
			1	2	3	4	5	6	7	8	9	10	11
	Cost of Energy Variance Accounts												
1	Heritage Deferral Account	2.1 L47	65	68	90	48	27	17	18	7	8	8	8
2	Non-Heritage Deferral Account	2.1 L48	(153)	(177)	(190)	(105)	(63)	(42)	(46)	(22)	(25)	(29)	(32)
3	Trade Income Deferral Account	2.1 L49	(227)	(227)	(234)	(126)	(71)	(44)	(46)	(19)	(20)	(20)	(21)
4	Load Forecast Variance Def. Acct.	2.1 L50	110	115	134	72	41	25	26	11	11	12	12
5	Biomass Energy Program Cost Def. Acct.	2.1 L51	(14)	(15)	(21)	(11)	(6)	(4)	(4)	(2)	(2)	(2)	(2)
6	Low Carbon Fuel Credits Variance	2.1 L52	0	0	0	0	0	0	0	0	0	0	0
	Total	2.1 L53	(220)	(236)	(220)	(121)	(72)	(47)	(52)	(24)	(28)	(31)	(35)
	Other Cash Variance Accounts												
7	Storm Restoration Costs	2.2 L185	(23)	(10)	(11)	(7)	(4)	(0)	(0)	(0)	(0)	(0)	(0)
8	Amortization of Capital Additions	2.2 L187	(0)	2	2	2	1	0	(0)	(0)	(0)	(0)	(0)
9	Total Finance Charges	2.2 L188	(61)	13	39	26	13	0	0	0	0	0	0
10	Remediation	2.2 L195	(27)	(23)	(34)	(23)	(11)	(0)	0	0	0	0	0
11	Real Property Sales	2.2 L196	47	48	48	50	51	53	54	56	58	60	61
12	Dismantling Cost	2.2 L198	(12)	(9)	(4)	(3)	(1)	(0)	(0)	(0)	(0)	(0)	(0)
13	Customer Crisis Fund	2.2 L200	34	35	35	21	7	(6)	(7)	(7)	(7)	(7)	(8)
14	Mining Customer Payment Plan	2.2 L201	7	7	7	5	3	0	0	0	0	0	0
15	Project Write-off Costs	2.2 L202	17	8	8	6	3	1	1	1	1	1	1
16	Electric Vehicle Program Expenses	2.2 L203	4	7	7	5	2	0	0	0	0	0	0
17	Mandatory Reliability Standard Costs	2.2 L204	0	0	16	11	5	0	0	0	0	0	0
18	Depreciation Study	2.2 L206	0	0	29	19	10	(0)	(0)	(0)	(0)	(0)	(0)
	Total		(14)	78	143	111	79	47	49	50	52	53	55
	Non-Cash Variance Accounts												
19	Foreign Exchange Gains/Losses	2.2 L183	6	3	7	7	7	6	5	5	4	0	0
20	Non-Current Pension Costs	2.2 L190	114	(1)	2	(28)	(58)	(87)	(117)	(147)	(155)	(127)	(99)
21	PEB Current Pension Costs	2.2 L199	(7)	(0)	(25)	(17)	(8)	0	0	0	0	0	0
22	Debt Management	2.2 L197	449	440	462	447	432	416	397	377	353	325	294
	Total		562	442	446	409	373	335	285	235	201	199	195
	Benefit Matching Accounts												
23	DSM	2.2 L179	881	871	869	886	905	923	936	906	884	866	852
24	First Nations Costs	2.2 L180	54	38	37	20	2	2	2	7	13	12	10
25	Site C	2.2 L182	523	532	542	569	598	618	613	606	599	592	585
26	Pre-1996 Contributions in Aid of Construction	2.2 L184	73	68	68	63	58	53	47	42	37	32	27
27	SMI	2.2 L189	173	151	151	130	108	86	65	43	22	0	0
28	Load Attraction Costs	2.2 L205	0	0	0	9	18	26	49	47	44	41	39
	Total		1,705	1,660	1,667	1,676	1,688	1,708	1,712	1,650	1,599	1,543	1,513
	Non-Cash Provisions												
29	First Nations Provisions	2.2 L181	432	436	432	436	440	444	449	448	443	448	452
30	Environmental Provisions	2.2 L191	321	263	274	234	189	168	149	142	136	130	124
	Total		753	699	705	670	629	613	598	590	580	578	576
	IFRS Transition Accounts												
31	IFRS Property, Plant and Equipment	2.2 L193	1,071	1,039	1,039	1,007	976	944	913	881	850	818	787
32	IFRS Pension	2.2 L194	421	382	382	344	306	268	229	191	153	115	76
	Total		1,491	1,421	1,421	1,352	1,282	1,212	1,142	1,072	1,003	933	863
	Total	2.1 L53+2.2 L207	**4,276**	**4,064**	**4,164**	**4,097**	**3,979**	**3,868**	**3,734**	**3,574**	**3,406**	**3,274**	**3,166**

As shown in Table 7-5, the total regulatory account balance is forecast to decrease by $0.296 billion from $4.164 billion forecast fiscal 2022 to $3.868 billion in forecast fiscal 2025. The decrease in the forecast is primarily due to the following:

- The balance of the Non-Current Pension Costs Regulatory Account is forecast to decrease due to amortization of previous test period additions;

- The Environmental Provisions Regulatory Account is forecast decrease as work is completed to relieve the associated obligations; and
- The IFRS Transition Accounts are forecast to decrease as the balance is amortized and no new additions are expected.

As shown in Table 7-5, BC Hydro has 32 regulatory accounts in use during the Test Period which includes the 29 accounts in place at March 31, 2021 plus the new Depreciation Study Impact Regulatory Account, Low Carbon Fuel Credits Regulatory Account, MRS Costs Regulatory Account and Load Attraction Costs Regulatory Account less the Rock Bay Regulatory Account that was approved for closure. The total net balance in the accounts is forecast to decline to $3.2 billion by the end of fiscal 2030.

BC Hydro has approved recovery mechanisms or has proposed recovery mechanisms to recover the balances of all of its regulatory accounts in rates.[473]

Almost all of the forecast balances in fiscal 2030 under our plan reside in regulatory accounts that are being recovered over a longer period of time as the nature of these accounts are long-term, including the following:

- The Non-Current Pension Costs Regulatory Account for which the balance is amortized over the expected average remaining service life (**EARSL**) of the active plan members at the start of the test period;
- The Debt Management Regulatory Account for which the gains/losses by contract are amortized over the term of the associated long-term debt issuances beginning in the test period subsequent to that in which the associated debt is issued;

[473] As discussed in section 7.3.3.7, the balance in the Real Property Sales Regulatory Account is expected to be offset by the gains and losses expected to be realized over fiscal 2023 to fiscal 2025. BC Hydro has proposed in section 7.3.3.7 to recover/refund the balance in the account (whether an asset or liability), at the beginning of the next test period, over the next test period and continue to record only actual gains. On this basis, BC Hydro considers this account to have a proposed recovery mechanism.

- The DSM Regulatory Account for which the expenditures added each year are recovered over the 15-year benefit period for customers;
- The Site C Regulatory Account, which BC Hydro is requesting to be recovered over the weighted average life of the assets of 84 years commencing in fiscal 2025;
- The First Nations Provisions Regulatory Account, which is drawn down as annual settlement payments are made over a longer period of time;
- Environmental Provisions Regulatory Account, which is drawn down as actual expenditures are incurred for PCB and Asbestos remediation which occur over a long period of time; and
- The two IFRS Transition Accounts, which are being amortized into rates over 20 years for the IFRS Pension Regulatory Account and 40 years for the IFRS Property, Plant and Equipment Regulatory Account so that the balances in those accounts are recovered over the same period of time as under the previous CGAAP accounting rules. This means that ratepayers are not subject to higher rates as a result of changes in accounting rules.

The balances shown in Table 7-5 and Table 7-6 for fiscal 2023 onward are forecasts based on current information and assumptions at the time the forecast was prepared and reflect our proposed requests in this application. Actual balances will be different than presented for the following reasons:

- First, the forecast indicates that the balance in the six Cost of Energy Variance Accounts will be reduced to $47 million by the end of fiscal 2025. These accounts capture the variances between forecast and actual energy costs, forecast and actual revenues from energy sales, and forecast and actual trade income in each fiscal year, which can be positive or negative. Forecasting energy costs, revenues from energy sales and low carbon fuel credits and trade income is challenging due to variables beyond BC Hydro’s control, such as weather. Therefore, actual additions will differ from the forecast amounts;

- Second, the Non-Current Pension Costs Regulatory Account captures actuarial gains and losses. Annual actuarial gains and losses are sensitive to changes in market discount rates, rates of return on pension plan assets and significant changes in key actuarial assumptions. This means that annual actuarial gains and losses are subject to large positive and negative fluctuations and therefore actuarial gains or losses at the end of each year are difficult to forecast;
- Third, the Debt Management Regulatory Account captures gains and losses from financial contracts that hedge future long-term debt and the values of the hedges are sensitive to changes in market interest rates. This means that annual gains and losses on unrealized hedges are subject to large positive and negative fluctuations and therefore these gains or losses are difficult to forecast;
- Fourth, the forecast DSM Regulatory Account balances are based on the activities and expenditures in the current DSM Plan, which includes placeholder amounts for the Test Period. In addition, actual load attraction costs will differ from planned amounts. Accordingly, forecast balances beyond the Test Period for the DSM Regulatory Account may differ; and
- Fifth, BC Hydro has several cash and non-cash variance accounts that capture variances between forecast and actual costs. BC Hydro expects the balances in these accounts will be different than the amounts forecast in this application due to non-controllable factors such as interest rates and weather.

Table 7-6 below sets out the fiscal 2023 to fiscal 2025 baseline forecast amounts. The variances deferred to these accounts will be determined from these baseline forecasts.

Table 7-6 Fiscal 2023 to Fiscal 2025 Baseline Forecast Amounts for Regulatory Accounts

Line	($ million)	Schedule Reference	F2021 Actual	F2022 Decision	F2022 Forecast	F2023 Plan	F2024 Plan	F2025 Plan
			1	2	3	4	5	6
	Heritage Deferral Account							
1	COE Subject to Deferral to HDA	4.0 L96	296.9	392.7	416.2	385.0	390.3	386.9
	Non-Heritage Deferral Account							
2	COE Subject to Deferral to NHDA	4.0 L115	1,258.0	1,185.8	1,170.5	1,294.6	1,448.8	1,507.9
3	External OATT	15.0 L9	14.1	11.1	11.6	12.2	12.3	11.9
4	NTL Supplemental Charge Revenue	15.0 L14	2.4	2.4	2.4	2.4	2.4	2.4
5	Load Variance	14.0 L52	4,950.5	5,187.7	5,218.6	5,306.8	5,510.9	5,765.2
6	Biomass Energy Program Variance - COE	4.0 L116	66.0	102.4	99.6	113.3	115.7	118.1
7	Biomass Energy Program Variance - Revenue	14.0 L53	13.5	15.9	18.9	21.7	18.5	17.4
8	Low Carbon Fuel Credits Variance	15.0 L35		31.4	31.4	31.4	31.4	31.4
9	Trade Income	1.0 L18	386.4	158.7	158.7	224.2	224.2	224.2
	Other Regulatory Accounts							
10	Non-Current PEB - Pension	8.0 L28	64.0	(52.0)	56.0	(53.3)	(57.3)	(61.6)
11	Current PEB - Operating Cost	N/A	73.7	113.1	88.3	91.4	94.7	98.1
12	Storm Restoration Costs	N/A	12.1	21.5	21.5	19.2	19.2	19.2
13	Total Finance Charges	8.0 L43-L27-L28	630.6	505.2	397.2	608.6	593.5	740.6
14	Amortization of Capital Additions	13.0 L50	80.8	26.6	27.3	29.8	89.6	174.7
15	Net Gain on Property Sales	5.01 L16	(10.0)	0.0	0.0	0.0	0.0	0.0
16	Dismantling Cost	5.01 L18	43.0	45.5	45.5	53.3	46.3	44.8

7.6 Impacts of COVID-19 on BC Hydro’s Regulatory Accounts

Although the full impacts of the COVID-19 pandemic are not yet known, the COVID-19 pandemic has impacted, and is expected to continue to impact, several regulatory accounts as follows:

- Differences between actual and forecast revenues in fiscal 2021 and fiscal 2022 caused by lower customer load, as well as any related impacts to cost of energy, are deferred to the Cost of Energy Variance Accounts. For further information on the impacts of the COVID-19 pandemic to customer load, refer to Chapter 3;
- Lower revenues in fiscal 2021 due to BC Hydro’s COVID-19 pandemic relief measures for residential and commercial customers were deferred to the Customer Crisis Fund Regulatory Account and the Mining Customer Payment

Plan Regulatory Account, respectively. The total amount deferred related to these programs is $48 million;

- The timing of capital additions has been impacted due to project schedule changes as a result of the COVID-19 pandemic in fiscal 2021, which had an impact to the Amortization of Capital Additions Regulatory Account. For further information, refer to Chapter 6, section 6.2.4; and
- Interest rate fluctuations in fiscal 2020 and fiscal 2021 lead to:
  - Higher or lower fair values of BC Hydro's interest rate hedges on future debt issuances, which are deferred to the Debt Management Regulatory Account;
  - Higher or lower finance charges, which are deferred to the Total Finance Charges Regulatory Account;
  - Higher or lower pension costs due to volatile discount rates which will impact BC Hydro's PEB Current Pension Costs Regulatory Account and Non-Current Pension Costs Regulatory Account; and
  - Actual total regulatory accounts balance at March 31, 2021 was $4.3 billion compared to the fiscal 2021 year-end forecast of $6.3 billion presented in the Fiscal 2022 Revenue Requirements Application, which was mainly due to decreases in the Non-Current Pension and Debt Management Account regulatory accounts as result of increases in interest and discount rates that occurred late in fiscal 2021.

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Chapter 8

Other Revenue Requirements

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List of Tables

8.1 Introduction

This chapter describes other revenue requirements items, including amortization expense, return on equity, finance charges, taxes, miscellaneous and inter-segment revenues, subsidiary net income, the allocation of BC Hydro's business support costs, provisions and other, and International Financial Reporting Standards (**IFRS**).

It is organized around the following points:

- Section 8.2 indicates where we have addressed the directives from the BCUC's decisions on BC Hydro's previous two revenue requirements applications;
- Section 8.3 describes Amortization Expense, the changes we have forecast over the Test Period which include increases due to capital additions, and the impacts of the depreciation study conducted by an independent expert;
- Section 8.4 describes the results of the net salvage study conducted by an independent expert and our proposal to implement negative net salvage no sooner than fiscal 2026;
- Section 8.5 addresses return on equity. Return on equity is prescribed for fiscal 2023, and BC Hydro is proposing to maintain interim rates for fiscal 2024 and fiscal 2025 based on placeholder amounts that maintain the *status quo* pending the BCUC's determination in BC Hydro's cost of capital proceeding;
- Section 8.6 describes BC Hydro's approach to finance charges, which is consistent with the Previous Application;
- Section 8.7 addresses taxes, which are an uncontrollable cost. We have forecast taxes in a manner consistent with previous revenue requirements applications;
- Section 8.8 describes BC Hydro's miscellaneous revenues, which are consistent with the Previous Application;

- Section 8.9 describes BC Hydro's inter-segment revenues, which are forecast to decrease relative to the Previous Application;
- Section 8.10 describes BC Hydro's subsidiary net income, which is forecast to increase relative to the Previous Application;
- Section 8.11 describes BC Hydro's allocation of business support costs, which is lower than the Previous Application;
- Section 8.12 describes BC Hydro's Provisions and Other, which is consistent with the Previous Application; and
- Section 8.13 describes how BC Hydro has prepared this application in accordance with International Financial Reporting Standards, consistent with the Previous Application.

8.2 BC Hydro Has Addressed BCUC Directives Regarding Other Revenue Requirements

Table 8-1 below provides a summary of directives from BCUC decisions on previous revenue requirements applications and provides references indicating where each directive is addressed in the Application.

Table 8-1 Summary of BCUC Directives (from the Previous Application and F2020-F2021 RRA)

No.	Directive/Recommendation	Reference
Applicable Directives from BCUC's Decision on the Previous Application and Order No. G-187-21		
25	Therefore, the Panel denies the depreciation rates for BC Hydro's EV charging stations and recommends the BCUC panel in the BC Hydro Public EV Fast Charging Rate Application proceeding review the depreciation rates.	Section 8.3.1.2.1 Appendix T
26	Therefore, the Panel directs BC Hydro to increase its fiscal 2022 forecast revenue by the estimated value of the low carbon fuel credits that it plans to transfer to other parties, if any, during fiscal 2022. The Panel also directs BC Hydro to record in all future RRAs, the forecast revenue based on an estimate of the value of the low carbon fuel credits that it plans to transfer to other parties.	Chapter 7, section 7.3.3.1 Section 8.8

No.	Directive/Recommendation	Reference
Applicable Directives from BCUC's F2020-F2021 RRA Decision and Order No. G-246-20		
36	Accordingly, the Panel directs BC Hydro to file a depreciation study by no later than the earlier of October 31, 2021 and the date it submits its Fiscal 2023 RRA.	Section 8.3.1 Appendix T
39	Therefore, the Panel directs BC Hydro to provide in its next RRA, an assessment of whether its current practice of expensing dismantling costs as they occur would result in intergenerational inequity and to provide options on how it could calculate and collect dismantling costs to better promote intergenerational equity. For these reasons, the Panel approves the use of the Dismantling Cost Regulatory Account, as requested by BC Hydro, for the Test Period only.	Section 8.4
40	Given the intergenerational equity concerns, the Panel directs BC Hydro to include in its upcoming depreciation study a net salvage study and, in the RRA immediately after the completion of the depreciation and net salvage studies, report on the results and recommendations, as well as BC Hydro's plan to implement those recommendations.	Section 8.4 Appendix T
57	Therefore, the Panel approves the requested depreciation rates for the infrastructure rights asset class for the Test Period only and directs BC Hydro to review the expected useful life of infrastructure rights in its upcoming depreciation study and to identify any differences from the requested 35 year useful life in the RRA immediately following the completion of the depreciation study.	Section 8.3.1.2.2

8.3 Amortization Expense

BC Hydro's forecast amortization expense is shown in Appendix A, Schedule 7.0, and includes:

- The amortization of property, plant and equipment (capital assets) in service;
- Amortization related to agreements that are recognized as leases in accordance with IFRS 16, *Leases*;
- Amortization of the following regulatory accounts:
  - DSM Regulatory Account;
  - Pre-1996 Contributions in Aid of Construction Regulatory Account; and
  - Amortization of Capital Additions Regulatory Account;
  - Amortization of Depreciation Study Regulatory Account.

Amortization expense is summarized in Table 8-2 below.

Table 8-2 Amortization Expense

	($ million)	Schedule Reference	F2021 Actual	F2022 Decision	F2022 Forecast	F2023 Plan	F2024 Plan	F2025 Plan
			1	2	3	4	5	6
1	Total Gross Amortization	7.0 L27	999.5	1,023.7	1,066.7	1,023.3	1,050.0	1,101.0
2	Transfer to NHDA	7.0 L28	0.3	-	-	-	-	-
3	Regulatory Account Transfers	7.0 L33	(0.8)	(0.5)	(29.8)	-	-	-
4	Total Transfer to Deferral & Regulatory		(0.5)	(0.5)	(29.8)	-	-	-
	Regulatory Account Recoveries							
5	DSM Amortization	7.0 L37	106.5	108.0	107.4	111.2	116.0	119.3
6	Pre-1996 CIAC Amortization	7.0 L38	5.1	5.1	5.1	5.1	5.1	5.1
7	Capital Additions Reg. Acct.	7.0 L39	9.4	(2.1)	(2.1)	0.9	0.9	0.8
8	Depreciation Study Reg. Acct.	7.0 L40	-	-	-	10.4	10.4	10.4
9	Regulatory Account Recoveries	7.0 L41	121.0	111.1	110.5	127.7	132.4	135.7
10	Total Current Amortization	7.0 L42	1,120.0	1,134.2	1,147.4	1,150.9	1,182.4	1,236.6

As shown in Table 8-2 above, total current amortization is forecast to increase by $16.7 million from $1.13 billion in Fiscal 2022 Decision to $1.15 billion in fiscal 2023, primarily due to the following:

- A decrease of $0.4 million in total gross amortization. Although there is little change in the total, there are large offsetting changes including:
  - An increase in Amortization of Capital Assets of $30.3 million primarily due to capital additions, net of the impact of the depreciation study on depreciation expense as described in section 8.3.1.1, and
  - A decrease in IPP lease amortization of $29.2 million, reflecting the assumption in the draft 2021 Integrated Resource Plan that the Energy Purchase Agreement for the Island Generation facility, which is set to expire in fiscal 2023, is not renewed (as discussed in Chapter 4, section 4.6.1.1);
- An increase of $10.4 million for the recovery of the balance in the Depreciation Study regulatory account related to the impact of the deprecation study that was deferred in fiscal 2022.

The fiscal 2024 and fiscal 2025 Plan amounts are forecast to increase by $31.5 million and $54.2 million, respectively, from $1.15 billion in the fiscal 2023 Plan, primarily due to an increase in amortization related to forecast capital additions as described in Chapter 6.

BC Hydro amortizes capital assets over the expected useful lives of the assets using the straight-line Average Service Life method, where amortization expense is recognized evenly over the expected useful life of an asset. The asset class depreciation rates and positive salvage percentages recommended by an independent expert in the Depreciation Study, Appendix T, have been used to forecast amortization expense in the Application.

8.3.1 BC Hydro Is Implementing Depreciation Study Recommendations

Directive 36 of the BCUC's decision of the F2020-F2021 RRA directed BC Hydro to file a depreciation study as part of its next revenue requirements application. In Directives 39 and 40, the BCUC also directed BC Hydro to assess its current practice of expensing dismantling costs and options on how to collect dismantling costs, and to conduct a net salvage study.[474]

In response to these directives, BC Hydro engaged Concentric Advisors, ULC (Concentric) to:

- Perform a depreciation study that reviewed existing depreciation rates and positive salvage percentages;
- Perform an assessment of methodologies used for recovery of dismantling costs in rates and to make a recommendation of an appropriate methodology for BC Hydro that would promote intergenerational equity;

[474] Directives 36, 39 and 40; BCUC Decision and Order No. G-246-20, BC Hydro Fiscal 2020 to Fiscal 2021 Revenue Requirements Application (October 2, 2020), pages 114 and 124.

- Perform a net salvage study for determination of negative salvage rates and to evaluate whether the implementation of net salvage rates is appropriate for BC Hydro; and
- Provide an assessment on the appropriateness of BC Hydro's use of Average Service Life methodology.

The Depreciation Study prepared by Concentric is attached in Section 1 of Appendix T. Concentric's *Report on Applicability of Inclusion of Net Salvage in the Depreciation Rate Calculation* (**Report**) is included in Appendix T. The conclusions of the Report and its proposals regarding dismantling costs are discussed in section 8.4 below.

BC Hydro is seeking approval from the BCUC to implement the recommendations from the Depreciation Study for ratemaking purposes beginning in fiscal 2022[475], which includes:

- Adoption of the revised useful lives and positive salvage percentages as listed in Table 1 in section 4 of the Depreciation Study to calculate depreciation expense, as discussed in sections 8.3.1.2 and 8.3.1.3 below;
- Adoption of the changes to vehicle asset classes as recommended in section 3.3 of the Depreciation Study and discussed in section 8.3.1.4 below; and
- Creation of a new asset class for Electric Vehicle Charging Station assets and useful life as recommended in section 3.5 of the Depreciation Study and discussed in section 8.3.1.2.1 below.

The following subsections explain why the current method of calculating depreciation is appropriate, discuss each of the key recommendations of the Depreciation Study and their implications, and show how implementing the Depreciation Study results in

[475] The impact of implementing the Depreciation Study in fiscal 2022 has been approved to be deferred to the Fiscal 2022 Depreciation Study Impact regulatory account.

a net reduction in the Revenue Requirement over the Test Period. Table 8-3 below provides a summary with the references to the appropriate sections of the changes:

Table 8-3 Depreciation Study Impact

$/millions Increase/(Decrease)	Section	F2022	F2023	F2024	F2025	F2023-F2025 Total
Useful lives (Depreciation Rates) and Positive Salvage Percentages	**8.3.1.2**	26.4	(5.8)	(3.9)	(4.9)	(14.6)
Accelerated Depreciation of Assets Pending Retirement (Life Span Dates)	**8.3.1.5**	9.7	4.0	3.2	1.4	8.5
Sub-Total Depreciation Expense Impact		**36.1**	**(1.8)**	**(0.7)**	**(3.5)**	**(6.0)**
Asset Retirements Expense Impact	**8.3.1.6**	(6.6)	(7.3)	(8.8)	(7.8)	(23.8)
Sub-Total Depreciation Expense and Asset Retirements Impact		**29.5**	**(9.1)**	**(9.5)**	**(11.3)**	**(29.9)**
Miscellaneous Revenue (Amortization of CIAC)	**8.3.1.7**	(0.9)	(0.3)	(0.3)	(0.3)	(0.8)
Net Impact from the Depreciation Study Before Regulatory Transfer		**28.6**	**(9.4)**	**(9.7)**	**(11.6)**	**(30.7)**
Regulatory Transfer (excl. interest)		**(28.6)**	**9.5**	**9.5**	**9.5**	**28.6**
Net Impact After Regulatory Transfer		**-**	**0.1**	**(0.2)**	**(2.1)**	**(2.1)**

8.3.1.1 BC Hydro's Straight-Line, Average Service Life Method of Calculating Depreciation is Appropriate and Widely Accepted

BC Hydro uses the straight-line, average service life method for calculating depreciation expense, which complies with IFRS. The key feature of this method is that depreciation expense is recognized evenly over the expected useful life of an asset.

As part of the Deprecation Study, BC Hydro asked Concentric to assess whether the use of the straight-line, average service life method was appropriate. Concentric provided the following opinion at page 3-1 of the Depreciation Study:

> Depreciation, as used in accounting, is a method of distributing fixed capital costs, less net salvage, over a time period by allocating annual amounts to expense. Each annual amount of such depreciation expense is part of that year's total cost of providing electric utility service. Normally, the time over which the fixed capital cost is allocated to the cost of service, is equal to the time over which an item renders service – that is, the item's service life. The most prevalent method of allocation is to distribute an equal amount of cost to each year of service life. This method is known as the Straight-Line method of depreciation.
>
> BC Hydro continues to determine depreciation using the Straight-Line method for all plant comprising regulated assets, based on the Average Life Group Procedure – Remaining Life Technique. The Average Life Group Procedure is the most commonly used depreciation procedure for North American utilities, whereby one average service life estimate is applied to all assets and vintages within the asset class. The Remaining Life Technique calculates depreciation on the basis of recovering the net book value of the investment over the remaining life of an asset, or group of assets, with no provision for separate accumulated depreciation true-up. As such, a common life and salvage estimate is applied to each of the assets. Concentric finds the application of the Straight-Line method and the Average Life Group Procedure – Remaining Life Technique results in a reasonable recovery of BC Hydro's capital investment over time and recommends their continued application.

Consistent with the above recommendations, BC Hydro will continue to use its straight-line, average service life methodology for calculating depreciation expense.

8.3.1.2 BC Hydro is Updating the Useful Lives of its Assets as Recommended by Concentric

The key component of the Depreciation Study is the review and assessment of the useful lives of BC Hydro's asset classes. BC Hydro uses the average service lives in conjunction with the asset ages to determine the remaining service life for calculating depreciation in accordance with the Remaining Life Technique, as recommended by Concentric.

In the Depreciation Study, Concentric reviewed 315 of 329 asset classes.[476] Concentric's methodology for assessing the average service lives for each asset class is discussed in section 2 and 3 of the Depreciation Study, and includes:

- An analysis of BC Hydro's retirement data;
- Discussions with BC Hydro management and operations representatives;
- Peer comparison analysis, including Ontario Power Generation, Manitoba Hydro, Newfoundland and Labrador Hydro Corporation and FortisBC Energy; and
- Concentric's professional judgement.

Section 3.5 of the Depreciation Study presents an overview of the factors considered by Concentric in the determination of the average service life estimates of a number of accounts, which comprise the majority of the investment analyzed. The recommended average service life for each asset class can be found in Table 1 in section 4 of the Depreciation Study.

In summary, the Depreciation Study recommends an increase to the useful lives of 52 asset classes, a decrease to the useful lives of 45 asset classes, no change to the useful lives of 217 (or 69 per cent) of the asset classes and one new rate for Electric Vehicle Charging Stations.[477] The majority of the 97 asset classes with recommended useful life changes were within +/- one to five years.

BC Hydro proposes to adopt the recommended changes in average service lives, which result in a $14.6 million or 0.5 per cent decrease in depreciation expense for the Test Period (i.e., fiscal 2023 to fiscal 2025), and a 0.24 per cent decrease for fiscal 2022 to fiscal 2031.

476 The full list of asset classes reviewed by Concentric is provided in Table 1 in Section 4 of the Depreciation Study. The asset classes that were not reviewed by Concentric are not subject to depreciation (e.g., land, perpetual land rights, assets held for sale) or are assets with lives determined based on contract or agreement (e.g., right of use assets).

477 The rate for Electric Vehicle Charging Stations is discussed further in section 8.3.1.2.1.

The useful life of two asset classes which have been the subject of BCUC directions are discussed below.

8.3.1.2.1. BC Hydro Proposes to Adopt the Recommended Depreciation Rate for Electric Vehicle Charging Stations

As part of the Depreciation Study, Concentric reviewed the proposed new asset class C59202 – Electric Vehicle Charging Stations and recommends a seven-year useful life. This new asset class excludes distribution assets installed as part of the electric vehicle charging station infrastructure, as asset classes already exist for these assets. Concentric describes its average service life assessment for this asset class on page 3-16 of the Depreciation Study, as follows:

> "The assets in this account relate to the upcoming Electric Vehicle Direct Current Fast Charging Program. These assets are located downstream of the electric service and consist solely of the battery charger system. These assets are highly technological in nature and are subject to the fast-paced nature of retirements common in technological accounts. As many of the forces of retirements anticipated in this account are related to the pace of change of technology, it is important that this account have a short average service life. There are few peer utilities in Canada with approved lives for electric vehicle charging stations, however Concentric has carried out discussions with personnel at many utilities across Canada in anticipation of upcoming technological changes. It is the experience of Concentric that the assets included in this account are expected to live approximately five to ten years. As such, Concentric recommends an Iowa 7-R3 to represent the future expectations for the investment in this account."

BC Hydro proposes to adopt the recommended depreciation rate, which is based on a seven-year life, for the asset class C59202 – Electric Vehicle Charging Stations.

BC Hydro acknowledges that Directive 25 in the BCUC's decision on the Previous Application denied the depreciation rates for BC Hydro's electric vehicle charging stations and recommended that the depreciation rates be reviewed in the BC Hydro

Public Electric Vehicle Fast Charging Rate Application proceeding.[478] BC Hydro submits that it is appropriate for the BCUC to consider the depreciation rate for electric vehicle charging stations in this proceeding, with the benefit of Concentric's expert evidence and recommended depreciation rate for this asset class.

8.3.1.2.2. BC Hydro's Useful Life for Infrastructure Rights Remains Appropriate

Infrastructure rights are BC Hydro contributions for voltage conversion projects involving customer owned equipment that provide BC Hydro with access rights to the customers' electrical infrastructure to facilitate delivery of electricity. In the F2020-F2021 RRA, BC Hydro requested a new asset class for Infrastructure Rights with a 35-year useful life. Directive 57 of the BCUC's decision on the F2020-F2021 RRA directed BC Hydro "to review the expected useful life of infrastructure rights in its upcoming depreciation study and to identify any differences from the requested 35-year useful life".[479]

Concentric reviewed asset class C11650 - Infrastructure Rights (Contributions - Infrastructure Rights) and recommended that the useful life remain at 35 years, consistent with the useful life of the underlying asset, distribution voltage transformers. On page 3-9 of the Depreciation Study, Concentric explains:

> "The assets in this account relate to contributions made related to the assets in Account C52201 – Distribution, Transformers. Consequently, the life of this account should be tied to the life of Account C52201. As such Concentric is recommending a of 35-SQ to match the life of Account C52201."

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[478] Directive 25; BCUC Decision and Order No. G-187-21, BC Hydro Fiscal 2022 Revenue Requirements Application (June 17, 2021), page 104.

[479] Directive 57; BCUC Decision and Order No. G-246-20, BC Hydro Fiscal 2020 to Fiscal 2021 Revenue Requirements Application (October 2, 2020), pages 172-173.

8.3.1.3 BC Hydro Is Updating Positive Salvage Percentages as Recommended by Concentric

In the Depreciation Study, Concentric also recommends updated positive salvage percentages, primarily related to the retirement of fleet vehicles. As is common practice, BC Hydro retires fleet vehicles when they reach a certain age or mileage. BC Hydro currently estimates a residual value known as positive salvage, as a percentage of the total cost. Reductions to the positive salvage percentages result in higher depreciation as the depreciable amount of an asset (i.e., the asset cost less its residual value or positive salvage) is increased. This in turn translates to a lower net book value at retirement or disposition, mitigating losses on sales.

Of the 329 BC Hydro asset classes, 22 utilize positive salvage percentages and are primarily vehicle-related asset classes. Concentric has recommended a decrease to the positive salvage percentages for 19 asset classes, an increase to one asset class and no change to two asset classes. The proposed positive salvage percentages are provided in Table 1 in section 4 of the Depreciation Study.

Concentric's recommended revised useful lives and positive salvage percentages for vehicles result in a reduction in the losses expected on the disposal of vehicles totalling $1.3 million in fiscal 2023, $1.4 million in fiscal 2024 and $1.0 million in fiscal 2025 which is also discussed in section 8.3.1.6.

8.3.1.4 BC Hydro is Aligning its Asset Class Structure for Vehicle Assets with Management of Vehicles

As part of the Depreciation Study, Concentric reviewed BC Hydro's current account (i.e., asset class) structure to find accounts where misalignment between the asset class life and the underlying assets may exist. As an outcome of this review, Concentric recommends that BC Hydro align its vehicle-related asset classes with its management of vehicle assets. Concentric notes that "the currently utilized account structure for vehicles was leading to non-homogeneous assets being grouped together".[480] BC Hydro highlights the following three examples:

- Asset class C81702 Line / Service / Van Body includes vehicle assets that in practice have varying economic lives and expected salvage rates. In the new structure, these assets are expected to be included in multiple classes: the Light Vehicles, Medium Vehicles and Walk-in Van asset classes;
- The asset class C81401 Trucks > = 1 Ton 4 Wheel Drive includes vehicle assets that in practice have varying economic lives and expected salvage rates. In the new structure, these assets are expected to be included in multiple classes: Medium Vehicles, Bucket Trucks > 50', Bucket Trucks 40 – 50', and Bucket Trucks < 40'; and
- Aerial devices are currently recorded in their own asset class with a 13-year useful life; however, in practice, aerial devices are attached to vehicles that can have a different useful life. When the vehicle is sold it includes the attached aerial device. In the new asset class structure, aerial devices will be included in the asset class of the underlying vehicle asset, better aligning with the expected economic life.

Replacing the current vehicle asset classes with the new proposed vehicle asset classes will result in the proceeds received on the sale of each vehicle asset being more closely aligned with its residual value (positive salvage) resulting in a reduction in individual vehicle asset gains or losses. While BC Hydro transitions to the new vehicle asset class structure, Concentric has provided composite rates, both useful lives and positive salvage percentages, for the existing asset classes.[481] The composite rates provided by Concentric for existing classes are expected to result in

[480] Depreciation Study, p. 3-6, section 3.5 of Appendix T.
[481] For further discussion, please refer to section 3.3 Account Reorganization of the Depreciation Study in Appendix T.

depreciation expense and asset losses that will approximate the results of using the new proposed asset classes.

BC Hydro plans to implement the new asset classes in fiscal 2022 and will capture new additions in the new asset classes once the asset classes are created. By the close of fiscal 2023 at the latest, BC Hydro will transfer assets in the existing asset classes to the new asset classes and then discontinue the existing asset classes.

8.3.1.5 BC Hydro is Accelerating Depreciation for Assets Pending Retirement

During the study, Concentric identified that it is important to evaluate where assets are scheduled for premature retirement and for which the standard asset class lives determined in the study may not apply. In section 3.2.6, *Life Span Dates,* of the study, Concentric states:

> "Life expectancy of electric generation and substation plant assets is impacted not only by physical wear and tear of the assets but also by economic factors including the feasibility of the economic replacement of major operating components or the economic viability of the plant as a whole."

BC Hydro identified assets at 19 locations which are primarily substations (Location Assets), that are scheduled for premature retirement or decommissioning between fiscal 2022 and fiscal 2035.

As stated by Concentric in section 3.2.6:

> "The use of life span dates for determining depreciable lives for regulated electric generation plant is common throughout many North American regulatory jurisdictions."

Concentric recommends the locations as listed in section 3.2.6 of the report be depreciated on a remaining life basis incorporating the life span dates[482] noted in the table. The net book value of all assets scheduled for premature retirement are

[482] A list of the location assets and Concentric's recommendations to adopt life span dates are found in Table 2 in Section 4 and section 3.2.6, Life Span Dates, of the Depreciation Study.

depreciated at a rate of 1/(Remaining life span). The impact of truncating the useful lives of these assets is an $8.5 million increase in depreciation expense over the Test Period.

The recommendation of Concentric is consistent with BC Hydro's practice of shortening asset lives where assets are scheduled for premature retirement.

8.3.1.6 BC Hydro is Forecasting Asset Retirement Losses based on Useful Lives, Positive Salvage Percentages, and Iowa Curve Recommendations

BC Hydro is updating its forecast asset retirement losses based on recommendations by Concentric in Table 1 of section 4 of the Deprecation Study.

BC Hydro incurs asset retirement losses upon the retirement of assets. BC Hydro records assets on an individual basis or on a mass (i.e., pooled) basis. Mass assets are typically high volume, low unit cost items, whereas individual units are typically low volume, high cost items. Assets are retired when the assets are replaced, retired, or decommissioned.

BC Hydro uses Iowa[483] survivor curve statistical retirement assumptions as a primary factor to forecast the retirements of mass assets and the losses attributable to those retirements. Each survivor curve identifies the amount of property existing at each age throughout the life of an original group. The amount of property that no longer exists (retirements) is the difference between the amount of property remaining at a point of time and the original amount of property. Retirements before the average life for the survivor curve result in losses as the property is not fully amortized prior to reaching the average age for the group. BC Hydro uses the difference between the existing property at time X, minus the existing property at time X-1, to forecast the amount of property retired in a period. The forecast

[483] The Iowa curves are survivor curves developed in a study at the University of Iowa comprised of a set of 31 standardized patterns of asset retirement dispersion.

remaining net book value associated with the forecast retired property for the period is the forecast loss.

In the Depreciation Study, Concentric recommends Iowa curves which have resulted in reductions in forecast retirements. The recommended Iowa curves for mass assets can be found in Table 1 of Section 4 of the Deprecation Study.

The combination of the reductions in forecast retirements and recommended changes in useful lives results in a reduction in forecast mass asset retirement losses, net of related impacts on contributions in aid amortization, for these asset classes. The decrease is $6.0 million in fiscal 2023, $7.4 million in fiscal 2024 and $6.8 million in fiscal 2025.

In addition, Concentric recommends updated useful lives and positive salvage percentages for fleet vehicles which is expected to reduce asset retirement losses. As discussed in section 8.3.1.3, the expected change is forecast to be a decrease of $1.3 million in fiscal 2023, $1.4 million in fiscal 2024, and $1.0 million in fiscal 2025.

The total of the change for mass asset retirements and changes to fleet assets is a decrease of $7.3 million in fiscal 2023, $8.8 million in fiscal 2024, and $7.8 million in fiscal 2025.

8.3.1.7 Implementation of Depreciation Study Results in Net Reduction in Depreciation Expense over the Test Period

BC Hydro forecasts that implementing Concentric's recommendations will result in a reduction in depreciation expense, asset retirement losses and Miscellaneous Revenue totalling $30.7 million over the Test Period, which represents a 1.0 per cent decrease. This is offset by a $28.6 million increase in depreciation expense, net of asset retirement expense and miscellaneous revenue impacts, as a result of implementing Concentric's recommendations for fiscal 2022, which BC Hydro has deferred to the Depreciation Study regulatory account for recovery over the Test Period. The reasons for these impacts are summarized below.

Implementing the useful life, life span dates and positive salvage percentage changes recommended in the Depreciation Study impacts depreciation expense in the following ways:

- The useful lives determine the period over which BC Hydro amortizes the remaining book values of the assets. Therefore, depreciation expense increases or decreases as the remaining book values of the assets are amortized over a shorter (i.e., useful life reduction) or longer (i.e., useful life extension) life, respectively, compared to the life of the asset used previously;
- The positive salvage percentages impact the amount of the book value to depreciate. The depreciable amount of an asset is the book value of the asset less the residual value of the asset. The depreciation expense for an asset increases if the salvage percentage decreases (i.e., residual value decreases) as the amount of the asset book value subject to depreciation increases; and
- The reduction in the useful lives of assets as a result of an end of life date (or life span date) increases depreciation expense as the asset remaining book values are depreciated over a shorter period.

Implementing the useful life and positive salvage percentage changes recommended in the Depreciation Study also impacts asset retirement expenses and miscellaneous revenue:

- Asset retirement expenses (losses on retirement) are impacted by the net book value of the assets at the time of retirement and the timing of retirement. The useful life and/or salvage percentages changes impact the net book values of assets at retirement. As mass asset retirements losses are forecast based on Iowa curve assumptions, changes in Iowa curve assignments impact the estimated timing of retirement; and
- Miscellaneous revenues include the amortization of contributions in aid of construction. Contributions in aid of construction are amortized over the useful

life of the related asset in most cases. Therefore, reducing or extending the useful life of assets will decrease or increase, respectively, the amortization of contributions in aid, recognized as Miscellaneous Revenue, over the Test Period.

Table 8-4 below provides a breakdown of the estimated increase / (decrease) in expenses as the result of implementing the recommendations of the Depreciation Study.

Table 8-4 Depreciation Study Impact

$/millions Increase/(Decrease)	F2022	F2023	F2024	F2025	F2023-F2025 Total
Useful lives (Depreciation Rates) and Positive Salvage Percentages	26.4	(5.8)	(3.9)	(4.9)	(14.6)
Accelerated Depreciation of Assets Pending Retirement (Life Span Dates)	9.7	4.0	3.2	1.4	8.5
Sub-Total Depreciation Expense Impact	**36.1**	**(1.8)**	**(0.7)**	**(3.5)**	**(6.0)**
Asset Retirements Expense Impact	(6.6)	(7.3)	(8.8)	(7.8)	(23.8)
Sub-Total Depreciation Expense and Asset Retirements Impact	**29.5**	**(9.1)**	**(9.5)**	**(11.3)**	**(29.9)**
Miscellaneous Revenue (Amortization of CIAC)	(0.9)	(0.3)	(0.3)	(0.3)	(0.8)
Net Impact from the Depreciation Study Before Regulatory Transfer	**28.6**	**(9.4)**	**(9.7)**	**(11.6)**	**(30.7)**
Regulatory Transfer (excl. interest)	**(28.6)**	**9.5**	**9.5**	**9.5**	**28.6**
Net Impact After Regulatory Transfer	**-**	**0.1**	**(0.2)**	**(2.1)**	**(2.1)**

Depreciation Expense, Asset Retirement Expense, and Miscellaneous Revenue (amortization of CIAC), using the new useful lives, Iowa curves, and salvage percentages, are forecast to decrease by 1.0 per cent in total for the fiscal 2023 to fiscal 2025 period, and decrease by 0.7 per cent for the 10-year period fiscal 2022 to fiscal 2031 compared to the forecast amounts for the same periods, using the pre-study assumptions. The aggregate change over the Test Period is a reduction in expense of $2.1 million.

The increase in fiscal 2022 expense is primarily due to the impact of decreasing the useful lives of 45 asset classes and the impact of accelerated depreciation of the assets pending retirement to match their retirement (or life span) dates.

Therefore, BC Hydro is seeking approval from the BCUC to implement the recommendations from the Depreciation Study for ratemaking purposes beginning in fiscal 2022,[484] which includes:

- Adoption of the revised useful lives and positive salvage percentages as listed in Table 1 in Section 4 of the Depreciation Study to calculate depreciation expense, as discussed in sections 8.3.1.2 and 8.3.1.3;
- Adoption of the changes to vehicle asset classes as recommended in section 3.3 of the Depreciation Study, as discussed in section 8.3.1.4; and
- Creation of a new asset class for Electric Vehicle Charging Station assets and useful life as recommend in section 3.5 of the Depreciation Study, as discussed in section 8.3.1.2.1.

8.4 BC Hydro Expects to Phase in a Traditional Approach to Net Salvage Beginning in the Next Test Period

8.4.1 BC Hydro has Responded to BCUC Directions on Dismantling Costs

Net Salvage represents the net costs that BC Hydro incurs when there is a difference between the positive salvage (i.e., what the retired asset was sold for) and the cost of dismantling an asset. Currently, BC Hydro only includes positive salvage percentages in its depreciation expense and expenses dismantling costs as incurred, which is referred to as the “pay as you go” approach to net salvage. In its Decision on BC Hydro’s F2020-F2021 RRA, the BCUC directed BC Hydro to:

[484] The impact of implementing the Depreciation Study in fiscal 2022 has been approved to be deferred to the Fiscal 2022 Depreciation Study Impact regulatory account.

- Assess the current approach for recovering dismantling costs and determine if it would result in intergenerational inequity;
- Assess alternatives to expensing dismantling as it is incurred; and
- Include as part of the Deprecation Study, a Net Salvage Study, and report on the results and recommendations along with BC Hydro's implementation plan.

As noted above, in response to these directives, BC Hydro retained Concentric to assess methodologies used for recovery of dismantling cost, recommend an appropriate methodology, perform a net salvage study for determination of negative salvage rates, and evaluate whether the implementation of net salvage rates is appropriate for BC Hydro.

Concentric completed a review of different net salvage recovery mechanisms used throughout North America and the applicability of these mechanisms to the BC Hydro system. The results of this review are included in the Report conducted by Larry Kennedy, Senior Vice President of Concentric, which is included in section 2 of Appendix T. In the Report, Concentric recommends the Traditional Method of net salvage applied on a functional group basis.[485]

Consistent with Concentric's recommendations, BC Hydro is requesting approval to implement net salvage rates for ratemaking purposes in the next test period using the Traditional Method and net salvage rates recommended by Concentric in Table 1, in section 4 of the Depreciation Study, and using a phased-in approach subject to BCUC review and approval in BC Hydro's next revenue requirements application.

The following subsections are organized as follows:

[485] Concentric's recommended negative salvage rates are included in Tables 1 and 3 of Section 4 of the Depreciation Study, in Section 1 of Appendix T.

- Section 8.4.2 discusses how BC Hydro's existing "pay as you go" approach can lead to intergenerational inequity;
- Section 8.4.3 discusses the alternative approaches to dismantling costs examined by Concentric, and the proposed Traditional Method; and
- Section 8.4.4 discusses BC Hydro's proposed phased approach to the implementation of net salvage rates using the Traditional Method.

8.4.2 Intergenerational Inequity of Dismantling Expense

BC Hydro's assessment is that its current approach of expensing dismantling costs as they occur can result in intergenerational inequity. This is because the cost of dismantling is recognized at a point in time, rather than being recognized equally over the life of the asset while it is in service. The population of ratepayers at the end of the asset's life will be a different population than those at the beginning, or through its life. The ratepayers at the asset's end of life will bear a disproportionate cost of the asset as they will bear the full cost of dismantling in addition to the amortization of the asset, whereas the ratepayers earlier in the asset life cycle will only pay for the amortization of the asset.

8.4.3 Alternatives and Recommended Approach for Recovering Dismantling Expense

In Section 2 of the Report, Concentric considers five alternative methodologies for the recovery of dismantling costs[486]:

- Use of the Traditional Method to calculate the required net salvage percentage;
- Use of the Constant Dollar Net Salvage to calculate the required net salvage percentage;
- Expensing cost of removal as incurred (also known as "Pay as you go"), which is BC Hydro's current methodology;

[486] Refer to section 2 of Appendix T for detailed descriptions of these five alternatives.

- Capitalizing cost of removal to the installation cost of replacement; and
- Trust Fund and Securitization methods.

In section 3 of the Report, Concentric analyzed the five alternatives, considering the following principles:

- Alignment and matching of the depreciation expense to the rate base providing used and useful service;
- Ability of the method to respond to changes in the cost of removal estimates;
- Ability to deal with the impacts of inflation;
- Impact on the revenue requirement;
- Ensuring the future cost requirements are adequately provided for;
- Providing for smoothed methods of Cost of Removal/Retirement recovery; and
- Regulator acceptance.

Based on its analysis, Concentric recommends that BC Hydro implement the Traditional Method of net salvage. The Traditional Method of net salvage uses analysis of historical retirements to determine a rate to be included in depreciation expense to account for dismantling or removals expenses over the life of the asset. The net salvage expense is accumulated in a liability account and is drawn down over time as assets are dismantled or removed. Concentric provides a detailed analysis of the methodology to calculate this method and provides advantages and disadvantages to the approach in section 2 of the Report. Concentric concludes:

> "When considering both the ranking of the various options to the identified objectives to consider, and the preference of most regulators to adopt a prospective rate making approach, I find the Traditional Method to be most appropriate for BC Hydro at this time. The recommended Traditional Approach is consistent with the recent approvals by the BCUC for the use of this same Traditional Approach for FortisBC Inc., FortisBC Energy, and Pacific Northern Gas. It is also the most accepted method of

> recovering future costs of removal by regulators throughout North America."

BC Hydro agrees with Concentric's recommendation to implement the Traditional Method of net salvage. BC Hydro considers that a net salvage approach provides intergenerational equity for the costs of dismantling, whereas the "pay as you go" method of expensing in the current period does not.

8.4.4 BC Hydro Requests Approval to Implement Net Salvage in its Next Revenue Requirements Application

In its next revenue requirements application, BC Hydro will propose an implementation plan for net salvage. BC Hydro currently expects to propose to phase in the implementation of net salvage percentages over six years, commencing in fiscal 2026 at the earliest (i.e., phase in over fiscal 2026 to fiscal 2031). There are two key reasons for this approach.

First, it is not feasible for BC Hydro to implement net salvage in the Test Period. To implement the Traditional Method, BC Hydro needs to:

- Establish net salvage expense policy and procedures;
- Determine specifically how net salvage will be calculated (e.g., monthly, one-year lag) and how variances to plan will be treated;
- Determine the approach to record net salvage transactions in the financial system;
- Refine the estimates of impacts to customer rates; and
- Finalize an implementation plan.

BC Hydro proposes to conduct this work over the Test Period and propose a fully developed implementation plan, in the next revenue requirements application, that would phase in net salvage beginning in fiscal 2026 at the earliest.

Second, BC Hydro is proposing a phase-in approach to mitigate the rate impact of implementing the recommended net salvage percentages.

Concentric recommends using a phase-in approach over a period of up to 10 years to help mitigate the short-term impact to rate payers. Concentric states:

> "The recovery of the future costs of removal on a prospective rate making approach through use of the Traditional Method, will eliminate the need for the currently estimated revenue requirement inclusion of the current period cost of removal. As such, the impact of implementation of the Traditional Approach will be partially offset by the exclusion of the pay as you go estimates currently being included in the revenue requirement. However, it is recognized that the implementation of the Traditional Method will have a revenue requirement impact, even after consideration that the "Pay as you go" amounts are eliminated. As such, I note that a phase-in period is often considered to be appropriate when the traditional method is introduced.
>
> A phase-in to complete implementation of the Traditional Method as soon as practicable best aligns with the objectives outlined in this evidence. However, implementation should also consider the need to mitigate rate impacts. As such, in my opinion, a period of complete implementation covering a period of up to 10 years is recommended."

BC Hydro's forecast dismantling costs are shown in Table 8-5 below.

Table 8-5 Forecast Dismantling Costs

$/millions Increase/(Decrease)	F2023	F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2023-F2030 Total
Forecast Dismantling Expenditures	53	46	45	53	52	70	48	105	472

If there is no phase-in approach to implementing net salvage, the applicable net salvage amounts would replace the dismantling amounts (from Table 8-5 above) immediately upon implementation (i.e., starting in fiscal 2026). Table 8-6 shows the resulting estimated increase in expense with no phase-in.

Table 8-6 No Phase-in, Net Salvage starting in Fiscal 2026

$/millions Increase/(Decrease)	F2023	F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2026-F2030 Total
Forecast Dismantling Expenditures	53	46	45	53	52	70	48	105	328
Net Salvage Estimated Expense	N/A	N/A	N/A	112	118	122	130	136	618
Change in Expense	**N/A**	**N/A**	**N/A**	**59**	**66**	**52**	**82**	**31**	**290**
Net Salvage Account Balance	**N/A**	**N/A**	**N/A**	**59**	**125**	**177**	**259**	**290**	

As shown in the table above, the expense amount that would be included in the fiscal 2026 revenue requirements would be the net salvage expense of $112 million, which is $59 million higher than if the dismantling approach was retained. The total expense amount for fiscal 2026 to fiscal 2030 would be the net salvage expense total of $618 million which is $290 million higher than if the dismantling approach was retained.

Under a phase-in approach, net salvage expense is calculated such that it replaces dismantling amounts over the phase-in period. Table 8-7 below estimates the impacts of implementing net salvage starting in fiscal 2026 with a 6-year phase-in approach.

Table 8-7 Six-Year Phase-in Approach

$/million Increase/(Decrease)	F2023	F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2026-F2030 Total
Forecast Dismantling Expenditures	53	46	45	53	52	70	48	105	328
Net Salvage Estimated Expense	N/A	N/A	N/A	63	74	96	103	131	467
Change in Expense	**N/A**	**N/A**	**N/A**	**10**	**22**	**26**	**55**	**26**	**139**
Net Salvage Account Balance	**N/A**	**N/A**	**N/A**	**10**	**32**	**58**	**113**	**139**	

As shown in Table 8-7 above, the expense amount that would be included in the fiscal 2026 revenue requirements would be the net salvage expense of $63 million, which is $10 million higher than if the dismantling approach was retained. The total expense amount for fiscal 2026 to fiscal 2030 would be the net salvage expense total of $467 million which is $139 million higher than if the dismantling approach was retained.

The net salvage estimate shown in Table 8-7 above is calculated as follows:

- The negative salvage rate for each functional group multiplied by the forecast asset cost balance for the applicable functional group; and
- For each year of the phase-in, the amount included in rates would be 1/6th of the above calculation plus the forecast dismantling expense less 1/6th of the forecast dismantling expense.

For clarity, in this example where the phase-in period is assumed to be six years, the phase-in approach net salvage expense calculation would result in 1/6th of the forecast net salvage calculated amount being included in year 1, as well as 5/6th of the forecasted dismantling expenditures for that year. In year 2, it would be 2/6th of forecast net salvage plus 4/6th of the forecast dismantling, and so on such that by year 6, dismantling expense is fully replaced by net salvage expense.

The estimated fiscal 2026 net salvage expense of $63 million is calculated as follows:

- Fiscal 2026 net salvage (per Table Y) = $112 million * 1/6th = $18.7 million
- Fiscal 2026 dismantling (per Table X) = $53 million * 5/6th = $44.2 million
- Total $62.9 million

BC Hydro acknowledges that the net salvage approach involves increased costs for ratepayers and will consider this further before finalizing its proposed approach in the next RRA, including whether to adjust the proposed phase-in period.

Implementation of net salvage will require BCUC approval of a new regulatory account. Without a regulatory account, the proposed adoption of the Traditional

Method of net salvage accounting is not compliant with IFRS. Under IFRS IAS 37 *Provisions, Contingent Liabilities and Contingent Assets,* provisions for asset decommissioning costs are only permitted when a legal or constructive obligation exists. The proposed adoption of the Traditional Method involves building up a provision for the future asset decommissioning costs for assets that do not meet the IAS 37 requirements for establishing decommissioning provisions.

Therefore, in its next revenue requirements application, BC Hydro expects to propose the establishment of a new Net Salvage Regulatory Account that would be classified as a benefits matching regulatory liability account as the future costs of expected net salvage would be recovered from ratepayers as they receive the benefits of the use of the assets. Under this approach, actual net salvage amortization expense would be deferred to the account. BC Hydro also expects to propose that the variance between forecast salvage amortization and actual salvage amortization would be deferred to the account and that the balance of the deferred variances at the end of a test period would be amortized over the following test period so that ratepayers are charged the actual net salvage amortization over time.

The regulatory account would exclude:

- Asset classes with positive salvage percentages as IAS 16 *Property, Plant and Equipment* requires positive salvage to be reflected in the calculation of depreciation expense; and
- Assets with Asset Retirement Obligations established in accordance with IAS 37 *Provisions, Contingent Liabilities and Contingent Assets.*

BC Hydro expects to propose that actual dismantling and restoration costs, excluding dismantling and restoration costs attributable to assets with Asset Retirement Obligations in accordance with IAS 37 *Provisions, Contingent Liabilities and Contingent Assets,* would be recorded as a reduction to the Net Salvage regulatory account regardless of whether the reductions resulted in the account having a debit balance.

Therefore, BC Hydro is requesting BCUC approval to:

- Implement net salvage rates for ratemaking purposes beginning in the next test period using the Traditional Method and the net salvage rates recommended by Concentric in Table 1, in section 4 of the Depreciation Study, and using a phased-in approach subject to BCUC review and approval in BC Hydro's next revenue requirements application.

As part of its next Revenue Requirement Application, BC Hydro will:

- Describe the phase-in approach for BCUC review and approval; and
- Request approval of a Net Salvage Regulatory Account to facilitate the implementation of net salvage.

8.5 Return on Equity

BC Hydro's return on equity is prescribed by section 3 of Direction No. 8 to the BCUC, as amended by Order in Council No. 172 issued on March 22, 2021, as a specific dollar amount of $712 million for fiscal 2022 and fiscal 2023. Specifically, Direction No. 8 requires that the BCUC must allow BC Hydro to collect sufficient revenue to achieve an annual rate of return on deemed equity to yield a distributable surplus of $712 million for each of fiscal 2022 and fiscal 2023.

Direction No. 8 (as amended by OIC No. 172) does not mandate BC Hydro's return on equity beyond fiscal 2023; for fiscal 2024 onwards, the BCUC is able to determine BC Hydro's Return on Equity. In the Final Report from Phase 1 of the Comprehensive Review of BC Hydro, the Government of B.C. indicated that "… Government may provide policy guidance to the BCUC and/or participate in regulatory proceedings to inform this process."[487] Government has not yet provided policy guidance in this regard.

BC Hydro will need to file a Cost of Capital application within fiscal 2022 to recommend an appropriate return on equity that would apply beginning in fiscal 2024. As discussed further in Chapter 1, section 1.4.1.2, BC Hydro proposes that fiscal 2024 and fiscal 2025 rates remain interim until the BCUC renders a decision on BC Hydro's Cost of Capital application. Interim rates would reflect the *status quo* forecasting of return on equity to collect sufficient revenue to achieve an annual rate of return on deemed equity to yield a distributable surplus of $712 million for fiscal 2024 and fiscal 2025 based on 30 per cent deemed equity. BC Hydro submits that using the *status quo* net income as a placeholder makes sense in the absence of any evidentiary basis to choose a different amount.

BC Hydro expects to seek approval of permanent rates based on its approved return on equity in a future compliance filing after the BCUC has issued its decision on BC Hydro's Cost of Capital application. The timing of fiscal 2024 and fiscal 2025 rates becoming permanent would depend on whether rates needed to remain interim for any other reason.[488] At the time rates are to be made permanent, BC Hydro will propose a mechanism to refund or collect from customers any variance between the forecast and approved return on equity.[489]

BC Hydro's dividend payment to the Province is prescribed by Heritage Special Directive No. HC1. In accordance with Order in Council No. 095 issued on March 5, 2014, for fiscal 2018 and subsequent years, the payment to the Province was reduced by $100 million per year based on the payment in the immediately

[487] Page 17 of the report, which can be found here: https://www2.gov.bc.ca/assets/gov/farming-natural-resources-and-industry/electricity-alternative-energy/electricity/bc-hydro-review/final_report_desktop_bc_hydro_review_v04_feb12_237pm-r2.pdf

[488] We discuss in Chapter 1, section 1.4.1 our proposal to leave rates interim in fiscal 2024 and fiscal 2025 pending future approval of a Demand Side Management expenditure schedule and a future assessment of the reasonableness of Site C Project costs.

[489] The calculation of BC Hydro's return on equity for the Test Period is set out in Appendix A, Schedule 9.

preceding fiscal year until it reached zero and will remain at zero until BC Hydro achieves a 60:40 debt to equity ratio.

There was no dividend payment to the Province for fiscal 2021. As shown on Appendix A, Schedule 9, line 20, BC Hydro’s forecast dividend payment to the Province is zero in each of fiscal 2022 to fiscal 2025 as BC Hydro’s forecast debt to equity ratio is higher than 60:40. BC Hydro’s debt to equity ratio is shown on Appendix A, Schedule 9, lines 24 and 25.

8.6 Finance Charges

BC Hydro’s approach to finance charges is consistent with the Previous Application.

Finance charges are primarily comprised of interest charges on BC Hydro’s debt. In addition, finance charges include interest related to leases recognized as lease obligations under IFRS 16, Leases and non-current pension costs. Total finance charges are calculated net of sinking fund income, finance charges capitalized to unfinished construction (interest during construction), and interest applied to regulatory accounts.

BC Hydro’s long-term debt is comprised of bonds and revolving borrowings obtained under agreement with the Government of B.C. BC Hydro’s debt is either held or guaranteed by the Government of B.C.

BC Hydro uses financial instruments, principally interest rate and foreign currency swaps, to manage interest rate and foreign exchange risks related to existing debt and forecast future debt issuances.

In accordance with BCUC Order No. G-42-16, mark-to-market gains and losses related to interest rate hedges of future long-term debt are captured in the Debt Management Regulatory Account and are amortized over the term of the associated long-term debt issuances beginning in the test period subsequent to that in which the associated debt is issued.[490]

To forecast finance charges, BC Hydro uses external market inputs and economic forecasts related to short and long-term interest rates and foreign exchange rates. This is consistent with the approach in the Previous Application.

Finance charges for debt are forecast as follows:

- For existing debt, BC Hydro forecasts finance charges based on the actual cost of the debt; BC Hydro's weighted average cost of existing debt at March 31, 2021 was 3.38 per cent;
- For debt that will be issued in the future that is unhedged, BC Hydro forecasts finance charges based on economic forecasts that are developed and provided by the Treasury Board of the Government of B.C. The most recent economic forecasts available at the time the finance charges forecast was prepared for the Application were as of March 2021 as shown in Table 8-8 below; and
- For debt that will be issued in the future and has either already been hedged or is expected to be hedged, BC Hydro forecasts finance charges based on the current market forward rates at the time the forecast is prepared. Mark-to-market gains or losses on hedges are recorded in the Debt Management Regulatory Account and these deferrals are shown in Table 8-8, line 3 below.

Table 8-8 below shows the forecast interest rates for debt that will be issued in the future that is unhedged and the forecast foreign exchange rates for fiscal 2023 to fiscal 2025 provided by the Treasury Board of the Government of B.C.

[490] As shown on Appendix A, Schedule 2.2. Further information regarding the Debt Management Regulatory Account is provided in Appendix R, and in the Fiscal 2021 Debt Management Regulatory Account Annual Status Report, provided as Appendix S.

Table 8-8 Forecast Interest Rates for Unhedged Debt and Forecast Foreign Exchange Rates

	F2022 Decision	F2023 Plan	F2024 Plan	F2025 Plan
Canadian Short-term Interest Rate (%)	0.39	0.31	0.61	1.30
U.S. Short-term Interest Rate (%)	0.48	0.39	0.71	1.45
Canadian Long-term Interest Rate (%) – 10-year	1.91	2.38	2.66	2.91
U.S. Long-term Interest Rate (%) – 10-year	1.97	2.25	2.61	2.86
US$/C$ Exchange Rate	0.7517	0.7867	0.7800	0.7810

Source: Treasury Board Forecast, July 2020 for F2022 Decision, March 2021 for F2023 to F2025 Plan.

BC Hydro's overall forecast Weighted Average Cost of Debt for fiscal 2023, fiscal 2024 and fiscal 2025 is 3.01 per cent, 2.98 per cent and 3.11 per cent, respectively.

Forecast finance charges are shown on Appendix A, Schedule 8.0 and are summarized in Table 8-9 below along with other regulatory account additions.

Table 8-9 Finance Charges

	($ million)	Schedule Reference	F2021 Actual	F2022 Decision	F2022 Forecast	F2023 Plan	F2024 Plan	F2025 Plan
			1	2	3	4	5	6
1	Total Gross Finance Charges	8.0 L12	251.6	555.6	720.8	581.2	564.5	704.1
2	Total Finance Charge Reg. Acct Additions	8.0 L32	61.7	-	(25.4)	-	-	-
3	Other Regulatory Account Additions	8.0 L14-L19+L33	509.0	(11.9)	(48.8)	(33.6)	(34.5)	(29.6)
4	Interest on Regulatory Accounts	8.0 L36	(18.2)	(24.5)	(18.0)	(19.4)	(21.0)	(22.8)
5	Regulatory Account Recoveries	8.0 L42	(108.3)	(65.2)	(173.8)	28.7	28.8	28.8
6	Total Current Finance Charges	8.0 L43	695.7	454.1	454.8	556.9	537.7	680.5

As shown in Table 8-9 above, total current finance charges are forecast to increase by $102.8 million from $454.1 million in fiscal 2022 Decision to $556.9 million in fiscal 2023 Plan, primarily due to:

- A change in regulatory account recoveries mainly related to Total Finance Charges Regulatory Account recoveries; and

- Increases in net debt.

Total current finance charges in fiscal 2024 Plan are forecast to decrease by $19.2 million (from $556.9 million in fiscal 2023 Plan to $537.7 million in fiscal 2024 Plan) primarily due to:

- An increase in interest during construction capitalized on increased unfinished construction balances; partially offset by
- Increases in net debt.

Total current finance charges in fiscal 2025 Plan are forecast to increase by $142.8 million (from $537.7 million in fiscal 2024 Plan to $680.5 million in fiscal 2025 Plan) primarily due to:

- A decrease in interest during construction because of lower unfinished construction balances mainly due to Site C assets going into service in fiscal 2025, and
- Increases in net debt.

8.7 Taxes

Taxes include school taxes and grants-in-lieu of general taxes. Consistent with the Previous Application:

- BC Hydro must pay provincial school taxes but is exempt from all other property taxes per the *Hydro and Power Authority Act*. School taxes are based on the assessed value of taxable assets as prepared by B.C. Assessment and tax rates that are established by the Government of B.C. School taxes are paid on all assessable property such as fee-owned land, buildings and electric system infrastructure (e.g., generating facilities, lines, stations) except for BC Hydro’s generation facilities on the Peace, Pend d'Oreille, and Columbia rivers; and

- The *Hydro and Power Authority Act* authorizes BC Hydro to pay grants-in-lieu of general municipal, rural area and regional district taxes. Order in Council No. 266/2016 and Order in Council No. 533/2017 set out the formula used to calculate the grant payments. Annual grants paid include the following items:
  - General grants equivalent to municipal, regional district and local improvement taxes on the assessed value of all land of BC Hydro and on the assessed value of improvements such as office buildings, field service buildings and substation control buildings. Assessed values of generating plants, substation equipment, transmission lines and distribution lines are excluded from this calculation;
  - Revenue grants equal to 1 per cent of gross revenue from sales of electricity within the province, excluding revenue from power sold to other distribution systems for resale; and
  - Special grants on dams, reservoirs and powerhouses. These grants are based on installed generating capacity, or imputed nameplate capacity in the case of storage dams.

Forecast school taxes and grants-in-lieu are shown on Appendix A, Schedule 6.0 and are summarized in Table 8-10 below.

Table 8-10 Taxes

	($ million)	Schedule Reference	F2021 Actual	F2022 Decision	F2022 Forecast	F2023 Plan	F2024 Plan	F2025 Plan
			1	2	3	4	5	6
1	Grants in Lieu	6.0 L18	117.3	118.0	124.6	126.8	131.9	135.6
2	School Taxes	6.0 L19	138.7	145.0	145.9	155.9	165.5	172.7
3	Other	6.0 L20+L22	0.8	0.8	0.8	0.8	0.8	0.9
4	Total Gross Taxes	6.0 L23	256.8	263.8	271.4	283.5	298.3	309.2
5	Transfer to NHDA	6.0 L24	-	-	-	-	-	-
6	Total Current Taxes	6.0 L25	256.8	263.8	271.4	283.5	298.3	309.2

As shown in Table 8-10 above, total taxes are forecast to increase by $19.7 million from $263.8 million in fiscal 2022 Decision to $283.5 million in fiscal 2023. Specifically:

- Grants in lieu are planned to increase in fiscal 2023 primarily due to higher municipal rates as well as anticipated increases to the assessed values of BC Hydro’s land and buildings, particularly in the Metro Vancouver region; and
- School Taxes are planned to increase in fiscal 2023 primarily due to:
  - A significant increase to the assessed values of all BC Hydro transmission lines and distribution lines resulting from the anticipated implementation by BC Assessment of an updated cost valuation model for these assets;
  - Anticipated increases to the assessed values of BC Hydro’s land, buildings and electric system assets; and
  - Elimination by the Province of the COVID-19 school tax relief provided for Business-class properties which impacts all of BC Hydro’s office facilities.

Fiscal 2024 and fiscal 2025 Plan amounts will be impacted by the same factors mentioned above. In addition, the fiscal 2024 and fiscal 2025 Plan amounts are forecast to increase due to an increase in Grants based on 1 per cent of increased domestic electricity sales.

8.8 Miscellaneous Revenues

Consistent with the Previous Application, miscellaneous revenues include revenues from amortization of contributions in aid of construction, lease and other revenues related to BC Hydro's purchase of the remaining two-thirds interest in the Waneta Dam from Teck Metals Ltd., external transmission revenues under the Open Access Transmission Tariff (**OATT**), meter/transformer rentals and power factor surcharges, late payment charges, building rentals, interconnections, low carbon fuel credits and other revenues.

Forecast miscellaneous revenues for the Test Period are shown on Appendix A, Schedule 15.0 and are summarized in Table 8-11 below.

Table 8-11 Miscellaneous Revenues[491]

	($ million)	Schedule Reference	F2021 Actual	F2022 Decision	F2022 Forecast	F2023 Plan	F2024 Plan	F2025 Plan
			1	2	3	4	5	6
1	Total Gross Miscellaneous Revenue	15.0 L46	261.1	289.0	300.5	288.5	292.9	295.3
2	Transfers to NHDA	15.0 L47	(5.0)	(15.5)	(15.5)	(2.8)	(3.7)	(2.4)
3	Transfers to Regulatory Accounts	15.0 L48	-	-	-	-	-	-
4	Total Current Miscellaneous Revenue	15.0 L49	256.1	273.5	285.0	285.7	289.2	292.8

As shown in Table 8-11 above, total Miscellaneous Revenues forecast for the Test Period, are relatively consistent with the fiscal 2022 Decision.

In its Decision on the Previous Application, the BCUC stated that it expects BC Hydro to justify any estimate of interconnections revenue not consistent with recent historical trends.[492] The interconnections revenue forecast is based on the operating cost forecast for interconnections. The average operating costs of the

[491] Based on the fiscal 2022 forecast amounts for various line items in the Application, thefiscal 2022 forecast net income was calculated at $697.5 million. However, as it remains early in the fiscal year and there is uncertainty in the forecast information, BC Hydro increased the fiscal 2022 forecast miscellaneous revenue amount by $6.9 million (from $293.6 million to $300.5 million) so that the fiscal 2022 net income forecast would be increased from $697.5 million to $704.4 million. This is a more appropriate forecast as BC Hydro expects to take steps to reduce the unfavourable fiscal 2022 net income forecast variance. The increase in the fiscal 2022 forecast miscellaneous revenue amount of $6.9 million has no impact on ratepayers.

[492] BCUC Decision and Order No. G-187-21, BC Hydro Fiscal 2022 Revenue Requirements Application (June 17, 2021), page 96.

three previous years (i.e., fiscal 2019, 2020 and 2021 actuals) was used to forecast the operating costs for interconnections studies and project work for the Test Period. Adjustments were made in fiscal 2024 and fiscal 2025 to reflect liquified natural gas (LNG) projects moving to the capital phase or slowing down, resulting in lower expected revenues from interconnections studies.

Table 8-12 below summarizes the interconnections revenue included in total gross Miscellaneous Revenue:

Table 8-12 Interconnections Revenue

($ million)	Reference	F2021 Actual	F2022 Decision	F2022 Forecast	F2023 Plan	F2024 Plan	F2025 Plan
Transmission Interconnection	Appendix A, sched 15, line 12	8.3	4.6	6.1	6.1	4.2	3.3
Distribution Interconnection	Appendix A, sched 15, line 18	-	-	0.9	0.9	0.9	0.9
Total Interconnection		8.3	4.6	6.9	7.0	5.0	4.1

Directive 26 of the BCUC's Decision on the Previous Application directed BC Hydro to increase its fiscal 2022 forecast revenue by the estimated value of the low carbon fuel credits that it plans to transfer to other parties, if any, during fiscal 2022. Directive 26 also directed BC Hydro to record forecast revenue, in all future revenue requirement applications, based on an estimate of the value of the low carbon fuel credits that it plans to transfer to other parties.[493]

Accordingly, included in total gross Miscellaneous Revenues, is Low Carbon Fuel Credits revenue of $31.4 million in Fiscal 2022 Decision and each year of the Test Period.[494]

BC Hydro transfers its low carbon fuel credits to Powerex in accordance with section 8 of the *Greenhouse Gas Reduction (Renewable and Low Carbon Fuel Requirements) Act* and section 11.11 of the *Renewable and the Low Carbon Fuel Requirements Regulation*. BC Hydro has estimated a value for the forecast revenue

[493] Directive 26;BCUC Decision and Order No. G-187-21, BC Hydro Fiscal 2022 Revenue Requirements Application (June 17, 2021), page 105.

[494] As shown in Appendix A, schedule 15.0, line 35.

related to low carbon fuel credits to comply with Directive 26. This value was calculated based on a historic five-year average. The low carbon fuel credit market is relatively new, and the policy framework continues to be developed. As a result, the volume of credits that BC Hydro will actually receive in a given fiscal year and the price that BC Hydro receives for these credits is highly uncertain.

Under this approach, BC Hydro calculated a dollar amount for each historical fiscal year as:

- The number of credits transferred by BC Hydro to Powerex in each fiscal year; multiplied by
- The observed market prices for the corresponding calendar year as reported by the Ministry of Energy, Mines and Low Carbon Innovation[495,496].

In the Compliance Filing for the Previous Application, BC Hydro used the formula above to calculate the dollar amount of low carbon fuel credit revenue for each of the fiscal years from 2016 to 2020 and determined a five-year average of $31.4 million.

Consistent with the Compliance Filing, the above formula was used to calculate a dollar amount for each of fiscal years from 2017 to 2021. The five-year average was then calculated as the average of those amounts, which is $31.4 million. This amount is used for fiscal 2023 through fiscal 2025.

The derivation of the annual and five-year average amounts is shown in Table 8-13 below.

[495] Refer to the Low Carbon Fuel Credit Market Report: https://www2.gov.bc.ca/assets/gov/farming-natural-resources-and-industry/electricity-alternative-energy/transportation/renewable-low-carbon-fuels/rlcf-017.pdf

[496] The results reported by the Ministry of Energy, Mines and Low Carbon Innovation are in calendar years. BC Hydro has mapped calendar year 2019 to fiscal 2020, since nine of the 12 months in calendar year 2019 are in fiscal 2020. Likewise, calendar year 2018 was mapped to fiscal 2019, and so on.

Table 8-13 Low Carbon Fuel Credits Revenue

		F2017	F2018	F2019	F2020	F2021	5 Year Average (F2017 to F2021)
A	Number of Low Carbon Fuel Credits Transferred to Powerex	145,831	144,160	154,895	153,535	148,713	
B	Average Price per Credit ($)	$ 170.93	$ 164.30	$ 193.44	$ 269.33	$ 250.44	
C=A*B	Value of Low Carbon Fuel Credits ($ million)	**$ 24.9**	**$ 23.7**	**$ 30.0**	**$ 41.4**	**$ 37.2**	**$ 31.4**

This methodology uses the observed market prices for the corresponding year, as reported by the Ministry of Energy, Mines and Low Carbon Innovation, as an input, which includes transactions by Powerex. As the BCUC stated in its Decision, "The Panel also recognizes that the amount received by Powerex would not be the same as the amount that BC Hydro would have received had it sold the credits directly."[497] An appropriate transfer price, which reflects the stand-alone value of the low carbon fuel credits to BC Hydro, will result in a different realized value.[498]

BC Hydro and Powerex have been engaged in negotiating a new transfer pricing agreement for low carbon fuel credits with a transfer price that reflects the stand-alone value of the low carbon fuel credits to BC Hydro. BC Hydro and Powerex expect to finalize this transfer pricing agreement by the end of fiscal 2022.

In addition to increasing miscellaneous revenue by $31.4 million, BC Hydro has made an equivalent reduction to planned Trade Income as discussed in section 8.10 Subsidiary Net Income. Since Powerex has been receiving these credits at zero cost and the sales of these credits have been reflected in Powerex's actual net income, which is used to calculate the rolling five-year average of Trade Income, any credit revenue included in BC Hydro's revenue forecast must be offset by an equivalent reduction in planned Trade Income, to prevent double-counting.

[497] BCUC Decision and Order No. G-187-21, BC Hydro Fiscal 2022 Revenue Requirements Application (June 17, 2021), page 105.

[498] For further discussion on this point, refer to BC Hydro's Compliance to the Previous Application, provided as Appendix Z.

8.9 Inter-Segment Revenues

Consistent with the Previous Application, Inter-Segment revenues include the following allocations:

- The allocation of business support costs to Powerex as discussed in section 8.11;
- Mark-to-Market Losses (Gains) related to transactions under the Transfer Pricing Agreement between BC Hydro and Powerex. These mark-to-market gains or losses are based on changes in forward prices and/or volumes. As they cannot be accurately forecast for a given fiscal year before that year starts, BC Hydro forecasts no gains or losses; and
- The allocation of point-to-point transmission costs to BC Hydro and Powerex under the 2020 Transfer Pricing Agreement between BC Hydro and Powerex.

Forecast Inter-Segment revenues for the Test Period are shown on Appendix A, Schedule 3.0 and are provided in Table 8-14 below.

Table 8-14 Inter-Segment Revenues

($ million)	Schedule Reference	F2021 Actual	F2022 Decision	F2022 Forecast	F2023 Plan	F2024 Plan	F2025 Plan
		1	2	3	4	5	6
Powerex - Corporate Allocation	3.0 L43	(2.9)	(2.9)	(2.9)	(0.3)	(0.3)	(0.4)
2020 TPA Revaluation Mark-to-Market (gains)/losses)	3.0 L44	90.0	-	-	-	-	-
Powerex PTP Charges	3.0 L45	(41.7)	(34.4)	(38.2)	(39.0)	(39.8)	(40.6)
BC Hydro PTP Charges	3.0 L46	(30.4)	(46.3)	(31.9)	(32.5)	(33.2)	(33.9)
Total Current Inter-Segment Revenues	3.0 L47	15.0	(83.5)	(73.0)	(71.8)	(73.4)	(74.8)

As shown in Table 8-14 above, total Current Inter-Segment Revenues are forecast to decrease by $11.7 million (from $83.5 million in the fiscal 2022 Decision to $71.8 million) in fiscal 2023, primarily due to a decrease in the total point-to-point cost forecast. In addition, in fiscal 2021, a revised calculation of the allocation of revenue recovered through the PTP allocation between BC Hydro and Powerex was developed to implement the 2020 Transfer Pricing Agreement (**TPA**), as the 2020 TPA differs from the 2003 TPA. The allocation of point-to-point charges between BC Hydro and Powerex is discussed in Chapter 9, section 9.2.7.

The fiscal 2024 and fiscal 2025 Plan amounts are forecast to be stable with annual increases of $1.6 million and $1.4 million, respectively.

8.10 Subsidiary Net Income

The inclusion of subsidiary net income in BC Hydro's revenue requirements reduces the overall revenue requirements. Consistent with the Previous Application, subsidiary net income includes Trade Income for Powerex Corp. (**Powerex**) and the net income of Powertech Labs (**Powertech**). In this application, BC Hydro is also including the planned net income of BCHPA Captive Insurance Company Ltd. (**BCHPA CIC**) and Columbia Hydro Constructors Ltd. (**CHC**).[499]

Trade Income

On March 22, 2021, the Government of B.C issued Order in Council (**OIC**) No. 172, which amended Direction No. 8 to the BCUC to provide a definition of Trade Income[500] and which directs the BCUC as follows:

- Section 4(3): "In setting rates for the authority for a fiscal year, the commission must subtract from the costs to be recovered in rates an amount equal to the net incomes, for the fiscal year, of Powerex Corp. and Powertech Labs Inc.";
- Section 4(4): "For the purposes of subsection (3), (a) the net income of Powerex Corp. for the fiscal year is the amount equal to the trade income forecast by the authority for that fiscal year, and (b) the net income of

[499] This is consistent with BC Hydro's proposed approach for these subsidiaries in BC Hydro's responses to BCUC staff compliance filing information requests related to the F2020-F2021 RRA. Specifically, refer to BC Hydro's response to BCUC Staff IRs 1.12.1 and 1.13.2 at: https://www.bcuc.com/Documents/Proceedings/2021/DOC_62011_2021-04-01-BCH-F20-F21RRA-Compliance-to-BCUC-Staff-IR-1.pdf

[500] Section 1.1 of Direction No. 8: Trade Income is the greater of (a) the amount that is equal to BC Hydro's consolidated net income, less BC Hydro's non-consolidated net income, less the net income of BC Hydro's subsidiaries except Powerex, less any foreign currency translation gains on intercompany balances between BC Hydro and Powerex, plus any foreign currency translation losses on intercompany balances between BC Hydro and Powerex; and (b) zero.

Powertech Labs Inc. for the fiscal year is the amount forecast by the authority"; and

- Section 9: "In regulating and setting rates for the authority, the commission must allow the authority to continue to defer to the trade income deferral account the variances between actual and forecast trade income."

BC Hydro's approach to forecasting Trade Income and Powertech net income is consistent with Direction No. 8. In the Test Period, Trade Income is forecast at $224.2 million in fiscal 2023, fiscal 2024 and fiscal 2025 and is calculated based on an average of actual Trade Income over the last five years (i.e., fiscal years 2017 through 2021).

In this application, Trade Income, as shown in Table 8-15 below, is adjusted to remove low carbon fuel credit revenue that is now forecast in BC Hydro miscellaneous revenue, as directed by the BCUC in its decision on the Previous Application.[501]

Table 8-15 Trade Income Adjusted for Low Carbon Fuel Credit Revenue

($ million)	F2017	F2018	F2019	F2020	F2021	5 Year Average
Trade Income	$ 130.2	$ 136.6	$ 435.7	$ 189.2	$ 386.4	$ 255.6
Less: Low Carbon Fuel Credit Adj	$ (31.4)	$ (31.4)	$ (31.4)	$ (31.4)	$ (31.4)	$ (31.4)
Adjusted Trade Income	$ 98.8	$ 105.2	$ 404.3	$ 157.8	$ 355.0	$ 224.2

In accordance with Direction No. 8, variances between forecast and actual Trade Income are deferred to the Trade Income Deferral Account on an ongoing basis. However, if actual Trade Income in a given fiscal year is less than zero (i.e., a net loss), the transfer to the Trade Income Deferral Account would be the difference between the forecast Trade Income and zero. This means that a net loss in Trade

[501] The low carbon fuel credit amount and the methodology for determining the amount is described in section 8.8.

Income would be borne by the Government of B.C. as BC Hydro's shareholder and therefore ratepayers do not bear the risk of net losses in Trade Income.

Powertech

Powertech net income is forecast at $3.0 million, $3.5 million and $4.0 million in fiscal 2023, fiscal 2024 and fiscal 2025, respectively.

BCHPA CIC

BCHPA CIC net income is forecast at $0.01 million in fiscal 2023 and $0.02 million in fiscal 2024 and fiscal 2025.

CHC

CHC net income is forecast at nil as no net income is expected over the Test Period because CHC operates on a cost recovery basis.

Forecast subsidiary net income for the Test Period is shown in Appendix A, Schedule 3.0 and is provided in Table 8-16 below.

Table 8-16 Subsidiary Net Income

	($ million)	Schedule Reference	F2021 Actual	F2022 Decision	F2022 Forecast	F2023 Plan	F2024 Plan	F2025 Plan
			1	2	3	4	5	6
1	Powerex Trade Income	1.0 L18	(386.4)	(158.7)	(158.7)	(224.2)	(224.2)	(224.2)
2	Powertech Net Income	1.0 L19	0.9	(2.0)	(2.0)	(3.0)	(3.5)	(4.0)
3	Captive Insurance Net Income	1.0 L20	-	-	-	-	-	-
4	Columbia Hydro Contractors Net Income	1.0 L21	-	-	-	-	-	-
5	Total Gross Subsidiary Net Income	1.0 L22	(385.5)	(160.7)	(160.7)	(227.2)	(227.7)	(228.2)
6	Deferral Account Additions	2.1 L19+L20	154.5	-	-	-	-	-
7	Deferral Account Recoveries	2.1 L22	(105.1)	-	-	(113.4)	(57.5)	(28.5)
8	Total Current Subsidiary Net Income	3.0 L51+L52	(336.1)	(160.7)	(160.7)	(340.6)	(285.1)	(256.7)

As shown in Table 8-16 above, total gross subsidiary net income (i.e., line 8 above) is forecast to increase by $179.9 million (from $160.7 million in the fiscal 2022 Decision to $340.6 million in fiscal 2023), primarily due to the following:

- An increase of approximately $65.5 million in the five-year average that is used to forecast Trade Income, which has been adjusted to remove low carbon fuel credit revenue that is now forecast in BC Hydro miscellaneous revenue as directed by the BCUC in its decision on the Previous Application; and
- An increase in Deferral Account Recoveries (line 7) made through the Deferral Account Rate Rider (**DARR**) that was set at 0 per cent for fiscal 2022 and is forecast to be (2.0) per cent in fiscal 2023.

The fiscal 2024 and fiscal 2025 Plan amounts are forecast to decrease by $55.5 million and $28.4 million, respectively, from fiscal 2023 and fiscal 2024 amounts, respectively, primarily due to the forecast change in rate of the DARR over the Test Period. As the DARR is proposed to be set at (2.0) per cent for fiscal 2023, (1.0) per cent for fiscal 2024 and (0.5) per cent for fiscal 2025, deferral account recoveries (Trade Income Deferral Account recoveries included in the DARR) are $(113.4) million for fiscal 2023, $(57.5) million for fiscal 2024 and $(28.5) million for fiscal 2025 (i.e., line 7 above), resulting in a decrease in total current subsidiary net income (i.e., line 8 above).

8.11 Allocation of Business Support Costs

Allocation of business support costs in the Test Period are based on a forecast methodology that is consistent with the methodology used in previous revenue requirement applications.

Consistent with the Previous Application, for the purpose of determining the Transmission Revenue Requirement, BC Hydro’s business support costs are allocated to generation, transmission, distribution, and customer care functions.

Business support costs are expenditures that are required to support BC Hydro’s Plan, Build, and Operate work functions. These are the costs related to BC Hydro’s Support work function (e.g., finance, technology, human resources, communications, regulatory, safety, legal, etc.) and reside in several business groups across the company.

The forecast allocation of business support costs is shown on Appendix A, Schedule 3.1 and are summarized in Table 8-17 below.

Table 8-17 Allocation of Business Support Costs

	($ million)	Schedule Reference	F2021 Actual	F2022 Decision	F2022 Forecast	F2023 Plan	F2024 Plan	F2025 Plan
			1	2	3	4	5	6
1	Business Support Costs		(819.9)	(823.5)	(812.8)	(774.9)	(789.6)	(793.8)
2	Allocation to functional groups:							
3	Generation	3.1 L50	220.8	219.6	216.5	200.6	204.4	206.0
4	Transmission	3.1 L51	232.0	239.1	235.8	229.0	233.2	234.1
5	Distribution	3.1 L52	279.1	297.9	294.4	283.9	289.3	291.1
6	Customer Care	3.1 L53	85.1	64.1	63.2	61.1	62.3	62.3
7	Powerex	3.1 L15	2.9	2.9	2.9	0.3	0.3	0.4
8	Allocation of Business Support Costs		819.9	823.5	812.8	774.9	789.6	793.8
9	Business Support Costs Fully Allocated		-	-	-	-	-	-

As shown in Table 8-17 above, total business support costs are forecast to decrease by $48.6 million (from $823.5 million in fiscal 2022 Decision to $774.9 million in fiscal 2023 Plan), primarily due to the following:

- A decrease in amortization costs related to the Non-Current Pension Costs Regulatory Account as described in Chapter 5, section 5.12.4.3; partially offset by
- An increase in amortization costs primarily related to an increase in capital additions and the recoveries of the Depreciation Study Regulatory Account balance, as noted in section 8.3 above; and
- An increase in operating costs, as further described in Chapter 5, section 5.5.4.

The fiscal 2024 and fiscal 2025 Plan amounts are forecast to increase by $14.7 million and a further $4.2 million, respectively, from the fiscal 2023 Plan. The increase is primarily due to an increase in operating costs, further described in Chapter 5, section 5.5.4 and an increase in amortization costs related to property, plant and equipment, due to an increase in capital additions, further described in Chapter 6.

8.12 Provisions and Other

Consistent with the Previous Application, provisions and other includes gains and losses on capital assets, dismantling costs, provision expenses and other costs that are not within the scope of other Nature View[502] expense items on BC Hydro's financial statements.

Gains and losses on capital assets include mass asset retirements and capital asset write-offs.

Forecast provisions and other are shown on Appendix A, Schedule 5.01 and are also summarized in Table 8-18 below.

Table 8-18 Provisions and Other

	($ million)	Schedule Reference	F2021 Actual	F2022 Decision	F2022 Forecast	F2023 Plan	F2024 Plan	F2025 Plan
			1	2	3	4	5	6
1	Total Gross Provisions & Other	5.01 L45	163.7	101.4	97.4	104.9	96.7	95.3
2	Deferral Account Additions	5.01 L37	-	-	-	-	-	-
3	Regulatory Account Transfers	5.01 L44	(53.0)	-	0.4	-	-	-
	Regulatory Account Recoveries							
4	Remediation, Dismantling and Other	5.01 L23:L27	43.3	63.9	63.9	32.9	38.9	13.3
5	Total Current Provisions & Other	5.01 L29	154.0	165.3	161.7	137.8	135.6	108.6

As shown in Table 8-18 above, total provisions and other are forecast to decrease by $27.5 million (from $165.3 million in fiscal 2022 Decision to $137.8 million in fiscal 2023), primarily due to a decrease in the amortization of the Remediation Costs Regulatory Account due to lower forecast PCB and Asbestos remediation expenditures and amortization of an opening credit balance over the Test Period.

The fiscal 2024 Plan is forecast to remain consistent with the fiscal 2023 Plan. The fiscal 2025 Plan is lower than the fiscal 2023 and fiscal 2024 Plan amounts primarily

[502] Under the Nature View presentation, costs are classified by their nature (i.e., labour, materials, services, energy purchases, water rentals, amortization, etc.), rather than by their function.

due to a reduction in forecast PCB remediation expenditures included in the amortization of the Remediation Costs Regulatory Account.

8.13 International Financial Reporting Standards (IFRS)

BC Hydro prepares its financial statements in accordance with IFRS including IFRS 14, *Regulatory Deferral Accounts*, and has prepared this application in accordance with IFRS in effect at the time the forecast for this application was prepared.

In the Application, there were no new accounting standards adopted by BC Hydro or significant changes to accounting standards that would impact the Test Period.

The International Accounting Standards Board (**IASB**) has published an exposure draft of a new standard 'Regulatory Assets and Regulatory Liabilities' that is intended to replace the interim standard IFRS 14, *Regulatory Deferral Accounts*. Based on the current IASB timeline, the permanent accounting standard for Rate Regulated accounting may be in effect for fiscal 2025. BC Hydro will assess the impacts of the new standard when it is finalized and, depending on the impacts, may seek BCUC approval for new or revised regulatory accounts to defer potential impacts at adoption, for recovery/refund in a future revenue requirements application.

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BC Hydro Fiscal 2023 to Fiscal 2025 Revenue Requirements Application

Chapter 9

Transmission Revenue Requirement

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9.1 Introduction

This chapter describes how BC Hydro's proposed Open Access Transmission Tariff (**OATT**) rates are determined to recover BC Hydro's Transmission Revenue Requirement (**TRR**), consistent with past BCUC Orders.

The OATT commercializes BC Hydro's transmission capacity and facilitates participation in the electric industry by entities that may not own their own transmission systems. The OATT contains BCUC-approved terms and conditions through which OATT customers can access BC Hydro's transmission system on a comparable basis to BC Hydro, and similar to how entities access the transmission systems of electric utilities throughout the Western Interconnection. The OATT rates are the prices for transmission services purchased from BC Hydro and are applicable to all usage of the transmission system, including usage by BC Hydro itself and by external OATT customers. OATT customers are able to reserve transmission capacity on the transmission system, which they can use to schedule their energy requirements. The OATT considers only the commercialization of transmission capacity and BC Hydro does not sell energy through the OATT except for some ancillary services.

The rates charged under the OATT are for Network Integration Transmission Service (**NITS**), Point-To-Point (**PTP**) Transmission Service and Ancillary Services, as set out in Appendix II and summarized in Table 9-4.

The rates charged under the OATT are designed to collect the TRR, which is the sum of all costs associated with the assets used to provide transmission service under the OATT, and for which OATT customers are responsible according to the principle of cost causation. The cost causation methodology used by BC Hydro to calculate the TRR in the Application is consistent with the method used by both BC Hydro and the British Columbia Transmission Corporation (**BCTC**) in previous revenue requirement applications, which has been consistently applied and approved by the BCUC.

BC Hydro and Powerex are the main users of the transmission system and therefore account for approximately 99 per cent of the revenue collected through the OATT (forecast to be $1,110.2 million for fiscal 2023). Other transmission customers account for only approximately 1 per cent of the revenue (forecast to be $12.2 million for fiscal 2023). The OATT therefore recovers only a small fraction of the TRR from external customers. The amount recovered from external customers is forecast to be approximately $1.2 million higher than was forecast in the Previous Application, due to both increased long-term contracts and increased short-term usage by external customers.

This chapter is organized around the following key points:

- Section 9.2 describes how the TRR is determined through the direct assignment or allocation of transmission-related costs to the transmission function, based on cost causation principles and consistent with past practice; and
- Section 9.3 describes how the OATT rates are calculated consistent with past practice and past BCUC Orders.

9.2 TRR is Calculated Using a Cost Causation Allocation Methodology Consistent with Past Practice

BC Hydro's TRR is comprised of the current costs associated with BC Hydro's transmission lines and high-voltage station equipment used to provide transmission service pursuant to the OATT (**OATT-Related Assets**), which excludes both generation-related transmission assets and substation distribution assets. The methodology used to derive the TRR is based on cost causation. It is consistent with the methodology used in past BC Hydro and BCTC applications.[3.]

Figure 9-1 illustrates the allocation and direct assignment of costs used to establish the proposed OATT rates for fiscal 2023.

Figure 9-1 Fiscal 2023 Transmission Revenue Requirement Components ($ million) with References to Appendix A Financial Schedules

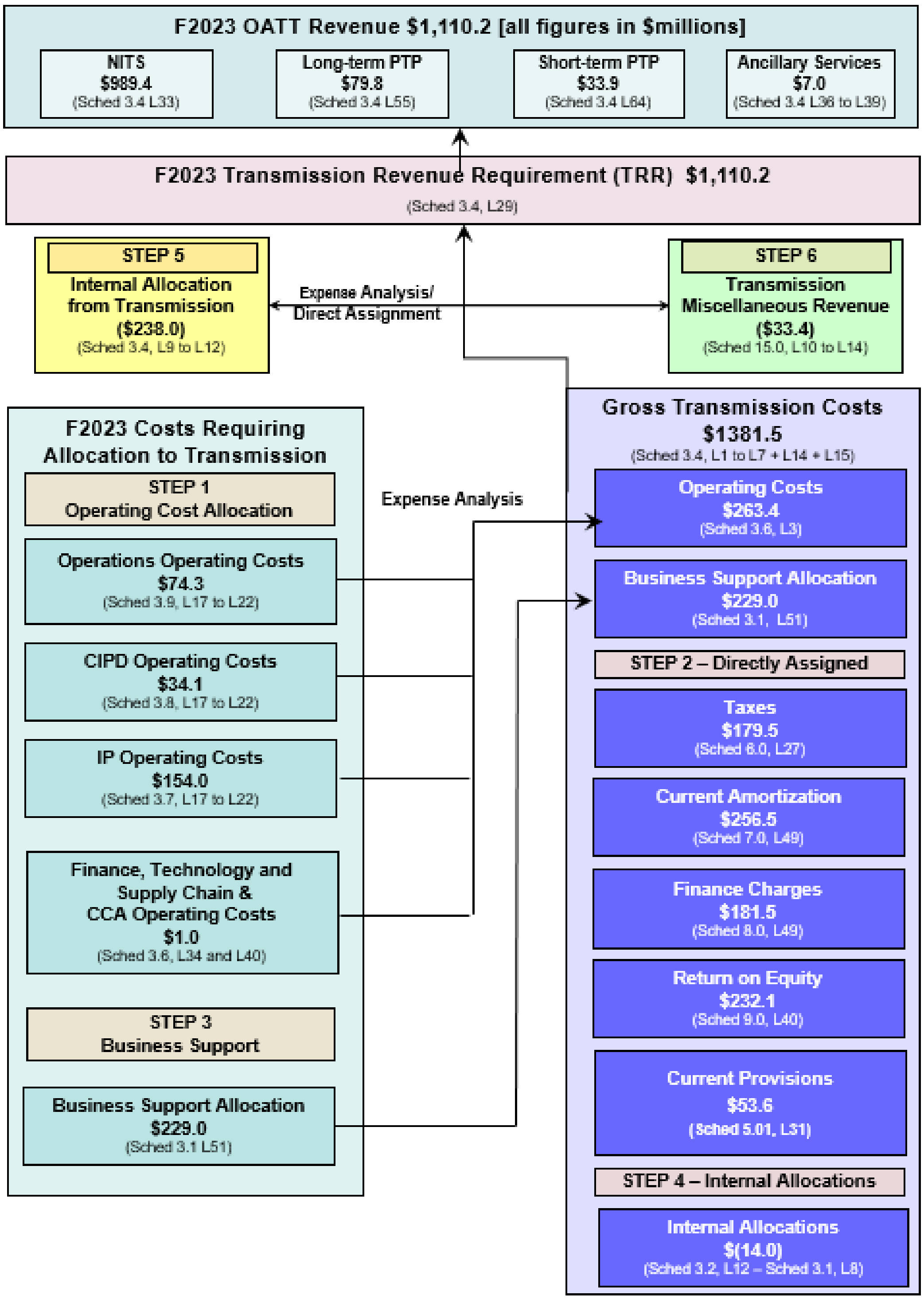

Table 9-1 below sets out the cost components that make up the TRR. The fiscal 2022 Decision amounts represent the approved amounts from the Previous Application, as reflected in the OATT rate schedules included in BC Hydro's Compliance Filing to the Previous Application. As shown in Table 9-1, the TRR increases by 3.7 per cent from fiscal 2022 decision to the fiscal 2023 Plan.

1 Table 9-1 Transmission Revenue Requirement

	($ million)	F2021 Actual	F2022 Decision	F2022 Forecast	F2023 Plan	F2024 Plan	F2025 Plan
		1	2	3	4	5	6
1	Operating Cost	242.0	247.2	209.4	263.4	266.3	263.6
2	Provisions and Other	31.1	62.8	61.5	53.6	59.2	32.8
3	Taxes	164.7	167.0	172.6	179.5	187.9	193.2
4	Amortization	235.8	239.2	264.7	256.5	262.1	271.7
5	Finance Charges	227.9	148.3	149.1	181.5	174.9	172.9
6	Allowed Net Income	225.2	232.5	231.0	232.1	231.5	180.9
7	Business Support Cost	232.0	239.1	235.8	229.0	233.2	234.1
8	Internal Allocations to Transmission						
9	Generation Ancillary Services	2.8	2.5	2.6	2.6	2.6	2.6
10	Transmission Capitalized Overhead	(16.3)	(16.6)	(16.6)	(16.6)	(16.6)	(16.6)
11	Gross Transmission Costs	1,345.2	1,322.0	1,310.1	1,381.5	1,401.0	1,335.0
12	Less Internal Allocations from Transmission						
13	Generation Related Transmission Assets	(43.3)	(43.3)	(43.3)	(54.0)	(54.7)	(52.1)
14	Generation Real Time Dispatch	(2.4)	(3.0)	(3.0)	(5.6)	(4.4)	(4.5)
15	Distribution Real Time Dispatch	(21.3)	(25.7)	(25.6)	(24.0)	(25.4)	(25.8)
16	Substation Distribution Assets	(129.0)	(149.3)	(156.7)	(154.4)	(155.9)	(148.1)
17	Less Miscellaneous Revenues						
18	FortisBC Inc. General Wheeling Agreement	(5.2)	(5.3)	(5.3)	(5.7)	(6.0)	(6.3)
19	Secondary Revenues	(7.3)	(7.1)	(6.7)	(6.8)	(6.8)	(6.9)
20	Interconnections	(8.3)	(4.6)	(6.1)	(6.1)	(4.2)	(3.3)
21	Amortization of Contributions	(15.3)	(11.0)	(12.0)	(12.4)	(11.9)	(12.5)
22	Northwest Transmission Line Supplemental Charges	(2.4)	(2.4)	(2.4)	(2.4)	(2.4)	(2.4)
23	Subtotal	(234.5)	(251.6)	(261.0)	(271.3)	(271.7)	(261.8)
24	Transmission Revenue Requirement	1,110.7	1,070.4	1,049.1	1,110.2	1,129.3	1,073.2

We allocate or direct assign the components of the TRR using the six steps described below. These steps are shown in Figure 9-1 above.

9.2.1 Step One: Direct Assignment and Allocation of Operating Costs and Provisions to Gross Transmission

Consistent with past practice, the first step in the cost allocation methodology to derive the TRR is to directly assign or allocate current operating costs and provisions to the transmission function based on cost causation. The result of this step is shown in line 1 of Table 9-1 above.

9.2.1.1 Identification of Business Groups and Functional Activities

First, BC Hydro identifies the Business Groups currently carrying out transmission functions, as follows:

1. Integrated Planning Business Group;
2. Capital Infrastructure Project Delivery Business Group;
3. Operations Business Group; and
4. Other Business Groups:
    a. Finance, Technology, Supply Chain; and
    b. Customer and Corporate Affairs.

BC Hydro then determines the relevant functional activity of each Key Business Unit (**KBU**) within the Business Groups. The functional activities performed by the relevant Business Groups are shown in Table 9-2 below.

Table 9-2 KBU Functional Activities

1	**Generation Function:**	
	(i)	Generation Real-time Dispatch
	(ii)	Generation Related Transmission Assets
	(iii)	Generation Other
2	**Transmission Function:**	
	(i)	Scheduling, System Control and Dispatch Service (OATT Rate Schedule 03)
	(ii)	Transmission Other
3	**Distribution Function:**	
	(i)	Substation Distribution Assets
	(ii)	Distribution Real-time Dispatch
	(iii)	Distribution Other

9.2.1.2 Methodologies for Allocating Costs to Functional Activities

Where possible, costs are directly assigned to one of the functional activities shown in Table 9-2 above. Where direct assignment is not possible, costs are allocated to the functional activities, using one or more of the following parameters to develop allocation factors:

(i) Planned expenditures for maintenance and/or capital programs that are representative of the work a KBU expects to undertake during the Test Period;

(ii) Historical expenditures for work performed by a KBU;

(iii) Work performed by Full-Time Equivalents (**FTEs**) within a KBU;

(iv) Manager and financial analyst interviews; and

(v) Direct allocation of certain specific activity costs.

In most cases, functionalization at the Director and Vice President levels is based on a roll-up of the overall allocation of the Departments or KBUs for which they are responsible.

Functionalization for provisions and others is based on an analysis of related current and historical capital programs.

Table 9-3 below summarizes the allocation approach used for each KBU or Department in the Capital Infrastructure Project Delivery, Integrated Planning, Operations, Finance, Technology, Supply Chain, and Customer and Corporate Affairs Business Groups.

Table 9-3 Allocation of Costs to Functional Activities

KBU/Department	Basis of Allocation to Functional Activities
Capital Infrastructure Project Delivery Business Group	
Business Unit Support	Direct assignment roll-up of overall allocation
Environment	Direct assignment and manager interviews
Indigenous Relations	Activity analysis and manager interviews
Project Delivery	Capital programs managed by the Project Delivery KBU and manager interviews
Properties	Direct assignment and manager interviews
Integrated Planning Business Group	
Business Unit Support	Direct assignment roll-up of overall allocation
Asset Planning	Direct assignment, maintenance and capital programs, and manager interviews
Dam Safety	Direct assignment to generation function
Energy Planning and Analytics	Direct assignment and manager interviews
Engineering Design	Direct assignment, capital programs and manager interviews
Engineering Services	Direct assignment, capital programs and manager interviews
Interconnections and Shared Assets	Direct assignment and manager interviews
Operations Business Group	
Business Unit Support	Direct assignment roll-up of overall allocation
Construction Services	Maintenance and capital programs, specific activity analysis, and manager interviews
Distribution Design and Customer Connections	Direct assignment to distribution function
Generation System Operations	Direct assignment to generation function
Line Field Operations	Direct assignment, maintenance and capital programs, specific activity analysis and manager interviews
Program and Contract Management	Specific activity analysis, maintenance and capital programs, and manager interviews
Stations Field Operations	Direct assignment, maintenance and capital programs, specific activity analysis, and manager interviews
T&D System Operations	Direct assignment, specific activity analysis, and manager interviews

KBU/Department	Basis of Allocation to Functional Activities
Finance, Technology, Supply Chain Business Group	
Materials Management	Manager interviews
Fleet Services	Manager interviews
Customer and Corporate Affairs Business Group	
Customer Services - Load Attraction	Direct Assignment

9.2.1.3 Resulting Portion of Business Groups Assigned to Gross Transmission Operating Costs

As a result of the above analysis, current operating costs and provisions were assigned to gross transmission, as shown in line 1 of Table 9-1 and line 1 of Appendix A, Schedule 3.4, as follows:

- 29 per cent of the Capital Infrastructure Project Delivery Business Group operating costs;
- 42 per cent of the Integrated Planning Business Group operating costs;
- 28 per cent of the Operations Business Group operating costs;
- 19 per cent of the Materials Management operating costs;
- 30 per cent of the Fleet Services operating costs; and
- 50 per cent of Customer Services for load attraction costs.

Portions of the total costs allocated to gross transmission from the Integrated Planning, Capital Infrastructure Project Delivery and Operations Business Groups are subsequently allocated to generation and distribution, as discussed in section 9.2.5 below.

As shown on line 1 of Table 9-1, the current operating cost allocation to gross transmission have increased by 6.5 per cent from fiscal 2022 Decision to fiscal 2023 Plan. Operating costs are discussed in Chapter 5.

9.2.2 Step Two: Costs Directly Assigned to Gross Transmission

The second step in the cost allocation methodology is to directly assign taxes, amortization, finance charges and return on equity to gross transmission. As noted below, the portion of these cost that are related to Generation Related Transmission Assets and Substation Distribution Assets must then be removed through a further allocation process.

9.2.2.1 Provisions and Other

Provisions and regulatory account recoveries are summarized on Schedule 5.01 of Appendix A. The Provisions and Other that are directly assigned to the gross transmission function are shown on line 2 of Table 9-1. There has been a 14.7 per cent decrease in the amount of Provisions and Other assigned to Gross Transmission. Provisions and Other are discussed in Chapter 8, section 8.12. These costs include Provisions and Other related to Generation Related Transmission Assets and Substation Distribution Assets. To derive the Provisions and Other specific to the OATT Related Assets, they are further allocated through direct assignment. These allocations of Provisions and Other are included in the internal allocations to Generation Related Transmission Assets and to Substation Distribution Assets on line 9 and line 12 of Appendix A, Schedule 3.4, as discussed in section 9.2.5 below.

9.2.2.2 Taxes

The taxes that are directly assigned to the gross transmission function are shown on line 3 of Appendix A, Schedule 3.4. Taxes that are directly assigned to the gross transmission function also include taxes related to Generation Related Transmission Assets and to Substation Distribution Assets. To derive the taxes specific to the OATT Related Assets, taxes are further allocated through direct assignment and asset analysis. These taxes are included in the internal allocations to Generation Related Transmission Assets and to Substation Distribution Assets on line 9 and line 12 of Appendix A, Schedule 3.4. As shown on line 3 of Table 9-1 and on line 29 of Appendix A, Schedule 6.0, there has been an 7.5 per cent increase in the taxes allocated to gross transmission from fiscal 2021 decision to fiscal 2022 plan. Taxes are discussed in Chapter 8, section 8.7.

9.2.2.3 Amortization, Finance Charges and Return on Equity

Amortization, finance charges and return on equity are directly assigned to gross transmission and are shown on lines 4, 5 and 6, respectively, of Appendix A, Schedule 3.4. Amortization, Finance Charges and Return on Equity are discussed in Chapter 8, sections 8.3, 8.6 and 8.5, respectively.

The amortization assigned to gross transmission includes amortization related to Generation Related Transmission Assets, Substation Distribution Assets, and OATT Related Assets, and 5 per cent of demand-side management amortization.[503] The remaining gross transmission amortization has been allocated to the functional activities using allocation factors derived from asset analysis. As shown on line 4 of Table 9-1 and on line 48 of Appendix A, Schedule 7.0, there has been a 7.2 per cent increase in the current amortization cost allocation to gross transmission from fiscal 2022 Decision to fiscal 2023 Plan.

The Finance Charges and Return On Equity assigned to gross transmission are allocated to the functional activities shown in Table 9-2 above based on the average rate base for each fiscal year. As shown on line 5 of Table 9-1 and on line 47 of Appendix A, Schedule 8.0, there has been a 22 per cent increase in the current Finance Charges allocated to gross transmission from fiscal 2022 Decision to fiscal 2023 Plan. As shown on line 6 of Table 9-1 and on line 42 of Appendix A Schedule 9.0, there has been a 0.2 per cent decrease in the Return on Equity allocated to gross transmission from fiscal 2022 Decision to fiscal 2023 Plan.

[503] By Order No. G-47-16, issued on March 31, 2016, the BCUC approved a Cost of Service Study and Rate Class Segmentation Negotiated Settlement Agreement, as part of BC Hydro's 2015 Rate Design Application. In section 8 on page 11 of the Negotiated Settlement Agreement appended to Order No. G-47-16, the negotiating parties agreed it was appropriate to functionalize 5 per cent of DSM costs to transmission, subject to BC Hydro revisiting the functionalization between generation, transmission and distribution in its fiscal 2019 Cost of Service Study.

9.2.3 Step Three: Business Support Cost Allocation

The third step is to allocate business support costs. Business support costs are allocated to the generation, transmission and distribution functional activities shown in Table 9-2 above, using allocation factors derived from activity analysis. The current business support costs assigned to gross transmission are shown on line 7 of Appendix A, Schedule 3.4. As shown on line 7 of Table 9-1 and on line 51 of Appendix A, Schedule 3.1, there has been a 4.2 per cent decrease in the current business support cost allocation to gross transmission from fiscal 2022 Decision to fiscal 2023 Plan. Business support costs are discussed in Chapter 8, section 8.11.

9.2.4 Step Four: Internal Allocations to Transmission

The fourth step is to allocate other internal costs attributable to transmission. The following costs are also assigned to transmission:

1. Generation operating costs relating to the generation ancillary services that BC Hydro provides to OATT customers, as shown on line 9 of Table 9-1 and on line 14 of Appendix A, Schedule 3.4; and
2. Transmission capitalized overhead, as shown on line 10 of Table 9-1 and on line 8 of Appendix A, Schedule 3.1.

These costs are functionalized directly to transmission and are not allocated further through the internal allocations from gross transmission discussed in section 9.2.5 below.

9.2.5 Step Five: Internal Allocations from Gross Transmission

The fifth step is to make internal allocations from gross transmission, as it is necessary to remove transmission-related costs that are not related to providing service under the OATT and therefore do not belong in the TRR. These allocations are shown on lines 12 to 16 of Table 9-1 and on lines 9 to 12 of Appendix A, Schedule 3.4, and are described below.

9.2.5.1 Generation Related Transmission Asset Allocation

BC Hydro's transmission assets related to the generation function are not used to provide service under the OATT and therefore must be removed to calculate the TRR. Removing these costs decreases the OATT PTP Rate and is therefore to the benefit of external OATT customers. However, it does not materially impact the total amount of revenue recovered from BC Hydro ratepayers.[504]

By Letter No. L-92-07, dated November 15, 2007 the BCUC accepted that a fixed charge of $43.3 million was appropriate for Generation Related Transmission Asset (**GRTA**) costs. In the reasons for decision the panel noted that it "requires considerable effort to identify GRTA and non-GRTA assets in any given year" and therefore a fixed cost approach was appropriate to manage the overall level of effort. The level of effort that would be required for a detailed bottom up estimation of GRTA costs has only increased since 2007. With BCTC's integration into BC Hydro the work would now require both the identification of the assets and the functionalization of their operating costs. Given this, BC Hydro has continued to use the fixed charge from Letter No. L-92-07. However, we believe that it is now appropriate to revisit the allocation methodology, in light of increased costs associated with transmission lines. For example, vegetation management costs have increased and in future there will the addition of new transmission facilities that may be designated as GRTA when the Site C Project comes into service in fiscal 2025. An important consideration in revisiting the allocation methodology continues to be to managing the potential for considerable amount of effort associated with the task, as cited in Letter No. L-92-07. Therefore, for this application, BC Hydro has developed a new approach to allocation of GRTA that

[504] The increase in GRTA will reduce the TRR by approximately $10.7/ $11.4/ 0.9 million for fiscal 2023, fiscal 2024 and fiscal 2025, or approximately 1 per cent, which results in a corresponding decrease in the PTP rate by the same 1 per cent. This results in a negligible increase in the amount recovered from BC Hydro ratepayers of only approximately $0.1 million, due to the fact that 99 per cent of the TRR is recovered though NITS and internal PTP usage and ultimately through BC Hydro's bundled service rates, while 100 per cent of the GRTA amount is recovered through the bundled service rates.

balances the need to increase accuracy of the estimate and manage the overall level of effort. This approach is further described below.

We propose that the GRTA allocation be determined for each fiscal year based on an asset analysis of the transmission system on the most recent fiscal year for which end of year (latest actual) net book value (**NBV**) is available, as recorded in BC Hydro's corporate asset database. More specifically, we propose that the GRTA allocation be calculated using the following formula:

$$(\text{GRTA})_{\text{fiscal}} = (\text{Gross Transmission})_{\text{fiscal}} \times \frac{(\text{GRTA NBV})_{\text{latest actual}}}{(\text{Gross Transmission NBV})_{\text{latest actual}}}$$

The GRTA assets include generation station switchyards and lines that connect remote generators to the grid and have been identified in a GRTA facilities list as either 100 per cent GRTA or some other percentage if they also provide a local service function (e.g., to a nearby community). The GRTA facilities can then be identified in BC Hydro's asset database and their current value, or net book value, compared to that for Gross Transmission assets. For the Test Period, the latest actual net book values are for fiscal 2021 and result in a multiplier of approximately 3.9 per cent to be applied to the Gross Transmission cost for each fiscal year of the Test Period as shown on line 11 of Table 9-1.

BC Hydro will undertake a review of the GRTA facilities list in advance of the next revenue requirements application to analyze in more detail which transmission facilities and what proportion should be designated as GRTA, and include the updated GRTA facilities as part of the next revenue requirement application.

On the above basis, the calculated internal allocation of GRTA costs from the transmission function to the generation function for the Test Period is ($54.0) million, ($54.7) million and ($52.1) million for fiscal 2023, fiscal 2024 and fiscal 2025, respectively. This is shown on line 13 of Table 9-1 and on line 9 of Appendix A, Schedule 3.4.

9.2.5.2 Generation Real Time Dispatch

Second, generation real time dispatch costs are not used to provide service under the OATT and therefore must be removed to calculate the TRR.

Generation real time dispatch activities performed by the T&D System Operations KBU include generation control, water conveyance, alarm monitoring, notification and reporting services, data services and Supervisory Control and Data Acquisition system services. These control centre activities support the operation of the generation and transmission systems.

The overall determination of the Real Time Dispatch revenue requirement is required to establish the Scheduling and Dispatch rate for OATT Rate Schedule 03. These costs are assumed to be transmission costs for the purpose of determining the Scheduling and Dispatch rate. A portion is then allocated to generation, representing Generation Real Time Dispatch. The internal allocation of generation real time dispatch costs from the transmission function to generation is shown on line 14 of Table 9-1 of and on line 10 of Appendix A, Schedule 3.4.

9.2.5.3 Distribution Real Time Dispatch

Third, distribution real time dispatch functions are not used to provide service under the OATT and therefore the costs must be removed to calculate the TRR.

Distribution real time dispatch supports the operation of the distribution system, and includes activities performed by the control centre within the T&D System Operations KBU. This activity supports the operation of the distribution system from inside the substation fence, downstream of the high-side of the step-down transformer, outside the substation fence, and also supports restoration of the distribution system outages. The cost for distribution real time dispatch includes costs for the restoration centre and an allocation of business support costs assigned to gross transmission and to the T&D System Operations KBU. Manager interviews were conducted to derive the allocation of the total cost for this activity.

Distribution real time dispatch costs are assumed to be transmission costs for the purpose of determining the Scheduling and Dispatch rate. A portion is then allocated to distribution, representing Distribution Real Time Dispatch. The internal allocation of distribution real time dispatch costs from the transmission function to distribution is shown on line 15 of Table 9-1 and on line 11 of Appendix A, Schedule 3.4.

9.2.5.4 Substation Distribution Assets Allocation

Fourth and lastly, Substation Distribution Assets are also not used to provide service under the OATT and therefore must be removed to calculate the TRR.

All substation assets, including distribution specific substation assets, are recorded as transmission property. Substations with both transmission and distribution functions include assets common to both functions, such as buildings and fences as well as heating, ventilation and air conditioning equipment.

The Substation Distribution Assets allocation is necessary to transfer the distribution-related portion of the substation costs, including an allocation of common assets, to the distribution function. To determine an appropriate share of gross transmission costs to allocate to Substation Distribution Assets, allocation factors are determined using asset analysis, maintenance, capital expenditures, manager interviews and direct assignment. The costs allocated to the Substation Distribution Asset functional activity include operating costs, capital related expenses, taxes and business support costs.

The internal allocation of Substation Distribution Asset costs from gross transmission to distribution is shown on line 16 of Table 9-1 and on line 12 of Appendix A, Schedule 3.4.

9.2.6 Step Six: Transmission Miscellaneous Revenue Allocated to the TRR

Miscellaneous revenues directly attributed to the OATT-Related Assets are directly assigned to the TRR and serve as an offset to TRR costs.

The miscellaneous revenue functionalized to transmission is shown on lines 18 to 22 of Table 9-1 and on line 8 of Appendix A, Schedule 3.4.

Miscellaneous revenue continues to be directly assigned to the transmission function, as shown on lines 10 to 14 of Appendix A, Schedule 15.0.

9.2.6.1 FortisBC Inc. General Wheeling Agreement

Wheeling is the transportation of electricity from one utility's service area to another utility's service area. BC Hydro collects wheeling revenue from FortisBC Inc. in accordance with the General Wheeling Agreement between BC Hydro and FortisBC Inc., which has been approved by the BCUC. The charges for the wheeling of electricity from the Point of Supply to the Creston, Okanagan and Princeton Points of Interconnection are set out in BC Hydro’s Rate Schedule 3817. In accordance with the General Wheeling Agreement, the forecast of wheeling revenue for the Test Period reflects annual rate increases equal to the forecast increases in the Consumer Price Index and expected increases in volumes, based on the nomination provided by FortisBC Inc.

The forecast of wheeling revenue from FortisBC Inc. is shown on line 18 of Table 9-1 and on line 10 of Appendix A, Schedule 15.0.

9.2.6.2 Secondary Revenue

Secondary revenue is revenue received from other parties for the non-electric use of transmission assets, such as facility and digital communications site rentals.

The forecast of secondary revenue is shown on line 19 of Table 9-1 and on line 11 of Appendix A, Schedule 15.0.

9.2.6.3 Interconnection Revenue

Interconnection revenue consists of payments for engineering studies done by BC Hydro for generator and load interconnection customers connecting to the transmission system. Under the OATT, BC Hydro conducts engineering studies for customers requesting service, and the customers pay for the engineering studies.

The forecast of transmission interconnection revenue is shown on line 20 of Table 9-1 and on line 12 of Appendix A, Schedule 15.0.

9.2.6.4 Amortization of Contributions

Amortization of Contributions revenue relates to contributions from external parties toward the construction of capital assets.

The forecast of Amortization of Contributions revenue is shown on line 21 of Table 9-1 and on line 13 of Appendix A, Schedule 15.0.

9.2.6.5 Northwest Transmission Line Supplemental Charge

Northwest Transmission Line (**NTL**) Supplemental Charge revenue consists of revenues collected under Electric Tariff Supplement No. 37. While approval to rescind Tariff Supplement No. 37 was granted by the BCUC in February 2021,[505] there are no outstanding customers amounts owed. Per IFRS accounting rules, this revenue is recognized over the expected lifetime of the customer's facilities, which includes the Test Period. The forecast of NTL Supplemental Charge revenue is shown on line 22 of Table 9-1 and on line 14 of Appendix A, Schedule 15.0.

9.2.7 Inter-Segment Revenue

A revised calculation of the allocation of revenue recovered through the PTP allocation between BC Hydro and Powerex was developed in fiscal 2021 to implement the 2020 Transfer Pricing Agreement (**TPA**),[506] since the 2020 TPA differs from the 2003 TPA.

[505] BCUC Order No. G-38-21 date February 5, 2021.

[506] 2020 Transfer Pricing Agreement available in Appendix A at: https://www.bcuc.com/Documents/Proceedings/2020/DOC_58223_B-1-BCH-2020-TransferPricingAgreement-Application.pdf

In particular, there is no longer an hourly determination of whether hourly export quantities reflect domestic sales versus trade activity. The revised calculation reflects the principles of section 6.2 of the 2020 TPA to provide a reasonable allocation of the PTP transmission costs incurred by BC Hydro in respect of Powerex's trading activities. In particular, BC Hydro is responsible for losses, ancillary services and the PTP transmission costs associated with serving Domestic Load[507] requirement, satisfying Inter-utility Agreement obligations (including under any operating procedures), responding to System Constraints,[508] satisfying BC Hydro's obligation to manage the Annual Flexible Surplus/Deficit[509] and delivering electricity pursuant to Non-Flexible Export Schedules, and receiving and/or delivering the Canadian Entitlement.[510]

The forecast Intersegment Revenue is shown on lines 19 and 20 of Appendix A, Schedule 3.4. Note that while this revenue is deducted from the Gross Transmission costs to calculate the Total Current Costs on line 22 of Appendix A, Schedule 3.4, it is added back to calculate the TRR on line 27 of Appendix A, Schedule 3.4 so that the PTP rate can be calculated.

507 "Domestic Load" means load that BC Hydro is obligated to serve under its electricity tariffs by reason of its status as a public utility, including transmission losses within the province of British Columbia;

508 "System Constraints" means any outage, suspension, constraint or curtailment in the operation of the BC Hydro System or the Transmission System, including forced outages on the BC Hydro System, forced outages on the Transmission System, and constraints arising as a result of minimum or maximum generation requirements or environmental, regulatory, or reservoir management requirements.

509 "Annual Flexible Surplus/Deficit" means, for each Transfer Period, the amount of energy determined as set out in section 9.1 of the Transfer Pricing Agreement.

510 "Canadian Entitlement" means at any time the downstream power benefits to which Canada is then entitled as described in Articles V(1) and VII of the Columbia River Treaty.

9.3 OATT Rates are Set to Recover the TRR Consistent with Past Orders

This section sets out our proposed OATT rates. BC Hydro determined the proposed OATT rates in a manner consistent with the longstanding cost causation rate design of the OATT rates. This OATT rate design was originally approved by the BCUC in Order No. G-43-98, and subsequently confirmed or altered through multiple OATT proceedings, including the comprehensive applications and regulatory processes resulting in Orders Nos. G-58-05, G-127-06 and G-102-09.

9.3.1 Summary of Proposed OATT Rates

Table 9-4 summarizes the proposed OATT rates.

Table 9-4 Proposed OATT Rates Fiscal 2023 o Fiscal 2025

	Rate Schedule	Rate Class	Reference	F2023 Plan	F2024 Plan	F2025 Plan
1	Attachment H	NITS Revenue Requirement ($)	Schedule 3.4 L33	989.4	1,004.8	950.6
2	RS 00	NITS Monthly Rate ($)	Schedule 3.4 L34	82.5	83.7	79.2
3	RS 01	Long Term Firm Point-to-Point				
4		Yearly - $/MW of Reserved Capacity per year	Schedule 3.4 L42	82,713	84,129	79,914
5		Short Term Firm and Non-Firm Maximum Price for Delivery				
6		Monthly - $/MW of Reserved Capacity per month	Schedule 3.4 L43	6,892.77	7,010.73	6,659.52
7		Weekly - $/MW of Reserved Capacity per week	Schedule 3.4 L44	1,590.64	1,617.86	1,536.81
8		Daily - $/MW of Reserved Capacity per day	Schedule 3.4 L45	226.61	230.49	218.94
9		Hourly - $/MW of Reserved Capacity per hour	Schedule 3.4 L46	9.44	9.60	9.12
10	RS 03	Scheduling, System Control and Dispatch Service ($)				
11		per MW of Reserved Capacity per hour	Schedule 3.4 L49	0.138	0.141	0.140

The NITS rate increases by 1.1 per cent from fiscal 2022 Decision to fiscal 2023 Plan. There is a 5.7 per cent increase in the long-term PTP rate between fiscal 2022 Decision and fiscal 2023 Plan. This is due to a 3.7 per cent increase in the TRR and a 1.9 per cent decrease in the maximum capacity supply billing determinant, which is the denominator for calculating the PTP rate, as discussed below. The Scheduling and Dispatch Ancillary Services fee decreases by 9.2 per cent as a result of an increase to the volume of scheduling in the fiscal 2023 Plan.

9.3.2 Calculation of OATT Rates Consistent with Approved Rate Design

Once the TRR is known, BC Hydro's OATT rates can be calculated in the following manner, consistent with the BCUC-approved OATT rate design:

- First, the revenue from Ancillary Services under the OATT is forecast based on forecast volumes of NITS and PTP transmission service;
- Second, the PTP transmission service rate is calculated based on the TRR minus the Ancillary Service revenue divided by the Maximum Supply Capacity;
- Third, the PTP revenue forecast is calculated based on the PTP rate and forecast volumes of PTP transmission service; and
- Lastly, the monthly NITS rate is calculated based on the TRR minus Ancillary Services and PTP revenue, divided by 12 months.

Each of the above steps is described in the subsections below.

9.3.3 Calculation of Ancillary Services Revenue

Ancillary Services are needed with transmission service to maintain the reliability of the interconnected transmission system. Of the Ancillary Services, only the Scheduling, System Control and Dispatch Rate is updated along with the TRR and is designed to recover the cost of provision of these scheduling services for the forecast transmission service to be sold under the OATT during the Test Period.

9.3.3.1 Calculation of the Scheduling, System Control and Dispatch Rate

Scheduling, System Control and Dispatch services include:

- Pre-scheduling, Settlements and Billing - transactional processing through market operation and business systems to ensure accurate transmission schedules are confirmed for customers, followed by timely invoicing, accounting and performance reporting;

- Revenue Reporting and Forecasting - providing monthly and annual revenue reports for OATT services and provision of the historical information and forecasts for future years, as required for determination of revenue requirements and rate setting; and
- Real-Time Scheduling - managing the transmission reservations and energy schedules in real-time. Interchange Operators coordinate with Bonneville Power Administration and the Alberta Electric System Operator at least every hour to match schedules and reach a net interchange schedule which is incorporated into the Automatic Generation Control system to maintain energy balance.

The Scheduling, System Control and Dispatch rate is a volume-driven rate, calculated as the total cost for Scheduling, System Control and Dispatch, divided by the total forecasted volumes for NITS, long-term PTP and short-term PTP services.

The derivation of the Scheduling, System Control and Dispatch rate is shown in Table 9-5 below. As shown, the scheduling fee on line 8 is calculated by dividing the cost to provide this service on line 7 by the forecast total volume on line 6.

1 **Table 9-5 Calculation of Scheduling, System Control and Dispatch Rate**

		Schedule Reference	F2021 Actual	F2022 Decision	F2022 Forecast	F2023 Plan	F2024 Plan	F2025 Plan
			1	2	3	4	5	6
1	**PTP Volumes (MWh)**							
2	Long-Term PTP	Schedule 3.4 L52	9,302,776	8,453,400	8,453,400	8,453,400	8,453,400	8,453,400
3	Short-Term PTP	Schedule 3.4 L61	10,044,869	4,087,966	12,777,198	13,569,715	14,418,500	15,243,843
4	**Total PTP Volumes**		19,347,645	12,541,366	21,230,598	22,023,115	22,871,900	23,697,243
5	NITS and Secondary Transmission		9,848,363	12,954,763	9,848,363	9,848,363	9,848,363	9,848,363
6	**Total Volumes**	**Schedule 3.4 L48**	29,196,008	25,496,129	31,078,961	31,871,478	32,720,263	33,545,606
7	**Scheduling, Control and Dispatch Cost ($ million)**	Schedule 3.4 L47	4.2	3.9	4.6	4.4	4.6	4.7
8	**Scheduling Fee[511] ($/MWh)**	**(L47/L48) =Schedule 3.4 L49**	0.144	0.152	0.149	0.138	0.141	0.140

511 Scheduling, System Control and Dispatch rate.

9.3.3.2 Other Ancillary Services

BC Hydro provides ancillary generation services for OATT customers. Other ancillary services include energy imbalance service, loss compensation service, spinning and supplemental operating reserve services, and reactive power service. The rates for these services are not tied to the cost of providing transmission services and do not change with the TRR.

BC Hydro forecasts the amount to be recovered from these services based on its forecast of the transmission service usage for the Test Period and an estimate of the ancillary services that are likely to be attracted by this usage. BC Hydro self supplies all ancillary services that are attracted by transmission service used by internal customers. Accordingly, the amount of internal ancillary services is shown as zero on line 36 of Appendix A, Schedule 3.4. The revenue from the sale of these service to external customers is shown as external ancillary services on line 37 of Appendix A, Schedule 3.4.

9.3.4 Calculation of the PTP Transmission Service Rate

As described in Part Two of the OATT, PTP service is the reservation of capacity and transmission of energy, on a firm or non-firm basis, from point A to point B, on the transmission system.

The PTP Service rate is designed to recover the cost of the TRR if PTP transmission service were used to transfer the maximum capacity supply on the system. In theory, if there were no NITS customer, the PTP charge would recover the TRR, less ancillary service revenue. Specifically, based on the approved rate design, the PTP Transmission Service rate is calculated as follows:

$$\text{PTP Rate} = \frac{\text{(TRR - Ancillary Services Revenue)}}{\text{(Maximum Capacity Supply)}}$$

The billing determinant for the long-term PTP Transmission Service rate is BC Hydro's Maximum Capacity Supply, which is BC Hydro's total dependable capacity including planned resources. The Ancillary Services revenue calculated in section 9.3.3 must be excluded from this calculation in order to avoid double-counting.

The derivation of the PTP Transmission Service rate is shown in Table 9-6 below.

1 **Table 9-6 Calculation of the PTP Transmission Service Rate**

		Reference	F2021 Actual	F2022 Decision	F2022 Forecast	F2023 Plan	F2024 Plan	F2025 Plan
			1	2	3	4	5	6
1	TRR ($ million)	Schedule 3.4 L29	1,110.7	1,070.4	1,049.1	1,110.2	1,129.3	1,073.2
2	Less Ancillary Services ($ million)	Schedule 3.4 L36 to L39	(7.7)	(6.4)	(7.3)	(7.0)	(7.3)	(7.3)
3	Net TRR ($ million)	Schedule 3.4 L40	1,103.0	1,064.0	1,041.8	1,103.1	1,122.0	1,065.8
4	Maximum Capacity Supply (MW)	Schedule 3.4 L.41	13,279	13,596	13,596	13,337	13,337	13,337
5	Annual Billing Determinants (MW month)	L4 x 12 months	159,348	163,152	163,152	160,044	160,044	160,044
6	PTP Rate ($/MW Month)	L3 X 1,000,000/L5 = Schedule 3.4 L43	6,832.35	6,521.81	6,385.65	6,892.77	7,010.73	6,659.52

9.3.5 Calculation of the PTP Revenue Forecast

BC Hydro derives the long-term PTP revenue from the forecast long-term PTP volumes and the proposed long-term PTP rates. The forecasts of long-term PTP volumes are based on committed long-term transmission contracts.

The short-term PTP (including non-firm PTP) revenue forecast reflects the discounting of short-term PTP rates on export and wheel-through transactions pursuant to Schedule 01 of the OATT. The applicable rates are $3.00/MWh during High (Heavy) Load Hours and $1.00/MWh during Low (Light) Load Hours, Sundays and North American Electricity Reliability Corporation (**NERC**) holidays. The forecast of external short-term PTP volumes are based on fiscal 2021 actual volumes and increased customer short term scheduling activity. The internal short-term PTP volumes are based on the Energy Studies model, which is discussed further in Chapter 4, section 4.3.

Table 9-7 summarizes the forecast PTP revenue and volumes.

Table 9-7 Summary of Forecast PTP Revenue and Volumes

		Schedule Reference	F2021 Actual	F2022 Decision	F2022 Forecast	F2023 Plan	F2024 Plan	F2025 Plan
			1	2	3	4	5	6
1	**PTP Revenue ($ million)**							
2	Long Term PTP	Schedule 3.4 L55	87.1	75.5	73.9	79.8	81.2	77.1
3	Short-Term PTP	Schedule 3.4 L64	33.5	10.2	31.9	33.9	36.0	38.1
4	**Total PTP Revenue**	**Schedule 3.4 L70**	120.5	85.7	105.9	113.7	117.2	115.2
5	**PTP Volumes (MWh)**							
6	Long-Term PTP	Schedule 3.4 L52	9,302,776	8,453,400	8,453,400	8,453,400	8,453,400	8,453,400
7	Short Term PTP	Schedule 3.4 L61	10,044,869	4,087,966	12,777,198	13,569,715	14,418,500	15,243,843
8	**Total PTP Volumes**		19,347,645	12,541,366	21,230,598	22,023,115	22,871,900	23,697,243
9	**PTP Average Price ($/MWh)**							
10	Long Term PTP	Schedule 3.4 L58	9.36	8.93	8.75	9.44	9.60	9.12
11	Short Term PTP	Schedule 3.4 L67	3.33	2.50	2.50	2.50	2.50	2.50

9.3.6 Calculation of the NITS Rate

Once the Ancillary Services and PTP revenues have been calculated, the NITS rate is determined as the residual TRR. As BC Hydro is the only NITS customer, the entire NITS rate, plus PTP and ancillary services used by BC Hydro, are ultimately recovered through BC Hydro's bundled service rates. Revenues from PTP services paid by Powerex reduce the revenue requirement to be recovered from the BC Hydro NITS service. Only the revenues from PTP and ancillary services used by parties other than BC Hydro and Powerex reduce the revenue requirement to be recovered through bundled service rates. Approximately 1 per cent of the total TRR collected under the OATT is collected from customers other than BC Hydro and Powerex.

As described in Part Three of the OATT, NITS is a flexible transmission service which allows the NITS customer to integrate, economically dispatch and regulate its designated generation resources to serve its designated loads, as well as deliver energy from non-designated generation resources on an as-available basis. This flexible use of the network to integrate resources and loads is different than PTP service, which is the reservation and transmission of capacity for the transmission of energy on a firm or non-firm basis from point A to point B.

The NITS charge is designed to recover the TRR, less any revenues from PTP and Ancillary services, as illustrated in the following equation:

$$\text{Monthly NITS Charge} = \frac{\text{TRR} - (\text{PTP Revenue} + \text{Ancillary Services Revenue})}{\text{12 months}}$$

The derivation of the monthly NITS charge is shown in Table 9-8 below.

Table 9-8 Calculation of Monthly NITS Charge

		Reference	F2021 Actual	F2022 Decision	F2022 Forecast	F2023 Plan	F2024 Plan	F2025 Plan
			1	2	3	4	5	6
1	**TRR ($ million)**	Schedule 3.4 L29	1,110.7	1,070.4	1,049.1	1,110.2	1,129.3	1,073.2
2	**Less PTP and Ancillary Services Revenue:**							
3	PTP Revenue ($ million)	Schedule 3.4 L70	(120.5)	(85.7)	(105.9)	(113.7)	(117.2)	(115.2)
4	Ancillary Service ($ million)	Schedule 3.4 L36 to L39	(7.7)	(6.4)	(7.3)	(7.0)	(7.3)	(7.3)
5	**Total PTP and Ancillary Services Revenue ($ million)**	L3+L4	(128.4)	(92.1)	(113.2)	(120.8)	(124.5)	(122.6)
6	**NITS Revenue Requirement ($ million)**	Schedule 3.4 L33	982.9	978.3	935.9	989.4	1,004.8	950.6
7	**Monthly NITS Charge ($ million)**	Schedule 3.4 L34	81.9	81.5	78.0	82.5	83.7	79.2

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Chapter 10

Electrification

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At this time, BC Hydro is filing Chapter 10 and Appendices U, V and W confidentially with the BCUC and can make this information available to registered interveners upon request and upon signing an appropriate undertaking to keep the information confidential. This information contains details that will be released through a public announcement expected to take place in mid to late September. Once that public announcement has been made, BC Hydro will provide notice to the BCUC so that these materials can be posted publicly and form part of the public record. Providing this information confidentially to the BCUC and interveners in advance of the public announcement will allow all parties to review the materials and draft information requests, on the same timeline as the rest of the Application.