BC Hydro
Power smart

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September 3, 2019

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

Dear Mr. Wruck:

**RE: Project No. 1598990**
**British Columbia Utilities Commission (BCUC or Commission)**
**British Columbia Hydro and Power Authority (BC Hydro)**
**Fiscal 2020 to Fiscal 2021 Revenue Requirements Application**
**Responses to Round 2 Information Requests**

BC Hydro writes in compliance with BCUC Order No. G-146-19 to provide its responses to Round 2 information requests as follows:

| | |
|---|---|
| Exhibit B-12 | Responses to BCUC IRs (Public Version) |
| Exhibit B-12-1 | Responses to BCUC IRs (Confidential Version) |
| Exhibit B-13 | Responses to Interveners IRs (Public Version) |
| Exhibit B-13-1 | Responses to Interveners IRs (Confidential Version) |

BC Hydro is filing a limited number of responses and/or attachments to responses confidentially with the BCUC, pursuant to section 42 of the *Administrative Tribunals Act* and Part 4 of the Commission's Rules of Practice and Procedure. We have limited the redactions to the greatest extent possible. In each instance where a redaction was necessary, we have provided an explanation for the request for confidential treatment in the public version of the IR response.

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

Yours sincerely,

Fred James
Chief Regulatory Officer

cs/rh

Enclosure

**201.0 A. CHAPTER 2 – LEGAL AND REGULATORY FRAMEWORK**

**Reference: LEGAL AND REGULATORY FRAMEWORK**
**Exhibit B-1, Application, Section 2.2.2; *Utilities Commission Act* (UCA) as amended by Bill 19, *Energy Statutes Amendment Act, 2019*, 4th session, 41st Parl, British Columbia, 2019 (first reading); Exhibit B-6, AMPC IR 17.3.2, BCSEA IR 3.1, BCOAPO IR 5.1; Office of the Auditor General of British Columbia, Rate-Regulated Accounting at BC Hydro[1], February 2019, pp. 22–23**
**BCUC jurisdiction**

As a result of amendments enacted by the *Energy Statutes Amendment, Act 2019*, the UCA states:

**Definitions**

1 (1) In this Act:

(2) This Act does not apply to Powerex Corp.

**Rate rebalancing**

58.1 (1) In this section, "revenue-cost ratio" means the amount determined by dividing a public utility's revenues from a class of customers during a period of time by the public utility's costs to serve that class of customers during the same period of time.

[...]

(7) The commission may not set rates for a public utility for the purpose of changing the revenue-cost ratio for a class of customers except on application by the public utility.

In response to AMPC IR 17.3.2, the British Columbia Hydro and Power Authority (BC Hydro) stated:

> Details of Powerex Corp's past, current and forecast business activities, unless otherwise publicly reported by BC Hydro (as in Section 8.9 of Chapter 8 and Appendix A of the Application) are commercially sensitive and thus confidential. Powerex net income is included in BC Hydro Trade Income to the benefit of BC Hydro ratepayers.

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1 https://www.bcauditor.com/sites/default/files/publications/reports/OAGBC_RRA_RPT.pdf.

> The *Energy Statutes Amendment Act 2019* amended the *Utilities Commission Act* so that the Act does not apply to Powerex Corp.

In Section 2.2.2 of the Application, BC Hydro states: "As an outcome of the Comprehensive Review, the Government of B.C. also announced that it intends to table legislation to further update BC Hydro's regulatory framework."

In response to BCSEA IR 3.1, BC Hydro stated:

> Bill 19, the *Energy Statutes Amendment Act, 2019*, received Royal Assent on May 16, 2019. This means that the changes described in section 2.2.2 of Chapter 2 of the Application have been completed. As a result of amendments contained in the *Energy Statutes Amendment Act, 2019*:
>
> - The definitions of 'expenditure for export,' 'feed-in tariff program' and 'integrated resource plan' and sections 2(p), 3 to 5, 7 (1)(i), 8(1)(b)(ii), 16 and 35(g), (h) and (m), of the *Clean Energy Act* have been repealed. With regards to expenditures for export, these changes have the same effect as section 6 of Direction No. 8 to the BCUC. For further information on the effect of these changes, please refer to BC Hydro's response to BCUC IR 1.3.1;
> - Section 44.1 of the *Utilities Commission Act* now applies to BC Hydro. This means that the BCUC will review BC Hydro's IRP [integrated resource plan] going forward and that traditional DSM [demand-side management] programs must meet the adequacy requirements set out in the Demand-Side Measures Regulation. A sub-section has been added to the *Utilities Commission Act* stating that BC Hydro need not file an IRP before February 28, 2021. Our DSM plans have always been consistent with the adequacy requirements set out in the Demand-Side Measures Regulation. Table 10-7 in section 10.3.1.4 of Chapter 10 of the Application shows how BC Hydro's proposed DSM Plan aligns with the adequacy requirements;
> - A sub-section has been added to the *Utilities Commission Act* stating that the Act does not apply to Powerex Corp. This sub-section has the same effect as section 8 of Direction No. 8 to the BCUC, except that the latter had only exempted Powerex from Part 3 of the Act; and
> - A sub-section has been added to the *Utilities Commission Act* stating that the BCUC must not set rates for a public utility for the purpose of changing the revenue-cost ratio for a class of customers except on application by the public utility. This sub-section has the same effect as section 5 of Direction No. 8 to the BCUC.

2.201.1 Considering the recent amendment to section 58.1 of the UCA, does the British Columbia Utilities Commission (BCUC) have the jurisdiction to order a public utility, including BC Hydro, to file a rate rebalancing application with the BCUC?

**RESPONSE:**

**The BCUC cannot order BC Hydro to file a rate rebalancing application. Under section 58.1 of the *Utilities Commission Act*, a rate rebalancing application must be initiated by a public utility.**

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[...]

(7) The commission may not set rates for a public utility for the purpose of changing the revenue-cost ratio for a class of customers except on application by the public utility.

In response to AMPC IR 17.3.2, the British Columbia Hydro and Power Authority (BC Hydro) stated:

> Details of Powerex Corp's past, current and forecast business activities, unless otherwise publicly reported by BC Hydro (as in Section 8.9 of Chapter 8 and Appendix A of the Application) are commercially sensitive and thus confidential. Powerex net income is included in BC Hydro Trade Income to the benefit of BC Hydro ratepayers.

1 https://www.bcauditor.com/sites/default/files/publications/reports/OAGBC_RRA_RPT.pdf.

> The Energy Statutes Amendment Act 2019 amended the Utilities Commission *Act* so that the Act does not apply to Powerex Corp.

In Section 2.2.2 of the Application, BC Hydro states: “As an outcome of the Comprehensive Review, the Government of B.C. also announced that it intends to table legislation to further update BC Hydro’s regulatory framework.”

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> - The definitions of ‘expenditure for export,’ ‘feed-in tariff program’ and ‘integrated resource plan’ and sections 2(p), 3 to 5, 7 (1)(i), 8(1)(b)(ii), 16 and 35(g), (h) and (m), of the *Clean Energy Act* have been repealed. With regards to expenditures for export, these changes have the same effect as section 6 of Direction No. 8 to the BCUC. For further information on the effect of these changes, please refer to BC Hydro’s response to BCUC IR 1.3.1;
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> - A sub-section has been added to the *Utilities Commission Act* stating that the BCUC must not set rates for a public utility for the purpose of changing the revenue-cost ratio for a class of customers except on application by the public utility. This sub-section has the same effect as section 5 of Direction No. 8 to the BCUC.

2.201.2 As a result of the amendments to the UCA, Hydro and Power Authority Act and Clean Energy Act as a result of the Energy Statutes Amendment Act, 2019 receiving royal assent, are there any changes to the BCUC's jurisdiction over BC Hydro that are not outlined in BC Hydro's response to BCSEA IR 3.1?

**RESPONSE:**

**In addition to the changes outlined in BC Hydro's response to BCSEA IR 1.3.1, changes to the BCUC's jurisdiction over BC Hydro as a result of the *Energy Statutes Amendment Act, 2019* receiving royal assent are as follows:**

- **An expansion to the scope of the definition of "electricity supply obligations" contained in section 6(1) of the *Clean Energy Act* to add a reference to the most recent long-term resource plan filed under section 44.1 of the *Utilities Commission Act*; and**

- **The addition of references to the most recent long-term resource plan filed by BC Hydro under section 44.1 of the *Utilities Commission Act* to sections 44.2(5.1), 46(3.3) and 71 of the *Utilities Commission Act*, as a consideration for the BCUC with respect to expenditure schedules, CPCNs and energy supply contracts, respectively.**

**These references are in addition to any existing references to BC Hydro's integrated resource plan.**

**201.0 A. CHAPTER 2 – LEGAL AND REGULATORY FRAMEWORK**

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**BCUC jurisdiction**

In response to BCOAPO IR 5.1, BC Hydro provided a table that shows the specific regulatory accounts, programs and capital projects that are not subject to the BCUC's review or are subject to limited BCUC review because of existing regulations. In the response, BC Hydro also noted that "other regulations, particularly Direction No. 8, also impact our revenue requirements for the test period and are discussed in Table 2-1 and section 2.5 of Chapter 2 of the Application."

In the Office of the Auditor General of British Columbia (OAG) report, Rate-Regulated Accounting at BC Hydro, it states:

> First, rates have largely been determined by government, rather than an independent third-party regulator (BCUC) or BC Hydro's own governing board (which is not empowered to establish rates for BC Hydro)…
>
> Second, rates have not been set within a framework that is designed to recover BC Hydro's costs of service…Government has directed BC Hydro's revenues, expenses and, in effect, its own bottom line. For example:
>
> - Government has set BC Hydro's net income… BC Hydro's profitability is no longer connected to risk or performance.
> - BC Hydro has also been directed by government to defer its annual revenue shortfall into the Rate Smoothing Regulatory Account, resulting in the premature recognition of revenue and higher annual net income than would otherwise result.
>
> Rates have not been designed to ensure that each customer class pays its appropriate share of the costs (that is, residential customers are underpaying and commercial customers are overpaying), and BCUC has not had the authority to rebalance the rate design of customer classes because of government direction.

[1] https://www.bcauditor.com/sites/default/files/publications/reports/OAGBC_RRA_RPT.pdf.

2.201.3 Given the items identified in response to BCOAPO IR 5.1, the contents of Direction No. 8 to the BCUC and the *Energy Statutes Amendment Act, 2019*, in BC Hydro's view, please discuss whether it has satisfied the OAG's comments regarding BC Hydro's eligibility to apply rate regulated accounting in the Test Period.

**RESPONSE:**

**The Office of the Auditor General removed its qualification on the Public Accounts (i.e., the Government of B.C.'s financial statements) regarding the use of rate-regulated accounting at BC Hydro in fiscal 2019.**

**In the Independent Auditor's Report included in the Public Accounts 2018/19, the Auditor General states the following:**

> **"For the year ending March 31, 2019, BC Hydro has implemented International Financial Reporting Standards (IFRS), including IFRS 14 (Regulatory Deferral Accounts). Government has made a number of changes to the regulatory framework, giving the regulator the ability to influence costs and rates. I believe the changes made to the regulatory framework are sufficient to allow me to remove my qualification on the use of rate-regulated accounting for the year ending March 31, 2019."**

**In addition, on page 11 of the Office of the Auditor General's report titled "Understanding Our Audit Opinion on B.C.'S 2018/19 Summary Financial Statements" the Auditor General states the following:**

> **"With these changes in government regulation and direction, the removal of the [Rate Smoothing Regulatory Account], and government's commitment to restore the authority of the BCUC, we agree with government's assessment that BC Hydro's use of rate-regulated accounting is now appropriately reflected in the [Summary Financial Statements], and have therefore removed our qualification for this year."**

**Based on the Auditor General's removal of the rate-regulated accounting qualification from the Public Accounts in fiscal 2019, BC Hydro's view is that the Auditor General's comments have been satisfied. The Auditor General will not issue an opinion on BC Hydro's fiscal 2020 financial statements until after the fiscal year ending March 31, 2020 is complete.**

**202.0 A. CHAPTER 2 – LEGAL AND REGULATORY FRAMEWORK**

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**Exhibit B-1, Appendix C, pp. 18–19; Exhibit B-6, Ince IR 13.5; Direction No. 8 to the BCUC, OIC 051/2019, section 7**
**Retail access**

The Comprehensive Review of BC Hydro: Phase 1 Final Report in Appendix C of the Application states:

> Retail access is the ability for customers to secure electricity from the market via a third-party provider rather than the local utility such as BC Hydro… In a surplus situation, allowing retail access increases the amount of surplus energy that BC Hydro must export, possibly at a loss, increasing costs borne by ratepayers who do not or cannot opt for retail access.
>
> To minimize potential costs to ratepayers, retail access for BC Hydro customers is currently prohibited, and, as a result of the Review, this prohibition will continue. The government has extended the prohibition of retail access through regulation. The prohibition will continue until or unless a public utility, in this case BC Hydro, requests otherwise.

Section 7 of Direction No. 8 to the BCUC states the following regarding "Retail access:"

> Except on application by the authority, the commission must not set rates for the authority 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 stated in response to Ince IR 13.5 that it has "no intention of requesting a repeal of section 7 of Direction No. 8."

2.202.1 Please discuss whether the inclusion of "…or to those who supply such customers" includes wholesale customers of BC Hydro. For example, those bulk electricity customers who then supply to its own end-use customers through its own distribution system.

**RESPONSE:**

**Retail access refers generally to the ability of a retail customer of a public utility to take some or all of its electricity supply from third-parties, such as third-party generators or energy marketers. In the context of retail access, BC Hydro**

**interprets "retail customers" to mean those customers who take electricity supply for their own consumption (also characterized as "end-use customers" or "end-users"). In contrast, a wholesale customer is a customer who purchases electricity for resale. An example of a BC Hydro wholesale customer is FortisBC Inc., which purchases electricity from BC Hydro to serve customers within FortisBC Inc.'s service territory.**

**For clarity, the term "wholesale customer" is also often used to refer to customers buying transmission service under BC Hydro's Open Access Transmission Tariff (OATT), such as an independent generator or an energy marketer. However, we assume the BCUC is referring to wholesale customers such as FortisBC Inc. as opposed to wholesale OATT customers in its question.**

**Section 7 of Direction No. 8 prohibits the BCUC from setting a rate for BC Hydro that enables retail customers within BC Hydro's service territory to use the OATT to secure electricity from a third-party generator (located in B.C. or elsewhere), unless BC Hydro chooses to file such a rate. BC Hydro does not currently have such a rate and, as a result, retail customers in BC Hydro's service territory may not take advantage of retail access opportunities.**

**The phrase "those who supply such customers" in section 7 of Direction No. 8 refers to those parties, such as energy marketers, who assist retail customers in securing electricity from a third-party generator. Those energy marketers would otherwise be considered wholesale customers because they are buying electricity for resale. This phrase in section 7 of Direction 8 is meant to ensure that a retail customer in BC Hydro's service territory cannot secure electricity indirectly by using such a party.**

**By BCUC Order No. G-36-14 and as required by section 14 of Direction No. 7 (predecessor of section 7 of Direction No. 8), the BCUC approved BC Hydro's application to withdraw any obligation to offer unbundled transmission services pursuant to BC Hydro's OATT to retail customers in BC Hydro's service territory. Accordingly, the direction prohibits the BCUC from setting rates for BC Hydro that would allow, directly or indirectly, for retail access.**

**The direction does not prevent the BCUC from setting rates for other utilities in British Columbia to allow retail access for retail customers outside of BC Hydro's service territory. Additionally, retail customers outside of BC Hydro's service territory, or those who supply such customers, could use BC Hydro's OATT to buy electricity from third party generators. Further, third party generators within B.C., including those in BC Hydro's service territory, can use the OATT to sell their energy to any party outside of BC Hydro's service territory.**

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> To minimize potential costs to ratepayers, retail access for BC Hydro customers is currently prohibited, and, as a result of the Review, this prohibition will continue. The government has extended the prohibition of retail access through regulation. The prohibition will continue until or unless a public utility, in this case BC Hydro, requests otherwise.

Section 7 of Direction No. 8 to the BCUC states the following regarding "Retail access:"

> Except on application by the authority, the commission must not set rates for the authority 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 stated in response to Ince IR 13.5 that it has "no intention of requesting a repeal of section 7 of Direction No. 8."

2.202.2 Please confirm, or explain otherwise, that section 7 of Direction No. 8 only prohibits "retail access" for BC Hydro's retail (end-use) customers.

**RESPONSE:**

**Confirmed. For further discussion, please refer to BC Hydro's response to BCUC IR 2.202.1.**

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Section 7 of Direction No. 8 to the BCUC states the following regarding “Retail access:”

> Except on application by the authority, the commission must not set rates for the authority 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 stated in response to Ince IR 13.5 that it has “no intention of requesting a repeal of section 7 of Direction No. 8.”

2.202.3 Please provide BC Hydro’s definition of the term “retail customers” as used in section 7 of Direction No. 8. Is this representative of BC Hydro’s end-use customers?

**RESPONSE:**

**Please refer to BC Hydro’s response to BCUC IR 2.202.1 where we provide BC Hydro’s definition of “retail customers” for the purposes of section 7 of Direction No. 8.**

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> To minimize potential costs to ratepayers, retail access for BC Hydro customers is currently prohibited, and, as a result of the Review, this prohibition will continue. The government has extended the prohibition of retail access through regulation. The prohibition will continue until or unless a public utility, in this case BC Hydro, requests otherwise.

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> Except on application by the authority, the commission must not set rates for the authority 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 stated in response to Ince IR 13.5 that it has “no intention of requesting a repeal of section 7 of Direction No. 8.”

2.202.4 Please discuss if section 7 of Direction No. 8 prohibits electricity producers outside of BC from using BC Hydro’s transmission system to supply electricity to BC Hydro’s retail customers.

**RESPONSE:**

**Please refer to BC Hydro’s response to BCUC IR 2.202.1 where we explain that as a result of section 7 of Direction No. 8, a third-party generator outside of B.C. cannot use BC Hydro’s transmission system to supply electricity to retail customers in BC Hydro’s service territory.**

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> To minimize potential costs to ratepayers, retail access for BC Hydro customers is currently prohibited, and, as a result of the Review, this prohibition will continue. The government has extended the prohibition of retail access through regulation. The prohibition will continue until or unless a public utility, in this case BC Hydro, requests otherwise.

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BC Hydro stated in response to Ince IR 13.5 that it has "no intention of requesting a repeal of section 7 of Direction No. 8."

2.202.5 Please discuss if section 7 of Direction No. 8 prohibits electricity producers outside of BC from using BC Hydro's transmission system to supply electricity to retail customers of other distribution utilities within BC.

**RESPONSE:**

**Please refer to BC Hydro's response to BCUC IR 2.202.1 where we explain that section 7 of Direction No. 8 does not affect the ability of third party generators outside of B.C. to sell energy to retail customers outside of BC Hydro's service territory.**

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Section 7 of Direction No. 8 to the BCUC states the following regarding “Retail access:”

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BC Hydro stated in response to Ince IR 13.5 that it has “no intention of requesting a repeal of section 7 of Direction No. 8.”

2.202.6 Please discuss if retail access as described by section 7 of Direction No. 8 includes electricity producers in BC who supply electricity to non-BC Hydro retail customers.

**RESPONSE:**

**Please refer to BC Hydro’s response to BCUC IR 1.202.1 where we explain that section 7 of Direction No. 8 does not affect the ability of third-party generators in B.C. to sell energy to retail customers outside of BC Hydro’s service territory.**

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BC Hydro stated in response to Ince IR 13.5 that it has “no intention of requesting a repeal of section 7 of Direction No. 8.”

2.202.7 Please discuss whether section 7 of Direction No. 8, or any other legislation, prohibits electricity producers in BC, other than BC Hydro, from obtaining unbundled transmission services through BC Hydro to move electricity to the BC border for sale to retail customers outside of BC.

**RESPONSE:**

**Please refer to BC Hydro’s response to BCUC IR 2.202.1 where we explain that section 7 of Direction No. 8 does not prohibit third party generators in B.C. from**

**using BC Hydro's Open Access Transmission Tariff (OATT) to transmit their electricity for sale outside of B.C. However, the third-party generators must comply with BC Hydro's requirements under the OATT in order to obtain service so as to transmit electricity across BC Hydro's transmission system.**

**BC Hydro is not aware of any legislation in B.C. that would prohibit a third party electricity generator from obtaining unbundled transmission services that would enable that generator to transmit electricity to the B.C. border.**

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**Retail access**

The Comprehensive Review of BC Hydro: Phase 1 Final Report in Appendix C of the Application states:

> Retail access is the ability for customers to secure electricity from the market via a third-party provider rather than the local utility such as BC Hydro… In a surplus situation, allowing retail access increases the amount of surplus energy that BC Hydro must export, possibly at a loss, increasing costs borne by ratepayers who do not or cannot opt for retail access.
>
> To minimize potential costs to ratepayers, retail access for BC Hydro customers is currently prohibited, and, as a result of the Review, this prohibition will continue. The government has extended the prohibition of retail access through regulation. The prohibition will continue until or unless a public utility, in this case BC Hydro, requests otherwise.

Section 7 of Direction No. 8 to the BCUC states the following regarding "Retail access:"

> Except on application by the authority, the commission must not set rates for the authority 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 stated in response to Ince IR 13.5 that it has "no intention of requesting a repeal of section 7 of Direction No. 8."

2.202.8 Please discuss if allowing electricity producers in BC, other than BC Hydro, to obtain unbundled transmission services through BC Hydro to move electricity to the BC border would have any impact on the following:

i. the ability of retail customers in BC to secure electricity from the market via a third-party provider;
ii. the amount of surplus energy that BC Hydro must export;
iii. the capacity on BC Hydro's transmission system; and
iv. the costs borne by BC Hydro ratepayers.

**RESPONSE:**

**Third-party electricity generators are currently able to obtain transmission service to transmit electricity through BC Hydro's transmission system to the B.C. border for sale outside of B.C. (Generator Exports) pursuant to BC Hydro's Open Access Transmission Tariff (OATT) approved by the BCUC.**

**(i) Generator Exports would not impact the fact that BC Hydro does not offer retail customers within BC Hydro's service territory the opportunity to secure electricity from a third party generator or energy marketer. Generator Exports would also not impact retail customers outside of BC Hydro's service territory as third party generators could elect to undertake Generator Exports to sell to those retail customers outside of BC Hydro's service territory.**

**(ii) If a third party generator is undertaking Generator Exports, it is doing so independent of BC Hydro. Since BC Hydro only manages and, if appropriate, exports energy that it owns, Generator Exports would not affect BC Hydro's export decisions. However, Generator Exports may impact BC Hydro's ability to export energy if the transmission system capacity is fully scheduled.**

**(iii) Generator Exports would likely not impact the Total Transfer Capability of the BC Hydro transmission system, but would impact the Available Transfer Capability of the BC Hydro transmission system since reservations of transmission service, if available, would be required to facilitate the exports. "Total Transfer Capability" and "Available Transfer Capability" are defined in BC Hydro's "TTC/ATC" business practice under the OATT.**

**(iv) Generator Exports may have an impact on BC Hydro's ratepayers. However, the nature of this impact cannot be determined in the abstract as the incremental transmission revenues received as a result of the Generator Exports under the OATT (which are included in Miscellaneous Revenues, as explained in section 8.7 of Chapter 8 of the Application) may be offset by lower revenues from exports to the extent that constrained transmission availability to the B.C. border causes shifts in when such exports occur.**

**203.0 B. CHAPTER 3 – LOAD AND REVENUE FORECAST**

**Reference: LOAD AND REVENUE FORECAST**
**Exhibit B-1, p. 3-5; Exhibit B-5, BCUC IR 5.1, 12.2.1**
**Internal audit**

In response to BCUC IR 12.2.1, BC Hydro provided a copy of the GDS Associates Inc. report as Attachment 1 to the response. GDS Associates Inc. provides recommendations regarding governance (section 2.2), methodology (section 3.2) and a summary of findings regarding the outputs in section 4.2 of the report.

BC Hydro states in its Application that “BC Hydro has addressed the audit recommendations and the issues raised by the BCUC.”

BC Hydro explained the difference between the October 2018 load forecast and May 2016 load forecast in response to BCUC IR 5.1.

2.203.1 Please explain whether all of the recommendations and findings included in the GDS Associates Inc. report are included in BC Hydro’s internal audit report.

**RESPONSE:**

**Each recommendation in the GDS Associates Inc. (GDS) report has an associated finding. The internal audit management report includes all GDS report recommendations with the following exception:**

> **Determine the value of replacing the existing econometric modeling process for weather normalizing substation peak demands (i.e., 220 individual models) with a single panel model.**

**Audit Services did not include the above recommendation in the internal audit management report as GDS concluded the peak demand forecasting process is comprehensive and incorporates best practice methodologies. Accordingly, Audit Services did not assess this as a key recommendation to include in the internal audit management report. This understanding was confirmed with GDS prior to issuing the internal report.**

**While this recommendation was not included in the internal audit management report, BC Hydro is currently reviewing its weather normalization processes as part of a broader dynamic energy planning program. This review was initiated in April 2019 and is expected to be complete in fiscal 2021. For further information**

**on BC Hydro's dynamic energy planning program, please refer to BC Hydro's response to CEC IR 2.112.1.**

**There are a number of findings in the GDS report which are not attached to specific recommendations. These findings are not considered to be material and accordingly, they are not reflected in the internal management audit report.**

**203.0 B. CHAPTER 3 – LOAD AND REVENUE FORECAST**

**Reference: LOAD AND REVENUE FORECAST**
**Exhibit B-1, p. 3-5; Exhibit B-5, BCUC IR 5.1, 12.2.1**
**Internal audit**

In response to BCUC IR 12.2.1, BC Hydro provided a copy of the GDS Associates Inc. report as Attachment 1 to the response. GDS Associates Inc. provides recommendations regarding governance (section 2.2), methodology (section 3.2) and a summary of findings regarding the outputs in section 4.2 of the report.

BC Hydro states in its Application that “BC Hydro has addressed the audit recommendations and the issues raised by the BCUC.”

BC Hydro explained the difference between the October 2018 load forecast and May 2016 load forecast in response to BCUC IR 5.1.

2.203.1 Please explain whether all of the recommendations and findings included in the GDS Associates Inc. report are included in BC Hydro’s internal audit report.

2.203.1.1 If not, please identify which recommendations and/or findings are not included and explain why those have been omitted.

**RESPONSE:**

**Please refer to BC Hydro’s response to BCUC IR 2.203.1.**

**203.0 B. CHAPTER 3 – LOAD AND REVENUE FORECAST**

**Reference: LOAD AND REVENUE FORECAST**
**Exhibit B-1, p. 3-5; Exhibit B-5, BCUC IR 5.1, 12.2.1**
**Internal audit**

In response to BCUC IR 12.2.1, BC Hydro provided a copy of the GDS Associates Inc. report as Attachment 1 to the response. GDS Associates Inc. provides recommendations regarding governance (section 2.2), methodology (section 3.2) and a summary of findings regarding the outputs in section 4.2 of the report.

BC Hydro states in its Application that “BC Hydro has addressed the audit recommendations and the issues raised by the BCUC.”

BC Hydro explained the difference between the October 2018 load forecast and May 2016 load forecast in response to BCUC IR 5.1.

2.203.2 Please confirm BC Hydro has also addressed all of the recommendations included in GDS Associates Inc.’s report.

**RESPONSE:**

**As discussed in BC Hydro’s response to BCUC IR 2.203.1, while one GDS recommendation was not included in the internal audit report, it is being addressed as part of a broader dynamic energy planning program.**

**The status of the GDS recommendations related to forecast methodology, which were incorporated into the internal audit report are summarized in BC Hydro’s response to BCOAPO IR 1.14.2.**

**The status of the GDS recommendations related to governance which were incorporated into the internal audit report are summarized in the table below.**

| Audit Recommendations | Management Actions Status |
|---|---|
| **1**<br>• **Review adequacy of existing resources and consider increases to current staffing level.** | **Complete**<br>• **Two staff have been added to the Load Forecast team.**<br>• **The annual consultant and subscription services budget has been increased from approximately $200,000 to $300,000.** |

| Audit Recommendations | Management Actions Status |
|---|---|
| **2**<br>• **Prepare load forecasting detailed procedural documentation to supplement the high-level process documentation.** | **Complete**<br>• **The Load Forecasting procedural manual was updated to include process maps and supplemental information related to the procedures to prepare the BC Hydro load forecast.** |
| **3**<br>• **Consider developing a dashboard to highlight key information and current assumptions/outlook that impact the load forecast** | **Complete**<br>• **BC Hydro prepares a monthly load variance report highlighting key information related to load and revenue variances in each of the key customer sectors.** |

**203.0 B. CHAPTER 3 – LOAD AND REVENUE FORECAST**

**Reference: LOAD AND REVENUE FORECAST**
**Exhibit B-1, p. 3-5; Exhibit B-5, BCUC IR 5.1, 12.2.1**
**Internal audit**

In response to BCUC IR 12.2.1, BC Hydro provided a copy of the GDS Associates Inc. report as Attachment 1 to the response. GDS Associates Inc. provides recommendations regarding governance (section 2.2), methodology (section 3.2) and a summary of findings regarding the outputs in section 4.2 of the report.

BC Hydro states in its Application that “BC Hydro has addressed the audit recommendations and the issues raised by the BCUC.”

BC Hydro explained the difference between the October 2018 load forecast and May 2016 load forecast in response to BCUC IR 5.1.

2.203.2 Please confirm BC Hydro has also addressed all of the recommendations included in GDS Associates Inc.’s report.

2.203.2.1 If not confirmed, please explain why those recommendations have not been addressed and, to the extent possible, address them in response to this question.

**RESPONSE:**

**Please refer to BC Hydro’s responses to BCUC IR 2.203.2.**

**204.0 B. CHAPTER 3 – LOAD AND REVENUE FORECAST**
**Reference: LOAD AND REVENUE FORECAST**
**Exhibit B-1, p. 3-48; BNN Bloomberg, Chevron seeks to turn Kitimat LNG plan into all-electric design, dated July 15, 2019[1]**
**Liquified natural gas (LNG) load forecast**

BC Hydro states in the Application that:

> Publically available information on LNG projects which informed our load forecast included:
>
> - LNG Canada Inc. recently made a positive final investment decision. Only construction-related load from this LNG facility is expected within the window of our load forecast;
> - Woodfibre LNG announced that it intends to make a final investment decision this winter. We included a probability weighted sales forecast from this facility in its load forecast; and
> - FortisBC Tilbury is in operation and we included forecast sales to this LNG facility.

In an online article from BNN Bloomsberg, it states:

> Chevron and its partner Woodside Petroleum Ltd. earlier this year had announced they'd applied to expand the capacity of their LNG project in Kitimat, British Columbia, by as much as 80% to 18 million metric tons a year… the project is proposing to become an 'all-electric plant' powered by hydroelectricity, allowing expanded capacity without the corresponding increase in emissions of a traditional LNG facility…
>
> Chevron and Woodside expect to make a final investment decision in 2022 to 2023 with production starting by 2029…

2.204.1 Please discuss in detail, and quantify where possible, what impact the above announcement regarding Kitimat LNG would have on BC Hydro's load forecast: i) within the test period; ii) within the fiscal 2019 to fiscal 2024 (F2019-F2024) period as presented in Appendix O of the Application; and iii) the 20-year load forecast to be filed on October 3, 2019, respectively.

[1] https://www.bnnbloomberg.ca/chevron-seeks-to-turn-canada-lng-plan-into-all-electric-design-1.1287377.

**RESPONSE:**

**The public version of the response to this information request has been redacted to maintain confidentiality over customer information. The un-redacted version of this response is being made available to the BCUC only, in order to protect the customer's commercial interests.**

[redacted]

[redacted]

[redacted]

**Given the current project schedule, Kitimat LNG would not have an impact on the October 2018 Load Forecast within the test period or within the fiscal 2019 to fiscal 2024 period.**

**205.0 B. CHAPTER 3 – LOAD AND REVENUE FORECAST**

**Reference: LOAD AND REVENUE FORECAST**
**BC Gov News, B.C. tops up electric vehicle rebate program, June 26, 2019 News Release[1]**
**Electric vehicle**

In a news release on BC Gov News, it states:

> Budget 2019 committed $41.5 million toward the CEVforBC rebate program for this fiscal year, with $15 million having been released. The changes made include lowering the maximum price eligibility threshold to $55,000 – ensuring the program supports the most affordable vehicles… The provincial rebate will be reduced to $3,000 for battery, fuel-cell, and longer-range plug-in hybrid electric vehicles and to $1,500 for shorter-range plug-in hybrid electric vehicles, effective June 22, 2019.

2.205.1 Please discuss whether, and if so by how much, the recent changes to the CEVforBC rebate program may impact BC Hydro's electric vehicle load forecast within the Test Period.

**RESPONSE:**

**The October 2018 mid EV energy forecast does not include any incentives or policies during the test period and therefore the inclusion of any incentive programs in the model would result in an increase of load relative to the mid forecast. One of the assumptions in our high EV energy forecast is a $5,000 EV purchase incentive throughout the entire forecast period, which in total equates to an additional load of approximately 40 GWh in fiscal 2020 and 60 GWh in fiscal 2021 over the mid forecast.**

**The changes made to the provincial government's CEVforBC rebate program combined with the federal government's $5,000 rebate program, are higher than the vehicle incentive assumptions used in our high EV energy forecast ($8,000 versus $5,000). However, the provincial program also includes a new maximum price eligibility threshold and incentives for plug-in hybrids that are currently not captured in our EV model.**

**While further analysis would be required to quantify the impacts of the revised incentives and threshold effects, BC Hydro believes the results described above for the test period from its high EV energy forecast provide a reasonable estimate of the energy impact of the announced revisions to the CEVforBC rebate program.**

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[1] https://news.gov.bc.ca/releases/2019EMPR0025-001302.

**206.0 B. CHAPTER 3 – LOAD AND REVENUE FORECAST**

**Reference: LOAD AND REVENUE FORECAST**
**Exhibit B-5, BCUC IR 13.1**
**Luxury electric vehicle load forecast**

BC Hydro stated in response to BCUC IR 13.1 that:

> The [electric vehicle] EV forecast is based on the most recent historical data from [Insurance Corporation of British Columbia] ICBC on electric vehicles, which spans from December 31, 2015 to June 30, 2016. During that time, the Tesla Model S was the dominant luxury EV, and our model uses that as a proxy when forecasting future high-end EV growth. Over that six month period, Tesla Model S EV sales grew by 15.7 per cent… in our view, this growth rate is too aggressive and is not representative of the potential for future luxury EV growth. Accordingly, we applied a 2 per cent annual growth rate for the remainder of the forecast period (i.e., January 1, 2019 to March 31, 2024).

2.206.1 Please explain why BC Hydro believes a 2 percent annual growth rate on luxury EV for the remainder of the forecast period is appropriate. Please include the relevant references and any analysis or studies commissioned to support this growth rate.

**RESPONSE:**

**BC Hydro applied professional judgement to grow the stock of luxury Electric Vehicles (EVs) at an annual growth rate of 2 per cent. This judgement is based on two considerations:**

- **Our EV energy forecasting model is designed to apply the EV purchase incentives just to EVs that meet the government purchase price threshold. Therefore, it was necessary to account for luxury EV sales separately. We do so by using a simple trend-based approach; and**
- **Extending the luxury EV forecast over the long term based on the historical semi-annual growth rate of 15.7 per cent would result in luxury EVs dominating the overall EV forecast, as well as causing the combined affordable and luxury EV forecasts to become unreasonably high. We do not believe this to be a realistic outcome over the long term as we have seen that more affordable EV models are rapidly becoming available. Therefore we applied a conservative long term trend assumption of 2 per cent annual growth rate.**

**The two per cent assumption is based on professional judgement rather than any detailed analysis or commissioned studies. In the short term, luxury EV sales are likely to continue to grow at a higher rate than the assumed 2 per cent rate. However, given the current small number of luxury EVs, the difference in the growth rate assumption does not have a significant impact over the forecast period. BC Hydro estimates the difference between the 15.7 per cent semi-annual growth rate and the 2 per cent annual growth rate to be approximately 25 GWh in fiscal 2024.**

**207.0 B. CHAPTER 3 – LOAD AND REVENUE FORECAST**

**Reference: LOAD AND REVENUE FORECAST**
**Exhibit B-5, BCUC IR 5.1**
**Load forecast beyond the Test Period**

In response to BCUC IR 5.1, BC Hydro stated that "The change in the commercial forecast primarily reflects the change in the calibration period… the May 2016 Load Forecast trajectory reflected more periods of historical growth towards the early part of the calibration period compared to the calibration period of the October 2018 Load Forecast."

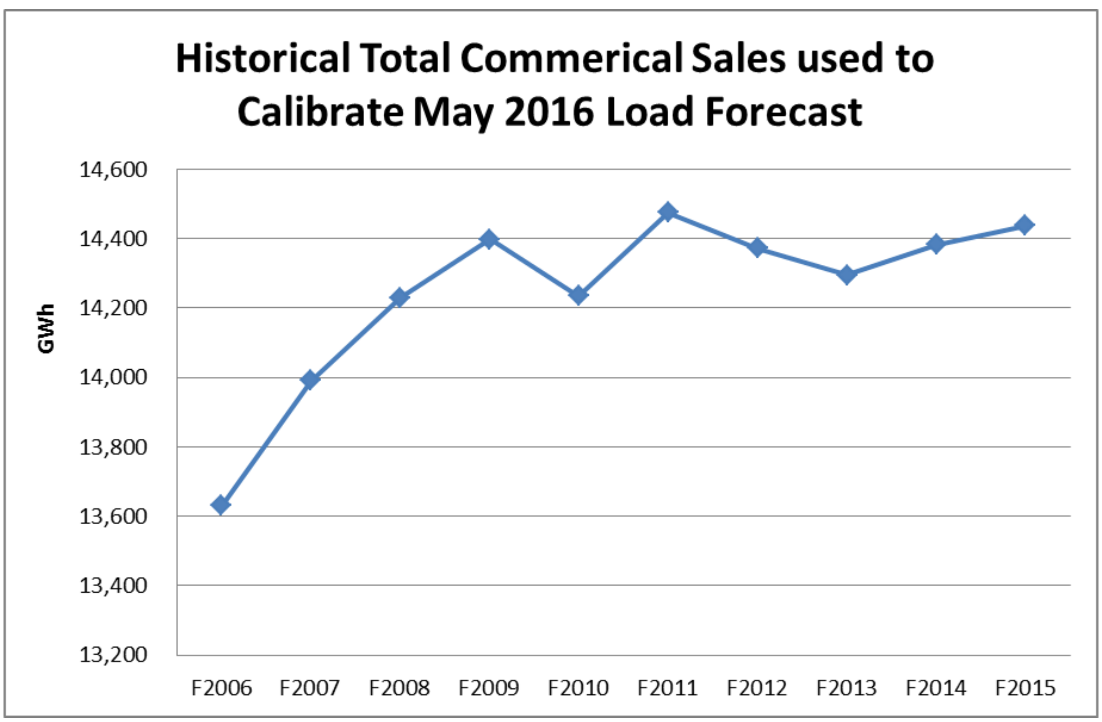
2.207.1 Please explain the higher historical growth in the early part of the May 2016 load forecast calibration period.

**RESPONSE:**

**This answer also responds to BCUC IR 2.207.1.1.**

**Figure 1 below shows the historical total commercial billed sales used to calibrate the eight May 2016 commercial statistically adjusted (SAE) end use models.**

**Figure 1**

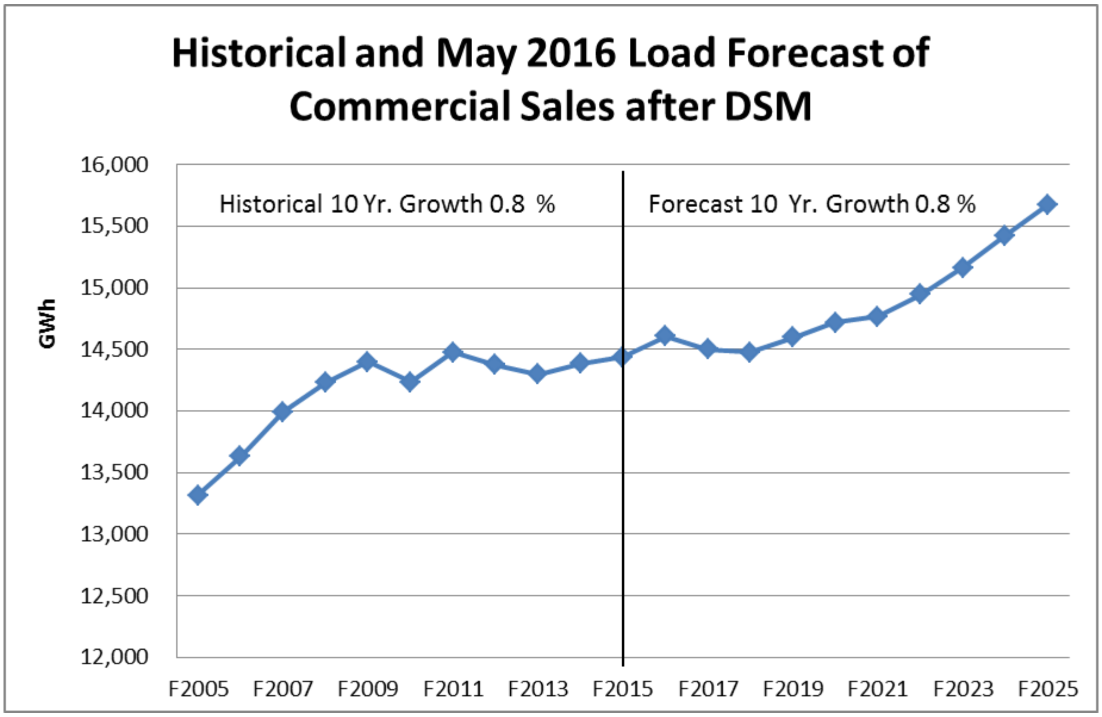


**Historical sales increased over the early part of the May 2016 calibration period by about 765 GWh or 5.6 per cent from fiscal 2006 to fiscal 2009. Because the commercial sector is comprised of approximately 180,000 accounts across a diverse range of business categories it is difficult pinpoint the exact reasons for the significant load growth across the entire sector. However, BC Hydro makes the following observations:**

1. **Sales increased in each of the eight major commercial load segments;**
2. **Within these commercial segments, the largest increase in sales occurred in the Lower Mainland over 35 kW per month load segment and the Vancouver Island over 35 kW per month load segment. These segments make up approximately 80 per cent of the total commercial sales; and**
3. **Total employment growth in BC Hydro's service area over the same time period averaged 2.4 per cent per annum. A large percentage of total employment resides in the Lower Mainland and Vancouver Island regions.**

**The global financial crisis that began in 2007 triggered a recession in Canada beginning in December 2008, which lasted approximately one year. Sales declined during this period and then increased from fiscal 2010 to fiscal 2015 by approximately 202 GWh or 1.4 per cent. Over the entire calibration period, sales grew by 0.8 per cent, on an annual compound basis. The May 2016 Load Forecast of commercial sales after rate impacts and after Demand-Side Management (DSM) savings was also 0.8 per cent, on a compound basis. The historical, forecast and compound growth figures for commercial sales are shown in Figure 2 below.**

**Figure 2**




**Notes:**

1. **Forecast is after impacts, after bottom up DSM savings, and savings for loss reductions referred to in the Previous Application as Var and Voltage Optimization.**
2. **Historical actual sales shown in Figure 2 have a historical growth rate of 0.8 per cent from fiscal 2005 to fiscal 2015. Historical temperature normalized sales have a historical growth rate of 0.9 per cent from fiscal 2005 to fiscal 2015.**

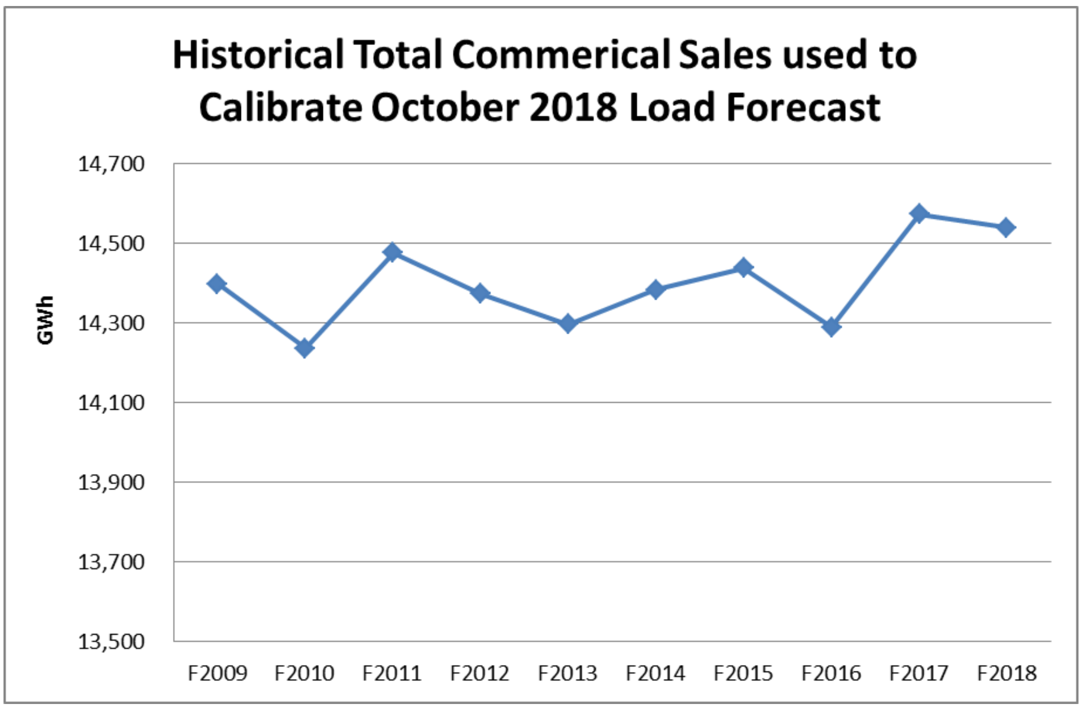
**While there is always uncertainty associated with future loads, we anticipate that sales over the test period are not likely to grow in a similar fashion to sales over the early part of May 2016 calibration period. This assessment is based on the following information:**

- **Recent Trends: Figure 3 below shows the most recent historical total commercial sales used to calibrate the October 2018 commercial SAE models. The most recent trend in historical sales over a three year period is different than that of the early part of the May 2016 Load Forecast;**
- **Economic: The October 2018 commercial forecast is developed with economic drivers that are different to those in the early calibration period. For example, the average growth in total employment is projected to be 1.4 per cent, which is lower than the average growth over the early calibration period; and**

- **Efficiency Impacts: The average efficiency profile of commercial end uses of electricity has increased relative to the early part of the forecast period. The forecast predicts further increases in the average efficiency of end uses of commercial electricity. For further details on the historical and the projected commercial average efficiency please see section 20 of Appendix O of the Application.**

**As described in Chapter 3 and Appendix O of the Application, there are a number of factors that can also lead to higher and lower sales relative to forecast. For example, there could be a greater increase in electric vehicles in the commercial sector than anticipated.**

**Figure 3**



**207.0 B. CHAPTER 3 – LOAD AND REVENUE FORECAST**

**Reference: LOAD AND REVENUE FORECAST**
**Exhibit B-5, BCUC IR 5.1**
**Load forecast beyond the Test Period**

In response to BCUC IR 5.1, BC Hydro stated that “The change in the commercial forecast primarily reflects the change in the calibration period… the May 2016 Load Forecast trajectory reflected more periods of historical growth towards the early part of the calibration period compared to the calibration period of the October 2018 Load Forecast.”

2.207.1 Please explain the higher historical growth in the early part of the May 2016 load forecast calibration period.

2.207.1.1 Please explain why this higher historical growth is not likely to continue in the Test Period.

**RESPONSE:**

**Please refer to BC Hydro’s response to BCUC IR 2.207.1.**

**207.0 B. CHAPTER 3 – LOAD AND REVENUE FORECAST**

**Reference: LOAD AND REVENUE FORECAST**
**Exhibit B-5, BCUC IR 5.1**
**Load forecast beyond the Test Period**

In response to BCUC IR 5.1, BC Hydro stated that “The change in the commercial forecast primarily reflects the change in the calibration period… the May 2016 Load Forecast trajectory reflected more periods of historical growth towards the early part of the calibration period compared to the calibration period of the October 2018 Load Forecast.”

2.207.2 Please quantify how much of the difference between the May 2016 and October 2018 load forecasts are attributable to the change in the calibration period.

**RESPONSE:**

**BC Hydro cannot precisely quantify how much of the difference between the May 2016 and October 2018 commercial forecasts is due to the calibration period, as there are other factors that contribute to changes in the forecast. That said, BC Hydro believes that recalibrating the commercial SAE models over the updated estimation period (i.e., latest 10 years of history) is a primary factor in the difference between the two forecasts. This is illustrated by the change in trend line estimation of the historical commercial sales data as provided in the figures in BC Hydro’s response to BCUC IR 1.5.1.**

**Other load drivers that contribute to the overall change in the commercial sector forecast include:**

- **Economic drivers;**
- **Elasticity coefficients;**
- **Efficiency and shares of commercial equipment;**
- **Projections and allocation of Electric Vehicle (EV) load to the commercial sector;**
- **Estimates for overlap in codes and standards; and**
- **Various reductions applied to the forecast including rate impacts, incremental Demand-Side Management savings and loss reduction savings.**

**To quantify the impact of the calibration in the models would require an extensive analysis to approximate the effect of the change in the calibration period.**

**The starting point of the analysis would involve determining the differences in the forecasts which originate with the projections from the commercial Statistically Adjusted End Use (SAE) models. This would require a two-step process:**

- **Step 1 - re-calibrate the commercial SAE models over the updated 10 year estimation period (i.e., fiscal 2009 to fiscal 2018) with updated historical commercial sales and updated historical load drivers used in the SAE models. The result from step 1 would be updated calibrated SAE models with estimated elasticity coefficients.**
- **Step 2 – develop commercial SAE model projections. Model projections are developed by applying (i.e., multiplying) the estimated coefficients from step 1 to the various forecast drivers included in the SAE models such as economic drivers, economic elasticities, average efficiency and shares of commercial end uses, and heating and cooling degree days.**

**As noted in BC Hydro's response to BCUC IR 1.5.1, there are several considerations when developing a fair comparison between the various vintages of SAE forecasts to isolate drivers, in order to account for the difference between the May 2016 and October 2018 forecasts. For example, the historical economic data, which is used in the model estimation stage, has changed as a result of the transition of economic consultants from Robert Fairholm Economic Consultant to the Conference Board of Canada. These additional considerations add complexity to the analysis and make it difficult to quantify the difference between the forecasts that can be attributed to the calibration period.**

**Prior to the next long term forecast, BC Hydro will be undertaking a further review of the commercial sales and sector. The review will include investigation into the historical load trends such as account growth and closures, utilization of commercial building stock (vacancy) and the impact of building codes. The review will also build on work with regards to the relationship between the load and economic drivers.**

**208.0 B. CHAPTER 3 – LOAD AND REVENUE FORECAST**

**Reference: LOAD AND REVENUE FORECAST**
**Exhibit B-5, BCUC IR 4.2.1, 15.3**
**Load forecast beyond the test period**

BC Hydro stated in response to BCUC IR 4.2.1 that:

> The October 2018 Load Forecast is one of the inputs to the Energy Studies models that forecast the Cost of Energy across a five-fiscal- year time horizon, which includes the two-year test period… The modeling horizon and load forecast inputs extend beyond the test period because system conditions beyond the test period can have impacts on optimal operations during the test period, which impacts the Cost of Energy.

BC Hydro stated in response to BCUC IR 15.3:

> The Energy Studies model operations for the next five years (i.e., to the end of fiscal 2024 in the current studies). These results are used for operational decision making (e.g., setting the threshold sale price) and for near-term financial forecasts (e.g., the Cost of Energy forecast in the Application).

2.208.1 In consideration that BC Hydro's Energy Studies are performed monthly, please explain how often BC Hydro updates the load forecast for the purpose of the monthly energy studies.

**RESPONSE:**

**Each month, BC Hydro updates the monthly Energy Studies with load actuals to date. The load forecast for the remaining portion of the five-year time horizon uses the latest approved load forecast.**

**Updated load forecasts will be entered to the Energy Studies model when a new load forecast becomes available. As described in BC Hydro's response to BCUC IR 2.209.1, BC Hydro normally completes a comprehensive load forecast once per year as part of BC Hydro's annual Service Plan schedule. The latest approved load forecast is the October 2018 Load Forecast, and it will be used in the Energy Studies until the next service plan load forecast is available in October 2019.**

**Each Energy Study informs the operational decisions until the next monthly Energy Study is complete. Operational decisions such as setting the threshold**

**sale or purchase price are typically adjusted each month upon completion of the Energy Study for that month.**

**Other tools such as spreadsheets, database applications and proprietary software are used within the month to make operational decisions to respond to rapidly changing conditions as described in the BC Hydro's response to BCUC IR 1.28.1, which can also include short-term changes to load.**

**Occasionally weather related adjustments to the Load Forecast as used in the Energy Studies are applied if warranted based upon short-term climatology forecasts. No such adjustments have been made since the end of fiscal 2019.**

**208.0 B. CHAPTER 3 – LOAD AND REVENUE FORECAST**

**Reference: LOAD AND REVENUE FORECAST**
**Exhibit B-5, BCUC IR 4.2.1, 15.3**
**Load forecast beyond the test period**

BC Hydro stated in response to BCUC IR 4.2.1 that:

> The October 2018 Load Forecast is one of the inputs to the Energy Studies models that forecast the Cost of Energy across a five-fiscal- year time horizon, which includes the two-year test period… The modeling horizon and load forecast inputs extend beyond the test period because system conditions beyond the test period can have impacts on optimal operations during the test period, which impacts the Cost of Energy.

BC Hydro stated in response to BCUC IR 15.3:

> The Energy Studies model operations for the next five years (i.e., to the end of fiscal 2024 in the current studies). These results are used for operational decision making (e.g., setting the threshold sale price) and for near-term financial forecasts (e.g., the Cost of Energy forecast in the Application).

2.208.1.1 Please discuss to what extent, and for which time periods, does the October 2018 load forecast inform operational decision making.

**RESPONSE:**

**Please refer to BC Hydro's response to BCUC IR 2.208.1.**

**209.0 B. CHAPTER 3 – LOAD AND REVENUE FORECAST**

**Reference: LOAD AND REVENUE FORECAST**
**Exhibit B-5, BCUC IR 5.3.1**
**Growth Domestic Product (GDP) growth projection**

BC Hydro stated in response to BCUC IR 5.3.1 that:

> Since BC Hydro's filing of the Application we have not received an updated regional economic forecast from the Conference Board of Canada. However, the following table shows that recent employment growth forecasts over the short term from the B.C. Ministry of Finance are very similar to those used by the Conference Board of Canada to develop the test period economic forecast.

In response to BCUC IR 5.3.1, BC Hydro further provided a comparison between the Conference Board of Canada (CBoC) Economic Forecast June 2018 with the BC Ministry of Finance BC Budget February 2019 values for total provincial BC GDP growth, total provincial employment growth forecast and total provincial housing starts.

2.209.1 Please explain how frequently BC Hydro updates its load forecast for internal purposes.

**RESPONSE:**

**BC Hydro normally makes changes to our load forecast in three ways, and each with different frequency:**

- **By building a comprehensive system level energy and peak load forecast, (referred to as a "comprehensive load forecast");**
- **By developing partial updates to a comprehensive load forecast, which we call a "load forecast update"; and**
- **By adjusting a version of a comprehensive load forecast or a load forecast update within a fiscal year for financial forecasting purposes.**

**The remainder of this response outlines the frequency and typical content of each of these updates.**

**Comprehensive Load Forecast**

**We normally complete a comprehensive load forecast once per year as part of BC Hydro's annual Service Plan schedule.**

**The most current Service Plan load forecast, referred to as the October 2018 Load Forecast, is also used in the cost of energy study that supports the same Service Plan. This is described in BC Hydro's response to BCUC IR 2.208.1. The comprehensive load forecast is also the starting point for other products and forecasts used within BC Hydro (e.g., the distribution substation peak forecast).**

**A comprehensive load forecast encompasses updates to key inputs and model calibration periods. Specific items involved in developing a comprehensive load forecast include the following:**

- **Economic forecasts, such as those currently provided by the Conference Board of Canada;**
- **Residential accounts forecasts, and residential and commercial statistical end-use model inputs, calibration and projections;**
- **Electric vehicle inputs, calibration and model projections;**
- **Light industrial model inputs and projections, account inputs and projections;**
- **Distribution peak model inputs, calibration, and guidelines for developing substation forecasts;**
- **System peak model inputs, calibration and projections;**
- **Demand-Side Management savings plan projections;**
- **Third-party market (consultant and subscriptions services) assessments and customer-specific assessments for the industrial sub-sectors (forestry, mining, oil and gas);**
- **Large industrial customer low, mid and high forecasts;**
- **Other utilities, smaller loads, and non-integrated areas inputs, model calibrations and projections;**
- **Rate impact projections; and**
- **Monte Carlo model simulations to develop low and high uncertainty bands for energy and peak forecasts.**

**Generally, both energy and peak forecast processes begin at the start of the fiscal year once the previous fiscal year's sales and peak demand data have been compiled. The energy portion of the forecast is scheduled to be completed every October as part of the Service Plan schedule and the system peak portion of the forecast is normally finalized one to two months later. Both the Service Plan and system peak forecasts are multi-year projections, including the current fiscal year. While the Load Forecast team is responsible for developing the company's system peak forecast, it does so in coordination with the Distribution Planning Department, which is responsible for developing the annual distribution substation peak forecast. This process is described in BC Hydro's response to BCOAPO IR 2.101.1.**

**Load Forecast Updates**

**BC Hydro will also develop partial updates to the comprehensive load forecast - referred to as a load forecast update – that use the most recent comprehensive load forecast and refreshes selected elements of that forecast. Load forecast updates are developed when specific business, planning and regulatory processes require current load forecast information, but do not allow for the necessary amount of time needed to develop a comprehensive load forecast. The time gap between the last comprehensive load forecast in May 2016 and the October 2018 Load Forecast was the result of two back-to-back regulatory proceedings (i.e., the Fiscal 2017-2019 RRA and the Site C Inquiry), which required an extensive time commitment from the Load Forecast team and necessitated altering the comprehensive load forecast schedule from its annual cycle.**

**Subject to timing and resource availability constraints, partial updates to the comprehensive load forecast have typically been limited to updates to:**

- **Specific light and large industrial accounts based on information provided directly to BC Hydro from existing customers or customers requesting service;**
- **Specific new loads for emerging sectors such as cannabis and crypto-currency that are included in distribution peak guideline updates that inform the annual distribution substation forecast; and**
- **Other elements depending on their relevance to a specific application (e.g., a regulatory submission). For example, the updated May 2016 Load Forecast filed as part of the Electricity Purchase Agreement Renewals for Sechelt Creek Hydro, Brown Lake Hydro and Walden North Hydro, only included updates to LNG assumptions, DSM and rate impacts (associated with BC Hydro's updated price elasticity assumption).**

**Intra-Year Adjustments for Financial Forecasting Purposes**

**Finally, within a fiscal year, adjustments to a comprehensive load forecast or a load forecast update are sometimes made for financial forecasting purposes. The timing depends on the materiality of year-to-date variances (i.e., how the forecast for the current year is tracking) or unexpected developments (e.g., temporary mill closures due to wild fires).**

**209.0 B. CHAPTER 3 – LOAD AND REVENUE FORECAST**

**Reference: LOAD AND REVENUE FORECAST**
**Exhibit B-5, BCUC IR 5.3.1**
**Growth Domestic Product (GDP) growth projection**

BC Hydro stated in response to BCUC IR 5.3.1 that:

> Since BC Hydro's filing of the Application we have not received an updated regional economic forecast from the Conference Board of Canada. However, the following table shows that recent employment growth forecasts over the short term from the B.C. Ministry of Finance are very similar to those used by the Conference Board of Canada to develop the test period economic forecast.

In response to BCUC IR 5.3.1, BC Hydro further provided a comparison between the Conference Board of Canada (CBoC) Economic Forecast June 2018 with the BC Ministry of Finance BC Budget February 2019 values for total provincial BC GDP growth, total provincial employment growth forecast and total provincial housing starts.

2.209.1.1 Please explain how frequently BC Hydro incorporates updated economic forecasts when it updates its load forecast.

**RESPONSE:**

**An updated economic forecast is included as part of an annual comprehensive load forecast schedule. For further information on this schedule, please refer to BC Hydro's response to BCUC IR 2.209.1.**

**209.0 B. CHAPTER 3 – LOAD AND REVENUE FORECAST**

**Reference: LOAD AND REVENUE FORECAST**
**Exhibit B-5, BCUC IR 5.3.1**
**Growth Domestic Product (GDP) growth projection**

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In response to BCUC IR 5.3.1, BC Hydro further provided a comparison between the Conference Board of Canada (CBoC) Economic Forecast June 2018 with the BC Ministry of Finance BC Budget February 2019 values for total provincial BC GDP growth, total provincial employment growth forecast and total provincial housing starts.

2.209.1.2 Please explain whether BC Hydro's load forecast produced for internal purposes relies on CBoC economic forecast.

**RESPONSE:**

**Please refer to BC Hydro's response to BCUC IR 2.210.2.1 for an explanation of the economic forecasts that are used to develop the load forecasts for the main customer sectors and sub-sectors.**

**209.0 B. CHAPTER 3 – LOAD AND REVENUE FORECAST**

**Reference: LOAD AND REVENUE FORECAST**
**Exhibit B-5, BCUC IR 5.3.1**
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In response to BCUC IR 5.3.1, BC Hydro further provided a comparison between the Conference Board of Canada (CBoC) Economic Forecast June 2018 with the BC Ministry of Finance BC Budget February 2019 values for total provincial BC GDP growth, total provincial employment growth forecast and total provincial housing starts.

2.209.1.2 Please explain whether BC Hydro's load forecast produced for internal purposes relies on CBoC economic forecast.

2.209.1.2.1 If not, please provide the source of the economic forecast and explain why CBoC's economic forecast is not used.

**RESPONSE:**

**Please refer to BC Hydro's response to BCUC IR 2.210.2.1 for an explanation of the economic forecasts that are used to develop the load forecast for the main customer sectors and subsectors.**

**209.0 B. CHAPTER 3 – LOAD AND REVENUE FORECAST**

**Reference: LOAD AND REVENUE FORECAST**
**Exhibit B-5, BCUC IR 5.3.1**
**Growth Domestic Product (GDP) growth projection**

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> Since BC Hydro's filing of the Application we have not received an updated regional economic forecast from the Conference Board of Canada. However, the following table shows that recent employment growth forecasts over the short term from the B.C. Ministry of Finance are very similar to those used by the Conference Board of Canada to develop the test period economic forecast.

In response to BCUC IR 5.3.1, BC Hydro further provided a comparison between the Conference Board of Canada (CBoC) Economic Forecast June 2018 with the BC Ministry of Finance BC Budget February 2019 values for total provincial BC GDP growth, total provincial employment growth forecast and total provincial housing starts.

2.209.2 Please explain how often CBoC updates its regional economic forecasts, and how often the BC Ministry of Finance updates its economic forecasts.

**RESPONSE:**

**The Conference Board of Canada (CBoC) is contracted by BC Hydro to provide at least one economic forecast on a regional and total provincial basis by April 30 of each year. Under the contract, an update to the forecast may also be required during the year. The Ministry of Finance publishes quarterly reports on the provincial economy and fiscal outlook. The Ministry's Third Quarterly Report is typically released with the Budget and Fiscal Plan in February of each year.**

**209.0 B. CHAPTER 3 – LOAD AND REVENUE FORECAST**

**Reference: LOAD AND REVENUE FORECAST**
**Exhibit B-5, BCUC IR 5.3.1**
**Growth Domestic Product (GDP) growth projection**

BC Hydro stated in response to BCUC IR 5.3.1 that:

> Since BC Hydro's filing of the Application we have not received an updated regional economic forecast from the Conference Board of Canada. However, the following table shows that recent employment growth forecasts over the short term from the B.C. Ministry of Finance are very similar to those used by the Conference Board of Canada to develop the test period economic forecast.

In response to BCUC IR 5.3.1, BC Hydro further provided a comparison between the Conference Board of Canada (CBoC) Economic Forecast June 2018 with the BC Ministry of Finance BC Budget February 2019 values for total provincial BC GDP growth, total provincial employment growth forecast and total provincial housing starts.

2.209.3 Please explain whether the frequency for CBoC to update its regional economic forecasts meets BC Hydro's load forecast needs (such as internal operational needs, financial reporting needs such as in this Application and for resource planning).

**RESPONSE:**

**Yes, the frequency of the Conference Board of Canada economic forecasts meets BC Hydro's needs. BC Hydro typically completes a comprehensive annual energy load forecast as part of our annual Service Plan. This forecast takes into account an updated regional B.C. economic forecast, which is a key input for the residential, commercial and light industrial load forecasts.**

**For a discussion regarding the load forecast schedule and inputs for internal operational needs and financial reporting, please refer to BC Hydro's response to BCUC IR 2.208.1.**

**210.0 B. CHAPTER 3 – LOAD AND REVENUE FORECAST**

**Reference: LOAD AND REVENUE FORECAST**
**Exhibit B-1, pp. 3-41, 3-42; Appendix O, Section 20, Table F-2; Exhibit B-5, BCUC IR 5.3.1, 7.2**
**GDP growth projection**

BC Hydro states on page 3-41 of its Application that the employment, retail sales and commercial GDP values are as provided by the CBoC Economic Forecast June 2018. All of these values are at the BC Hydro-wide service area while regional forecasts of these variables are used in developing sales forecasts which comes from the commercial statistical adjusted end-use (SAE) models.

BC Hydro states on page 3-42 of the Application that "Demand growth from other light industrial customers is driven by projected provincial GDP which shows lower growth over the test period relative to past load forecasts." BC Hydro also presents Table 3-7 in its Application, and is replicated below:

**Table 3-7 Real GDP Growth – British Columbia**

| Calendar Year | 2015 (Actual) | 2016 (Actual) | 2017 (Actual) | 2018 (Forecast) | 2019 (Forecast) | 2020 (Forecast) |
|---|---|---|---|---|---|---|
| Real GDP Growth (%) | 3.5 | 3.5 | 3.6 | 2.2 | 1.8 | 2.0 |

Source: B.C. Ministry of Finance First Quarter Report Issued September 7, 2018.

In response to BCUC IR 5.3.1, BC Hydro provided the following table comparing the total provincial BC GDP growth between the CBoC Economic Forecast June 2018 and the BC Ministry of Finance BC Budget February 2019.

**Total Provincial BC GDP Growth (%)**

| Calendar Year | Conference Board of Canada Economic Forecast June 2018 (%) | BC Ministry of Finance BC Budget February 2019[1] (%) |
|---|---|---|
| **2019** | **1.8** | **2.4** |
| **2020** | **2.0** | **2.3** |

2.210.1 Please explain whether the provincial GDP growth of 1.8 percent for 2019 and 2.0 percent for 2020 is from the CBoC Economic Forecast June 2018 or from the BC Ministry of Finance First Quarter Report issued September 7, 2018.

**RESPONSE:**

**The forecast of real provincial GDP growth of 1.8 per cent for 2019 and 2.0 per cent for 2020 is from the B.C. Ministry of Finance First Quarter Report issued on September 7, 2018.**

**In responding to this question, BC Hydro identified an error in the table contained in BC Hydro's response to BCUC IR 1.5.3.1. The first column in the table titled Total Provincial BC GDP Growth (%) should be labelled as B.C. Ministry of Finance First Quarter Report, September 7, 2018, rather than Conference Board of Canada Economic Forecast (CBoC) June 2018. The corrected table is provided below.**

**Total Provincial BC GDP Growth (%)**

| Calendar Year | B.C. Ministry of Finance First Quarter Report, September 7, 2018 (%) | B.C. Ministry of Finance BC Budget February 2019[1] (%) | Conference Board of Canada Economic Forecast June 2018 (%) |
|---|---|---|---|
| **2019** | **1.8** | **2.4** | **2.2** |
| **2020** | **2.0** | **2.3** | **2.3** |

[1] **Source is BC Ministry of Finance, BC Budget and Fiscal Plan 2019/20 to 2021/22 February 19, 2019.**

**210.0 B. CHAPTER 3 – LOAD AND REVENUE FORECAST**

**Reference: LOAD AND REVENUE FORECAST**
**Exhibit B-1, pp. 3-41, 3-42; Appendix O, Section 20, Table F-2; Exhibit B-5, BCUC IR 5.3.1, 7.2**
**GDP growth projection**

BC Hydro states on page 3-41 of its Application that the employment, retail sales and commercial GDP values are as provided by the CBoC Economic Forecast June 2018. All of these values are at the BC Hydro-wide service area while regional forecasts of these variables are used in developing sales forecasts which comes from the commercial statistical adjusted end-use (SAE) models.

BC Hydro states on page 3-42 of the Application that "Demand growth from other light industrial customers is driven by projected provincial GDP which shows lower growth over the test period relative to past load forecasts." BC Hydro also presents Table 3-7 in its Application, and is replicated below:

**Table 3-7 Real GDP Growth – British Columbia**

| Calendar Year | 2015 (Actual) | 2016 (Actual) | 2017 (Actual) | 2018 (Forecast) | 2019 (Forecast) | 2020 (Forecast) |
|---|---|---|---|---|---|---|
| Real GDP Growth (%) | 3.5 | 3.5 | 3.6 | 2.2 | 1.8 | 2.0 |

Source: B.C. Ministry of Finance First Quarter Report Issued September 7, 2018.

In response to BCUC IR 5.3.1, BC Hydro provided the following table comparing the total provincial BC GDP growth between the CBoC Economic Forecast June 2018 and the BC Ministry of Finance BC Budget February 2019.

**Total Provincial BC GDP Growth (%)**

| Calendar Year | Conference Board of Canada Economic Forecast June 2018 (%) | BC Ministry of Finance BC Budget February 2019[1] (%) |
|---|---|---|
| 2019 | 1.8 | 2.4 |
| 2020 | 2.0 | 2.3 |

2.210.2 Please clarify whether the GDP growth forecast used to estimate the light industrial load forecast is from CBoC or the BC Ministry of Finance.

**RESPONSE:**

**The GDP forecast used for 2019 and 2020 light industrial sector is from the BC Ministry of Finance but only impacts the "other" sub-sector of the light industrial sector. The load forecast for the oil and gas, coal and forestry sub-sectors of the light industrial sector are not developed from a GDP forecast.**

**The load forecast for the coal and oil and gas sub-sectors are determined on an account-by-account basis. The forecast for the forestry sub-sector is determined by developing mill-by-mill production forecasts, aggregating those forecasts by region and then multiplying the total by the historical electricity use intensity for each region and mill type.**

**210.0 B. CHAPTER 3 – LOAD AND REVENUE FORECAST**

**Reference: LOAD AND REVENUE FORECAST**
**Exhibit B-1, pp. 3-41, 3-42; Appendix O, Section 20, Table F-2; Exhibit B-5, BCUC IR 5.3.1, 7.2**
**GDP growth projection**

BC Hydro states on page 3-41 of its Application that the employment, retail sales and commercial GDP values are as provided by the CBoC Economic Forecast June 2018. All of these values are at the BC Hydro-wide service area while regional forecasts of these variables are used in developing sales forecasts which comes from the commercial statistical adjusted end-use (SAE) models.

BC Hydro states on page 3-42 of the Application that "Demand growth from other light industrial customers is driven by projected provincial GDP which shows lower growth over the test period relative to past load forecasts." BC Hydro also presents Table 3-7 in its Application, and is replicated below:

**Table 3-7 Real GDP Growth – British Columbia**

| Calendar Year | 2015 (Actual) | 2016 (Actual) | 2017 (Actual) | 2018 (Forecast) | 2019 (Forecast) | 2020 (Forecast) |
|---|---|---|---|---|---|---|
| Real GDP Growth (%) | 3.5 | 3.5 | 3.6 | 2.2 | 1.8 | 2.0 |

Source: B.C. Ministry of Finance First Quarter Report Issued September 7, 2018.

In response to BCUC IR 5.3.1, BC Hydro provided the following table comparing the total provincial BC GDP growth between the CBoC Economic Forecast June 2018 and the BC Ministry of Finance BC Budget February 2019.

**Total Provincial BC GDP Growth (%)**

| Calendar Year | Conference Board of Canada Economic Forecast June 2018 (%) | BC Ministry of Finance BC Budget February 2019[1] (%) |
|---|---|---|
| **2019** | **1.8** | **2.4** |
| **2020** | **2.0** | **2.3** |

2.210.2 Please clarify whether the GDP growth forecast used to estimate the light industrial load forecast is from CBoC or the BC Ministry of Finance.

2.210.2.1 If the GDP growth forecast is from the BC Ministry of Finance, please explain why CBoC forecasts are not consistently applied for all customer segments' load forecast.

**RESPONSE:**

**To maintain consistency with the source of other financial assumptions used within the company, BC Hydro prefers to use the BC Ministry of Finance's economic forecasts, where applicable. However, these economic forecasts are produced only at the provincial level and only for a five-year forecast horizon.**

**The residential and commercial load forecasts for the entire forecast horizon are developed on a regional basis using economic forecasts from the Conference Board of Canada (CBoC). As the BC Ministry of Finance forecasts are not provided on a regional basis, BC Hydro relies upon the regional economic forecasts provided by the CBoC. For further information on the methodologies used to develop the residential and commercial sector load forecasts, please refer to sections 4 and 5 of Appendix O of the Application. For further information on the economic forecasts used to develop the load forecasts for the residential and commercial sectors, please also refer to section 20 of Appendix O of the Application.**

**The load forecast for the "other" sub-sector, which is part of the light industrial sector, is developed at the provincial level using the BC Ministry of Finance GDP forecast. In this case, we are able to use the BC Ministry of Finance forecast for the first five years of the forecast and the CBoC forecast for the remainder of the forecast period.**

**The large industrial load forecast is developed on an account by account basis and does not use B.C. GDP as a direct input.**

**210.0 B. CHAPTER 3 – LOAD AND REVENUE FORECAST**

**Reference: LOAD AND REVENUE FORECAST**
**Exhibit B-1, pp. 3-41, 3-42; Appendix O, Section 20, Table F-2; Exhibit B-5, BCUC IR 5.3.1, 7.2**
**GDP growth projection**

BC Hydro stated in response to BCUC IR 7.2 that:

> The perturbation process used the Conference Board of Canada's GDP growth forecast (refer to Appendix O, section 20, Table F-2 of the Application) as the base. That base was then perturbed randomly using a normal distribution with a mean of zero and standard deviation of 1.7 that was itself derived from the actual, annual values for GDP growth for British Columbia over the past twenty years (refer to Appendix O, section 20, Table F-2, Note 3) in order to incorporate variability.

Table F-2 in Section 20 of Appendix O of the Application shows the commercial economic drivers (employment annual growth, real retail sales annual growth and real commercial GDP annual growth) and the BC provincial GDP annual growth as the light industrial economic driver. Note 2 to the table regarding commercial economic drivers states: "history and forecast for all data in the table above comes from the Conference Board of Canada June, 2018 Economic Forecast." Note 3 regarding light industrial economic drivers states: "history comes from BC Stats while forecast of real BC GDP growth from 2018 to 2022 comes [from] BC Ministry of Finance, First Quarter Report, issued September 7, 2018."

2.210.3 Please clarify whether the perturbation process was performed on each of the commercial economic drivers and the light industrial economic driver.

**RESPONSE:**

**This answer also responds to BCUC IRs 2.210.3.1, 2.210.3.2, 2.210.3.2.1, 2.210.3.2.2, 2.210.4, 2.210.4.1 and 2.210.4.2.**

**Gross domestic product (GDP) growth is the only economic driver used as part of the Monte Carlo perturbation process to determine the high and low forecasts for each of the major customer sectors (including light industrial and commercial) as well as the total system.**

**While there are several economic drivers that go into developing the mid load forecasts for the commercial and light industrial sectors, we believe that GDP is the most relevant economic driver to be applied to the Monte Carlo analysis for**

**determining the uncertainty bands for the combined light industrial and commercial sectors and the total system. The reasons for this are:**

- **GDP growth is correlated with other economic drivers such as commercial GDP, which is used to develop segments of the commercial load forecast, and**
- **BC Hydro retained DNV GL to review and confirm the appropriateness of using GDP in its load forecast uncertainty analysis. Their report, which is included in Appendix Q to the Application, concluded that the approach BC Hydro utilizes for addressing uncertainty in load forecasts by using variations in GDP growth and elasticity is reasonable and should be continued.**

**BC Hydro confirms that the perturbation process using GDP in the Monte Carlo analysis involves a random perturbation growth rate that is normally distributed with a mean of zero and a standard deviation of 1.70 per cent. For further details on the perturbation of the light industrial and commercial sectors please see section 11.2.2 of Appendix O of the Application.**

**BC Hydro would like to clarify its response to BCUC IR 1.7.2. In that response we indicated that the GDP perturbation process in the Monte Carlo used the Conference Board of Canada's June 2018 GDP growth forecast. This only applies to the last year of the forecast (fiscal 2024). The forecast growth of real GDP over the entire forecast period that was perturbed in the Monte Carlo analysis comes from the BC Ministry of Finance, First Quarter Report issued September 2018, for the first five years of the forecast and the Conference Board of Canada June 2018 Economic forecast for the last year of the forecast. The GDP forecast over the entire forecast period can be found in Appendix O, section 20, page 162 Table F-2 of the Application.**

**210.0 B. CHAPTER 3 – LOAD AND REVENUE FORECAST**

**Reference: LOAD AND REVENUE FORECAST**
**Exhibit B-1, pp. 3-41, 3-42; Appendix O, Section 20, Table F-2; Exhibit B-5, BCUC IR 5.3.1, 7.2**
**GDP growth projection**

BC Hydro stated in response to BCUC IR 7.2 that:

> The perturbation process used the Conference Board of Canada's GDP growth forecast (refer to Appendix O, section 20, Table F-2 of the Application) as the base. That base was then perturbed randomly using a normal distribution with a mean of zero and standard deviation of 1.7 that was itself derived from the actual, annual values for GDP growth for British Columbia over the past twenty years (refer to Appendix O, section 20, Table F-2, Note 3) in order to incorporate variability.

Table F-2 in Section 20 of Appendix O of the Application shows the commercial economic drivers (employment annual growth, real retail sales annual growth and real commercial GDP annual growth) and the BC provincial GDP annual growth as the light industrial economic driver. Note 2 to the table regarding commercial economic drivers states: "history and forecast for all data in the table above comes from the Conference Board of Canada June, 2018 Economic Forecast." Note 3 regarding light industrial economic drivers states: "history comes from BC Stats while forecast of real BC GDP growth from 2018 to 2022 comes [from] BC Ministry of Finance, First Quarter Report, issued September 7, 2018."

2.210.3 Please clarify whether the perturbation process was performed on each of the commercial economic drivers and the light industrial economic driver.

2.210.3.1 If the perturbation process is also performed on the light industrial economic driver, please explain whether the "base" references CBoC's GDP growth forecast or references the BC Ministry of Finance growth forecast.

**RESPONSE:**

**Please refer to BC Hydro's response to BCUC IR 2.210.3 which explains the perturbation process that BC Hydro uses.**

**210.0 B. CHAPTER 3 – LOAD AND REVENUE FORECAST**

**Reference: LOAD AND REVENUE FORECAST**
**Exhibit B-1, pp. 3-41, 3-42; Appendix O, Section 20, Table F-2; Exhibit B-5, BCUC IR 5.3.1, 7.2**
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Table F-2 in Section 20 of Appendix O of the Application shows the commercial economic drivers (employment annual growth, real retail sales annual growth and real commercial GDP annual growth) and the BC provincial GDP annual growth as the light industrial economic driver. Note 2 to the table regarding commercial economic drivers states: "history and forecast for all data in the table above comes from the Conference Board of Canada June, 2018 Economic Forecast." Note 3 regarding light industrial economic drivers states: "history comes from BC Stats while forecast of real BC GDP growth from 2018 to 2022 comes [from] BC Ministry of Finance, First Quarter Report, issued September 7, 2018."

2.210.3 Please clarify whether the perturbation process was performed on each of the commercial economic drivers and the light industrial economic driver.

2.210.3.2 If the perturbation process is only performed on the commercial economic drivers, please explain whether the variability to GDP on the commercial GDP annual growth is applied to the light industrial forecast.

**RESPONSE:**

**Please refer to BC Hydro's response to BCUC IR 2.210.3 which explains the perturbation process that BC Hydro uses.**

**210.0 B. CHAPTER 3 – LOAD AND REVENUE FORECAST**

**Reference: LOAD AND REVENUE FORECAST**
**Exhibit B-1, pp. 3-41, 3-42; Appendix O, Section 20, Table F-2; Exhibit B-5, BCUC IR 5.3.1, 7.2**
**GDP growth projection**

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2.210.3.2 If the perturbation process is only performed on the commercial economic drivers, please explain whether the variability to GDP on the commercial GDP annual growth is applied to the light industrial forecast.

2.210.3.2.1 If yes, please elaborate on why that is appropriate.

**RESPONSE:**

**Please refer to BC Hydro's response to BCUC IR 2.210.3 which explains the perturbation process that BC Hydro uses, including that gross domestic product (GDP) growth is the only economic driver used as part of the Monte Carlo perturbation process to determine the high and low forecasts for each of the major customer sectors (including light industrial and commercial) as well as the total system.**

**210.0 B. CHAPTER 3 – LOAD AND REVENUE FORECAST**

**Reference: LOAD AND REVENUE FORECAST**
**Exhibit B-1, pp. 3-41, 3-42; Appendix O, Section 20, Table F-2; Exhibit B-5, BCUC IR 5.3.1, 7.2**
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> The perturbation process used the Conference Board of Canada's GDP growth forecast (refer to Appendix O, section 20, Table F-2 of the Application) as the base. That base was then perturbed randomly using a normal distribution with a mean of zero and standard deviation of 1.7 that was itself derived from the actual, annual values for GDP growth for British Columbia over the past twenty years (refer to Appendix O, section 20, Table F-2, Note 3) in order to incorporate variability.

Table F-2 in Section 20 of Appendix O of the Application shows the commercial economic drivers (employment annual growth, real retail sales annual growth and real commercial GDP annual growth) and the BC provincial GDP annual growth as the light industrial economic driver. Note 2 to the table regarding commercial economic drivers states: "history and forecast for all data in the table above comes from the Conference Board of Canada June, 2018 Economic Forecast." Note 3 regarding light industrial economic drivers states: "history comes from BC Stats while forecast of real BC GDP growth from 2018 to 2022 comes [from] BC Ministry of Finance, First Quarter Report, issued September 7, 2018."

2.210.3.2 If the perturbation process is only performed on the commercial economic drivers, please explain whether the variability to GDP on the commercial GDP annual growth is applied to the light industrial forecast.

2.210.3.2.2 If no, please explain how variability to the GDP growth is applied to the light industrial load forecast.

**RESPONSE:**

**Please refer to BC Hydro's response to BCUC IR 2.210.3 which explains the perturbation process that BC Hydro uses, including that gross domestic product (GDP) growth is the only economic driver used as part of the Monte Carlo perturbation process to determine the high and low forecasts for each of the major customer sectors (including light industrial and commercial) as well as the total system.**

**210.0 B. CHAPTER 3 – LOAD AND REVENUE FORECAST**

**Reference: LOAD AND REVENUE FORECAST**
**Exhibit B-1, pp. 3-41, 3-42; Appendix O, Section 20, Table F-2; Exhibit B-5, BCUC IR 5.3.1, 7.2**
**GDP growth projection**

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Table F-2 in Section 20 of Appendix O of the Application shows the commercial economic drivers (employment annual growth, real retail sales annual growth and real commercial GDP annual growth) and the BC provincial GDP annual growth as the light industrial economic driver. Note 2 to the table regarding commercial economic drivers states: "history and forecast for all data in the table above comes from the Conference Board of Canada June, 2018 Economic Forecast." Note 3 regarding light industrial economic drivers states: "history comes from BC Stats while forecast of real BC GDP growth from 2018 to 2022 comes [from] BC Ministry of Finance, First Quarter Report, issued September 7, 2018."

2.210.4 Please confirm, or explain otherwise, that the perturbation distribution (normal distribution with a mean of zero and standard deviation of 1.7) is the same for all economic drivers presented in Table F-2.

**RESPONSE:**

**Not confirmed. Please refer to BC Hydro's response to BCUC IR 2.210.3 which explains the perturbation process that BC Hydro uses, including that gross domestic product (GDP) growth is the only economic driver used as part of the Monte Carlo perturbation process to determine the high and low forecasts for each of the major customer sectors (including light industrial and commercial) as well as the total system.**

**210.0 B. CHAPTER 3 – LOAD AND REVENUE FORECAST**

**Reference: LOAD AND REVENUE FORECAST**
**Exhibit B-1, pp. 3-41, 3-42; Appendix O, Section 20, Table F-2; Exhibit B-5, BCUC IR 5.3.1, 7.2**
**GDP growth projection**

BC Hydro stated in response to BCUC IR 7.2 that:

> The perturbation process used the Conference Board of Canada's GDP growth forecast (refer to Appendix O, section 20, Table F-2 of the Application) as the base. That base was then perturbed randomly using a normal distribution with a mean of zero and standard deviation of 1.7 that was itself derived from the actual, annual values for GDP growth for British Columbia over the past twenty years (refer to Appendix O, section 20, Table F-2, Note 3) in order to incorporate variability.

Table F-2 in Section 20 of Appendix O of the Application shows the commercial economic drivers (employment annual growth, real retail sales annual growth and real commercial GDP annual growth) and the BC provincial GDP annual growth as the light industrial economic driver. Note 2 to the table regarding commercial economic drivers states: "history and forecast for all data in the table above comes from the Conference Board of Canada June, 2018 Economic Forecast." Note 3 regarding light industrial economic drivers states: "history comes from BC Stats while forecast of real BC GDP growth from 2018 to 2022 comes [from] BC Ministry of Finance, First Quarter Report, issued September 7, 2018."

2.210.4 Please confirm, or explain otherwise, that the perturbation distribution (normal distribution with a mean of zero and standard deviation of 1.7) is the same for all economic drivers presented in Table F-2.

2.210.4.1 If confirmed, please explain why BC Hydro considers it appropriate to use the same distribution. Please include any analysis or studies to support this assumption.

**RESPONSE:**

**Please refer to BC Hydro's response to BCUC IR 2.210.3 which explains the perturbation process that BC Hydro uses, including that gross domestic product (GDP) growth is the only economic driver used as part of the Monte Carlo perturbation process to determine the high and low forecasts for each of the major customer sectors (including light industrial and commercial) as well as the total system.**

**210.0 B. CHAPTER 3 – LOAD AND REVENUE FORECAST**

**Reference: LOAD AND REVENUE FORECAST**
**Exhibit B-1, pp. 3-41, 3-42; Appendix O, Section 20, Table F-2; Exhibit B-5, BCUC IR 5.3.1, 7.2**
**GDP growth projection**

BC Hydro stated in response to BCUC IR 7.2 that:

> The perturbation process used the Conference Board of Canada's GDP growth forecast (refer to Appendix O, section 20, Table F-2 of the Application) as the base. That base was then perturbed randomly using a normal distribution with a mean of zero and standard deviation of 1.7 that was itself derived from the actual, annual values for GDP growth for British Columbia over the past twenty years (refer to Appendix O, section 20, Table F-2, Note 3) in order to incorporate variability.

Table F-2 in Section 20 of Appendix O of the Application shows the commercial economic drivers (employment annual growth, real retail sales annual growth and real commercial GDP annual growth) and the BC provincial GDP annual growth as the light industrial economic driver. Note 2 to the table regarding commercial economic drivers states: "history and forecast for all data in the table above comes from the Conference Board of Canada June, 2018 Economic Forecast." Note 3 regarding light industrial economic drivers states: "history comes from BC Stats while forecast of real BC GDP growth from 2018 to 2022 comes [from] BC Ministry of Finance, First Quarter Report, issued September 7, 2018."

2.210.4 Please confirm, or explain otherwise, that the perturbation distribution (normal distribution with a mean of zero and standard deviation of 1.7) is the same for all economic drivers presented in Table F-2.

2.210.4.2 If not confirmed, please present the distribution assumption for each applicable economic driver.

**RESPONSE:**

**Please refer to BC Hydro's response to BCUC IR 2.210.3 which explains the perturbation process that BC Hydro uses, including that gross domestic product (GDP) growth is the only economic driver used as part of the Monte Carlo perturbation process to determine the high and low forecasts for each of the major customer sectors (including light industrial and commercial) as well as the total system.**

**211.0 B. CHAPTER 3 – LOAD AND REVENUE FORECAST**

**Reference: LOAD AND REVENUE FORECAST**
**Exhibit B-5, BCUC IR 5.3.1**
**Rate and price elasticity**

BC Hydro stated in response to BCUC IR 5.3.1 that "There are challenges and uncertainties in forecasting actual future rates. BC Hydro developed the rate impacts for the October 2018 Load Forecast using the past five years of the 2013 10-Year Rates Plan. However, the rates within that rate plan are not the same as the rates we are now seeking within this Application."

2.211.1 Please explain why the rates BC Hydro is seeking within this Application is not used as an input to estimate rate and price elasticity in the Test Period load forecast.

**RESPONSE:**

**The rates BC Hydro is seeking in the Application were not used as an input to estimate the rate impacts and price elasticity during the test period because BC Hydro had not finalized its updated five-year rates forecast at the time the October 2018 Load Forecast was developed.**

**211.0 B. CHAPTER 3 – LOAD AND REVENUE FORECAST**

**Reference: LOAD AND REVENUE FORECAST**
**Exhibit B-5, BCUC IR 5.3.1**
**Rate and price elasticity**

BC Hydro stated in response to BCUC IR 5.3.1 that "There are challenges and uncertainties in forecasting actual future rates. BC Hydro developed the rate impacts for the October 2018 Load Forecast using the past five years of the 2013 10-Year Rates Plan. However, the rates within that rate plan are not the same as the rates we are now seeking within this Application."

2.211.2 Please compare the assumed rates used in the October 2018 load forecast and the rates BC Hydro is seeking within this Application.

**RESPONSE:**

**This answer also responds to BCUC IR 2.211.2.1.**

**As indicated on page 3-14 of Chapter 3 of the Application, the rate increases used in the October 2018 Load Forecast are based on bill impact projections in real dollars (net of inflation), based on the last five years of the 2013 10 Year Rates Plan. For the test period, the bill impacts in real dollars are estimated to be 0.39 per cent for fiscal 2020 and 0.59 per cent for fiscal 2021.**

**Based on the rate increases sought in the Fiscal 2020 to Fiscal 2021 Revenue Requirements Application Evidentiary Update (EU) filed on August 22, 2019, the real dollar bill impacts are estimated to be -0.33 per cent for fiscal 2020 and -2.93 per cent for fiscal 2021.**

**The following table provides a comparison of the annual bill impacts on a nominal and real dollar basis, and the total domestic billed sales forecasts for fiscal 2020 and fiscal 2021, based on the rate increases used in the October 2018 Load Forecast compared to the rate increases sought in the EU. As indicated in the table below, the October 2018 total domestic billed sales forecast for fiscal 2020 is 53,561 GWh, while the EU forecast is 53,624 GWh (63 GWh or 0.1 per cent higher). For fiscal 2021 the October 2018 total domestic billed sales forecast is 53,253 GWh, while the EU forecast is 53,513 GWh (260 GWh or 0.5 per cent higher). To derive the impact on the October 2018 Load Forecast of the rate increases sought in the EU, BC Hydro used the price elasticity assumption of -0.1, which is based on the recommendations contained in the DNV GL report provided in Appendix Q to the Application. The report reviewed a number of jurisdictions which were assumed to experience positive real rate increases. As such, it is**

**uncertain how customers will respond to declining rates, as this was not specifically reviewed by DNV GL in their report.**

| | F2020 | | F2021 | |
|---|---|---|---|---|
| | Rate Increase Used in October 2018 Load Forecast | Rate Increase Sought in the EU Application | Rate Increase Used in October 2018 Load Forecast | Rate Increase Sought in the EU Application |
| Annual bill increase / (decrease) - nominal | 2.60% | 1.76% | 2.60% | -0.99% |
| Annual bill increase / (decrease) - real | 0.39% | -0.33% | 0.59% | -2.93% |
| Total Domestic Billed Sales Forecast (GWh) | 53,561 | 53,624 | 53,253 | 53,513 |

**211.0 B. CHAPTER 3 – LOAD AND REVENUE FORECAST**

**Reference: LOAD AND REVENUE FORECAST**
**Exhibit B-5, BCUC IR 5.3.1**
**Rate and price elasticity**

BC Hydro stated in response to BCUC IR 5.3.1 that “There are challenges and uncertainties in forecasting actual future rates. BC Hydro developed the rate impacts for the October 2018 Load Forecast using the past five years of the 2013 10-Year Rates Plan. However, the rates within that rate plan are not the same as the rates we are now seeking within this Application.”

2.211.2.1 Please quantify the impact to the Test Period load forecast if the rates BC Hydro is seeking within this Application is used to estimate rate and price elasticity.

**RESPONSE:**

**Please refer to BC Hydro’s response to BCUC IR 2.211.2.**

**212.0 B. CHAPTER 3 – LOAD AND REVENUE FORECAST**

**Reference: LOAD AND REVENUE FORECAST**
**Exhibit B-5, BCUC IR 9.4**
**Top-down and bottom-up forecast**

In response to BCUC IR 9.4, BC Hydro stated:

> The bottom-up and top-down forecasts are iterated until they converge by adjusting the following parameters… For instance, if the bottom-up forecast for one of the six sub-regions is much higher than what is in the top-down forecast, we would check the bottom-up assumptions for defensibility. If it is felt that the probability weightings in the bottom-up were too high, then the iteration would be to lower them until the bottom-up and top-down forecasts align.

2.212.1 Please elaborate on whether the top-down forecasts are also tested for defensibility and adjusted accordingly.

**RESPONSE:**

**Yes, the top-down forecast is tested for defensibility and is adjusted accordingly.**

**As a general comment, BC Hydro retained the services of GLJ Petroleum Consultants (GLJ), to provide third-party subject matter expertise in supporting the development of the top-down forecast. Previously we had not relied on external subject matter experts to provide a comprehensive analysis of B.C. shale gas development and therefore this additional capability improves the overall defensibility of the top-down forecast.**

**In addition, the terms of reference for GLJ's contract includes the requirement to provide explanations and/or reasons for the variances between outlooks provided and actual output once actual or estimated data becomes available. This requirement is one of the recommendations of the internal load forecast audit. GLJ will provide this information as part of BC Hydro's next load forecast.**

**As described on pages 83 to 84 of section 7.5.2.1, in Appendix O to the Application, the bottom-up and top-down forecasts are updated with current information and aligned. If the bottom-up and top-down forecasts for one of the six sub-regions is different, BC Hydro would also check the top-down assumptions for defensibility. In our response to BCUC IR 1.9.4, three potential iteration parameters for the top-down forecast were identified, and these parameters are reproduced below:**

- **Gas demand parameters (e.g., LNG export, export to North America and gas liquids demand for oil sands);**
- **Gas supply parameters (e.g., well production characteristics and drilling activity); and**
- **Electrification parameters (e.g., regional service electrification characteristics and electrical load intensities).**

**When one of the six sub-regions differs between the bottom-up and top-down forecasts, specific parameters may be adjusted to converge the forecasts. These parameters are identified in the table below. The table also reports how the parameters can be tested for defensibility and adjusted accordingly.**

| Top-down Parameters | Description, Defensibility Test & Adjustment Degree |
|---|---|
| **Gas Demand Parameters** | |
| **BC LNG export** | **DESCRIPTION: Volume (MMcf/day) of BC LNG terminal requirements to be serviced by BC Montney gas suppliers. BC Hydro uses a number of external LNG experts that provide a likelihood assessment and production volume forecasts.**<br>**DEFENSIBILITY TEST: BC Hydro is able to use these experts, on an ongoing basis, to evaluate its own terminal volume and likelihood forecasts.**<br>**ADJUSTMENT DEGREE: No adjustments are required to the parameter since the LNG forecast is developed in a separate process. Gas production forecasts from that process are consistently applied to both top-down (i.e., LNG-driven gas production) and bottom-up forecasts (i.e., LNG-dependent customer requests) within the shale gas model.** |
| **BC consumption, pipeline exports to North America and other** | **DESCRIPTION: Volume (MMcf/day) of demand from major consumers. This information is provided from GLJ.**<br>**DEFENSIBILITY TEST: Compare forecasts against other third-party experts and government sources of actual activity.**<br>**ADJUSTMENT DEGREE: If BC Hydro has concerns, then discussions with the consultant would be directed at reaching a revised forecast. However, once updated with current information it is generally not adjusted in the iteration process.**<br>**For illustration please refer to BC Hydro’s response to BCUC IR 2.212.2, which describes adjustments made to the gas production forecast using revised drilling activity levels.** |

| Top-down Parameters | Description, Defensibility Test & Adjustment Degree |
|---|---|
| **Gas Supply Parameters** | |
| **Well production** | **DESCRIPTION: This is the representative well production forecast (in MMcf/day) used in producing the Montney gas production forecast. This is provided by GLJ, and is based on over 1,000 well profiles throughout the Montney area.**<br>**DEFENSIBILITY TEST: Compare to what Montney area producers and industry experts are observing or projecting.**<br>**ADJUSTMENT DEGREE: If BC Hydro has concerns, it can discuss the matter with GLJ. However, once updated, it is generally not adjusted in the iterative process.** |
| **Drilling activity** | **DESCRIPTION: The annual forecast of wells drilled in the Montney area. It is used in producing the Montney gas production forecast. The drilling activity data inputs used are initially selected to produce Montney forecast that closely mirrors the GLJ forecast.**<br>**DEFENSIBILITY TEST: Compare with actual drilling data that is reported by the BC Oil and Gas Commission (BCOGC). From this report, BC Hydro also extracts locational information to produce a BC Hydro drill report. This report identifies the drilling activity in each of the six sub-regions (which is used to test the accuracy of its production and service percentage assumptions mentioned below). Since this BCOGC drill report is produced on a monthly basis, it can be used to identify current trends that signal future gas production growth.**<br>**ADJUSTMENT DEGREE: In the iterative process, drilling activity is a primary tool in the iterative process. It helps align the forecasts by serving to increase or decrease Montney gas production. The data inputs used are selected to keep the resulting Montney forecast within reasonable bounds of the GLJ forecast; it is kept within reasonable bounds by comparing the resulting production forecast with that produced by GLJ.**<br>**For illustration please refer to BC Hydro's response to BCUC IR 2.212.2, which describes adjustments made to the gas production forecast via revised drilling activity levels.** |

| Top-down Parameters | Description, Defensibility Test & Adjustment Degree |
|---|---|
| **Montney gas area production** | **DESCRIPTION: Natural gas production forecast for the BC Montney area (in MMcf/day). As indicated above, there are two forecasts: GLJ's and BC Hydro's. Initially, BC Hydro's forecast is a mirror of the GLJ forecast, but is calculated from the well production and drilling activity forecasts. This allows BC Hydro to iterate the Montney production forecast (by way of adjustments to drilling activity) to capture information that may have been overlooked.**<br>**DEFENSIBILITY TEST: Compare to what other industry experts are forecasting.**<br>**ADJUSTMENT DEGREE: In the iterative process, BC Hydro can tweak the forecast (by adjusting drilling activity); major adjustments can be discussed and reconciled with GLJ. Any revisions would be within the bounds of market fundamentals and/or other industry expert forecasts.**<br>**For illustration please refer to BC Hydro's response to BCUC IR 2.212.2, which describes adjustments made to the gas production forecast using revised drilling activity levels.** |
| **Electrification Parameters** | |
| **Service percentages** | **DESCRIPTION: Percentage of volume of gas production served by BC Hydro relative to total gas produced. It is based on a number of factors: BC Hydro service requests, drilling activity and existing and planned transmission proximity in each of the six sub-regions. This is produced by BC Hydro.**<br>**DEFENSIBILITY TEST: An overall test for service percentage in the Montney area would be to compare the total production from BC Hydro serviced plant to total gas production. A test for each of the six sub-region service percentages would be to compare them against the above mentioned BC Hydro drill report (for each of the six sub-regions). Since the drilling report is prepared monthly, it can be used to identify potential service percentage changes.**<br>**ADJUSTMENT DEGREE: In the iterative process, professional judgement is used. Adjustments are kept within reasonable bounds informed by BC Hydro service requests, drilling activity and existing and planned transmission proximity in each of the six sub-regions.**<br>**For illustration please refer to BC Hydro's response to BCUC IR 2.212.2, which describes adjustments made to the gas production forecast via revised drilling activity levels.** |

| Top-down Parameters | Description, Defensibility Test & Adjustment Degree |
|---|---|
| **Energy intensity** | **DESCRIPTION: Representative gas plant energy requirements (in MW per MMcf/day). This metric is used to convert the Montney gas production forecast into a MW forecast. BC Hydro's calculation is based on new customer load requests and plant production volumes to determine an intensity estimate for each plant. It is also able to estimate intensities in liquid rich and dry areas as well as produce intensity estimates for the six sub-regions. This estimate is produced by BC Hydro.**<br>**DEFENSIBILITY TEST: Compare with requests for new plant loads (including booster stations) for a given level of production.**<br>**ADJUSTMENT DEGREE: Keep within reasonable bounds of new plant service requests.**<br>**For illustration please refer to BC Hydro's response to BCUC IR 2.212.2, which describes adjustments made to the energy intensity factor.** |
| **Sub-region gas production** | **DESCRIPTION: The percentage breakdown of Montney area gas production for each of the six sub-regions. This breakdown is produced by BC Hydro, but is informed by information from GLJ, and is based on gas liquids presence and drilling activity in each of the sub-regions.**<br>**DEFENSIBILITY TEST: Compare the forecast activity against the above mentioned BC Hydro drill report which can signal future production in each of the sub-regions.**<br>**ADJUSTMENT DEGREE: This is a primary tool used in the iterative process. Professional judgement is used to keep estimate within reasonable bounds.** |

**The major parameters listed above are those that can be adjusted during the iterative process as necessary. In addition, there are a number of other components of the top-down model that serve to inform the test for defensibility and evaluate adjustment reasonability. These include:**

- **A component that ensures that forecast gas production in each of the six sub-regions does not exceed gas- in-place estimates;**
- **Pipeline-related analysis for BC gas exports to North American markets;**
- **Well production costs within the BC Montney compared with the rest of North America;**
- **BC Montney gas liquids production forecasts;**
- **Natural gas and gas liquids price forecasts; and**
- **Oil sands development and condensate demand analysis.**

**212.0 B. CHAPTER 3 – LOAD AND REVENUE FORECAST**

**Reference: LOAD AND REVENUE FORECAST**
**Exhibit B-5, BCUC IR 9.4**
**Top-down and bottom-up forecast**

In response to BCUC IR 9.4, BC Hydro stated:

> The bottom-up and top-down forecasts are iterated until they converge by adjusting the following parameters… For instance, if the bottom-up forecast for one of the six sub-regions is much higher than what is in the top-down forecast, we would check the bottom-up assumptions for defensibility. If it is felt that the probability weightings in the bottom-up were too high, then the iteration would be to lower them until the bottom-up and top-down forecasts align.

2.212.2 Please elaborate on how BC Hydro determines whether the top-down or the bottom-up forecasts requires adjustment, and by how much respectively, in order for the two forecasts to converge.

**RESPONSE:**

**As clarified in BC Hydro's response to BCUC IR 1.9.4, this iteration process only applies to the development of BC Hydro's Montney region shale gas segment load forecast.**

**Professional judgment is used to determine if any adjustments are required to the bottom-up and/or top-down forecasts of the six sub-regions, so that the forecasts converge, while ensuring that each forecast is supported by detailed customer requested information and independent macroeconomic analysis.**

**BC Hydro determines that adjustments to the bottom-up and/or top-down forecasts are required when there is a material difference between the initial bottom-up and top-down forecasts (as measured in MW). Material differences may occur at an aggregate regional level or at each of the six sub-regions.**

**Overall, the bottom-up/top-down convergence process entails a number of iterations, with the most significant adjustment occurring after the bottom-up and top-down forecasts have been updated with current expectations.**

**The bottom-up forecast is based on customer-specific information and analysis and serves as the official shale gas segment forecast. The bottom-up forecast is developed by compiling the current and expected customer load requests, to arrive at load forecasts for each of the six sub-regions. During this process each**

**customer request is evaluated, shaped and discounted based on information from various internal and external sources as described in section 7.5.2.1.2 of Appendix O to the Application. When subtotalled, this produces six bottom-up sub-region forecasts.**

**The top-down forecast is a macro forecast that is primarily used as a guide to check and confirm the reasonableness of the bottom-up forecast. The top-down forecast is derived by creating and the multiplying three data sets, as follows:**

**Top down forecast (MW) = gas production (MMcf/day) x energy intensity (MW/MMcf) x electricity service per cent (%)**

**Energy intensity and electricity service per cent are direct inputs into the top-down forecast, whereas gas production is derived by varying well profile inputs and drilling activity inputs.**

**For the October 2018 Load Forecast, the initial comparison between the bottom-up and top-down forecasts indicated a difference of approximately 14 MW or 3.5 per cent (using fiscal 2024 as the reference year). In order to converge the bottom-up and top-down forecasts the following adjustments were made to three specific top-down forecast inputs relative to their initial input assumptions: (1) increased drilling activity, (2) increased work energy intensity and (3) decreased service percentages.**

1. **Energy intensity. The assumed energy intensity was revised upward from 0.14 MW/MMcf to 0.17 MW/MMcf to be consistent with the energy intensity assumptions obtained via new customer requests (i.e., information from the bottom-up forecast). The new customer requests were considered to be more representative of future requirements for production and processing facilities operating in liquids-rich areas. For further information regarding energy intensity factors please refer to BC Hydro's response to CEABC IR 1.9.3;**

2. **Service percentage. The assumed service percentage was revised downward across all six sub-regions relative to what was assumed in the initial top-down forecast. This revision was based on historical actual data, combined with reduced expectations that customers will take electricity service from BC Hydro. The reduced service percentages were revised to be consistent with the assumptions obtained via the new customer requests (i.e., from the bottom-up forecast). Similar to item (1) above the bottom-up electrification assessments were considered to be more representative of future requirements of the shale gas segment. For further information regarding energy intensity factors please refer to BC Hydro's response to CEABC IR 2.41.1; and**

3. **Drilling activity. The initial drilling activity assumptions were increased to a level necessary to increase expected Montney shale gas production by**

**approximately one bcf/day. This revision was made following a review of the gas production forecasts underlying each of the top-down and bottom-up forecasts. The B.C. gas supply and demand assumptions were subsequently reviewed with our consultant GLJ Petroleum Consultants (GLJ) and it was determined that the top-down forecast did not fully account for shale gas production that is likely to replace the projected decline in conventional gas production, and also that there would be minimal gas imports from Alberta. The shortfall was estimated to be approximately one bcf/day by fiscal 2024. Since well profile input assumptions were already updated by GLJ, increasing drilling activity was the appropriate basis for increasing the top-down gas production forecast.**

**For the October 2018 Load Forecast, the only adjustments made to the bottom-up forecast were minor adjustments applied to new customer start-up probabilities and start dates. These adjustments did not have a significant impact on the forecast load and largely involved revising start-up probability weightings between individual customers or revising start date expectations (i.e., resulting in minimal changes in aggregate load). No adjustments were made to the assumptions regarding the likelihood of electrification since this information is largely based on information provided directly to BC Hydro by customer's requesting or expressing interest in receiving electricity service.**

**213.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-5, BCUC IR 33.1**
**Change in organization structure**

In response to BCUC IR 33.1, BC Hydro stated:

> Our current Plan-Build-Operate-Support model completes the functional centralization we've pursued over the past decade with the Environment, Finance, Information Technology, Human Resources, Project Delivery, Safety, and Supply Chain functions. The positive results from these previous organizational changes gave us the confidence to continue with the functional centralization of larger functions, such as planning and operations.

2.213.1 Please comment on whether there are further organizational changes planned. If so, please discuss: i) the timeline; ii) the types of changes and the expected benefits; and iii) associated costs.

**RESPONSE:**

**There are no further organizational changes planned at the company-wide level. From time to time, there may be organizational changes at the KBU level in response to changing needs or priorities.**

**As discussed in section 5.3.2 of Chapter 5 of the Application, the Plan-Build-Operate-Support model completes our move towards a centralized and functionally-aligned organizational structure.**

**BC Hydro has pursued this shift towards centralizing functions over time starting with our Finance, Supply Chain and Safety functions and more recently, with the centralization of our Planning and Operations functions. This functional alignment encourages consistent adoption of best practices used across the company and facilitates stronger collaboration and cooperation in similar functions across our business.**

**213.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-5, BCUC IR 33.1**
**Change in organization structure**

In response to BCUC IR 33.1, BC Hydro stated:

> Our current Plan-Build-Operate-Support model completes the functional centralization we've pursued over the past decade with the Environment, Finance, Information Technology, Human Resources, Project Delivery, Safety, and Supply Chain functions. The positive results from these previous organizational changes gave us the confidence to continue with the functional centralization of larger functions, such as planning and operations.

2.213.2 Please discuss if there are any programs planned for the Test Period, where similar to the Accenture repatriation or Workforce Optimization program, there will be impacts to the number of Full Time Equivalents (FTEs), or operating expenditures. If so, please provide the details of the program(s).

**RESPONSE:**

**There are currently no programs planned for the test period similar to the Accenture Repatriation and the Workforce Optimization Program that would result in a material impact to the number of FTEs or operating expenditures.**

**BC Hydro is focused on managing operating costs to limit or absorb costs increases within the existing operating cost budget. Over the Test Period and beyond BC Hydro continues to implement initiatives such as Work Smart to achieve efficiencies and process improvements. These efficiencies help absorb cost pressures resulting from the increasing complexity of work such as those described in BC Hydro's response to BCUC IRs 1.64.1 and 2.214.1. For example, the increasing compliance requirements resulting from the North American Electric Reliability Corporation Critical Infrastructure Protection (NERC CIP) program results in significant cost pressures. Initiatives such as the Work Smart program are critical to ensuring BC Hydro is able to absorb these types of cost pressures.**

**214.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-5, BCUC IR 64.1**
**Change in the type, complexity and volume of work**

In response to BCUC IR 64.1, BC Hydro stated that although the "core work has remained the same, the type, complexity, and volume of work BC Hydro performs has changed and increased since the Previous Application. In particular, the compliance burden on BC Hydro has increased, creating additional coordination requirement and costs."

In the response, BC Hydro also provided examples of changes and increases to the volume and complexity of the work since the previous revenue requirement application (RRA).

2.214.1 For each example provided in response to BCUC IR 64.1 and summarized below, please quantify the impact on operating costs for F2020 plan and F2021 plan where possible.

- North American Electric Reliability Corporation Critical Infrastructure Protection
- Safety Regulations
- Indigenous Relations
- Greater Involvement of Subject Matter Experts in Field Work
- Provincial Water Sustainability Act
- Species at Risk
- Invasive species

**RESPONSE:**

**In BC Hydro's response to BCUC IR 1.64.1, we provided examples of areas that have increased the volume and complexity of our work.**

**We expect that these areas will continue to drive change and will continue to increase the volumes and complexity of our work, resulting in additional time, effort and cost. The nature and timing of such continuing changes is unknown. As a result, it is not possible to know (or even to reasonably estimate) the impact on operating costs for fiscal 2020 plan, fiscal 2021 plan or future fiscal years.**

**BC Hydro has thus far attempted to absorb additional costs relating to changes in these areas. We expect that it will be difficult to continue to do so, depending on factors such as the pace and nature of changes. Please refer to BC Hydro's**

**response to BCUC IR 2.231.1 where we note that BC Hydro faces a challenge to address cost pressures and that there is no unallocated funds budget to do so for fiscal 2020 and fiscal 2021. BC Hydro's process to manage its operating budget in light of arising cost pressures is discussed in BC Hydro's response to BCUC IR 2.231.4.**

**The following expands on the examples provided in BC Hydro's response to BCUC IR 1.64.1 for the changes and increases to the volume and complexity of work, and ultimately costs.**

**North American Electric Reliability Corporation Critical Infrastructure Protection**

**NERC Critical Infrastructure Protection Standards are a part of the Mandatory Reliability Standards (MRS) adopted by the BCUC that increase the reliability and security of the Bulk Electric System. These standards include both physical and cybersecurity requirements to protect BC Hydro's critical infrastructure. BC Hydro complies with these Standards and costs for maintaining compliance are embedded within overall operating costs across the organization. The sustainment costs have been increasing over the years as new and revised Standards are adopted and are expected to increase in the future as the Standards are developed and sustained, such as NERC CIP v. 6 and v.7. There are also one-time costs for implementation of standard change / upgrade. Because of these factors the future sustainment costs for MRS compliance are difficult to quantify and are expected to increase. Each year, BC Hydro completes an annual assessment report submitted to the BCUC for new and revised Standards which includes estimating the costs for both one-time adoption and on-going sustainment.**

**For non-NERC environments that fall outside of MRS requirements, another source for potential required cybersecurity protections and procedures is the recent audit report from the Office of Auditor General of British Columbia, where a series of cybersecurity recommendations were presented to BC Hydro. These recommendations are expected to result in additional operating costs. For example, as noted in BC Hydro's responses to BCUC IR 1.123.2.1 and BCUC IR 2.257.1, BC Hydro expects to incur a cost of $0.3 million for a related risk assessment. This cost was not included in the Application as the need for (and cost of) the assessment was unknown at the Application currency date. BC Hydro continues to evaluate the recommendations for adoption. The audit report can be found at:**

**https://www.bcauditor.com/sites/default/files/publications/reports/OABGC_Cybersecurity-ICS-BC-Hydro_RPT.pdf**

**Safety Regulations**

**Safety regulations change on an ongoing basis and can have widespread impacts across the organization. Changes in safety regulations, while introduced to improve safety outcomes for workers and the public, impact operating costs. The costs of achieving and maintaining regulatory compliance are incurred within overall actual operating costs. The cost impacts are not tracked because changes in work activity requirements, for example, are part of the normal workflow. Changes could be an expanded tailboard discussion to cover off additional compliance requirements, or, in the case of recent changes to heat stress regulations, prescribed rest periods when a specific temperature and humidity threshold is reached to avoid heat stroke. These changes, for example, lead to additional time being required to complete work and thus result in higher costs.**

**An example of a new safety regulation is the new WorkSafe BC storage rack regulations governing the installation, inspection, use and maintenance of steel storage racks which has led to the need to correct various deficiencies at the 81 locations across BC Hydro with storage racks. Deficiencies were identified via engineering reviews of storage racks within two phases, with the high risk sites addressed first.**

**Indigenous Relations**

**BC Hydro is incorporating the United Nations Declaration on the Rights of Indigenous Peoples (UNDRIP) and the Calls to Action of the Truth and Reconciliation Commission (TRC) and advancing reconciliation, as per BC Hydro's mandate letter (Appendix E of the Application). To do this, BC Hydro must continue to adapt how we work with Indigenous peoples. We continue to develop an understanding of what this will involve, which requires the Indigenous Relations KBU to work internally across BC Hydro, with the Government of B.C. and with First Nation communities. Phase 2 of the Comprehensive Review that is currently underway is expected to provide some direction with respect to incorporating the UNDRIP and TRC into our business.**

**During the test period we will advance understanding and implement near term measures (e.g., Indigenous Awareness training for BC Hydro employees) – this new work has not resulted in increased costs as the Indigenous Relations KBU has reprioritized its work and resources. However, as our understanding of the further steps BC Hydro can take to advance reconciliation is continuing to evolve, BC Hydro cannot comment on the incremental operating costs that will be required.**

**Greater Involvement of Subject Matter Experts in Field Work**

**BC Hydro has required greater involvement of its subject matter experts in field work, in order to support regulatory compliance efforts for specific priority areas.**

**Examples include:**

**Archaeological work**

**Along with increases in our capital plan and replacement of existing infrastructure, BC Hydro needs to take extra measures to ensure we avoid potential impacts to archaeological sites by our work activities. This has required new and standardization of existing planning tools and procedures for screening our work and heritage awareness training to avoid potential impacts.**

**Increased consultation and engagement with First Nations directly in archaeological protection has also required subject matter expert support and Indigenous cultural monitors to both facilitate discussions as well as ensure BC Hydro incorporates Indigenous perspectives in the work.**

**Amendments to the *Heritage Conservation Act* and additional provincial permitting and reporting requirements (such as new requirements for permit notification content and annual blanket permit reporting) have also necessitated additional subject matter expert involvement in ensuring programs and projects are fully addressing regulatory requirements.**

**Confined space**

**As a result of WorkSafeBC's focus on confined spaces as high risk work and BC Hydro's more rigorous interpretation of current regulations, BC Hydro made the decision to support confined space field work with the attendance of OSH Specialists, as Safety Subject Matter Experts. OSH Specialists also deliver field-focussed confined space training modules and perform competency assessments of confined space supervisors, plus support them in filling their competency gaps. The associated operating cost impacts are absorbed in existing budgets.**

***Provincial Water Sustainability Act***

**Construction excavation dewatering for everything from minor pole holes to large excavations now requires Use Approval to be obtained from the provincial Ministry of Forests, Lands, Natural Resource Operations & Rural Development.**

**Added requirements are related to application fees and labour to prepare the application, manage use approval compliance during construction and complete post-construction reporting. In some instances, additional laboratory testing fees are incurred to satisfy conditions. In other instances, the conditions have required treatment of pumped waters. The added cost (expense and hours) varies depending on scale and duration of the construction dewatering but can vary from a few thousand dollars to a few million. The majority of effort and associated costs is being incurred on capital projects. The operating cost portion is currently being absorbed in existing budgets. These changes impact Project Delivery, Programs and Contract Management and Properties KBUs in addition to Environment.**

**Species at Risk (SAR)**

**For each Species at Risk (SAR), BC Hydro must consider how operations will interact with SAR recovery objectives and the Species at Risk Act (SARA) prohibitions. For individual SAR where interactions with operations are possible, additional planning requirements generally include: (1) delays and seasonal restrictions for scheduling operational tasks (which result in additional mobilization and demobilization costs), (2) sourcing qualified environmental professionals to oversee work in sensitive areas, (3) dedicated field surveys, and (4) modified desktop screening. In some cases a SARA permit may be needed prior to conducting normal operations, which requires planning well in advance and may result in additional cost (e.g., monitoring).**

**The list of SAR also has the potential for conflict amongst management objectives, because avoiding impacts to individual SAR sometimes leads to impacts to other SAR, or to species valued by First Nations, or to species under provincial jurisdiction (e.g., deer, moose). Such conflicts require specialized resources to resolve. These challenges are compounded by newly-listed SAR each year.**

**Invasive Species**

**Increased invasive species including aquatic and vegetation species may present ongoing financial and operational risks and challenges to BC Hydro's operations, maintenance and work programs.**

**As an example, BC Hydro has been supportive of the B.C. Invasive Mussel Defence Program since it was piloted in 2015. This support has increased to include partial funding of the province's preventative watercraft inspection program, as well as contracts to monitor watercourses for the presence of mussels and suppression of pike, an invasive fish species. Currently, invasive**

**species' impacts are impacting our ability to meet our Fish and Wildlife Compensation Program and Water Use Plan objectives. In the future if this issue grew or went unmanaged, the impacts could spread to our facilities. For example, invasive mussel infestations have, in other jurisdictions, led to a reduction in the efficiency of turbines and water conveyances, and increased maintenance costs to remove them. The Mussel Defence Program has an annual operating cost of $1.3 million which has been absorbed over recent years.**

**214.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-5, BCUC IR 64.1**
**Change in the type, complexity and volume of work**

Further in response to BCUC IR 64.1, BC Hydro stated it has:

> …established a new company-wide initiative for fiscal 2020: make it easier to get work done. This objective means that everyone considers the impact of trickledown effect of the work they're doing in front-line Operations employees. It includes removing barriers and engaging our front-line Operations teams early in process development, so that they have more time to complete core work.

2.214.2 Please elaborate on the "make it easier to get work done" initiative. As part of the response, please identify any quantitative and qualitative benefits resulting from the initiative.

**RESPONSE:**

**The "make it easier to get work done" initiative was started in response to increasing frontline worker feedback that aspects of their work are harder or more time-consuming to complete than in the past, largely due to an increasing number of work steps and complexity of processes to complete tasks. For further discussion on BC Hydro's growing and more complex workload, please refer to BC Hydro's response to BCUC IR 1.64.1.**

**The objective of the "make it easier to get work done" initiative is to identify and implement small to medium sized improvements that are most meaningful to frontline operations employees, because they either increase support for carrying out their job responsibilities or clarify and simplify work steps.**

**The initiative focussed on getting direct feedback from frontline employees (town-halls and employee meetings, frontline councils, surveys) to develop a prioritized list of areas of focus and specific improvements. The recommendations from the field employees fall into 3 general categories of improvements:**

- **Improving tools and access to information;**
- **Simplifying processes; and**
- **Improving digital work flow.**

**Approximately a dozen "making it easier to get work done" projects/activities were prioritized and selected for starting implementation this year. The table below provides a summary of these projects/activities and the associated benefits. This list will evolve with continuous frontline feedback throughout the year.**

| Focus Areas | Activity | Phase | Improvement/Benefits |
|---|---|---|---|
| Tools and Information | Support Technical Training Advisory Groups | Implementation | Support for Crew Lead and Frontline Manager competencies |
| | Update Learning Plan for Frontline Leaders | Implementation | Support for Crew Lead and Frontline Manager competencies |
| | Final phase of mobile devices deployment | Implementation | Improved access to information for workers |
| | Improve fleet/vehicle processes & availability | Definition | Improvement in tools/vehicles fit for purpose |
| | Streamline communications to Field | Definition | Improved access to information for workers |
| | Field Access to Safety Information | Implementation | Improved access to information for workers |
| | Deploy Spidacalc Engineering tool in Design | Definition | Improved engineering tools for Designers |
| Simplify Processes | Confined space procedures | Implementation | Less administrative complexity for crews |
| | Tailboards for Stations | Implementation | Less administrative complexity for crews |
| | Drafting request process | Implementation | Improvement in drafting response time to Designers |
| | Updating of Operating Orders | Definition | Timely updates of operational information for frontline |
| | Safe Work Observations | Definition | Ease of use in collecting and storing information for supervisors |
| Improve Workflow | Implement Stations Planning & Work Scheduling Project | Implementation | 5% improvement in time on tools for crews with better planning |
| | Expand use of ServiceLink work order dispatch tool | Implementation | Crew access to information and work scheduling |
| | Implement electronic payments for new connections | Implementation | Improves ability of Designers to serve their customers |

**Through this corporate-wide initiative, all Key Business Units, including Human Resources and Technology, are re-prioritizing other work to support the above frontline focussed projects, as required. Most of the improvement activities are relatively small and involve a small team of employees.**

**One of the current projects under this initiative has direct quantifiable benefits for capacity hours. The Stations Work Planning and Execution project estimates a 5 per cent increase in "time on tools" for stations crews, through dedicated planners and schedulers providing better work planning and management of work package pre-requisites. The changes are headcount neutral and, when fully implemented in a few years, will enable $5 million more work to flow through Stations crews annually.**

**The remainder of the current activities are small improvements, largely focussed on reducing worker frustration and improving the tools employees have to execute their work. While quantitative benefits cannot be directly correlated to these activities, on a collective basis, they are contributing to positive employee morale (addressing frontline desire to keep their work throughput high) and offsetting the impacts of increased regulatory complexity for executing work.**

**214.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-5, BCUC IR 64.1**
**Change in the type, complexity and volume of work**

Further in response to BCUC IR 64.1, BC Hydro stated it has:

> …established a new company-wide initiative for fiscal 2020: make it easier to get work done. This objective means that everyone considers the impact of trickledown effect of the work they're doing in front-line Operations employees. It includes removing barriers and engaging our front-line Operations teams early in process development, so that they have more time to complete core work.

2.214.3 Please discuss if the "make it easier to get work done" initiative contributes to capacity hours gained, similar to the Work Smart program. If not, why not?

**RESPONSE:**

**Please refer to BC Hydro's response to BCUC IR 2.214.2 where we provide a list of projects/activities currently being undertaken as part of the "make it easier to get work done" initiative. The initiative is focussed on improving the experience of the frontline worker as they carry out their daily tasks in an increasingly complex work environment. While most of the projects/activities listed indirectly contribute to capacity hours gained, the initiative is focused on relatively small but meaningful improvements to tools, information, processes and workflow for frontline workers, to offset increasing complexity in their daily tasks.**

**214.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-5, BCUC IR 64.1**
**Change in the type, complexity and volume of work**

Further in response to BCUC IR 64.1, BC Hydro stated it has:

> …established a new company-wide initiative for fiscal 2020: make it easier to get work done. This objective means that everyone considers the impact of trickledown effect of the work they're doing in front-line Operations employees. It includes removing barriers and engaging our front-line Operations teams early in process development, so that they have more time to complete core work.

2.214.4 Please comment on the expected annual reductions in operating costs as a result of this initiative.

**RESPONSE:**

**The "making it easier to get work done" initiative is intended to help BC Hydro avoid operating cost increases from a growing and more complex workload. In the absence of this initiative and other initiatives, such as the Work Smart Program, discussed further in BC Hydro's response to BCUC IR 2.223.9, BC Hydro would expect its operating costs to be driven higher, as a result of increased regulatory and compliance requirements, which are discussed further in BC Hydro's response to BCUC IR 1.64.1.**

**The "making it easier to get work done" initiative is focused on making relatively small but meaningful improvements to tools, information, processes and workflow for frontline workers, to offset increasing complexity in their daily tasks. For further information, please refer to BC Hydro's response to BCUC IR 2.214.2.**

**215.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-5, BCUC IR 65.1, 104.1; Exhibit B-6, BCOAPO IR 36.1**
**Allocation of costs**

In response to BCUC IR 65.1, BC Hydro stated:

> BC Hydro's internal labour must be directly attributable to the capital project and program to be eligible for capitalization under IFRS. As a result, many KBUs [Key Business Units] do not charge internal labour to capital projects and programs.
>
> As part of the annual and future year budgeting processes, operating, capital, and deferred work plans (projects and programs) are developed. The work plans include estimates of internal labour, external contractors, materials, and services required to deliver the work. Based on the skillsets required and resource availability, BC Hydro decides whether to complete the work with internal or external resources. For internal resources, based on the nature of the work, BC Hydro plans labour as either operating, capital and deferred.

2.215.1 Please discuss the factors for determining whether a cost is operating, capital or deferred.

**RESPONSE:**

**BC Hydro determines the classification of costs in accordance with IFRS. IFRS 14, *Regulatory Deferral Accounts* paragraph 7 states:**

> **"any amounts that are permitted or required to be recognised as assets or liabilities in accordance with other Standards shall not be included within the amounts classified as regulatory deferral account balances".**

**Therefore, BC Hydro must determine whether costs are eligible for capitalization as assets before determining amounts eligible for deferral to regulatory accounts.**

**BC Hydro determines whether costs are eligible for capitalization in accordance with IAS 16 *Property, Plant and Equipment*. IAS 16 paragraph 16(b) requires that costs are directly attributable to a capital project to be eligible for capitalization. Therefore, BC Hydro capitalizes costs when they are directly attributable to capital projects.**

**Costs that are not required by IFRS to be included in assets or liabilities are recognized as operating costs. If operating costs are within the scope of regulatory accounts, the costs are deferred to the regulatory accounts.**

**215.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-5, BCUC IR 65.1, 104.1; Exhibit B-6, BCOAPO IR 36.1**
**Allocation of costs**

In response to BCUC IR 65.1, BC Hydro stated:

> BC Hydro's internal labour must be directly attributable to the capital project and program to be eligible for capitalization under IFRS. As a result, many KBUs [Key Business Units] do not charge internal labour to capital projects and programs.
>
> As part of the annual and future year budgeting processes, operating, capital, and deferred work plans (projects and programs) are developed. The work plans include estimates of internal labour, external contractors, materials, and services required to deliver the work. Based on the skillsets required and resource availability, BC Hydro decides whether to complete the work with internal or external resources. For internal resources, based on the nature of the work, BC Hydro plans labour as either operating, capital and deferred.

2.215.2 Please explain if there has been any change in the methodology for planning labour (operating, capital and deferred costs) since the last RRA. If so, please comment on each of the changes and the reason the change was implemented.

**RESPONSE:**

**There have been no changes to the methodology for planning labour since the Previous Application.**

## 215.0 C. CHAPTER 5 – OPERATING COSTS

**Reference: OPERATING COSTS**
**Exhibit B-5, BCUC IR 65.1, 104.1; Exhibit B-6, BCOAPO IR 36.1**
**Allocation of costs**

In response to BCUC IR 104.1, BC Hydro stated that "[e]ligible capital overhead is shown as a reduction to operating expenses in Appendix A."

In response to BCOAPO IR 36.1, BC Hydro provided the following break down of capitalized costs by fiscal year:

| ($ million) | Schedule Reference | F2017 RRA | F2017 Actual | F2018 RRA | F2018 Actual | F2019 RRA | F2019 Forecast | F2020 Plan | F2021 Plan |
|---|---|---|---|---|---|---|---|---|---|
| | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 |
| <u>Eligible Capital Overhead</u> | | | | | | | | | |
| Integrated Planning | | (3.1) | (3.6) | (3.1) | (2.9) | (3.1) | (2.7) | (2.7) | (2.7) |
| Capital Infrastructure Project Delivery | | (0.5) | (0.4) | (0.5) | (0.3) | (0.5) | (0.4) | (0.4) | (0.4) |
| Operations | | (19.7) | (18.2) | (19.7) | (19.1) | (19.7) | (20.7) | (20.7) | (20.7) |
| Finance, Technology, Supply Chain | | (44.5) | (44.4) | (45.3) | (46.4) | (46.0) | (46.1) | (46.7) | (47.1) |
| People, Customer, Corporate Affairs | | (0.4) | (0.4) | (0.4) | (0.3) | (0.4) | (0.5) | (0.5) | (0.5) |
| Total | Appendix A 5S line 7 | (68.2) | (67.0) | (69.0) | (69.0) | (69.7) | (70.4) | (71.0) | (71.4) |
| IFRS Ineligible Capital Overhead | Appendix A 5.0 line 58 | (112.0) | (112.0) | (89.6) | (89.6) | (67.2) | (67.2) | (44.8) | (22.4) |
| Total Capitalized Overhead | 5.7 L18 | (180.2) | (179.0) | (158.6) | (158.6) | (136.9) | (137.6) | (115.8) | (93.8) |

2.215.3 Please discuss the methodology for allocating capital overhead.

**RESPONSE:**

**The steps used to allocate eligible capital overhead to individual capital projects are as follows:**

1. **The eligible capital overhead amounts determined for each organizational grouping are classified by the function (i.e., distribution, generation, and transmission) supported by the organization. The classification of eligible capital overhead by function is to a single function if the organization primarily supports a single function or it is allocated if the organization supports multiple functions. For example, Fleet Services' (part of the Finance, Technology, Supply Chain Business Group) eligible capital overhead is allocated to all three functions based on the percentage of vehicle usage by function;**
2. **Forecast direct capital expenditures (comprised of capital projects) which are eligible for capital overhead allocation are determined by function;**
3. **The eligible capital overhead by function determined in step 1 is divided by the forecast direct capital expenditures by function determined in step 2 to determine a capital overhead loading rate for each function; and**
4. **Capital overhead amounts are added to capital projects by multiplying the capital overhead loading percentage, determined in step 3, for the applicable function by the actual direct expenditures on the project.**

**IFRS Ineligible Capital Overhead is not allocated to capital projects as the allocation of regulatory deferral amounts to Property, Plant and Equipment is not permitted under IFRS.**

**215.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-5, BCUC IR 65.1, 104.1; Exhibit B-6, BCOAPO IR 36.1**
**Allocation of costs**

In response to BCUC IR 104.1, BC Hydro stated that "[e]ligible capital overhead is shown as a reduction to operating expenses in Appendix A."

In response to BCOAPO IR 36.1, BC Hydro provided the following break down of capitalized costs by fiscal year:

| ($ million) | Schedule Reference | F2017 RRA | F2017 Actual | F2018 RRA | F2018 Actual | F2019 RRA | F2019 Forecast | F2020 Plan | F2021 Plan |
|---|---|---|---|---|---|---|---|---|---|
| | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 |
| <u>Eligible Capital Overhead</u> | | | | | | | | | |
| Integrated Planning | | (3.1) | (3.6) | (3.1) | (2.9) | (3.1) | (2.7) | (2.7) | (2.7) |
| Capital Infrastructure Project Delivery | | (0.5) | (0.4) | (0.5) | (0.3) | (0.5) | (0.4) | (0.4) | (0.4) |
| Operations | | (19.7) | (18.2) | (19.7) | (19.1) | (19.7) | (20.7) | (20.7) | (20.7) |
| Finance, Technology, Supply Chain | | (44.5) | (44.4) | (45.3) | (46.4) | (46.0) | (46.1) | (46.7) | (47.1) |
| People, Customer, Corporate Affairs | | (0.4) | (0.4) | (0.4) | (0.3) | (0.4) | (0.5) | (0.5) | (0.5) |
| Total | Appendix A 5S line 7 | (68.2) | (67.0) | (69.0) | (69.0) | (69.7) | (70.4) | (71.0) | (71.4) |
| IFRS Ineligible Capital Overhead | Appendix A 5.0 line 58 | (112.0) | (112.0) | (89.6) | (89.6) | (67.2) | (67.2) | (44.8) | (22.4) |
| Total Capitalized Overhead | 5.7 L18 | (180.2) | (179.0) | (158.6) | (158.6) | (136.9) | (137.6) | (115.8) | (93.8) |

2.215.3.1 Please explain if there has been any change in the process or controls for allocating overhead costs since the last RRA. If so, please comment on each of the changes and the reason the change was implemented.

**RESPONSE:**

**There have been no changes in the process or controls for allocating capital overhead costs since the Previous Application.**

**215.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-5, BCUC IR 65.1, 104.1; Exhibit B-6, BCOAPO IR 36.1**
**Allocation of costs**

In response to BCUC IR 104.1, BC Hydro stated that "[e]ligible capital overhead is shown as a reduction to operating expenses in Appendix A."

In response to BCOAPO IR 36.1, BC Hydro provided the following break down of capitalized costs by fiscal year:

| ($ million) | Schedule Reference | F2017 RRA | F2017 Actual | F2018 RRA | F2018 Actual | F2019 RRA | F2019 Forecast | F2020 Plan | F2021 Plan |
|---|---|---|---|---|---|---|---|---|---|
| | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 |
| <u>Eligible Capital Overhead</u> | | | | | | | | | |
| Integrated Planning | | (3.1) | (3.6) | (3.1) | (2.9) | (3.1) | (2.7) | (2.7) | (2.7) |
| Capital Infrastructure Project Delivery | | (0.5) | (0.4) | (0.5) | (0.3) | (0.5) | (0.4) | (0.4) | (0.4) |
| Operations | | (19.7) | (18.2) | (19.7) | (19.1) | (19.7) | (20.7) | (20.7) | (20.7) |
| Finance, Technology, Supply Chain | | (44.5) | (44.4) | (45.3) | (46.4) | (46.0) | (46.1) | (46.7) | (47.1) |
| People, Customer, Corporate Affairs | | (0.4) | (0.4) | (0.4) | (0.3) | (0.4) | (0.5) | (0.5) | (0.5) |
| Total | Appendix A 5S line 7 | (68.2) | (67.0) | (69.0) | (69.0) | (69.7) | (70.4) | (71.0) | (71.4) |
| IFRS Ineligible Capital Overhead | Appendix A 5.0 line 58 | (112.0) | (112.0) | (89.6) | (89.6) | (67.2) | (67.2) | (44.8) | (22.4) |
| Total Capitalized Overhead | 5.7 L18 | (180.2) | (179.0) | (158.6) | (158.6) | (136.9) | (137.6) | (115.8) | (93.8) |

2.215.4 Please describe the types of eligible capital overhead incurred by the Operations and the Finance, Technology, Supply Chain KBUs.

**RESPONSE:**

**The Operations Business Group's costs included in capital overhead consist primarily of the following:**

- **Construction Services supervisory labour, travel, small tools and consumable materials costs;**
- **Distribution design manager, design technologist and design assistant labour costs;**
- **Lines and stations supervisory labour costs; and**
- **Program and Contact Management labour costs.**

**The Finance, Technology and Supply Chain Business Group's costs included in capital overhead consist primarily of the following:**

- **Fleet operations and maintenance labour, materials and services costs attributable to the use of vehicles on capital projects and acquisition of vehicles;**
- **Materials Management labour and services costs attributable to the acquisition, receiving, handling and distribution of materials for capital projects; and**
- **Labour costs attributable to the acquisition of material and services for capital projects.**

**216.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-5, BCUC IR 40.2.1**
**Operating cost increases – impact on net operating cost increases**

In response to BCUC IR 40.2.1, BC Hydro stated the following:

> $(54.3) million – lower IPP capital lease costs due to impact of the new accounting standard on leases, IFRS 16 which is further explained in Chapter 5, section 5G.6 of the Application.

2.216.1 Please comment on the impact the adoption of International Financial Reporting Standards (IFRS) 16 has had on loan covenants, credit ratings and borrowing costs.

**RESPONSE:**

**BC Hydro adopted International Financial Reporting Standard 16, Leases on April 1, 2019 and it has not had an impact on credit ratings or borrowing costs. BC Hydro does not have any loan covenants.**

**217.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-5, BCUC IR 41.1, 42.3.1; Exhibit B-6, AMPC IR 3.1.3**
**Operating cost increases – labour costs**

In response to BCUC IR 41.1, BC Hydro provided a summary of changes to its base operating costs from F2017 plan to F2021 plan. Included in this table is the line item “Labour” with cost increases in F2017 plan to F2021 plan, as shown below:

| | ($ million) | | F2017 Plan | F2018 Plan | F2019 Plan | F2020 Plan | F2021 Plan |
|---|---|---|---|---|---|---|---|
| 1 | F2016 Revenue Requirement Application Plan | | 826.9 | | | | |
| 2 | | | | | | | |
| 3 | Less: | | | | | | |
| 4 | IFRS Ineligible Capital Overhead (Schedule 5.0, line 10) | | (80.5) | | | | |
| 5 | Independent Power Producer Capital Leases (Schedule 5.0, line 11) | | (33.8) | | | | |
| 6 | Base Operating Costs (Carry Forward) (Schedule 5.0, line 9) | A | 712.7 | 756.6 | 757.4 | 769.5 | 777.9 |
| 7 | | | | | | | |
| 8 | Compliance Filing Adjustment (Schedule 5.0, line 8) | B | 10.1 | 0.1 | 0.2 | | |
| 9 | | | | | | | |
| 10 | Cost Savings | C | (33.2) | (0.3) | (0.2) | (13.6) | (0.4) |
| 11 | | | | | | | |
| 12 | Cost Increases | | | | | | |
| 13 | Labour | | 4.9 | 8.4 | 9.1 | 11.0 | 10.3 |
| 14 | Storm restoration | | 2.8 | | | 11.1 | |
| 15 | Unavoidable costs (mandatory fees, crane remediation) | | 5.2 | (0.8) | 0.2 | | |
| 16 | Capital Driven (maintenance, capital project dispute resolution costs, capital project investigation costs) | | 19.0 | (3.1) | 2.6 | | |
| 17 | Initiatives (safety, customer strategy) | | 6.5 | (1.5) | - | | |
| 18 | Other | | 6.5 | (0.6) | 0.2 | | |
| 19 | Smart Metering and Infrastructure | D | 22.1 | (1.4) | (0.1) | | |
| 20 | | | | | | | |
| 21 | Total Cost Increases | E | 67.0 | 1.0 | 12.0 | 22.1 | 10.3 |

2.217.1 Please explain why the labour cost increases are rising over time, and have more than doubled in F2020 compared to F2017. Please breakout the components contributing to the labour cost increase for each year (e.g. Work Force Optimization program, Accenture Repatriation, Standard Labour Rate Increases, etc.) and include the associated cost for each component.

**RESPONSE:**

**Please refer to Attachment 1 to this response, which has expanded the table provided in BC Hydro’s response to BCUC IR 1.42.3.1 to include a breakdown of the fiscal 2017 to fiscal 2021 labour cost increases on line 13 of the table in the preamble.**

**The increases included in line 13 of the table in the preamble, and broken down in Attachment 1 to this response all relate to increases to the components of the Standard Labour Rates for the budgeted FTEs in the current test period which include the FTEs from the Accenture Repatriation and Workforce Optimization Program.**

**The operating labour costs related to both the Workforce Optimization Program and the Accenture Repatriation had offsetting non-labour reductions resulting in net savings. Therefore, they did not result in a cost increase to BC Hydro in the test period and are not included in line 13 of the table.**

| Item | Fiscal 2017 Incremental ($ million) | Percentage Increase/ Decrease of total Labour cost change % | Fiscal 2018 Incremental ($ million) | Percentage Increase/ Decrease of total Labour cost change % | Fiscal 2019 Incremental ($ million) | Percentage Increase/ Decrease of total Labour cost change % | Fiscal 2020 Incremental ($ million) | Percentage Increase/ Decrease of total Labour cost change % | Fiscal 2021 Incremental ($ million) | Percentage Increase/ Decrease of total Labour cost change % |
|---|---|---|---|---|---|---|---|---|---|---|
| Salary Increases | 6.9 | 140.8 | 6.1 | 72.6 | 6.2 | 68.9 | 10.1 | 56.1 | 8.9 | 86.4 |
| Employer Health Tax | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 7.9 | 43.9 | (1.9) | (18.4) |
| Employee Benefit Plan | 2.3 | 46.9 | 1.5 | 17.9 | 2.0 | 22.2 | 2.1 | 11.7 | 2.0 | 19.4 |
| Current Service Costs | (4.3) | (87.8) | 0.8 | 9.5 | 0.8 | 8.9 | (2.1) | (11.7) | 1.3 | 12.6 |
| Total Labour Cost Change | 4.9 | 100.0 | 8.4 | 100.0 | 9.0 | 100.0 | 18.0 | 100.0 | 10.3 | 100.0 |
| Unallocated Funds Reduction | 0.0 | | 0.0 | | 0.0 | | (7.0) | | 0.0 | |
| Labour Cost Total | 4.9 | | 8.4 | | 9.0 | | 11.0 | | 10.3 | |

**217.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-5, BCUC IR 41.1, 42.3.1; Exhibit B-6, AMPC IR 3.1.3**
**Operating cost increases – labour costs**

In response to BCUC IR 42.3.1, BC Hydro provided a breakdown of the incremental operating labour costs over the Test Period as shown below:

| Item | Fiscal 2020 Incremental ($ million) | Percentage Increase/ Decrease of total labour cost change % | Fiscal 2021 Incremental ($ million) | Percentage Increase/ Decrease of total labour cost change % |
|---|---|---|---|---|
| Salary Increases | 10.1 | 56.1 | 8.9 | 86.4 |
| Employer Health Tax | 7.9 | 43.9 | (1.9) | (18.4) |
| Employee Benefit Plan | 2.1 | 11.7 | 2.0 | 19.4 |
| Current Service Costs | (2.1) | (11.7) | 1.3 | 12.6 |
| Total Labour Cost Change | 18.0 | 100.0 | 10.3 | 100.0 |
| Unallocated Funds Reduction | (7.0) | | 0.0 | |
| Labour Cost Total | 11.0 | | 10.3 | |

2.217.2 Please expand the table above by adding columns that provide: i) the actual labour costs for F2012 through F2019; and ii) the percentage increase over the prior year for all fiscal years.

**RESPONSE:**

**BC Hydro does not track actual costs related to salary increases in isolation from the total salary costs incurred in any fiscal year.**

**In addition, the Unallocated Funds Reduction and the new Employer Health Tax are items impacting the current test period only (i.e., they did not impact the years referenced in the question).**

**In BC Hydro's response to BCUC IR 2.217.1, the table included in the preamble has been expanded to include the prior test period. This provides a breakdown of the planned labour cost increases and percentage increase/decrease of total**

**labour cost change from fiscal 2017 to fiscal 2021. A breakdown for fiscal 2012 to fiscal 2016 is not readily available due to multiple revisions to planned amounts during this time period (e.g., BC Hydro filed the Fiscal 2012 to Fiscal 2014 Revenue Requirements Application and then re-filed that application following the 2011 Government Review).**

**217.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-5, BCUC IR 41.1, 42.3.1; Exhibit B-6, AMPC IR 3.1.3**
**Operating cost increases – labour costs**

In response to AMPC IR 3.1.3, BC Hydro provided the following table with a break down of the operating labour cost increases from F2019 forecast to F2020 plan by Business Group.

| | Integrated Planning | Capital Infrastructure Project Delivery | Operations | Safety | Finance, Technology, Supply Chain | People, Customer, Corporate Affairs | Other | Total |
|---|---|---|---|---|---|---|---|---|
| Accenture Repatriation | - | 0.4 | - | - | 3.2 | 31.7 | - | 35.3 |
| Workforce Optimization Program | 2.9 | 2.1 | 5.7 | 1.4 | 14.6 | 4.6 | 0.6 | 32.0 |
| Labour Cost Increases | 5.2 | 1.2 | 5.1 | 1.9 | 3.4 | 1.1 | 0.1 | 18.0 |
| Unallocated Funds Reduction | (2.0) | (0.5) | (2.0) | (0.7) | (1.3) | (0.4) | (0.1) | (7.0) |
| Vacancy Factor Savings | (1.2) | (1.6) | (0.5) | (0.2) | (1.4) | (0.5) | (0.3) | (5.6) |
| Other Labour Adjustments | (3.6) | 0.5 | 3.1 | (0.6) | (2.1) | (2.4) | (0.6) | (5.7) |
| Total | 1.3 | 2.1 | 11.4 | 1.8 | 16.3 | 34.1 | (0.2) | 66.8 |

2.217.3 Please explain why the incremental cost increase for the Workforce Optimization program from F2019 forecast to F2020 plan is $32.0 million. Please reconcile to the number of expected contractors to internal FTE conversions for that period.

**RESPONSE:**

**BC Hydro notes that BC Hydro's response to AMPC IR 1.3.1.3 compared the fiscal 2020 RRA Plan to the fiscal 2019 RRA Plan and not the fiscal 2019 forecast as stated in the question.**

**The $32.0 million increase from fiscal 2019 RRA plan to fiscal 2020 RRA plan reflects the incremental operating labour costs associated with the 535 Workforce Optimization Program FTE increases since the Previous Application.**

**The $32.0 million in operating labour cost increases associated with the additional FTEs are fully offset by equivalent operating cost reductions.**

**217.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-5, BCUC IR 41.1, 42.3.1; Exhibit B-6, AMPC IR 3.1.3**
**Operating cost increases – labour costs**

In response to AMPC IR 3.1.3, BC Hydro provided the following table with a break down of the operating labour cost increases from F2019 forecast to F2020 plan by Business Group.

| | Integrated Planning | Capital Infrastructure Project Delivery | Operations | Safety | Finance, Technology, Supply Chain | People, Customer, Corporate Affairs | Other | Total |
| --- | --- | --- | --- | --- | --- | --- | --- | --- |
| Accenture Repatriation | - | 0.4 | - | - | 3.2 | 31.7 | - | 35.3 |
| Workforce Optimization Program | 2.9 | 2.1 | 5.7 | 1.4 | 14.6 | 4.6 | 0.6 | 32.0 |
| Labour Cost Increases | 5.2 | 1.2 | 5.1 | 1.9 | 3.4 | 1.1 | 0.1 | 18.0 |
| Unallocated Funds Reduction | (2.0) | (0.5) | (2.0) | (0.7) | (1.3) | (0.4) | (0.1) | (7.0) |
| Vacancy Factor Savings | (1.2) | (1.6) | (0.5) | (0.2) | (1.4) | (0.5) | (0.3) | (5.6) |
| Other Labour Adjustments | (3.6) | 0.5 | 3.1 | (0.6) | (2.1) | (2.4) | (0.6) | (5.7) |
| Total | 1.3 | 2.1 | 11.4 | 1.8 | 16.3 | 34.1 | (0.2) | 66.8 |

2.217.4 Please elaborate on what is included in “Other Labour Adjustments.” Please specify the items and the associated costs.

**RESPONSE:**

**The Other Labour Adjustments row in the table provided in BC Hydro’s response to AMPC IR 1.3.1.3 includes a number of small changes to the Business Groups’ operating labour budget that are not captured in the other rows of the table. While there are many items which can affect each Business Group’s operating labour budget each year, the following are examples of the changes that may be captured in the Other Labour Adjustments row:**

- **Budget transfers between Business Groups resulting from re-organizations (note: these are net neutral to BC Hydro’s total operating labour budget);**

- **More or less labour costs planned to capital projects and work programs;**
- **Changes to budgeted overtime hours; and**
- **Job grouping changes.**

**As there have been a number of re-organizations and work plan changes since the Previous Application was prepared, BC Hydro cannot quantify the specific dollar impacts of each item listed above, nor the many other factors that could impact the operating labour budget.**

**218.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-1, Section 5.6.5.2, p. 5-47; Exhibit B-5, BCUC IR 40.2.1, 42.4**
**Operating cost increases – standard labour rates**

In response to BCUC IR 40.2.1, BC Hydro stated that "[w]hile there is discretion in determining management and professional salary increase budgets, it would be difficult to continue to attract and retain employees if salaries do not increase over time and remain competitive with the market."

BC Hydro stated in response to BCUC IR 42.4: "benchmarking indicates that the value of BC Hydro's existing Total Rewards offer is consistent with median market rates."

In its Application, BC Hydro states its "voluntary turnover rate is 1.3 per cent, which is below the 3.8 per cent average of the Power and Utilities industry as reported by the Conference Board of Canada."

2.218.1 Considering BC Hydro's existing Total Rewards offer is consistent with median market rates and BC Hydro's voluntary turnover rate is 2.5 percent lower than industry average, please explain whether these comparisons factor into management's decision on management and professional salary increases. If so, please explain how.

**RESPONSE:**

**Yes, the comparisons mentioned in the question factor into management's decision on management and professional salary increases. They demonstrate that we are at the appropriate compensation placement relative to market and are able to retain employees. As such, our planned salary increases in the test period are intended to keep pace with market increases so that we remain at our current compensation placement and are able to continue to attract and retain employees.**

**219.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-5, BCUC IR 42.1, 42.6**
**Operating cost increases – general wage increase**

In response to BCUC IR 42.6, BC Hydro stated:

> The primary considerations for determining management and professional salary increases are Public Sector Employers' Council policy and labour budgets.
>
> Public Sector Employers' Council sets policies for exempt compensation in the B.C. Public Sector. For example, from 2012 to 2018 their manager salary freeze policy limited salary increases between 0 per cent to 2 per cent per year. As such, management and professional salaries did not increase at the same rate as union wages during that period…
>
> BC Hydro participates in and collects information from a number of local and Canadian market salary increase forecast surveys. Those sources indicate that the median salary increase forecast for 2019 if 2.5 per cent.

2.219.1 Please explain whether BC Hydro's management and professional employee salary increases from 2012 to 2018 were the maximum annual allowed during that time. If not, please explain why not?

**RESPONSE:**

**Salary increases for management and professional employees from 2012 to 2018 were in accordance with the limits set by Public Sector Employers' Council policy. Specifically:**

- **No salary increase was provided from the implementation of the policy in 2012 to 2014; and**
- **2 per cent was the maximum increase that could be provided to an individual employee per year from 2015 to 2018. However, this was a targeted increase, not a general wage increase. Increases were provided to employees depending on their performance and salary range position and not all employees received salary increases. This resulted in an overall salary increase of less than 2 per cent in those years. For example, the overall increase was 1.5 per cent in 2017.**

**The Public Sector Employers' Council policy applied to most management and professional jobs. Some lower-level professional positions were excluded from the policy and were therefore able to receive higher increases.**

**219.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-5, BCUC IR 42.1, 42.6**
**Operating cost increases – general wage increase**

In response to BCUC IR 42.1, BC Hydro stated:

> Planned salary increases for union employees over the test period are 2 per cent per year which is consistent with the bargaining mandate set by the Public Sector Employers Council. It's improbable that collective agreements could be renewed without providing an increase that is consistent with this mandate.
>
> Planned salary increases for management and professional employees over the test period are 2.5 per cent per year which is similar to forecast inflation and market salary increases. While there is discretion in determining management and professional salary increase budgets, it would be difficult to continue to attract and retain employees if salaries do not increase over time and remain competitive with the market.

2.219.2 Please confirm, or explain otherwise, that the general wage increase BC Hydro included in the Application is 2.0 percent for union employees and 2.5 percent for management and professional employees, and that this is the only increase to employee compensation in the Test Period.

**RESPONSE:**

**The only planned wage and salary increases in the test period are annual increases of 2.0 per cent for union employees and 2.5 per cent for management and professional employees. Changes to individual or overall wages and salaries over the test period may occur as a result of employee movement. For example, an employee retires and is replaced by an internally promoted employee or a new hire at a different salary.**

**220.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-5, BCUC IR 42.10, 42.10.1**
**Incentive pay**

In response to BCUC IR 42.10, BC Hydro stated that "[o]nly Executive and Director level positions receive incentive pay. These positions represent approximately 1 per cent of all management and professional employees."

> In response to BCUC IR 42.10.1, BC Hydro provided details of the structure of the incentive pay (salary holdback) that only Executives and Director level positions receive and stated:
>
> The maximum annual award an employee can receive is 10 per cent or 20 per cent of their salary, depending on their position. Awards are based on corporate and individual performance.
>
> Corporate performance is based on results achieved on BC Hydro's Service Plan performance measures…
>
> Individual performance is based on the employee's individual performance objectives established at the start of the year and assessed by the employee's manager at year end…
>
> The only change to the program since the Previous Application is an increase in the weighting of the corporate component from 40 per cent to 60 per cent for Executives.

2.220.1 Please explain whether the current incentive (holdback) program replaced a prior incentive program.

**RESPONSE:**

**The current incentive (holdback) program replaced a previous incentive program which was referred to as variable pay. This change occurred in 2013 in accordance with the Crown Corporation Executive Compensation policy set by the Public Sector Employers' Council.**

**220.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-5, BCUC IR 42.10, 42.10.1**
**Incentive pay**

In response to BCUC IR 42.10, BC Hydro stated that "[o]nly Executive and Director level positions receive incentive pay. These positions represent approximately 1 per cent of all management and professional employees."

In response to BCUC IR 42.10.1, BC Hydro provided details of the structure of the incentive pay (salary holdback) that only Executives and Director level positions receive and stated:

The maximum annual award an employee can receive is 10 per cent or 20 per cent of their salary, depending on their position. Awards are based on corporate and individual performance.

Corporate performance is based on results achieved on BC Hydro's Service Plan performance measures…

Individual performance is based on the employee's individual performance objectives established at the start of the year and assessed by the employee's manager at year end…

The only change to the program since the Previous Application is an increase in the weighting of the corporate component from 40 per cent to 60 per cent for Executives.

2.220.2 Please discuss whether there are any other employee groups that receive some form of incentive or performance pay. If so, comment on how the pay criteria are designed and measured.

**RESPONSE:**

**No other management and professional employee groups receive incentive pay. Management and professional salary increases are based on an individual employee's performance. Annually, employees establish performance plans with their manager and at fiscal year-end the manager provides an overall performance rating which is used, along with the employee's position in the salary range, to determine the applicable salary increase.**

**Unionized employees receive gainsharing. The program provides a maximum annual award of 5 per cent of the union employee's wages paid in the fiscal year. A maximum of 2 per cent is based on results achieved on BC Hydro's Service Plan measures and a maximum of 3 per cent is based on results achieved on department specific objective(s) established at the start of each fiscal year.**

**220.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-5, BCUC IR 42.10, 42.10.1**
**Incentive pay**

In response to BCUC IR 42.10, BC Hydro stated that "[o]nly Executive and Director level positions receive incentive pay. These positions represent approximately 1 per cent of all management and professional employees."

In response to BCUC IR 42.10.1, BC Hydro provided details of the structure of the incentive pay (salary holdback) that only Executives and Director level positions receive and stated:

The maximum annual award an employee can receive is 10 per cent or 20 per cent of their salary, depending on their position. Awards are based on corporate and individual performance.

Corporate performance is based on results achieved on BC Hydro's Service Plan performance measures…

Individual performance is based on the employee's individual performance objectives established at the start of the year and assessed by the employee's manager at year end…

The only change to the program since the Previous Application is an increase in the weighting of the corporate component from 40 per cent to 60 per cent for Executives.

2.220.3 Please explain whether financial objectives (i.e. operational efficiencies for Business Groups and KBUs and reductions in operating costs) are included as part of the corporate or individual performance objectives. If not, why not? If yes, please describe the financial objectives and provide examples.

**RESPONSE:**

**The corporate performance objectives align with the BC Hydro Service Plan performance measures. The financial performance measure in the Service Plan is the capital project budget to actual cost measure. As described in the Service Plan, "[t]his measure compares actual project costs at completion to the original approved full scope implementation budgets, not including project reserve amounts, for capital projects that were put into service during the five-year rolling period."**

**All Executive Team members have financial objective(s) on their individual performance plan. An example of this type of objective is:**

> **"Come in "at or under" the Business Group's budget with a primary objective of coming in "at or under" the BC Hydro budget as a team (ensuring best and highest use of organizational spend).**

**220.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-5, BCUC IR 42.10, 42.10.1**
**Incentive pay**

In response to BCUC IR 42.10, BC Hydro stated that "[o]nly Executive and Director level positions receive incentive pay. These positions represent approximately 1 per cent of all management and professional employees."

In response to BCUC IR 42.10.1, BC Hydro provided details of the structure of the incentive pay (salary holdback) that only Executives and Director level positions receive and stated:

The maximum annual award an employee can receive is 10 per cent or 20 per cent of their salary, depending on their position. Awards are based on corporate and individual performance.

Corporate performance is based on results achieved on BC Hydro's Service Plan performance measures…

Individual performance is based on the employee's individual performance objectives established at the start of the year and assessed by the employee's manager at year end…

The only change to the program since the Previous Application is an increase in the weighting of the corporate component from 40 per cent to 60 per cent for Executives.

2.220.4 Please discuss whether executives and director level employees are involved in setting/changing the Service Plan performance measures, targets and the weighting.

**RESPONSE:**

**While Executives and Director level employees are involved in the development of the Service Plan performance measures, the Board of Directors is responsible for reviewing and approving the Service Plan performance measures, targets, weighting and overall document. For further information on the role of the Board of Directors, please refer to BC Hydro's response to BCUC IR 2.220.4.1.**

**Specifically, the Board Chair Accountability Statement states that:**

> **"the Board is accountable for the contents of the plan, including what has been included in the plan and how it has been reported. The Board is responsible for the validity and reliability of information included in the plan."**

**The Accountability Statement also states that:**

> **"The performance measures presented are consistent with the *Budget Transparency and Accountability Act,* BC Hydro's mandate and goals, and focus on aspects critical to the organization's performance. The targets in this plan have been determined based on an assessment of BC Hydro's operating environment, forecast conditions, risk assessment and past performance."**

**The Business Groups responsible for the performance measures review the Service Plan measures and targets annually to set or make adjustments, as part of the development of the following year's plan.**

**Adjustments to targets may be made for a variety of reasons including long-term historic reliability trends, current year performance, previous years' investments, future years' investment plans, timing of savings for anticipated codes and standards and timing of large customer projects.**

**Executives and Director level employees work with their teams to develop or adjust Service Plan performance measures and targets and review all performance measure results, targets and forecasts. In addition, the Executive Team reviews and approves the Service Plan performance measures and targets, for recommendation to the Board of Directors.**

**The weighting of Service Plan measures as they apply to holdback pay, is reviewed by the Executive Team and approved by the Governance and Human Resources Committee of the Board of Directors.**

**220.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-5, BCUC IR 42.10, 42.10.1**
**Incentive pay**

In response to BCUC IR 42.10, BC Hydro stated that "[o]nly Executive and Director level positions receive incentive pay. These positions represent approximately 1 per cent of all management and professional employees."

> In response to BCUC IR 42.10.1, BC Hydro provided details of the structure of the incentive pay (salary holdback) that only Executives and Director level positions receive and stated:
>
> The maximum annual award an employee can receive is 10 per cent or 20 per cent of their salary, depending on their position. Awards are based on corporate and individual performance.
>
> Corporate performance is based on results achieved on BC Hydro's Service Plan performance measures…
>
> Individual performance is based on the employee's individual performance objectives established at the start of the year and assessed by the employee's manager at year end…
>
> The only change to the program since the Previous Application is an increase in the weighting of the corporate component from 40 per cent to 60 per cent for Executives.

2.220.4.1 Please clarify the role of the Board of Directors with respect to setting/changing Service Plan performance measures.

**RESPONSE:**

**BC Hydro's Board of Directors reviews and approves the Service Plan framework, metrics and overall document.**

**The Operations and Planning Committee of the Board of Directors receives a presentation on the Service Plan framework and performance measures annually, at the November Board meeting. The discussion includes Management's recommended approach to the development of the document so that the proposed framework and performance measures are consistent with BC Hydro's mission as well as the priorities identified in the Government of B.C.'s Mandate Letter to BC Hydro. The presentation also includes discussion on target setting**

**for the performance measures and an overview of any proposed changes to the coming years' performance measures compared to previous Service Plans.**

**If the proposed framework and performance targets are approved as proposed by Management, the Operations and Planning Committee passes a resolution recommending that the Board of Directors approve the Service Plan Framework and Metrics, as presented to the Board at the full Board meeting. The Directors review Management's recommended approach and performance measure targets, including any changes, and if approved, pass a resolution to that effect.**

**Each January, the Board of Directors receives the full Service Plan document for review and there is a full Board meeting to review and approve the full document.**

**220.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-5, BCUC IR 42.10, 42.10.1**
**Incentive pay**

In response to BCUC IR 42.10, BC Hydro stated that "[o]nly Executive and Director level positions receive incentive pay. These positions represent approximately 1 per cent of all management and professional employees."

> In response to BCUC IR 42.10.1, BC Hydro provided details of the structure of the incentive pay (salary holdback) that only Executives and Director level positions receive and stated:
>
> The maximum annual award an employee can receive is 10 per cent or 20 per cent of their salary, depending on their position. Awards are based on corporate and individual performance.
>
> Corporate performance is based on results achieved on BC Hydro's Service Plan performance measures…
>
> Individual performance is based on the employee's individual performance objectives established at the start of the year and assessed by the employee's manager at year end…
>
> The only change to the program since the Previous Application is an increase in the weighting of the corporate component from 40 per cent to 60 per cent for Executives.

2.220.4.1.1 Please discuss if the Board of Directors receive incentive pay. If so, please discuss if this incentive pay is based on the annual Service Plan performance measures.

**RESPONSE:**

**The Board of Directors do not receive incentive pay.**

**Remuneration guidelines for Directors of all Crown Corporations are set out by Treasury Board directive. For further information, please refer to the current Treasury Board directive at: https://www2.gov.bc.ca/assets/gov/british-columbians-our-governments/government-finances/treasury-board-directives/tbd2-17-remuneration-guidelines-for-appointees-to-crown-agency-boards.pdf.**

**221.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-5, BCUC IR 51.6**
**Overtime**

In response to BCUC IR 51.6, BC Hydro stated that it actively manages overtime using certain strategies.

2.221.1 Please confirm, or explain otherwise, that an overtime target is the equivalent to planned or budgeted overtime.

**RESPONSE:**

**Confirmed.**

**221.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-5, BCUC IR 51.6**
**Overtime**

In response to BCUC IR 51.6, BC Hydro stated that it actively manages overtime using certain strategies.

2.221.2 Please provide the annual overtime targets and actual overtime by KBU and by affiliation for F2017 to F2019 actual, and the annual overtime targets for the Test Period. Please explain significant variances for the target to actual comparisons.

**RESPONSE:**

**As discussed in BC Hydro's response to BCUC IR 1.51.6, the majority of overtime worked within BC Hydro is by IBEW unionized trades staff. IBEW employees are predominantly located within the KBUs in the Operations Business Group and the Learning and Development KBU within the Safety Business Group. A detailed breakdown of these KBUs is shown in the tables below.**

**The strategies discussed in BC Hydro's response to BCUC IR 1.51.6 are primarily applied to the Operations Business group as they incur a majority of the overtime within the organization. These strategies have resulted in the overtime hours for Operations Business Group being within 1 per cent of Plan from fiscal 2017 to fiscal 2019. Individual KBU variances in the tables below are a result of:**

- **Headcount variances from Actual to Plan;**
- **Frequency, severity and timing of emergent events;**
- **Seasonal work demands; and**
- **Reduced apprentice intake in fiscal 2019.**

Construction Services KBU Overtime Hours

| Affiliation | 2017 Actuals | 2017 Plan | 2017 Variance | 2018 Actuals | 2018 Plan | 2018 Variance | 2019 Actuals | 2019 Plan | 2019 Variance | 2020 Plan | 2021 Plan |
|---|---|---|---|---|---|---|---|---|---|---|---|
| MoveUp | 2,088 | 2,048 | (40) | 2,795 | 2,048 | (747) | 2,151 | 2,048 | (103) | 2,480 | 2,480 |
| IBEW | 123,710 | 112,016 | (11,694) | 122,876 | 112,016 | (10,859) | 123,656 | 112,016 | (11,639) | 105,965 | 105,965 |
| M&P | 1,232 | | (1,232) | 1,697 | | (1,697) | 1,558 | | (1,558) | | |
| Total | 127,030 | 114,064 | (12,966) | 127,368 | 114,064 | (13,304) | 127,364 | 114,064 | (13,300) | 108,445 | 108,445 |

Distribution Design Customer Connections KBU Overtime Hours

| Affiliation | 2017 Actuals | 2017 Plan | 2017 Variance | 2018 Actuals | 2018 Plan | 2018 Variance | 2019 Actuals | 2019 Plan | 2019 Variance | 2020 Plan | 2021 Plan |
|---|---|---|---|---|---|---|---|---|---|---|---|
| MoveUp | 23,977 | 41,588 | 17,611 | 29,316 | 41,588 | 12,273 | 28,625 | 41,588 | 12,963 | 51,037 | 51,037 |
| IBEW | | | | | | | | | | | |
| M&P | 415 | 25 | (390) | 713 | 25 | (688) | 894 | 25 | (868) | 25 | 25 |
| Total | 24,392 | 41,613 | 17,222 | 30,029 | 41,613 | 11,585 | 29,519 | 41,613 | 12,095 | 51,062 | 51,062 |

Generation System Operations KBU Overtime Hours

| Affiliation | 2017 Actuals | 2017 Plan | 2017 Variance | 2018 Actuals | 2018 Plan | 2018 Variance | 2019 Actuals | 2019 Plan | 2019 Variance | 2020 Plan | 2021 Plan |
|---|---|---|---|---|---|---|---|---|---|---|---|
| MoveUp | 99 | 115 | 17 | 119 | 115 | (4) | 144 | 115 | (29) | 115 | 115 |
| IBEW | | | | | | | | | | | |
| M&P | 95 | 25 | (70) | 53 | 25 | (28) | 33 | 25 | (8) | 25 | 25 |
| Total | 194 | 140 | (54) | 172 | 140 | (32) | 177 | 140 | (37) | 140 | 140 |

Line Field Operations KBU Overtime Hours

| Affiliation | 2017 Actuals | 2017 Plan | 2017 Variance | 2018 Actuals | 2018 Plan | 2018 Variance | 2019 Actuals | 2019 Plan | 2019 Variance | 2020 Plan | 2021 Plan |
|---|---|---|---|---|---|---|---|---|---|---|---|
| MoveUp | 11,103 | 8,090 | (3,012) | 10,315 | 8,090 | (2,224) | 13,771 | 8,090 | (5,680) | 8,979 | 8,979 |
| IBEW | 267,265 | 254,241 | (13,023) | 277,455 | 254,241 | (23,214) | 276,539 | 254,241 | (22,297) | 285,815 | 285,816 |
| M&P | 8,893 | 7,070 | (1,822) | 10,883 | 7,070 | (3,813) | 10,596 | 7,070 | (3,525) | 7,030 | 7,030 |
| Total | 287,260 | 269,402 | (17,858) | 298,653 | 269,402 | (29,251) | 300,905 | 269,402 | (31,503) | 301,824 | 301,824 |

Program & Contract Management KBU Overtime Hours

| Affiliation | 2017 Actuals | 2017 Plan | 2017 Variance | 2018 Actuals | 2018 Plan | 2018 Variance | 2019 Actuals | 2019 Plan | 2019 Variance | 2020 Plan | 2021 Plan |
|---|---|---|---|---|---|---|---|---|---|---|---|
| MoveUp | 14,266 | 21,955 | 7,689 | 11,448 | 21,955 | 10,507 | 11,824 | 21,955 | 10,131 | 21,524 | 21,524 |
| IBEW | 4,153 | 4,400 | 247 | 3,451 | 4,400 | 949 | 2,665 | 4,400 | 1,735 | 3,850 | 3,850 |
| M&P | 1,741 | 4,380 | 2,639 | 2,036 | 4,380 | 2,344 | 2,297 | 4,380 | 2,083 | 3,141 | 3,140 |
| Total | 20,160 | 30,735 | 10,575 | 16,934 | 30,735 | 13,801 | 16,786 | 30,735 | 13,949 | 28,515 | 28,515 |

Stations Field Operations KBU Overtime Hours

| Affiliation | 2017 Actuals | 2017 Plan | 2017 Variance | 2018 Actuals | 2018 Plan | 2018 Variance | 2019 Actuals | 2019 Plan | 2019 Variance | 2020 Plan | 2021 Plan |
|---|---|---|---|---|---|---|---|---|---|---|---|
| MoveUp | 5,459 | 2,769 | (2,690) | 6,566 | 2,769 | (3,797) | 5,991 | 2,769 | (3,222) | 1,639 | 1,639 |
| IBEW | 139,062 | 156,294 | 17,232 | 135,694 | 156,294 | 20,600 | 136,935 | 156,294 | 19,358 | 158,600 | 158,600 |
| M&P | 8,073 | 8,942 | 868 | 7,357 | 8,942 | 1,584 | 8,070 | 8,942 | 872 | 4,030 | 4,030 |
| Total | 152,594 | 168,004 | 15,410 | 149,617 | 168,004 | 18,387 | 150,996 | 168,004 | 17,008 | 164,269 | 164,269 |

T&D System Operations KBU Overtime Hours

| Affiliation | 2017 Actuals | 2017 Plan | 2017 Variance | 2018 Actuals | 2018 Plan | 2018 Variance | 2019 Actuals | 2019 Plan | 2019 Variance | 2020 Plan | 2021 Plan |
|---|---|---|---|---|---|---|---|---|---|---|---|
| MoveUp | 244 | 273 | 28 | 178 | 273 | 95 | 288 | 273 | (15) | 590 | 590 |
| IBEW | 13,730 | 9,059 | (4,671) | 15,088 | 9,059 | (6,029) | 14,241 | 9,059 | (5,182) | 12,104 | 12,104 |
| M&P | 1,100 | 2,219 | 1,119 | 1,902 | 2,219 | 317 | 1,491 | 2,219 | 728 | 2,594 | 2,594 |
| Total | 15,074 | 11,551 | (3,524) | 17,167 | 11,551 | (5,617) | 16,020 | 11,551 | (4,470) | 15,289 | 15,289 |

Learning & Development KBU Overtime Hours

| Affiliation | 2017 Actuals | 2017 Plan | 2017 Variance | 2018 Actuals | 2018 Plan | 2018 Variance | 2019 Actuals | 2019 Plan | 2019 Variance | 2020 Plan | 2021 Plan |
|---|---|---|---|---|---|---|---|---|---|---|---|
| MoveUp | 3,294 | 940 | (2,354) | 3,071 | 940 | (2,131) | 3,130 | 940 | (2,190) | | |
| IBEW | 103,767 | 104,758 | 991 | 104,587 | 104,758 | 171 | 81,853 | 104,758 | 22,905 | 64,717 | 57,657 |
| M&P | 2,518 | | (2,518) | 1,468 | | (1,468) | 1,169 | | (1,169) | | |
| Total | 109,579 | 105,698 | (3,881) | 109,126 | 105,698 | (3,427) | 86,152 | 105,698 | 19,546 | 64,717 | 57,657 |

**221.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-5, BCUC IR 51.6**
**Overtime**

In response to BCUC IR 51.6, BC Hydro stated that it actively manages overtime using certain strategies.

2.221.3 Please explain what is meant by "capacity of internal workers." Include a discussion on how the capacity of an internal worker is measured and how it impacts the number of overtime hours, and overtime costs.

**RESPONSE:**

**Capacity of internal workers reflects the total hours planned in each fiscal year and represents the availability of internal resources to perform work, which is synonymous with capacity.**

**The total hours planned in each fiscal year include regular time hours consistent with the standard labour hours per FTE provided in Table 5-15 on page 5-48 of Chapter 5 of the Application, and planned overtime hours based on annual targets set. The targets set each year consider factors such as project(s), work location(s) and expected work requirements in the coming year.**

**To monitor hours worked compared to the internal workers' capacity, regular time and overtime hours worked and their associated costs are reported on and compared to planned hours and dollars each month as part of the monthly financial reporting cycle discussed in BC Hydro's response to BCUC IR 1.36.1.**

**221.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-5, BCUC IR 51.6**
**Overtime**

In response to BCUC IR 51.6, BC Hydro stated that it actively manages overtime using certain strategies.

2.221.4 Please explain how the difference in standard labour rates of ~9 percent across International Brotherhood of Electrical Workers (IBEW) trades were calculated and discuss how this difference correlates to regular and overtime costs for IBEW trades (i.e. each overtime hour worked costs ~9 percent more than a regular hour worked). Please provide the same for the Movement of United Professionals (MoveUP) management and professional employees.

**RESPONSE:**

**The approximate 9 per cent difference between regular time and overtime standard labour rates across International Brotherhood of Electrical Workers trades was based on a direct comparison of the standard labour rate groups within the International Brotherhood of Electrical Workers affiliation.**

**The following table provides a comparison of the average weighted difference between regular and overtime rates by affiliation which accounts for the volume of overtime hours by each standard labour rate group. As there are select International Brotherhood of Electrical Workers standard labour rate groups that incur the majority of the regular and overtime hours (i.e., Powerline Technicians, Electricians, CPC Technicians), the weighted average presented in the table below is different than equivalent average provided BC Hydro's response to BCUC IR 1.51.6.**

| Affiliation | Average Weighted SLR (Regular) ($) | Average Weighted SLR (Overtime) ($) | Difference (%) |
|---|---|---|---|
| International Brotherhood of Electrical Workers (IBEW) | 81.67 | 95.99 | 18 |
| Movement of United Professional (Move UP) | 59.28 | 71.20 | 20 |
| Management and Professional (M&P) – excluding Executive | 99.97 | 80.43 | -20 |

**As noted in BC Hydro's response to BCUC IR 1.52.4, there are several components captured within the regular standard labor rates including benefits and current service costs.**

**The overtime standard labour rates only include the hourly salary or wage rate at 2.0 times for International Brotherhood of Electrical Workers and MoveUp employees and 1.5 times for Management and Professional employees for most standard labour rate groups. The exception is select International Brotherhood of Electrical Workers standard labour rate groups which also include benefit costs. Benefit costs are included in the overtime standard labour rates for these International Brotherhood of Electrical Workers groups as they routinely work significant overtime each year (i.e., Powerline Technicians and Electricians).**

**For the International Brotherhood of Electrical Workers and MoveUp, because the benefit and current service costs are captured in the regular time standard labour rate for most standard labour rate groups, overtime is less than 2.0 times regular time rates.**

**For Management and Professional, the average weighted overtime standard labour rate is lower than the average weighted regular time standard labour rate because (a) the benefits and current service costs are captured in the regular time standard labour rates and (b) overtime is only 1.5 times.**

**221.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-5, BCUC IR 51.6**
**Overtime**

In response to BCUC IR 51.6, BC Hydro stated that it actively manages overtime using certain strategies.

2.221.5 Please explain how BC Hydro verifies that the strategies used to actively manage overtime are consistently applied across the organization and are effective.

**RESPONSE:**

**The strategies for managing overtime described in BC Hydro's response to BCUC IR 1.51.6 are primarily applied to the Operations Business Group, which incurs the majority of overtime in the organization. As described in BC Hydro's response to BCUC IR 2.221.2, these strategies have resulted in the Operations Business Group being within 1 per cent of planned overtime hours from fiscal 2017 to fiscal 2019, which supports the effectiveness of these strategies.**

**Overtime incurred in the other Business Groups in the organization is managed at a Departmental or KBU level using the guidelines provided in BC Hydro's response to BCUC IR 1.45.3.**

**222.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-1, Section 5.6.4, Table 5-14, p. 5-46; Section 6.2.1, Table 6-1, p. 6-6;**
**Exhibit B-5, BCUC IR 47.5, 51.4, 51.7.1; Exhibit B-6, BCOAPO IR 30.1; AMPC IR 3.2**
**Summary of FTE changes**

In response to BCUC IR 51.7.1, BC Hydro provided a table that includes a high-level explanation for significant differences in FTEs between the RRA and F2017 and F2018 actuals and F2019 forecast. The table is broken down by KBUs according to Business Group.

In response to BCUC IR 47.5, BC Hydro provided a table illustrating the breakdown of FTEs added through the Workforce Optimization program by Business Group and by funding source.

2.222.1 Please explain why the F2019 increases described in BCUC IR 51.7.1 and listed below (that are attributed primarily to the Workforce Optimization Program for the Business Groups) are significantly greater than the number of FTE conversions in F2019 as listed in response to BCUC IR 47.5 for the same business group.

- Integrated Planning
- Capital Infrastructure Project Delivery
- Operations

**RESPONSE:**

**BC Hydro's response to BCUC IR 1.51.7.1 provides the total FTE change between fiscal 2019 RRA Plan and fiscal 2019 Forecast, while the figures provided in the fiscal 2019 column of BC Hydro's response to BCUC IR 1.47.5 provide the regular time FTEs (excluding overtime FTEs) added through the Workforce Optimization program in fiscal 2019 only.**

**The table below provides the total Workforce Optimization program FTE additions from fiscal 2017 to fiscal 2019, excluding those already included in the Previous Application for comparison to the total FTE changes provided in BC Hydro's response to BCUC IR 1.51.7.1.**

| BCUC IR 1.47.5 Response | Integrated Planning | Capital Infrastructure Project Delivery | Operations |
|---|---|---|---|
| Fiscal 2017 | 16 | 54 | 22 |
| Fiscal 2018 | 40 | 73 | 50 |
| Fiscal 2019 | 32 | 78 | 75 |
| Sub-Total | 88 | 205 | 147 |
| Less: Workforce Optimization program FTE Additions in Previous Application | (16) | (82) | (26) |
| Total | 72 | 123 | 121 |
| | | | |
| BCUC IR 1.51.7.1 Response | 68 | 130 | 140 |
| | | | |
| Difference | (4) | 7 | 19 |

**The differences shown in the table above are due to various factors such as overtime FTEs, re-organizations, and the Accenture repatriation.**

**222.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-1, Section 5.6.4, Table 5-14, p. 5-46; Section 6.2.1, Table 6-1, p. 6-6;**
**Exhibit B-5, BCUC IR 47.5, 51.4, 51.7.1; Exhibit B-6, BCOAPO IR 30.1; AMPC IR 3.2**
**Summary of FTE changes**

In response to BCUC IR 51.7.1, BC Hydro provided a table that includes a high-level explanation for significant differences in FTEs between the RRA and F2017 and F2018 actuals and F2019 forecast. The table is broken down by KBUs according to Business Group.

In response to BCUC IR 47.5, BC Hydro provided a table illustrating the breakdown of FTEs added through the Workforce Optimization program by Business Group and by funding source.

2.222.2 Please provide the number of temporary hires for the line Field Operations KBU in F2019 and explain why these temporary hires were required.

**RESPONSE:**

**Line Field Operations had 10 temporary hires in fiscal 2019.**

**Six of the 10 temporary hires were field workers. Five of the six were required to fill vacancies due to long-term sick leave. The other temporary hire was required to cover a six month leave of absence.**

**Three of the 10 temporary hires were in the Operations Support Processing Center. One was required to cover for maternity leave, one for a long-term sick leave and one for an employee on a one year temporary assignment in another department.**

**One of the 10 temporary hires was in the Hydro Restoration Center. This hire was required to cover a maternity leave as well as an employee on a temporary assignment in another department.**

**222.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-1, Section 5.6.4, Table 5-14, p. 5-46; Section 6.2.1, Table 6-1, p. 6-6;**
**Exhibit B-5, BCUC IR 47.5, 51.4, 51.7.1; Exhibit B-6, BCOAPO IR 30.1; AMPC IR 3.2**
**Summary of FTE changes**

In response to BCUC IR 51.7.1, BC Hydro provided a table that includes a high-level explanation for significant differences in FTEs between the RRA and F2017 and F2018 actuals and F2019 forecast. The table is broken down by KBUs according to Business Group.

In response to BCUC IR 47.5, BC Hydro provided a table illustrating the breakdown of FTEs added through the Workforce Optimization program by Business Group and by funding source.

2.222.3 With respect to the Distribution, Design & Customer Connect KBU, please break down the increase of 41 FTEs from F2018 to F2019, between the Workforce Optimization program and higher overtime.

**RESPONSE:**

**The increase of 41 FTEs from fiscal 2018 RRA to fiscal 2019 Forecast consists of 35 regular time FTEs for Designer and Express Coordinator positions added through the Workforce Optimization Program and six overtime FTEs. The six overtime FTEs are based on standard overtime levels for the 35 additional positions that were added.**

**For additional details on the FTEs added to the Distribution Design and Customer Connect KBU through the Workforce Optimization Program, please refer to Table 5-10 on page 5-36 of Chapter 5 of the Application.**

**222.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-1, Section 5.6.4, Table 5-14, p. 5-46; Section 6.2.1, Table 6-1, p. 6-6;**
**Exhibit B-5, BCUC IR 47.5, 51.4, 51.7.1; Exhibit B-6, BCOAPO IR 30.1; AMPC IR 3.2**
**Summary of FTE changes**

In response to BCUC IR 51.7.1, BC Hydro provided a table that includes a high-level explanation for significant differences in FTEs between the RRA and F2017 and F2018 actuals and F2019 forecast. The table is broken down by KBUs according to Business Group.

In response to BCUC IR 47.5, BC Hydro provided a table illustrating the breakdown of FTEs added through the Workforce Optimization program by Business Group and by funding source.

2.222.4 Please explain what is meant by “unplanned new hires” in the Field Services KBU in F2019 as indicated in BCUC IR 51.7.1. Please quantify the number of unplanned new hires and explain why they were needed.

**RESPONSE:**

**The unplanned new hires were for labour resources added to the Field Safety Services KBU. BC Hydro does not have a Field Services KBU.**

**The term “unplanned new hires” refers to additional positions that were not in the original fiscal 2019 RRA plan for the Field Safety Services KBU. Subsequent to the development of the fiscal 2019 RRA plan, four additional full time temporary Occupational Safety and Health (OSH) Specialists were added to the KBU.**

- **Two OSH Specialists were added to support confined space field work as a result of the Confined Space Safety Directive discussed further on page 5D-33 of Chapter 5D of the Application;**
- **One OSH Specialist was added to provide increased support for construction project work; and**
- **One OSH Specialist was added to support the delivery of the capital plan and the expansion of the Contractor Safety Management Program.**

**222.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-1, Section 5.6.4, Table 5-14, p. 5-46; Section 6.2.1, Table 6-1, p. 6-6;**
**Exhibit B-5, BCUC IR 47.5, 51.4, 51.7.1; Exhibit B-6, BCOAPO IR 30.1; AMPC IR 3.2**
**Summary of FTE changes**

In response to BCUC IR 51.4, BC Hydro stated: “As shown in Figure 5-6 on page 5-31 of Chapter 5 of the Application, there was considerable growth of capital expenditures from fiscal 2011 to fiscal 2018. The largest growth is in the Business Groups that primarily deliver Capital projects (Capital infrastructure Delivery and Operations) as well as in the Site C Project.”

Table 5-14 in the Application provides a summary of the total FTEs by function. The capital portion of the table is reproduced below:

**Table 5-14 Total FTEs by Function**

| FTEs (including Overtime) | F2017 RRA | F2017 Actual | F2018 RRA | F2018 Actual | F2019 RRA | F2019 Forecast | F2020 Plan | F2021 Plan |
|---|---|---|---|---|---|---|---|---|
| **Capital** | | | | | | | | |
| Integrated Planning | 365 | 325 | 365 | 346 | 367 | 411 | 416 | 416 |
| Capital Infrastructure Project Delivery | 276 | 307 | 301 | 360 | 302 | 418 | 418 | 417 |
| Operations | 1,215 | 1,077 | 1,219 | 1,100 | 1,219 | 1,344 | 1,343 | 1,340 |
| Safety | 186 | 154 | 188 | 152 | 188 | 138 | 124 | 114 |
| Finance, Technology, Supply Chain | 31 | 36 | 39 | 46 | 44 | 54 | 70 | 70 |
| People, Customer, Corporate Affairs | 8 | 6 | 8 | 8 | 8 | 8 | 8 | 8 |
| Other | 189 | 168 | 192 | 227 | 202 | 394 | 465 | 477 |
| Total (Schedule 16 line 70) | 2,269 | 2,072 | 2,311 | 2,239 | 2,329 | 2,766 | 2,843 | 2,841 |
| Percentage Change | | | | | | 19% | 3% | 0% |

Table 6-1 in the Application provides the actual and planned growth and sustaining capital expenditures from F2017 to F2021.

2.222.5 Please reproduce Table 6-1 to include only: generation (removing the Site C Project and Generation – Waneta 2/3 line items); transmission; and distribution capital expenditures.

**RESPONSE:**

**The information in Table 6-1 has been reproduced to include only Generation, Transmission and Distribution capital expenditures and is shown below.**

**The financial information provided in this response has been updated based on the information included in BC Hydro’s Evidentiary Update.**

| ($ millions) | F2017 | | F2018 | | F2019 | | F2020 | F2021 |
|---|---|---|---|---|---|---|---|---|
| | RRA | Actual | RRA | Actual | RRA | Actual | Plan | Plan |
| Generation | | | | | | | | |
| Growth (Schedule 13, Line 1) | 20.0 | 21.2 | 2.4 | 10.2 | 0.7 | 5.5 | 3.2 | - |
| Sustaining (Schedule 13, Line 3) | 530.0 | 563.6 | 534.1 | 533.9 | 424.3 | 364.7 | 341.8 | 435.5 |
| Total Generation (excluding Site C and Waneta 2/3) | 550.0 | 584.8 | 536.5 | 544.1 | 425.0 | 370.2 | 345.1 | 435.5 |
| | | | | | | | | |
| Transmission | | | | | | | | |
| Growth (Schedule 13, Line 4) | 262.0 | 247.3 | 222.0 | 280.5 | 192.7 | 224.3 | 185.0 | 198.9 |
| Sustaining (Schedule 13, Line 5) | 255.5 | 268.1 | 326.3 | 218.3 | 373.9 | 193.0 | 222.6 | 286.5 |
| Total Transmission | 517.5 | 515.4 | 548.3 | 498.8 | 566.6 | 417.3 | 407.6 | 485.4 |
| Distribution | | | | | | | | |
| Growth (Schedule 13, Line 6) | 224.7 | 226.0 | 233.4 | 287.6 | 209.5 | 296.0 | 300.0 | 284.6 |
| Sustaining (Schedule 13, Line 7) | 185.0 | 224.5 | 160.1 | 235.2 | 187.6 | 206.7 | 187.5 | 176.8 |
| Total Distribution | 409.8 | 450.5 | 393.4 | 522.8 | 397.0 | 502.7 | 487.5 | 461.4 |
| | | | | | | | | |
| TOTAL | 1,477.2 | 1,550.7 | 1,478.2 | 1,565.7 | 1,388.7 | 1,290.2 | 1,240.2 | 1,382.3 |
| Less: Contribution in Aid | (86.4) | (138.4) | (100.2) | (156.3) | (106.4) | (185.3) | (157.8) | (148.4) |
| | | | | | | | | |
| TOTAL | 1,390.8 | 1,412.3 | 1,378.0 | 1,409.4 | 1,282.3 | 1,104.9 | 1,082.4 | 1,233.9 |

**222.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-1, Section 5.6.4, Table 5-14, p. 5-46; Section 6.2.1, Table 6-1, p. 6-6;**
**Exhibit B-5, BCUC IR 47.5, 51.4, 51.7.1; Exhibit B-6, BCOAPO IR 30.1; AMPC IR 3.2**
**Summary of FTE changes**

In response to BCUC IR 51.4, BC Hydro stated: "As shown in Figure 5-6 on page 5-31 of Chapter 5 of the Application, there was considerable growth of capital expenditures from fiscal 2011 to fiscal 2018. The largest growth is in the Business Groups that primarily deliver Capital projects (Capital infrastructure Delivery and Operations) as well as in the Site C Project."

Table 5-14 in the Application provides a summary of the total FTEs by function. The capital portion of the table is reproduced below:

**Table 5-14 Total FTEs by Function**

| FTEs (including Overtime) | F2017 RRA | F2017 Actual | F2018 RRA | F2018 Actual | F2019 RRA | F2019 Forecast | F2020 Plan | F2021 Plan |
|---|---|---|---|---|---|---|---|---|
| **Capital** | | | | | | | | |
| Integrated Planning | 365 | 325 | 365 | 346 | 367 | 411 | 416 | 416 |
| Capital Infrastructure Project Delivery | 276 | 307 | 301 | 360 | 302 | 418 | 418 | 417 |
| Operations | 1,215 | 1,077 | 1,219 | 1,100 | 1,219 | 1,344 | 1,343 | 1,340 |
| Safety | 186 | 154 | 188 | 152 | 188 | 138 | 124 | 114 |
| Finance, Technology, Supply Chain | 31 | 36 | 39 | 46 | 44 | 54 | 70 | 70 |
| People, Customer, Corporate Affairs | 8 | 6 | 8 | 8 | 8 | 8 | 8 | 8 |
| Other | 189 | 168 | 192 | 227 | 202 | 394 | 465 | 477 |
| Total (Schedule 16 line 70) | 2,269 | 2,072 | 2,311 | 2,239 | 2,329 | 2,766 | 2,843 | 2,841 |
| Percentage Change | | | | | | 19% | 3% | 0% |

Table 6-1 in the Application provides the actual and planned growth and sustaining capital expenditures from F2017 to F2021.

2.222.5.1 Please comment on the trend of capital expenditures in the re-produced table from F2017 actual to F2021 plan.

**RESPONSE:**

**There is no clear trend of capital expenditures from fiscal 2017 actuals to the fiscal 2021 plan, excluding the Site C project and the Waneta Two-thirds Interest Acquisition.**

**The figures indicate a drop in capital expenditures in fiscal 2019, which can be primarily attributed to the life cycle of large projects. During fiscal 2017 and**

**fiscal 2018, some large projects were at the peak of construction during Implementation phase, and have since been placed in-service. As of the currency date, the largest active projects in the capital plan are not yet in Implementation phase and are not expected to have large capital expenditures until after fiscal 2021.**

**222.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-1, Section 5.6.4, Table 5-14, p. 5-46; Section 6.2.1, Table 6-1, p. 6-6;**
**Exhibit B-5, BCUC IR 47.5, 51.4, 51.7.1; Exhibit B-6, BCOAPO IR 30.1; AMPC IR 3.2**
**Summary of FTE changes**

In response to BCUC IR 51.4, BC Hydro stated: "As shown in Figure 5-6 on page 5-31 of Chapter 5 of the Application, there was considerable growth of capital expenditures from fiscal 2011 to fiscal 2018. The largest growth is in the Business Groups that primarily deliver Capital projects (Capital infrastructure Delivery and Operations) as well as in the Site C Project."

Table 5-14 in the Application provides a summary of the total FTEs by function. The capital portion of the table is reproduced below:

**Table 5-14 Total FTEs by Function**

| FTEs (including Overtime) | F2017 RRA | F2017 Actual | F2018 RRA | F2018 Actual | F2019 RRA | F2019 Forecast | F2020 Plan | F2021 Plan |
|---|---|---|---|---|---|---|---|---|
| **Capital** | | | | | | | | |
| Integrated Planning | 365 | 325 | 365 | 346 | 367 | 411 | 416 | 416 |
| Capital Infrastructure Project Delivery | 276 | 307 | 301 | 360 | 302 | 418 | 418 | 417 |
| Operations | 1,215 | 1,077 | 1,219 | 1,100 | 1,219 | 1,344 | 1,343 | 1,340 |
| Safety | 186 | 154 | 188 | 152 | 188 | 138 | 124 | 114 |
| Finance, Technology, Supply Chain | 31 | 36 | 39 | 46 | 44 | 54 | 70 | 70 |
| People, Customer, Corporate Affairs | 8 | 6 | 8 | 8 | 8 | 8 | 8 | 8 |
| Other | 189 | 168 | 192 | 227 | 202 | 394 | 465 | 477 |
| Total (Schedule 16 line 70) | 2,269 | 2,072 | 2,311 | 2,239 | 2,329 | 2,766 | 2,843 | 2,841 |
| Percentage Change | | | | | | 19% | 3% | 0% |

Table 6-1 in the Application provides the actual and planned growth and sustaining capital expenditures from F2017 to F2021.

2.222.6 Please discuss the level of FTEs in the Integrated Planning, Capital Infrastructure Project Delivery and Operations KBUs considering the trend in capital expenditures over the same period.

**RESPONSE:**

**The growth in FTEs from fiscal 2017 to fiscal 2021 is primarily due to the Workforce Optimization Program, not changes in capital expenditures. The Workforce Optimization Program converted work previously performed by contractors to internal FTEs and has resulted in estimated annual costs savings of $18.5 million, as described in section 5.6.1 of Chapter 5 of the Application.**

**222.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-1, Section 5.6.4, Table 5-14, p. 5-46; Section 6.2.1, Table 6-1, p. 6-6;**
**Exhibit B-5, BCUC IR 47.5, 51.4, 51.7.1; Exhibit B-6, BCOAPO IR 30.1; AMPC IR 3.2**
**Summary of FTE changes**

In response to AMPC IR 3.2, BC Hydro provided the following table:

| FTEs (includes regular and overtime) | Fiscal 2012 Actual | Fiscal 2013 Actual | Fiscal 2014 Actual | Fiscal 2015 Actual | Fiscal 2016 Actual | Fiscal 2017 Actual | Fiscal 2018 Actual | Fiscal 2019 Forecast | Fiscal 2020 Plan | Fiscal 2021 Plan |
|---|---|---|---|---|---|---|---|---|---|---|
| Operating | 4,415 | 4,096 | 4,089 | 4,036 | 4,042 | 4,082 | 4,209 | 4,051 | 4,047 | 4,043 |
| Capital | 1,527 | 1,662 | 1,752 | 1,872 | 1,828 | 1,905 | 2,013 | 2,378 | 2,383 | 2,370 |
| Deferred | 309 | 250 | 258 | 223 | 188 | 161 | 162 | 165 | 164 | 164 |
| Total FTEs (Chapter 1, Figure 1-3, page 1-19) | 6,251 | 6,007 | 6,099 | 6,131 | 6,058 | 6,148 | 6,385 | 6,593 | 6,594 | 6,577 |
| Smart Metering and Infrastructure FTEs | 81 | 119 | 112 | 85 | 69 | - | - | - | - | - |
| Site C FTEs | 56 | 82 | 92 | 97 | 108 | 167 | 226 | 389 | 460 | 472 |
| Accenture Repatriation FTEs | - | - | - | - | - | - | - | 423 | 423 | 423 |
| Total FTEs (Appendix A, Schedule 16.0, line 60) | 6,388 | 6,208 | 6,303 | 6,312 | 6,234 | 6,315 | 6,611 | 7,405 | 7,477 | 7,471 |
| **Labour Costs $ Million** | | | | | | | | | | |
| Total Labour Costs | 717.3 | 718.9 | 749.9 | 751.7 | 780.8 | 792.3 | 832.7 | 921.4 | 966.6 | 983.0 |
| Capital Labour Costs | 205.8 | 192.8 | 208.9 | 218.8 | 243.6 | 267.4 | 295.5 | 342.0 | 366.5 | 372.9 |

2.222.7 Please present as separate line items: i) the Site C capital labour costs; and ii) the capital labour costs excluding Site C.

**RESPONSE:**

**This answer also responds to BCOAPO IR 2.121.1.**

**The financial information provided in this response has been updated based on the information in BC Hydro's Evidentiary Update.**

**The table has also been updated to include the fiscal 2019 RRA FTEs in response to BCOAPO IR 2.121.1.**

**Please see the table below, which has been updated to include separate line items for:**

**(i) Site C capital labour costs, and**

**(ii) Capital labour costs excluding Site C.**

| **FTEs (includes regular and overtime)** | Fiscal 2012 Actual | Fiscal 2013 Actual | Fiscal 2014 Actual | Fiscal 2015 Actual | Fiscal 2016 Actual | Fiscal 2017 Actual | Fiscal 2018 Actual | Fiscal 2019 RRA | Fiscal 2019 Actual | Fiscal 2020 Update | Fiscal 2021 Update |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Operating | 4,415 | 4,096 | 4,089 | 4,036 | 4,042 | 4,082 | 4,209 | 3,884 | 4,185 | 4,047 | 4,043 |
| Capital | 1,527 | 1,662 | 1,752 | 1,872 | 1,828 | 1,905 | 2,013 | 2,130 | 2,061 | 2,383 | 2,370 |
| Deferred | 309 | 250 | 258 | 223 | 188 | 161 | 162 | 152 | 171 | 164 | 164 |
| Total FTEs (Chapter 1, Figure 1-3, page 1-19) | 6,251 | 6,007 | 6,099 | 6,131 | 6,058 | 6,148 | 6,385 | 6,166 | 6,416 | 6,594 | 6,577 |
| Smart Metering and Infrastructure FTEs | 81 | 119 | 112 | 85 | 69 | - | - | | | - | - |
| Site C FTEs | 56 | 82 | 92 | 97 | 108 | 167 | 226 | 199 | 322 | 460 | 472 |
| Accenture Repatriation FTEs 1 | - | - | - | - | - | - | - | | 423 | 423 | 423 |
| Total FTEs (Appendix A, Schedule 16.0, line 60) | 6,388 | 6,208 | 6,303 | 6,312 | 6,234 | 6,315 | 6,611 | 6,365 | 7,161 | 7,477 | 7,471 |

| **Labour Costs $ Million** | Fiscal 2012 Actual | Fiscal 2013 Actual | Fiscal 2014 Actual | Fiscal 2015 Actual | Fiscal 2016 Actual | Fiscal 2017 Actual | Fiscal 2018 Actual | Fiscal 2019 RRA | Fiscal 2019 Actual | Fiscal 2020 Update | Fiscal 2021 Update |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Total Labour Costs | 717.3 | 718.9 | 749.9 | 751.7 | 780.8 | 792.3 | 832.7 | 825.2 | 883.2 | 982.5 | 1,000.1 |
| Capital Labour Costs | 205.8 | 192.8 | 208.9 | 218.8 | 243.6 | 267.4 | 295.5 | 293.8 | 310.0 | 366.5 | 372.9 |
| Site C Capital Labour | | | | | 20.6 | 29.8 | 37.6 | 32.3 | 51.1 | 66.2 | 68.4 |
| Capital Labour Costs Excluding Site C | 205.8 | 192.8 | 208.9 | 218.8 | 223.0 | 237.6 | 257.9 | 261.5 | 258.9 | 300.3 | 304.5 |

Note:

1. Actual Accenture Repatriation FTEs are not being tracked following repatriation and therefore the above table reports the fiscal 2019 planned Accenture Repatriation FTEs of 423 for fiscal 2019 actuals.

**222.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-1, Section 5.6.4, Table 5-14, p. 5-46; Section 6.2.1, Table 6-1, p. 6-6;**
**Exhibit B-5, BCUC IR 47.5, 51.4, 51.7.1; Exhibit B-6, BCOAPO IR 30.1; AMPC IR 3.2**
**Summary of FTE changes**

In response to AMPC IR 3.2, BC Hydro provided the following table:

| FTEs (includes regular and overtime) | Fiscal 2012 Actual | Fiscal 2013 Actual | Fiscal 2014 Actual | Fiscal 2015 Actual | Fiscal 2016 Actual | Fiscal 2017 Actual | Fiscal 2018 Actual | Fiscal 2019 Forecast | Fiscal 2020 Plan | Fiscal 2021 Plan |
|---|---|---|---|---|---|---|---|---|---|---|
| Operating | 4,415 | 4,096 | 4,089 | 4,036 | 4,042 | 4,082 | 4,209 | 4,051 | 4,047 | 4,043 |
| Capital | 1,527 | 1,662 | 1,752 | 1,872 | 1,828 | 1,905 | 2,013 | 2,378 | 2,383 | 2,370 |
| Deferred | 309 | 250 | 258 | 223 | 188 | 161 | 162 | 165 | 164 | 164 |
| Total FTEs (Chapter 1, Figure 1-3, page 1-19) | 6,251 | 6,007 | 6,099 | 6,131 | 6,058 | 6,148 | 6,385 | 6,593 | 6,594 | 6,577 |
| Smart Metering and Infrastructure FTEs | 81 | 119 | 112 | 85 | 69 | - | - | - | - | - |
| Site C FTEs | 56 | 82 | 92 | 97 | 108 | 167 | 226 | 389 | 460 | 472 |
| Accenture Repatriation FTEs | - | - | - | - | - | - | - | 423 | 423 | 423 |
| Total FTEs (Appendix A, Schedule 16.0, line 60) | 6,388 | 6,208 | 6,303 | 6,312 | 6,234 | 6,315 | 6,611 | 7,405 | 7,477 | 7,471 |
| **Labour Costs $ Million** | | | | | | | | | | |
| Total Labour Costs | 717.3 | 718.9 | 749.9 | 751.7 | 780.8 | 792.3 | 832.7 | 921.4 | 966.6 | 983.0 |
| Capital Labour Costs | 205.8 | 192.8 | 208.9 | 218.8 | 243.6 | 267.4 | 295.5 | 342.0 | 366.5 | 372.9 |

2.222.8 Please comment on the change/trend in capital labour costs (excluding Site C) from F2017 actual to F2021 plan. Please discuss this change/trend to the change in capital FTEs over the same period.

**RESPONSE:**

**Capital FTEs and associated labour costs have increased from fiscal 2017 actual to fiscal 2021 plan primarily as a result of the Workforce Optimization Program. This program converted work previously performed by contractors to internal FTEs. The program has resulted in estimated annual costs savings of $18.5 million, as described in section 5.6.1 of Chapter 5 of the Application.**

**222.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-1, Section 5.6.4, Table 5-14, p. 5-46; Section 6.2.1, Table 6-1, p. 6-6;**
**Exhibit B-5, BCUC IR 47.5, 51.4, 51.7.1; Exhibit B-6, BCOAPO IR 30.1; AMPC IR 3.2**
**Summary of FTE changes**

In response to AMPC IR 3.2, BC Hydro provided the following table:

| FTEs (includes regular and overtime) | Fiscal 2012 Actual | Fiscal 2013 Actual | Fiscal 2014 Actual | Fiscal 2015 Actual | Fiscal 2016 Actual | Fiscal 2017 Actual | Fiscal 2018 Actual | Fiscal 2019 Forecast | Fiscal 2020 Plan | Fiscal 2021 Plan |
|---|---|---|---|---|---|---|---|---|---|---|
| Operating | 4,415 | 4,096 | 4,089 | 4,036 | 4,042 | 4,082 | 4,209 | 4,051 | 4,047 | 4,043 |
| Capital | 1,527 | 1,662 | 1,752 | 1,872 | 1,828 | 1,905 | 2,013 | 2,378 | 2,383 | 2,370 |
| Deferred | 309 | 250 | 258 | 223 | 188 | 161 | 162 | 165 | 164 | 164 |
| Total FTEs (Chapter 1, Figure 1-3, page 1-19) | 6,251 | 6,007 | 6,099 | 6,131 | 6,058 | 6,148 | 6,385 | 6,593 | 6,594 | 6,577 |
| Smart Metering and Infrastructure FTEs | 81 | 119 | 112 | 85 | 69 | - | - | - | - | - |
| Site C FTEs | 56 | 82 | 92 | 97 | 108 | 167 | 226 | 389 | 460 | 472 |
| Accenture Repatriation FTEs | - | - | - | - | - | - | - | 423 | 423 | 423 |
| Total FTEs (Appendix A, Schedule 16.0, line 60) | 6,388 | 6,208 | 6,303 | 6,312 | 6,234 | 6,315 | 6,611 | 7,405 | 7,477 | 7,471 |
| **Labour Costs $ Million** | | | | | | | | | | |
| Total Labour Costs | 717.3 | 718.9 | 749.9 | 751.7 | 780.8 | 792.3 | 832.7 | 921.4 | 966.6 | 983.0 |
| Capital Labour Costs | 205.8 | 192.8 | 208.9 | 218.8 | 243.6 | 267.4 | 295.5 | 342.0 | 366.5 | 372.9 |

2.222.8.1 Please comment on the change/trend in Site C capital labour costs from F2017 actual to F2021 plan. Please discuss this change/trend to the change in Site C FTEs over the same period.

**RESPONSE:**

**On February 9, 2018, the Total Project Budget was revised to an approved amount of $10.7 billion (including Treasury Board Reserve). This increase, along with fiscal 2019 to fiscal 2023 being the key construction period, are the main reasons for the change/trend in Site C capital labour costs.**

**The trend in Site C FTEs from fiscal 2017 actual to fiscal 2021 plan is aligned with the increase in Site C capital labour costs with the key difference being that a higher proportion of intermediate and junior roles are being hired during this period, which decreases the overall average cost per FTE.**

**222.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-1, Section 5.6.4, Table 5-14, p. 5-46; Section 6.2.1, Table 6-1, p. 6-6;**
**Exhibit B-5, BCUC IR 47.5, 51.4, 51.7.1; Exhibit B-6, BCOAPO IR 30.1; AMPC IR 3.2**
**Summary of FTE changes**

In response to BCOAPO IR 30.1, BC Hydro provided the regular time FTEs for F2011 through F2018 breaking out those attributable to Smart Meter Infrastructure (SMI) and Site C.

| FTE | F2011 | F2012 | F2013 | F2014 | F2015 | F2016 | F2017 | F2018 |
|---|---|---|---|---|---|---|---|---|
| BC Hydro Excluding SMI and Site C | 5,743 | 5,738 | 5,511 | 5,571 | 5,512 | 5,462 | 5,578 | 5,791 |
| SMI | 33 | 80 | 115 | 108 | 83 | 67 | 0 | - |
| Site C | 29 | 55 | 81 | 91 | 96 | 106 | 157 | 212 |
| Total | 5,805 | 5,873 | 5,707 | 5,770 | 5,690 | 5,635 | 5,736 | 6,004 |

2.222.9 Please explain why the “BC Hydro FTEs Excluding SMI and Site C” results in the above table do not agree to the provided “Total FTEs (Chapter 1, Figure 1-3, page 1-19)” in response to AMPC IR 3.2.

**RESPONSE:**

**The “Total FTEs (Chapter 1, Figure 1-3, page 1-19)” included in BC Hydro’s response to AMPC IR 1.3.2 includes overtime FTEs. The table provided in BC Hydro’s response to BCOAPO IR 1.30.1 referred to in the preamble reflects regular time FTEs only and excludes overtime FTEs.**

**222.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-1, Section 5.6.4, Table 5-14, p. 5-46; Section 6.2.1, Table 6-1, p. 6-6;**
**Exhibit B-5, BCUC IR 47.5, 51.4, 51.7.1; Exhibit B-6, BCOAPO IR 30.1; AMPC IR 3.2**
**Summary of FTE changes**

In response to BCOAPO IR 30.1, BC Hydro provided the regular time FTEs for F2011 through F2018 breaking out those attributable to Smart Meter Infrastructure (SMI) and Site C.

| FTE | F2011 | F2012 | F2013 | F2014 | F2015 | F2016 | F2017 | F2018 |
| --- | --- | --- | --- | --- | --- | --- | --- | --- |
| BC Hydro Excluding SMI and Site C | 5,743 | 5,738 | 5,511 | 5,571 | 5,512 | 5,462 | 5,578 | 5,791 |
| SMI | 33 | 80 | 115 | 108 | 83 | 67 | 0 | - |
| Site C | 29 | 55 | 81 | 91 | 96 | 106 | 157 | 212 |
| Total | 5,805 | 5,873 | 5,707 | 5,770 | 5,690 | 5,635 | 5,736 | 6,004 |

2.222.9.1 Please explain why the FTEs for “SMI” and “Site C” in the above table do not agree to the “Smart Metering and Infrastructure FTEs” and “Site C FTEs” provided in response to AMPC IR 3.2.

**RESPONSE:**

**Please refer to BC Hydro’s response to BCUC IR 2.222.9 which explains that the difference between the tables is the inclusion of overtime FTEs.**

**223.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-5, BCUC IR 38.3, 38.6, 38.8, 38.9, 38.10, 38.11.1, 38.13, 38.13.1; Exhibit B-6, BCOAPO IR 26.2; Government of British Columbia June 2011 Review of BC Hydro[1], Section 2.2.3, p. 40**
**Work Smart Program**

In response to BCUC IR 38.6, BC Hydro stated that "[i]n subsequent years, project recommendations are revisited on a sample basis with the process owner to ensure the approved future state that was implemented is still in effect and that the capacity hours gained remain."

2.223.1 Please explain if there is a set schedule which establishes the timeline for evaluation of all approved future states that were implemented.

**RESPONSE:**

**BC Hydro reviews, on a sample basis, future states with capacity hours gained stemming from Work Smart initiatives within a two to four-year period post-implementation. Initiatives with large capacity hours gained are prioritized earlier in the schedule.**

1 https://news.gov.bc.ca/files/Newsroom/downloads/bchydroreview.pdf.

**223.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-5, BCUC IR 38.3, 38.6, 38.8, 38.9, 38.10, 38.11.1, 38.13, 38.13.1; Exhibit B-6, BCOAPO IR 26.2; Government of British Columbia June 2011 Review of BC Hydro[1], Section 2.2.3, p. 40**
**Work Smart Program**

In response to BCUC IR 38.6, BC Hydro stated that "[i]n subsequent years, project recommendations are revisited on a sample basis with the process owner to ensure the approved future state that was implemented is still in effect and that the capacity hours gained remain."

2.223.2 Please comment on whether the approved future states for all implemented project recommendations have the same number of capacity hours gained as measured when first implemented. If not, please discuss why and quantify the impact on costs and the total number of capacity hours gains.

**RESPONSE:**

**Only one of the sampled initiatives concerning Vegetation Management from fiscal 2015 had less capacity hours gained due to certain recommendations not being implemented. This was one of the BC Hydro pilot initiatives performed and initially measured by a third-party consultant. In fiscal 2016 when the Work Smart Program Office began adding internal resources to deliver initiatives, greater focus was placed on calculating capacity hours gained, and pursuing recommendations considered practical and likely to be implemented. Approximately 95 per cent of capacity hours gained from fiscal 2015 have been evaluated. The revised capacity hours gained were already reflected in BC Hydro's response to BCUC IR 1.38.9.**

1 https://news.gov.bc.ca/files/Newsroom/downloads/bchydroreview.pdf.

**223.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-5, BCUC IR 38.3, 38.6, 38.8, 38.9, 38.10, 38.11.1, 38.13, 38.13.1; Exhibit B-6, BCOAPO IR 26.2; Government of British Columbia June 2011 Review of BC Hydro[1], Section 2.2.3, p. 40**
**Work Smart Program**

In response to BCUC IR 38.8, BC Hydro provided a table outlining the approximate total incremental costs incurred related to the Work Smart program from inception through F2019:

| | | F2015 ($) | F2016 ($) | F2017 ($) | F2018 ($) | F2019 ($) | Cumulative Total ($) |
|---|---|---|---|---|---|---|---|
| | Initial Program Development | 25,200 | | | | | 25,200 |
| | Training | 48,000 | 34,850 | | | | 82,850 |
| A | Subtotal – Development Costs | 73,200 | 34,850 | | | | 108,050 |
| B | Initiative Facilitation (by third parties) (Note 1) | 424,879 | 113,165 | | | | 538,044 |
| C | Work Smart Program Office (Incremental FTE) | | 175,879 | 257,151 | 460,831 | 869,428 | 1,763,289 |
| D=A+B+C | Total Program Costs | 498,079 | 323,894 | 257,151 | 460,831 | 869,428 | 2,409,383 |

Further, in response to BCUC IR 38.13.1, BC Hydro stated:

> Planned costs for the Work Smart program in fiscal 2020 are expected to be approximately $953,000… The increase from fiscal 2018 ($460,831) to fiscal 2020 ($953,000) is due to the addition of two and a half full time equivalents to support a greater volume of projects, training offerings, and new tools including Design Thinking and Lean Daily Management.
>
> Planned costs in fiscal 2021 are expected to be consistent with fiscal 2020 plus any adjustments to the standard labour rate.

2.223.3 Please provide a breakdown of the expenditures included in the Work Smart Program Office costs. Please also explain what these expenditures are for.

1 https://news.gov.bc.ca/files/Newsroom/downloads/bchydroreview.pdf.

**RESPONSE:**

**The table below provides the Work Smart Program Office costs from inception through fiscal 2020.**

| | F2015 ($) | F2016 ($) | F2017 ($) | F2018 ($) | F2019 ($) | F2020 ($) |
|---|---|---|---|---|---|---|
| **Program Manager - joined April 1, 2015** | | **175,879** | **176,332** | **200,583** | **219,143** | **226,632** |
| **Program Advisor - joined October 12, 2016** | | | **80,819** | **178,456** | **176,349** | **181,682** |
| **Program Advisor - joined October 14, 2017** | | | | **81,792** | **176,349** | **181,682** |
| **Program Advisor - joined April 3, 2018** | | | | | **176,349** | **181,682** |
| **Program Advisor - joined July 23, 2018** | | | | | **121,240** | **181,682** |
| **Work Smart Program Office** | | **175,879** | **257,151** | **460,831** | **869,428** | **953,359** |
| **FTEs as at fiscal year-end** | | **1.0** | **2.0** | **3.0** | **5.0** | **5.0** |

**The increase in FTEs to the Work Smart Program Office has enabled the program to:**

- **Increase the number of initiatives performed each year from 6 in fiscal 2015 to 31 in fiscal 2020;**
- **Reduce the use of third party consultants to zero since fiscal 2016;**
- **Introduce enhanced tools to drive more opportunities for process improvements including Lean Daily Management and Design Thinking; and**
- **Develop and offer several training options to empower employees with a set of tools and methods for effective process improvement and create a culture engaged in continuously improving.**

**223.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-5, BCUC IR 38.3, 38.6, 38.8, 38.9, 38.10, 38.11.1, 38.13, 38.13.1; Exhibit B-6, BCOAPO IR 26.2; Government of British Columbia June 2011 Review of BC Hydro[1], Section 2.2.3, p. 40**
**Work Smart Program**

In response to BCUC IR 38.8, BC Hydro provided a table outlining the approximate total incremental costs incurred related to the Work Smart program from inception through F2019:

| | | F2015 ($) | F2016 ($) | F2017 ($) | F2018 ($) | F2019 ($) | Cumulative Total ($) |
|---|---|---|---|---|---|---|---|
| | Initial Program Development | 25,200 | | | | | 25,200 |
| | Training | 48,000 | 34,850 | | | | 82,850 |
| A | Subtotal – Development Costs | 73,200 | 34,850 | | | | 108,050 |
| B | Initiative Facilitation (by third parties) (Note 1) | 424,879 | 113,165 | | | | 538,044 |
| C | Work Smart Program Office (Incremental FTE) | | 175,879 | 257,151 | 460,831 | 869,428 | 1,763,289 |
| D=A+B+C | Total Program Costs | 498,079 | 323,894 | 257,151 | 460,831 | 869,428 | 2,409,383 |

Further, in response to BCUC IR 38.13.1, BC Hydro stated:

> Planned costs for the Work Smart program in fiscal 2020 are expected to be approximately $953,000… The increase from fiscal 2018 ($460,831) to fiscal 2020 ($953,000) is due to the addition of two and a half full time equivalents to support a greater volume of projects, training offerings, and new tools including Design Thinking and Lean Daily Management.
>
> Planned costs in fiscal 2021 are expected to be consistent with fiscal 2020 plus any adjustments to the standard labour rate.

2.223.4 Please explain why the Work Smart Program Office costs increased from $257,151 in F2017 to $460,831 in F2018.

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[1] https://news.gov.bc.ca/files/Newsroom/downloads/bchydroreview.pdf.

**RESPONSE:**

**Please refer to BC Hydro's response to BCUC IR 2.223.3 for a breakdown of Work Smart Program Office costs and a discussion of how the program has put this investment to use.**

**Work Smart Program Office costs increased from $257,151 in fiscal 2017 to $460,831 in fiscal 2018 primarily due to an additional FTE. Two additional FTEs were added in fiscal 2019, resulting in an increase in Work Smart Program Office costs to $869,428. The increase in fiscal 2020 is primarily due to a full complement of five FTEs for the entire fiscal year as one Program Advisor joined part-way through fiscal 2019 on July 23, 2018.**

**223.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-5, BCUC IR 38.3, 38.6, 38.8, 38.9, 38.10, 38.11.1, 38.13, 38.13.1; Exhibit B-6, BCOAPO IR 26.2; Government of British Columbia June 2011 Review of BC Hydro[1], Section 2.2.3, p. 40**
**Work Smart Program**

In response to BCUC IR 38.9, BC Hydro provided the following cost benefit analysis:

| | A | B | C | D = C/A |
|---|---|---|---|---|
| Fiscal Year | Incremental Cost ($) | Capacity Hours Gained | Imputed Value ($) | Value/ Cost |
| | | | | |
| 2015 + 2016 (Note 1) | 821,971 | 17,417 | 1,594,966 | 1.9 |
| 2017 | 257,151 | 22,631 | 2,171,186 | 8.4 |
| 2018 | 460,831 | 39,965 | 3,871,659 | 8.4 |
| Total through 2018 | 1,539,955 | 80,013 | 7,637,811 | 5.0 |

Further in Attachment 1 of this same response, BC Hydro provided details on how the estimated imputed program benefit of $7.6 million was calculated.

2.223.5 Please explain what is meant by "Imputed Value" (column C) and how it impacts the Test Period revenue requirement.

**RESPONSE:**

**The imputed value is the calculated value as shown in Attachment 1 to BC Hydro's response to BCUC IR 1.38.9. The imputed value is the capacity hours gained translated into a dollar equivalent using the average hourly compensation of employees participating in processes improved through the program. BC Hydro considers the imputed value of the program to be a measure of avoided costs. In other words, the $7.6 million represents an estimate of how much costs would have increased if not for the initiatives delivered through the Work Smart program.**

**Please refer to BC Hydro's response to BCUC IR 2.223.9, in which we discuss the effectiveness of the Work Smart program.**

1 https://news.gov.bc.ca/files/Newsroom/downloads/bchydroreview.pdf.

**223.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-5, BCUC IR 38.3, 38.6, 38.8, 38.9, 38.10, 38.11.1, 38.13, 38.13.1; Exhibit B-6, BCOAPO IR 26.2; Government of British Columbia June 2011 Review of BC Hydro[1], Section 2.2.3, p. 40**
**Work Smart Program**

In response to BCUC IR 38.9, BC Hydro provided the following cost benefit analysis:

| | A | B | C | D = C/A |
|---|---|---|---|---|
| Fiscal Year | Incremental Cost ($) | Capacity Hours Gained | Imputed Value ($) | Value/ Cost |
| | | | | |
| 2015 + 2016 (Note 1) | 821,971 | 17,417 | 1,594,966 | 1.9 |
| 2017 | 257,151 | 22,631 | 2,171,186 | 8.4 |
| 2018 | 460,831 | 39,965 | 3,871,659 | 8.4 |
| Total through 2018 | 1,539,955 | 80,013 | 7,637,811 | 5.0 |

Further in Attachment 1 of this same response, BC Hydro provided details on how the estimated imputed program benefit of $7.6 million was calculated.

2.223.5.1 Please clarify whether the "Imputed Value" can be considered the avoided costs. If not, why not?

**RESPONSE:**

**Confirmed. BC Hydro considers this to be a reasonable perspective.**

**Please refer to BC Hydro's response to BCUC IR 2.223.9. The imputed value is an estimate of how much costs would have increased if not for the initiatives delivered through the Work Smart program.**

[1] https://news.gov.bc.ca/files/Newsroom/downloads/bchydroreview.pdf.

**223.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-5, BCUC IR 38.3, 38.6, 38.8, 38.9, 38.10, 38.11.1, 38.13, 38.13.1; Exhibit B-6, BCOAPO IR 26.2; Government of British Columbia June 2011 Review of BC Hydro[1], Section 2.2.3, p. 40**
**Work Smart Program**

In response to BCUC IR 38.9, BC Hydro provided the following cost benefit analysis:

| | A | B | C | D = C/A |
|---|---|---|---|---|
| Fiscal Year | Incremental Cost ($) | Capacity Hours Gained | Imputed Value ($) | Value/ Cost |
| | | | | |
| 2015 + 2016 (Note 1) | 821,971 | 17,417 | 1,594,966 | 1.9 |
| 2017 | 257,151 | 22,631 | 2,171,186 | 8.4 |
| 2018 | 460,831 | 39,965 | 3,871,659 | 8.4 |
| Total through 2018 | 1,539,955 | 80,013 | 7,637,811 | 5.0 |

Further in Attachment 1 of this same response, BC Hydro provided details on how the estimated imputed program benefit of $7.6 million was calculated.

2.223.6 Please confirm, or explain otherwise, that the cumulative value (or avoided operating cost) of each capacity hour gained from 2015 to 2018 is $95.46 (= $7,637,811 / 80,013).

**RESPONSE:**

**Confirmed that the cumulative imputed value of each capacity hour gained from fiscal 2015 to fiscal 2018 is $95.46; however, this relates to both operating and capital costs.**

[1] https://news.gov.bc.ca/files/Newsroom/downloads/bchydroreview.pdf.

**223.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-5, BCUC IR 38.3, 38.6, 38.8, 38.9, 38.10, 38.11.1, 38.13, 38.13.1; Exhibit B-6, BCOAPO IR 26.2; Government of British Columbia June 2011 Review of BC Hydro[1], Section 2.2.3, p. 40**
**Work Smart Program**

In response to BCUC IR 38.9, BC Hydro provided the following cost benefit analysis:

| | A | B | C | D = C/A |
|---|---|---|---|---|
| Fiscal Year | Incremental Cost ($) | Capacity Hours Gained | Imputed Value ($) | Value/ Cost |
| | | | | |
| 2015 + 2016 (Note 1) | 821,971 | 17,417 | 1,594,966 | 1.9 |
| 2017 | 257,151 | 22,631 | 2,171,186 | 8.4 |
| 2018 | 460,831 | 39,965 | 3,871,659 | 8.4 |
| Total through 2018 | 1,539,955 | 80,013 | 7,637,811 | 5.0 |

Further in Attachment 1 of this same response, BC Hydro provided details on how the estimated imputed program benefit of $7.6 million was calculated.

2.223.6 Please confirm, or explain otherwise, that the cumulative value (or avoided operating cost) of each capacity hour gained from 2015 to 2018 is $95.46 (= $7,637,811 / 80,013).

2.223.6.1 If confirmed, please discuss whether $95.46 is comparable to the average hourly compensation of those employees who participate in the Work Smart program.

**RESPONSE:**

**$95.46 is comparable to the average hourly labour cost of employees participating in processes improved through the Work Smart program.**

1 https://news.gov.bc.ca/files/Newsroom/downloads/bchydroreview.pdf.

**223.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-5, BCUC IR 38.3, 38.6, 38.8, 38.9, 38.10, 38.11.1, 38.13, 38.13.1; Exhibit B-6, BCOAPO IR 26.2; Government of British Columbia June 2011 Review of BC Hydro[1], Section 2.2.3, p. 40**
**Work Smart Program**

In response to BCUC IR 38.9, BC Hydro provided the following cost benefit analysis:

| | A | B | C | D = C/A |
|---|---|---|---|---|
| Fiscal Year | Incremental Cost ($) | Capacity Hours Gained | Imputed Value ($) | Value/ Cost |
| | | | | |
| 2015 + 2016 (Note 1) | 821,971 | 17,417 | 1,594,966 | 1.9 |
| 2017 | 257,151 | 22,631 | 2,171,186 | 8.4 |
| 2018 | 460,831 | 39,965 | 3,871,659 | 8.4 |
| Total through 2018 | 1,539,955 | 80,013 | 7,637,811 | 5.0 |

Further in Attachment 1 of this same response, BC Hydro provided details on how the estimated imputed program benefit of $7.6 million was calculated.

2.223.7 Please quantify the capacity hours gained as a percentage of total labour hours and discuss whether there is a capacity hours gained target, and whether this target has been achieved in each of the years since initiation.

**RESPONSE:**

**Capacity hours gained as a percentage of total labour hours is as follows:**

- **Capacity hours gained from inception to fiscal 2018 = 80,013 hours;**
- **Fiscal 2018 total labour hours = 10,197,930 hours; and**
- **Capacity hours gained from inception to fiscal 2018 (80,013) / fiscal 2018 total labour hours (10,197,930) = 0.8 per cent.**

[1] https://news.gov.bc.ca/files/Newsroom/downloads/bchydroreview.pdf.

**The above inputs are consistent with Attachment 1 to BC Hydro's response to BCUC IR 1.38.9.**

**Please refer to BC Hydro's response to BCUC IR 1.38.3 for an estimate of annual capacity hours. The values presented act as our target and the targets have been achieved in each year. In particular, the 80,013 annual capacity hours gained from inception to fiscal 2018 greatly exceeds the forecast in the Previous Application of 46,550 hours.**

**223.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-5, BCUC IR 38.3, 38.6, 38.8, 38.9, 38.10, 38.11.1, 38.13, 38.13.1; Exhibit B-6, BCOAPO IR 26.2; Government of British Columbia June 2011 Review of BC Hydro[1], Section 2.2.3, p. 40**
**Work Smart Program**

In response to BCUC IR 38.10, BC Hydro stated that it "expect[s] that the natural result of increasing the capacity of the existing workforce to absorb new work would be avoiding or delaying the need to add resources to perform that work. However, fewer expected contract hours and fewer expected new hires are not measures we use to assess performance."

In response to BCUC IR 38.11.1, BC Hydro stated: "[w]ithout the capacity hours gained delivered through the Work Smart program, BC Hydro's operating costs (and thus its revenue requirements) would be higher."

2.223.8 Please explain whether BC Hydro considers there is value to adding a performance measure to the Work Smart program, which measures the cost savings, avoided costs and/or the impact on contract hours and number of new hires. Please explain why or why not.

**RESPONSE:**

**Please refer to BC Hydro's response to BCUC IR 2.223.9, where we note that we measure the effectiveness of the Work Smart program by looking at capacity hours gained. In future revenue requirements applications, BC Hydro will continue to report on the imputed value of the program as shown in BC Hydro's response to BCUC IR 1.38.9. BC Hydro generally does not see value in measuring the other items mentioned in the question for the following reasons:**

- **Cost savings – as noted in BC Hydro's response to BCUC IR 2.223.5.1, BC Hydro considers the imputed value of the program (e.g., $7.6 million per year as at the end of fiscal 2018) to be a measure of avoided costs. Cost savings in the form of budget reductions are not the objective of the Work Smart program; and**
- **Impact on contractor hours and number of new hires – it is not possible to quantify the impact of Work Smart in terms of these measures.**

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1 https://news.gov.bc.ca/files/Newsroom/downloads/bchydroreview.pdf.

**223.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-5, BCUC IR 38.3, 38.6, 38.8, 38.9, 38.10, 38.11.1, 38.13, 38.13.1; Exhibit B-6, BCOAPO IR 26.2; Government of British Columbia June 2011 Review of BC Hydro[1], Section 2.2.3, p. 40**
**Work Smart Program**

On page 40 of the Government of BC June 2011 Review of BC Hydro, it states:

> BC Hydro, recognizing that it has not been operating to optimum efficiency, has initiatives to streamline processes, eliminating low value work and leveraging technology, but there is some question as to the effectiveness of these initiatives as they have not demonstrated significant reductions to operating costs.

2.223.9 Please explain whether BC Hydro can demonstrate the effectiveness of the Work Smart program through reductions to operating costs. If so, please elaborate.

**RESPONSE:**

**BC Hydro considers the effectiveness of the Work Smart program to be demonstrated through annual capacity hours gained of 80,013 hours (annual benefit in fiscal 2018), which has an estimated imputed value of $7.6 million annually. This capacity is used to manage increases in workload and work complexity as well as enabling employees to focus on the highest value work.**

**The $7.6 million represents an estimate of how much costs would have increased if not for the initiatives delivered through the Work Smart program. In other words, without Work Smart initiatives to date, BC Hydro estimates that its annual costs would be $7.6 million higher than applied for in the Application.**

**As shown in BC Hydro's response to BCUC IR 1.38.9 the program has an imputed return on investment of five to one since its inception to fiscal 2018.**

**BC Hydro notes that a number of questions, as well as comments in the BCUC's decision from the Previous Application, seek to understand why capacity hours gained (which can be considered avoided costs) are BC Hydro's measure of the effectiveness of the Work Smart program instead of other measures such as incremental savings and headcount reductions. A fundamental principle of the**

1 https://news.gov.bc.ca/files/Newsroom/downloads/bchydroreview.pdf.

**Work Smart program is that employees have the solutions to improve processes and their participation in Work Smart initiatives is vital in identifying and implementing them, which leads to capacity hours gained that enable employees to deal with workload challenges and focus on the highest value work. Work Smart team members do not have these solutions – instead, Work Smart provides the tools, facilitation skills, and structure to collaboratively identify and implement the solutions from employee teams.**

**As noted in BC Hydro's response to BCUC IR 1.64.1, BC Hydro faces a growing and more complex workload caused by a number of factors. Since BC Hydro's headcount (excluding Workforce Optimization, Accenture Repatriation, and Site C) has not been growing as shown in Table 5-12 of Chapter 5 of the Application, and since BC Hydro has been unable to fund many cost pressures as discussed in BC Hydro's response to BCUC IR 1.34.3, capacity hours delivered through Work Smart initiatives are a critical way for BC Hydro to make its processes more efficient, enable a growing workload to be absorbed, and to minimize cost increases.**

**If, on the other hand, Work Smart solutions were required to deliver incremental cost and headcount savings (instead of avoiding higher costs), the program would not be successful. More specifically, employees and teams facing a growing and more complex workload would not participate since they would not obtain the capacity hours gained that they need. Instead, they would be disincented to participate and offer the best solutions to improve processes as their position could be terminated as a result. Without positive participation from employees involved in the process, Work Smart initiatives would be unsuccessful.**

**Our approach is also consistent with that of other companies with similar Work Smart programs. As noted in BC Hydro's response to BCUC IR 1.39.6, BC Hydro considers the goals of Washington State's Results Washington Program and ICBC's Operational Excellence Program to be similar to those of Work Smart. Neither Results Washington nor ICBC Operational Excellence place an objective on cost savings.**

**BC Hydro's approach to Work Smart also enables employees to:**

- **Identify process improvement opportunities known only to employees close to the work;**
- **Work with other process stakeholders from across the company, which drives further collaboration and productivity;**
- **Leverage their expertise and the expertise of employees close to the work, meaning less investigation and analysis is required by program employees enabling us to have a higher throughput of initiatives each year;**

- **Implement changes and sustain the improvements; and**
- **Improve their own work processes, thereby increasing employee engagement, which leads to higher productivity.**

**223.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-5, BCUC IR 38.3, 38.6, 38.8, 38.9, 38.10, 38.11.1, 38.13, 38.13.1; Exhibit B-6, BCOAPO IR 26.2; Government of British Columbia June 2011 Review of BC Hydro[1], Section 2.2.3, p. 40**
**Work Smart Program**

On page 40 of the Government of BC June 2011 Review of BC Hydro, it states:

> BC Hydro, recognizing that it has not been operating to optimum efficiency, has initiatives to streamline processes, eliminating low value work and leveraging technology, but there is some question as to the effectiveness of these initiatives as they have not demonstrated significant reductions to operating costs.

2.223.10 Please discuss how the Work Smart program generates efficiencies in operating costs.

**RESPONSE:**

**Please refer to BC Hydro's response to BCUC IR 2.223.9, which provides a discussion on the effectiveness of the Work Smart program and how the program generates benefits through capacity hours gained.**

[1] https://news.gov.bc.ca/files/Newsroom/downloads/bchydroreview.pdf.

**223.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-5, BCUC IR 38.3, 38.6, 38.8, 38.9, 38.10, 38.11.1, 38.13, 38.13.1; Exhibit B-6, BCOAPO IR 26.2; Government of British Columbia June 2011 Review of BC Hydro[1], Section 2.2.3, p. 40**
**Work Smart Program**

BC Hydro provided 31 Work Smart initiatives planned for F2020 in response in BCUC IR 38.13. And in response to BCUC IR 38.3, BC Hydro stated:

> Of the 31 projects, the first 19 projects are process focused and expected to yield annual capacity gains consistent with prior years. In other words, we expect to achieve approximately 22,800 annual capacity hours gained from these projects (1,200 hours/project X 19 projects).
>
> The remaining 12 projects are not conventional projects, have different objectives and therefore may not yield annual capacity hours gained that can be reliably measured.

2.223.11 Please discuss whether BC Hydro's expectation to implement 31 Work Smart initiatives in F2020 is consistent with the number of initiatives implemented in past years.

**RESPONSE:**

**BC Hydro's expectation to implement 31 Work Smart initiatives is higher than previous years and commensurate with the current number of employees in the Work Smart Program Office versus prior years. Program resources were increased to fulfill demand for program services and to deliver expanded services as described in BC Hydro's response to BCUC IR 2.223.3.**

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[1] https://news.gov.bc.ca/files/Newsroom/downloads/bchydroreview.pdf.

**223.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-5, BCUC IR 38.3, 38.6, 38.8, 38.9, 38.10, 38.11.1, 38.13, 38.13.1; Exhibit B-6, BCOAPO IR 26.2; Government of British Columbia June 2011 Review of BC Hydro[1], Section 2.2.3, p. 40**
**Work Smart Program**

BC Hydro provided 31 Work Smart initiatives planned for F2020 in response in BCUC IR 38.13. And in response to BCUC IR 38.3, BC Hydro stated:

> Of the 31 projects, the first 19 projects are process focused and expected to yield annual capacity gains consistent with prior years. In other words, we expect to achieve approximately 22,800 annual capacity hours gained from these projects (1,200 hours/project X 19 projects).
>
> The remaining 12 projects are not conventional projects, have different objectives and therefore may not yield annual capacity hours gained that can be reliably measured.

2.223.12 Please explain if BC Hydro will continue to measure the annual number of capacity hours gained and the imputed value of the capacity hours gained. If not, why not? If so, please comment on whether the methodology for measuring these values is expected to change.

**RESPONSE:**

**Confirmed. BC Hydro will continue to measure the annual number of capacity hours gained and the imputed value of the capacity hours gained. This methodology is not expected to change.**

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1 https://news.gov.bc.ca/files/Newsroom/downloads/bchydroreview.pdf.

**224.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-5, BCUC IR 46.2, 48.2, 48.3; Exhibit B-6, BCOAPO IR 29.1**
**Workforce Optimization Program – annual net savings**

In response to BCUC IR 46.2, BC Hydro provided Attachment 1 which breaks down the estimated costs and savings by business group for the Workforce Optimization Program workforce adjustment requests.

In response to BCUC IR 48.3, BC Hydro provided a breakdown of Workforce Optimization program FTEs from inception to F2019 by function (operating, capital or deferred).

**Number of Workforce Optimization FTEs by Fiscal Year (F17-19) and Function**

| | F2017 | | | F2018 | | | F2019 | | |
|---|---|---|---|---|---|---|---|---|---|
| Business Group | OMA | Capital | Deferred | OMA | Capital | Deferred | OMA | Capital | Deferred |
| Integrated Planning | 2.6 | 13.4 | 0.0 | 16.1 | 23.9 | 0.0 | 7.4 | 24.6 | 0.0 |
| Capital Infrastructure Project Delivery | 7.0 | 47.0 | 0.0 | 12.8 | 58.8 | 1.0 | 10.0 | 67.7 | 1.0 |
| Operations | 4.3 | 17.7 | 0.0 | 17.2 | 31.9 | 0.9 | 46.8 | 28.2 | 0.0 |
| Finance Technology and Supply Chain | 1.5 | 3.0 | 0.0 | 61.0 | 17.0 | 0.0 | 40.7 | 0.4 | 0.0 |
| Safety | 8.8 | 1.2 | 0.0 | 3.1 | 2.9 | 0.0 | 6.8 | 2.2 | 0.0 |
| People, Customer, Corporate Affairs | 2.0 | 0.0 | 0.0 | 9.5 | 0.0 | 9.5 | 23.3 | 0.9 | 2.9 |
| Other | 1.3 | 0.7 | 0.0 | 2.8 | 1.2 | 0.0 | 1.0 | 0.0 | 0.0 |
| Total | 27.5 | 83.0 | 0.0 | 122.4 | 135.8 | 11.4 | 136.1 | 123.9 | 3.9 |

In response to BCUC IR 48.2, BC Hydro provided a breakdown of the planned Workforce Optimization program FTEs to be added through contract conversion in F2020 and F2021 by function (operating, capital or deferred).

**Number of Workforce Optimization FTEs by Fiscal Year (F20 & F21) and Function**

| | F2020 | | | F2021 | | |
|---|---|---|---|---|---|---|
| Business Group | OMA | Capital | Deferred | OMA | Capital | Deferred |
| Integrated Planning | 1.6 | 0.4 | 0.0 | | | |
| Capital Infrastructure Project Delivery | 0.7 | 9.3 | 0.0 | | | |
| Operations | 17.2 | 7.8 | 0.0 | | | |
| Finance Technology and Supply Chain | 13.7 | 4.3 | 0.0 | | | |
| Safety | 0.0 | 0.0 | 0.0 | | | |
| People, Customer, Corporate Affairs | 1.3 | 0.0 | 0.0 | | | |
| Other | 0.0 | 0.0 | 0.0 | | | |
| Total | 34.6 | 21.7 | 0.0 | 0.0 | 0.0 | 0.0 |

2.224.1 Please confirm, or explain otherwise, that the annual costs, savings and net savings are cumulative (i.e. each year provides the total costs, savings and net savings from all contractor conversions to internal FTEs up to the end of that fiscal year).

**RESPONSE:**

**Confirmed. The annual costs, savings and net savings presented in BC Hydro's response to BCUC IR 1.46.2 are cumulative.**

**224.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-5, BCUC IR 46.2, 48.2, 48.3; Exhibit B-6, BCOAPO IR 29.1**
**Workforce Optimization Program – annual net savings**

In response to BCUC IR 46.2, BC Hydro provided Attachment 1 which breaks down the estimated costs and savings by business group for the Workforce Optimization Program workforce adjustment requests.

In response to BCUC IR 48.3, BC Hydro provided a breakdown of Workforce Optimization program FTEs from inception to F2019 by function (operating, capital or deferred).

**Number of Workforce Optimization FTEs by Fiscal Year (F17-19) and Function**

| | F2017 | | | F2018 | | | F2019 | | |
|---|---|---|---|---|---|---|---|---|---|
| Business Group | OMA | Capital | Deferred | OMA | Capital | Deferred | OMA | Capital | Deferred |
| Integrated Planning | 2.6 | 13.4 | 0.0 | 16.1 | 23.9 | 0.0 | 7.4 | 24.6 | 0.0 |
| Capital Infrastructure Project Delivery | 7.0 | 47.0 | 0.0 | 12.8 | 58.8 | 1.0 | 10.0 | 67.7 | 1.0 |
| Operations | 4.3 | 17.7 | 0.0 | 17.2 | 31.9 | 0.9 | 46.8 | 28.2 | 0.0 |
| Finance Technology and Supply Chain | 1.5 | 3.0 | 0.0 | 61.0 | 17.0 | 0.0 | 40.7 | 0.4 | 0.0 |
| Safety | 8.8 | 1.2 | 0.0 | 3.1 | 2.9 | 0.0 | 6.8 | 2.2 | 0.0 |
| People, Customer, Corporate Affairs | 2.0 | 0.0 | 0.0 | 9.5 | 0.0 | 9.5 | 23.3 | 0.9 | 2.9 |
| Other | 1.3 | 0.7 | 0.0 | 2.8 | 1.2 | 0.0 | 1.0 | 0.0 | 0.0 |
| Total | 27.5 | 83.0 | 0.0 | 122.4 | 135.8 | 11.4 | 136.1 | 123.9 | 3.9 |

In response to BCUC IR 48.2, BC Hydro provided a breakdown of the planned Workforce Optimization program FTEs to be added through contract conversion in F2020 and F2021 by function (operating, capital or deferred).

**Number of Workforce Optimization FTEs by Fiscal Year (F20 & F21) and Function**

| | F2020 | | | F2021 | | |
|---|---|---|---|---|---|---|
| Business Group | OMA | Capital | Deferred | OMA | Capital | Deferred |
| Integrated Planning | 1.6 | 0.4 | 0.0 | | | |
| Capital Infrastructure Project Delivery | 0.7 | 9.3 | 0.0 | | | |
| Operations | 17.2 | 7.8 | 0.0 | | | |
| Finance Technology and Supply Chain | 13.7 | 4.3 | 0.0 | | | |
| Safety | 0.0 | 0.0 | 0.0 | | | |
| People, Customer, Corporate Affairs | 1.3 | 0.0 | 0.0 | | | |
| Other | 0.0 | 0.0 | 0.0 | | | |
| Total | 34.6 | 21.7 | 0.0 | 0.0 | 0.0 | 0.0 |

2.224.2 Please confirm, or explain otherwise, that the F2020 and F2021 estimated costs and savings are equivalent because there are no expected contractor conversions to internal FTEs planned for F2021.

**RESPONSE:**

**Confirmed.**

**224.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-5, BCUC IR 46.2, 48.2, 48.3; Exhibit B-6, BCOAPO IR 29.1**
**Workforce Optimization Program – annual net savings**

In response to BCUC IR 46.2, BC Hydro provided Attachment 1 which breaks down the estimated costs and savings by business group for the Workforce Optimization Program workforce adjustment requests.

In response to BCUC IR 48.3, BC Hydro provided a breakdown of Workforce Optimization program FTEs from inception to F2019 by function (operating, capital or deferred).

**Number of Workforce Optimization FTEs by Fiscal Year (F17-19) and Function**

| | F2017 | | | F2018 | | | F2019 | | |
|---|---|---|---|---|---|---|---|---|---|
| **Business Group** | **OMA** | **Capital** | **Deferred** | **OMA** | **Capital** | **Deferred** | **OMA** | **Capital** | **Deferred** |
| Integrated Planning | 2.6 | 13.4 | 0.0 | 16.1 | 23.9 | 0.0 | 7.4 | 24.6 | 0.0 |
| Capital Infrastructure Project Delivery | 7.0 | 47.0 | 0.0 | 12.8 | 58.8 | 1.0 | 10.0 | 67.7 | 1.0 |
| Operations | 4.3 | 17.7 | 0.0 | 17.2 | 31.9 | 0.9 | 46.8 | 28.2 | 0.0 |
| Finance Technology and Supply Chain | 1.5 | 3.0 | 0.0 | 61.0 | 17.0 | 0.0 | 40.7 | 0.4 | 0.0 |
| Safety | 8.8 | 1.2 | 0.0 | 3.1 | 2.9 | 0.0 | 6.8 | 2.2 | 0.0 |
| People, Customer, Corporate Affairs | 2.0 | 0.0 | 0.0 | 9.5 | 0.0 | 9.5 | 23.3 | 0.9 | 2.9 |
| Other | 1.3 | 0.7 | 0.0 | 2.8 | 1.2 | 0.0 | 1.0 | 0.0 | 0.0 |
| **Total** | 27.5 | 83.0 | 0.0 | 122.4 | 135.8 | 11.4 | 136.1 | 123.9 | 3.9 |

In response to BCUC IR 48.2, BC Hydro provided a breakdown of the planned Workforce Optimization program FTEs to be added through contract conversion in F2020 and F2021 by function (operating, capital or deferred).

**Number of Workforce Optimization FTEs by Fiscal Year (F20 & F21) and Function**

| | F2020 | | | F2021 | | |
|---|---|---|---|---|---|---|
| **Business Group** | **OMA** | **Capital** | **Deferred** | **OMA** | **Capital** | **Deferred** |
| Integrated Planning | 1.6 | 0.4 | 0.0 | | | |
| Capital Infrastructure Project Delivery | 0.7 | 9.3 | 0.0 | | | |
| Operations | 17.2 | 7.8 | 0.0 | | | |
| Finance Technology and Supply Chain | 13.7 | 4.3 | 0.0 | | | |
| Safety | 0.0 | 0.0 | 0.0 | | | |
| People, Customer, Corporate Affairs | 1.3 | 0.0 | 0.0 | | | |
| Other | 0.0 | 0.0 | 0.0 | | | |
| **Total** | 34.6 | 21.7 | 0.0 | 0.0 | 0.0 | 0.0 |

2.224.3 Please clarify why the total estimated annual net savings has been declining from F2017 ($16.5 million) to F2019 ($15.2 million) when contractors were converted to internal capital and operating FTEs during this period.

**RESPONSE:**

**Attachment 1 to BC Hydro's response to BCUC IR 1.46.2 contained errors where savings to be achieved by fiscal 2019 were inadvertently identified in fiscal 2017 for some workforce adjustment cases.**

**Attachment 1 to this response provides a revised table with the errors corrected, providing the estimated costs and savings by Business Group for the Workforce Optimization Program workforce adjustment requests.**

**As shown in the corrected attachment, estimated annual net savings increase from $4.9 million in fiscal 2017 to $15.2 million in fiscal 2019.**

**Workforce Optimization Program Annual Net Savings**

| ($ millions) | Costs | | | | | Savings | | | | | Net Savings | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | F2017 | F2018 | F2019 | F2020 | F2021 | F2017 | F2018 | F2019 | F2020 | F2021 | F2017 | F2018 | F2019 | F2020 | F2021 |
| Business Group | Estimated | Estimated | Estimated | Estimated | Estimated | Estimated | Estimated | Estimated | Estimated | Estimated | Estimated | Estimated | Estimated | Estimated | Estimated |
| Integrated Planning | | | | | | | | | | | | | | | |
| Capital | 1.8 | 4.0 | 6.2 | 6.4 | 6.4 | (2.2) | (6.4) | (9.0) | (9.2) | (9.2) | (0.4) | (2.3) | (2.8) | (2.8) | (2.8) |
| Operating | 0.4 | 2.2 | 3.0 | 3.3 | 3.3 | (0.4) | (2.3) | (3.1) | (3.6) | (3.6) | 0.0 | (0.1) | (0.1) | (0.2) | (0.2) |
| Total Integrated Planning | 2.1 | 6.2 | 9.1 | 9.7 | 9.7 | (2.5) | (8.7) | (12.1) | (12.7) | (12.7) | (0.4) | (2.4) | (2.9) | (3.0) | (3.0) |
| Capital Infrastructure Project Delivery | | | | | | | | | | | | | | | |
| Capital | 9.7 | 17.3 | 25.0 | 26.2 | 26.2 | (12.4) | (21.9) | (30.5) | (31.8) | (31.8) | (2.7) | (4.5) | (5.5) | (5.6) | (5.6) |
| Operating | 2.1 | 3.3 | 4.5 | 5.1 | 5.1 | (0.6) | (1.3) | (1.9) | (2.5) | (2.5) | 1.5 | 2.1 | 2.6 | 2.6 | 2.6 |
| Total Capital Infrastructure Project Delivery | 11.8 | 20.7 | 29.5 | 31.2 | 31.2 | (13.0) | (23.2) | (32.4) | (34.3) | (34.3) | (1.2) | (2.5) | (2.9) | (3.0) | (3.0) |
| Operations | | | | | | | | | | | | | | | |
| Capital | 2.2 | 5.9 | 9.2 | 9.8 | 9.8 | (3.6) | (10.2) | (15.1) | (16.6) | (16.6) | (1.4) | (4.3) | (5.9) | (6.8) | (6.8) |
| Operating | 0.9 | 2.6 | 4.3 | 7.1 | 7.1 | (0.8) | (2.5) | (3.2) | (8.1) | (8.1) | 0.0 | 0.2 | 1.0 | (1.0) | (1.0) |
| Total Operations | 3.1 | 8.5 | 13.4 | 16.9 | 16.9 | (4.4) | (12.6) | (18.3) | (24.7) | (24.7) | (1.4) | (4.2) | (4.9) | (7.9) | (7.9) |
| Safety | | | | | | | | | | | | | | | |
| Capital | 0.2 | 0.6 | 1.2 | 1.2 | 1.2 | (0.3) | (1.0) | (2.0) | (2.0) | (2.0) | (0.1) | (0.4) | (0.8) | (0.8) | (0.8) |
| Operating | 1.4 | 1.8 | 2.8 | 2.8 | 2.8 | (2.1) | (2.5) | (3.3) | (3.4) | (3.4) | (0.7) | (0.7) | (0.5) | (0.5) | (0.5) |
| Total Safety | 1.6 | 2.4 | 3.9 | 4.0 | 4.0 | (2.4) | (3.5) | (5.3) | (5.3) | (5.3) | (0.9) | (1.1) | (1.3) | (1.3) | (1.3) |
| Finance, Technology, Supply Chain | | | | | | | | | | | | | | | |
| Capital | 1.1 | 4.2 | 5.6 | 6.4 | 6.4 | (1.4) | (5.2) | (6.8) | (7.6) | (7.6) | (0.2) | (1.0) | (1.1) | (1.3) | (1.3) |
| Operating | 1.2 | 9.9 | 16.7 | 18.0 | 18.0 | (1.2) | (10.9) | (17.7) | (19.0) | (19.0) | (0.1) | (1.0) | (1.0) | (1.0) | (1.0) |
| Total Finance, Technology, Supply Chain | 2.3 | 14.1 | 22.4 | 24.4 | 24.4 | (2.6) | (16.1) | (24.5) | (26.6) | (26.6) | (0.3) | (2.0) | (2.1) | (2.2) | (2.2) |
| People, Customer, Corporate Affairs | | | | | | | | | | | | | | | |
| Capital | 0.0 | 0.7 | 1.2 | 1.2 | 1.2 | 0.0 | (1.4) | (2.0) | (2.0) | (2.0) | 0.0 | (0.7) | (0.8) | (0.8) | (0.8) |
| Operating | 0.3 | 1.9 | 4.6 | 4.9 | 4.9 | (0.3) | (2.0) | (4.1) | (4.4) | (4.4) | (0.0) | (0.1) | 0.5 | 0.5 | 0.5 |
| Total People, Customer, Corporate Affairs | 0.3 | 2.6 | 5.8 | 6.1 | 6.1 | (0.3) | (3.4) | (6.0) | (6.4) | (6.4) | (0.0) | (0.8) | (0.3) | (0.3) | (0.3) |
| Other | | | | | | | | | | | | | | | |
| Capital | 0.1 | 0.3 | 0.3 | 0.3 | 0.3 | (0.9) | (1.1) | (1.1) | (1.1) | (1.1) | (0.7) | (0.7) | (0.7) | (0.7) | (0.7) |
| Operating | 0.2 | 0.6 | 0.8 | 0.8 | 0.8 | (0.2) | (0.6) | (0.8) | (0.8) | (0.8) | (0.0) | (0.0) | (0.0) | (0.0) | (0.0) |
| Total Other | 0.4 | 0.9 | 1.2 | 1.2 | 1.2 | (1.1) | (1.7) | (1.9) | (1.9) | (1.9) | (0.8) | (0.8) | (0.8) | (0.8) | (0.8) |
| **Total** | **21.5** | **55.4** | **85.4** | **93.5** | **93.5** | **(26.4)** | **(69.1)** | **(100.6)** | **(112.0)** | **(112.0)** | **(4.9)** | **(13.7)** | **(15.2)** | **(18.5)** | **(18.5)** |

**224.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-5, BCUC IR 46.2, 48.2, 48.3; Exhibit B-6, BCOAPO IR 29.1**
**Workforce Optimization Program – annual net savings**

In response to BCUC IR 46.2, BC Hydro provided Attachment 1 which breaks down the estimated costs and savings by business group for the Workforce Optimization Program workforce adjustment requests.

In response to BCUC IR 48.3, BC Hydro provided a breakdown of Workforce Optimization program FTEs from inception to F2019 by function (operating, capital or deferred).

**Number of Workforce Optimization FTEs by Fiscal Year (F17-19) and Function**

| | F2017 | | | F2018 | | | F2019 | | |
|---|---|---|---|---|---|---|---|---|---|
| Business Group | OMA | Capital | Deferred | OMA | Capital | Deferred | OMA | Capital | Deferred |
| Integrated Planning | 2.6 | 13.4 | 0.0 | 16.1 | 23.9 | 0.0 | 7.4 | 24.6 | 0.0 |
| Capital Infrastructure Project Delivery | 7.0 | 47.0 | 0.0 | 12.8 | 58.8 | 1.0 | 10.0 | 67.7 | 1.0 |
| Operations | 4.3 | 17.7 | 0.0 | 17.2 | 31.9 | 0.9 | 46.8 | 28.2 | 0.0 |
| Finance Technology and Supply Chain | 1.5 | 3.0 | 0.0 | 61.0 | 17.0 | 0.0 | 40.7 | 0.4 | 0.0 |
| Safety | 8.8 | 1.2 | 0.0 | 3.1 | 2.9 | 0.0 | 6.8 | 2.2 | 0.0 |
| People, Customer, Corporate Affairs | 2.0 | 0.0 | 0.0 | 9.5 | 0.0 | 9.5 | 23.3 | 0.9 | 2.9 |
| Other | 1.3 | 0.7 | 0.0 | 2.8 | 1.2 | 0.0 | 1.0 | 0.0 | 0.0 |
| Total | 27.5 | 83.0 | 0.0 | 122.4 | 135.8 | 11.4 | 136.1 | 123.9 | 3.9 |

In response to BCUC IR 48.2, BC Hydro provided a breakdown of the planned Workforce Optimization program FTEs to be added through contract conversion in F2020 and F2021 by function (operating, capital or deferred).

**Number of Workforce Optimization FTEs by Fiscal Year (F20 & F21) and Function**

| | F2020 | | | F2021 | | |
|---|---|---|---|---|---|---|
| Business Group | OMA | Capital | Deferred | OMA | Capital | Deferred |
| Integrated Planning | 1.6 | 0.4 | 0.0 | | | |
| Capital Infrastructure Project Delivery | 0.7 | 9.3 | 0.0 | | | |
| Operations | 17.2 | 7.8 | 0.0 | | | |
| Finance Technology and Supply Chain | 13.7 | 4.3 | 0.0 | | | |
| Safety | 0.0 | 0.0 | 0.0 | | | |
| People, Customer, Corporate Affairs | 1.3 | 0.0 | 0.0 | | | |
| Other | 0.0 | 0.0 | 0.0 | | | |
| Total | 34.6 | 21.7 | 0.0 | 0.0 | 0.0 | 0.0 |

2.224.4 Please explain why the operating net savings are positive for the following business groups: i) Capital Infrastructure Project Delivery (F2017 to F2021); ii) Operations (F2018 and F2019); and iii) People, Customer, Corporate Affairs (F2019 to F2021). Please include discussion on the number of contractors converted to internal capital and operating FTEs for each Business Group during this period.

**RESPONSE:**

**In the revised table provided in BC Hydro's response to BCUC IR 2.224.3, the operating cost net savings are positive (i.e., result in increased operating costs) for these Business Groups as the contractors converted to internal employees are primarily for capital work. Employee costs such as professional development and safety training cannot be capitalized and therefore result in an operating cost increase. These operating cost increases are more than offset with capital cost savings.**

**224.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-5, BCUC IR 46.2, 48.2, 48.3; Exhibit B-6, BCOAPO IR 29.1**
**Workforce Optimization Program – annual net savings**

In response to BCUC IR 46.2, BC Hydro provided Attachment 1 which breaks down the estimated costs and savings by business group for the Workforce Optimization Program workforce adjustment requests.

In response to BCUC IR 48.3, BC Hydro provided a breakdown of Workforce Optimization program FTEs from inception to F2019 by function (operating, capital or deferred).

**Number of Workforce Optimization FTEs by Fiscal Year (F17-19) and Function**

| | F2017 | | | F2018 | | | F2019 | | |
|---|---|---|---|---|---|---|---|---|---|
| **Business Group** | **OMA** | **Capital** | **Deferred** | **OMA** | **Capital** | **Deferred** | **OMA** | **Capital** | **Deferred** |
| Integrated Planning | 2.6 | 13.4 | 0.0 | 16.1 | 23.9 | 0.0 | 7.4 | 24.6 | 0.0 |
| Capital Infrastructure Project Delivery | 7.0 | 47.0 | 0.0 | 12.8 | 58.8 | 1.0 | 10.0 | 67.7 | 1.0 |
| Operations | 4.3 | 17.7 | 0.0 | 17.2 | 31.9 | 0.9 | 46.8 | 28.2 | 0.0 |
| Finance Technology and Supply Chain | 1.5 | 3.0 | 0.0 | 61.0 | 17.0 | 0.0 | 40.7 | 0.4 | 0.0 |
| Safety | 8.8 | 1.2 | 0.0 | 3.1 | 2.9 | 0.0 | 6.8 | 2.2 | 0.0 |
| People, Customer, Corporate Affairs | 2.0 | 0.0 | 0.0 | 9.5 | 0.0 | 9.5 | 23.3 | 0.9 | 2.9 |
| Other | 1.3 | 0.7 | 0.0 | 2.8 | 1.2 | 0.0 | 1.0 | 0.0 | 0.0 |
| **Total** | **27.5** | **83.0** | **0.0** | **122.4** | **135.8** | **11.4** | **136.1** | **123.9** | **3.9** |

In response to BCUC IR 48.2, BC Hydro provided a breakdown of the planned Workforce Optimization program FTEs to be added through contract conversion in F2020 and F2021 by function (operating, capital or deferred).

**Number of Workforce Optimization FTEs by Fiscal Year (F20 & F21) and Function**

| | F2020 | | | F2021 | | |
|---|---|---|---|---|---|---|
| **Business Group** | **OMA** | **Capital** | **Deferred** | **OMA** | **Capital** | **Deferred** |
| Integrated Planning | 1.6 | 0.4 | 0.0 | | | |
| Capital Infrastructure Project Delivery | 0.7 | 9.3 | 0.0 | | | |
| Operations | 17.2 | 7.8 | 0.0 | | | |
| Finance Technology and Supply Chain | 13.7 | 4.3 | 0.0 | | | |
| Safety | 0.0 | 0.0 | 0.0 | | | |
| People, Customer, Corporate Affairs | 1.3 | 0.0 | 0.0 | | | |
| Other | 0.0 | 0.0 | 0.0 | | | |
| **Total** | **34.6** | **21.7** | **0.0** | **0.0** | **0.0** | **0.0** |

2.224.5 Please explain why the total net savings is reduced over time for the following business groups: i) Capital Infrastructure Project Delivery; ii) Safety; iii) Finance, Technology, Supply Chain; and iv) People, Customer, Corporate Affairs. Please include discussion on the number of contractors converted to internal capital and operating FTEs for each Business Group during this period.

**RESPONSE:**

**Please refer to BC Hydro's response to BCUC IR 2.224.3 which provides an updated attachment that corrects the attachment provided in BC Hydro's original response to BCUC IR 1.46.2.**

**As shown in the revised attachment, the estimated total net savings for these Business Groups increased from $2.4 million in fiscal 2017 to $6.8 million in fiscal 2021.**

**224.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-5, BCUC IR 46.2, 48.2, 48.3; Exhibit B-6, BCOAPO IR 29.1**
**Workforce Optimization Program – annual net savings**

In response to BCUC IR 46.2, BC Hydro provided Attachment 1 which breaks down the estimated costs and savings by business group for the Workforce Optimization Program workforce adjustment requests.

In response to BCUC IR 48.3, BC Hydro provided a breakdown of Workforce Optimization program FTEs from inception to F2019 by function (operating, capital or deferred).

**Number of Workforce Optimization FTEs by Fiscal Year (F17-19) and Function**

| | F2017 | | | F2018 | | | F2019 | | |
|---|---|---|---|---|---|---|---|---|---|
| Business Group | OMA | Capital | Deferred | OMA | Capital | Deferred | OMA | Capital | Deferred |
| Integrated Planning | 2.6 | 13.4 | 0.0 | 16.1 | 23.9 | 0.0 | 7.4 | 24.6 | 0.0 |
| Capital Infrastructure Project Delivery | 7.0 | 47.0 | 0.0 | 12.8 | 58.8 | 1.0 | 10.0 | 67.7 | 1.0 |
| Operations | 4.3 | 17.7 | 0.0 | 17.2 | 31.9 | 0.9 | 46.8 | 28.2 | 0.0 |
| Finance Technology and Supply Chain | 1.5 | 3.0 | 0.0 | 61.0 | 17.0 | 0.0 | 40.7 | 0.4 | 0.0 |
| Safety | 8.8 | 1.2 | 0.0 | 3.1 | 2.9 | 0.0 | 6.8 | 2.2 | 0.0 |
| People, Customer, Corporate Affairs | 2.0 | 0.0 | 0.0 | 9.5 | 0.0 | 9.5 | 23.3 | 0.9 | 2.9 |
| Other | 1.3 | 0.7 | 0.0 | 2.8 | 1.2 | 0.0 | 1.0 | 0.0 | 0.0 |
| Total | 27.5 | 83.0 | 0.0 | 122.4 | 135.8 | 11.4 | 136.1 | 123.9 | 3.9 |

In response to BCUC IR 48.2, BC Hydro provided a breakdown of the planned Workforce Optimization program FTEs to be added through contract conversion in F2020 and F2021 by function (operating, capital or deferred).

**Number of Workforce Optimization FTEs by Fiscal Year (F20 & F21) and Function**

| | F2020 | | | F2021 | | |
|---|---|---|---|---|---|---|
| Business Group | OMA | Capital | Deferred | OMA | Capital | Deferred |
| Integrated Planning | 1.6 | 0.4 | 0.0 | | | |
| Capital Infrastructure Project Delivery | 0.7 | 9.3 | 0.0 | | | |
| Operations | 17.2 | 7.8 | 0.0 | | | |
| Finance Technology and Supply Chain | 13.7 | 4.3 | 0.0 | | | |
| Safety | 0.0 | 0.0 | 0.0 | | | |
| People, Customer, Corporate Affairs | 1.3 | 0.0 | 0.0 | | | |
| Other | 0.0 | 0.0 | 0.0 | | | |
| Total | 34.6 | 21.7 | 0.0 | 0.0 | 0.0 | 0.0 |

2.224.6 Please comment on why some contractor conversions to internal FTEs were done at a net cost to BC Hydro (i.e. Capital Infrastructure Project Delivery, Operations and People Customer Corporate Affairs Business Groups).

**RESPONSE:**

**Please refer to BC Hydro's response to BCUC IR 2.224.3 where we provide a corrected version of the original attachment provided in BC Hydro's response to BCUC IR 1.46.2.**

**As shown in the revised attachment, no Business Groups had a net cost increase as a result of the Workforce Optimization Program. In fiscal 2021, estimated total net savings are $18.5 million.**

**224.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-5, BCUC IR 46.2, 48.2, 48.3; Exhibit B-6, BCOAPO IR 29.1**
**Workforce Optimization Program – annual net savings**

In response to BCUC IR 46.2, BC Hydro provided Attachment 1 which breaks down the estimated costs and savings by business group for the Workforce Optimization Program workforce adjustment requests.

In response to BCUC IR 48.3, BC Hydro provided a breakdown of Workforce Optimization program FTEs from inception to F2019 by function (operating, capital or deferred).

**Number of Workforce Optimization FTEs by Fiscal Year (F17-19) and Function**

| | F2017 | | | F2018 | | | F2019 | | |
|---|---|---|---|---|---|---|---|---|---|
| Business Group | OMA | Capital | Deferred | OMA | Capital | Deferred | OMA | Capital | Deferred |
| Integrated Planning | 2.6 | 13.4 | 0.0 | 16.1 | 23.9 | 0.0 | 7.4 | 24.6 | 0.0 |
| Capital Infrastructure Project Delivery | 7.0 | 47.0 | 0.0 | 12.8 | 58.8 | 1.0 | 10.0 | 67.7 | 1.0 |
| Operations | 4.3 | 17.7 | 0.0 | 17.2 | 31.9 | 0.9 | 46.8 | 28.2 | 0.0 |
| Finance Technology and Supply Chain | 1.5 | 3.0 | 0.0 | 61.0 | 17.0 | 0.0 | 40.7 | 0.4 | 0.0 |
| Safety | 8.8 | 1.2 | 0.0 | 3.1 | 2.9 | 0.0 | 6.8 | 2.2 | 0.0 |
| People, Customer, Corporate Affairs | 2.0 | 0.0 | 0.0 | 9.5 | 0.0 | 9.5 | 23.3 | 0.9 | 2.9 |
| Other | 1.3 | 0.7 | 0.0 | 2.8 | 1.2 | 0.0 | 1.0 | 0.0 | 0.0 |
| Total | 27.5 | 83.0 | 0.0 | 122.4 | 135.8 | 11.4 | 136.1 | 123.9 | 3.9 |

In response to BCUC IR 48.2, BC Hydro provided a breakdown of the planned Workforce Optimization program FTEs to be added through contract conversion in F2020 and F2021 by function (operating, capital or deferred).

**Number of Workforce Optimization FTEs by Fiscal Year (F20 & F21) and Function**

| | F2020 | | | F2021 | | |
|---|---|---|---|---|---|---|
| Business Group | OMA | Capital | Deferred | OMA | Capital | Deferred |
| Integrated Planning | 1.6 | 0.4 | 0.0 | | | |
| Capital Infrastructure Project Delivery | 0.7 | 9.3 | 0.0 | | | |
| Operations | 17.2 | 7.8 | 0.0 | | | |
| Finance Technology and Supply Chain | 13.7 | 4.3 | 0.0 | | | |
| Safety | 0.0 | 0.0 | 0.0 | | | |
| People, Customer, Corporate Affairs | 1.3 | 0.0 | 0.0 | | | |
| Other | 0.0 | 0.0 | 0.0 | | | |
| Total | 34.6 | 21.7 | 0.0 | 0.0 | 0.0 | 0.0 |

2.224.7 Please explain why no contractor conversions are planned for F2021.

**RESPONSE:**

**There are no planned contractor conversions in fiscal 2021 as we forecast to have all planned conversions implemented by the end of fiscal 2020. As shown in BC Hydro's response to BCUC IR 1.48.2, the number of conversions in fiscal 2020 was lower than in previous years, demonstrating that BC Hydro has been successful at implementing the opportunities identified to convert contractors to FTEs to reduce costs and/or improve outcomes.**

**Accordingly, the Workforce Optimization Program has now been closed. The program began in September 2016 and was not intended to continue indefinitely.**

**While the Workforce Optimization Program has been closed, BC Hydro will continue to manage its labour resources in an optimal manner to execute our work plans. This will include consideration of where best to focus resources across the company based on corporate priorities and workloads, as well as opportunities which would provide financial benefits.**

**224.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-5, BCUC IR 46.2, 48.2, 48.3; Exhibit B-6, BCOAPO IR 29.1**
**Workforce Optimization Program – annual net savings**

In response to BCUC IR 46.2, BC Hydro provided Attachment 1 which breaks down the estimated costs and savings by business group for the Workforce Optimization Program workforce adjustment requests.

In response to BCUC IR 48.3, BC Hydro provided a breakdown of Workforce Optimization program FTEs from inception to F2019 by function (operating, capital or deferred).

**Number of Workforce Optimization FTEs by Fiscal Year (F17-19) and Function**

| | F2017 | | | F2018 | | | F2019 | | |
|---|---|---|---|---|---|---|---|---|---|
| Business Group | OMA | Capital | Deferred | OMA | Capital | Deferred | OMA | Capital | Deferred |
| Integrated Planning | 2.6 | 13.4 | 0.0 | 16.1 | 23.9 | 0.0 | 7.4 | 24.6 | 0.0 |
| Capital Infrastructure Project Delivery | 7.0 | 47.0 | 0.0 | 12.8 | 58.8 | 1.0 | 10.0 | 67.7 | 1.0 |
| Operations | 4.3 | 17.7 | 0.0 | 17.2 | 31.9 | 0.9 | 46.8 | 28.2 | 0.0 |
| Finance Technology and Supply Chain | 1.5 | 3.0 | 0.0 | 61.0 | 17.0 | 0.0 | 40.7 | 0.4 | 0.0 |
| Safety | 8.8 | 1.2 | 0.0 | 3.1 | 2.9 | 0.0 | 6.8 | 2.2 | 0.0 |
| People, Customer, Corporate Affairs | 2.0 | 0.0 | 0.0 | 9.5 | 0.0 | 9.5 | 23.3 | 0.9 | 2.9 |
| Other | 1.3 | 0.7 | 0.0 | 2.8 | 1.2 | 0.0 | 1.0 | 0.0 | 0.0 |
| Total | 27.5 | 83.0 | 0.0 | 122.4 | 135.8 | 11.4 | 136.1 | 123.9 | 3.9 |

In response to BCUC IR 48.2, BC Hydro provided a breakdown of the planned Workforce Optimization program FTEs to be added through contract conversion in F2020 and F2021 by function (operating, capital or deferred).

**Number of Workforce Optimization FTEs by Fiscal Year (F20 & F21) and Function**

| | F2020 | | | F2021 | | |
|---|---|---|---|---|---|---|
| Business Group | OMA | Capital | Deferred | OMA | Capital | Deferred |
| Integrated Planning | 1.6 | 0.4 | 0.0 | | | |
| Capital Infrastructure Project Delivery | 0.7 | 9.3 | 0.0 | | | |
| Operations | 17.2 | 7.8 | 0.0 | | | |
| Finance Technology and Supply Chain | 13.7 | 4.3 | 0.0 | | | |
| Safety | 0.0 | 0.0 | 0.0 | | | |
| People, Customer, Corporate Affairs | 1.3 | 0.0 | 0.0 | | | |
| Other | 0.0 | 0.0 | 0.0 | | | |
| Total | 34.6 | 21.7 | 0.0 | 0.0 | 0.0 | 0.0 |

2.224.8 Please reconcile the Workforce Optimization program results from F2019 ($0.6 million reduction in net savings from prior year and 263.9 [136.1 + 123.9 + 3.9] FTEs converted) with the expected results in F2020 ($3.3 million increase [from $15.2 million to

$18.5 million] in net savings from prior year and 56.3 [34.6 + 21.47] FTEs converted).

**RESPONSE:**

**Please refer to BC Hydro's response to BCUC IR 2.224.3 where we provide a revised attachment that corrects errors in the attachment provided in BC Hydro's response to BCUC IR 1.46.2.**

**224.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-5, BCUC IR 46.2, 48.2, 48.3; Exhibit B-6, BCOAPO IR 29.1**
**Workforce Optimization Program – annual net savings**

Further in response to BCOAPO IR 29.1, BC Hydro provided the number of incremental FTEs approved through the Workforce Optimization program since F2016, broken down by fiscal year and Business Group.

| Business Group | F2017 | F2018 | F2019 | F2020 | F2021 | Total |
|---|---|---|---|---|---|---|
| Integrated Planning | 16 | 40 | 32 | 2 | - | 90 |
| Capital Infrastructure Project Delivery | 54 | 73 | 79 | 13 | - | 218 |
| Operations | 22 | 50 | 75 | 25 | - | 172 |
| Finance Technology and Supply Chain | 5 | 78 | 41 | 21 | - | 145 |
| Safety, Security, Emergency Management | 10 | 6 | 9 | 1 | - | 26 |
| People, Customer, Corporate Affairs | 2 | 19 | 27 | 0 | - | 48 |
| Other (Office of the General Counsel KBU) | 2 | 4 | 1 | - | - | 7 |
| Total | 111 | 270 | 264 | 62 | - | 706 |

2.224.9 Please explain why the F2020 total in the above table does not agree with the total planned contract conversions to internal FTEs in F2020 as shown in response to BCUC IR 48.2. Please provide an updated table, if applicable.

**RESPONSE:**

**The tables do not agree as the information requests differed.**

**BCOAPO IR 1.29.1 requested all FTE added through the Workforce Optimization Program regardless of funding source. In fiscal 2020 this included six FTE that were funded by repurposing vacancies or reducing other expenditures.**

**BCUC IR 1.48.2 requested FTEs “added through contract conversions” which does not include the six FTEs funded by repurposing vacancies or reducing other expenditures in fiscal 2020.**

**Please refer to BC Hydro’s response to BCUC IR 1.47.5 for a breakdown of FTEs by funding source and fiscal year.**

**225.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-1, Section 5.6, p. 5-28; Section 5.6.1.3, Footnote 161, p. 5-34; Exhibit B-5, BCUC IR 35.1, 46.3, 46.5, 47.1, 47.3, 47.4, 47.4.1, 47.5, 48.1; Exhibit B-6, AMPC IR 3.7; BC Hydro F2017-F2019 RRA proceeding, Exhibit B-1-1, Section 5.3.1.3, p. 5-16**
**Workforce Optimization Program – contractor conversions to internal FTEs**

In response to BCUC IR 46.5, BC Hydro provided an estimate for the total contractor workforce as of the end of F2018, where it stated:

> BC Hydro does not track contractor FTE equivalency. However, BC Hydro estimates that its total contractor workforce as of the end of fiscal 2018 was approximately 4300 to 5800 FTEs, excluding contractors on the Site C Project. This number is an estimate based on contractor spend less non-labour costs (e.g., materials) and estimates of hourly rates and hours worked per year.

2.225.1 If possible, using the same methodology, please provide the estimated total annual contractor workforce at the end of F2015 to F2021 plan. Please comment on any trends.

**RESPONSE:**

**As discussed in BC Hydro's response to BCUC IR 1.48.1.1, BC Hydro does not track contractor FTE equivalency. BC Hydro does not have estimates available for other fiscal years.**

**225.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-1, Section 5.6, p. 5-28; Section 5.6.1.3, Footnote 161, p. 5-34; Exhibit B-5, BCUC IR 35.1, 46.3, 46.5, 47.1, 47.3, 47.4, 47.4.1, 47.5, 48.1; Exhibit B-6, AMPC IR 3.7; BC Hydro F2017-F2019 RRA proceeding, Exhibit B-1-1, Section 5.3.1.3, p. 5-16**
**Workforce Optimization Program – contractor conversions to internal FTEs**

In response to BCUC IR 47.1, BC Hydro stated:

> Equivalent cost reduction is the reduction to external contractor costs as well as other cost reductions, if required, to fully offset the cost of the additional FTE.
>
> […]
>
> Billings from external contractors include other costs such as their profit and professional development/training costs.

In Footnote 161 on page 5-34 of the Application, BC Hydro states:

> FTE additions through the Workforce Optimization Program Plan must be fully funded through an equivalent cost reduction. In most cases, this means a reduction in funding for external contractors; however, in some cases, FTE additions may be funded through reductions to other expenditures (e.g., materials, building and equipment, etc.), or by re-purposing other vacant positions.

Further in response to BCUC IR 47.3, BC Hydro stated that "less than 1 per cent of the total Workforce Optimization FTEs were funded through a reduction to other expenditures." As part of this response, BC Hydro also provides examples of this type of funding as part of the Workforce Optimization program.

2.225.2 Please clarify what is meant by "funded through reductions to other expenditures (i.e., materials, building and equipment, etc.)"

**RESPONSE:**

**The Workforce Optimization Program was developed to optimally manage the labour resources required to execute our work plan. Rather than manage to a specific number of employees as had been previously required by the**

**Government of B.C., resources were managed within a total cost model. The primary focus of the Program was to convert work performed by contractors to internal FTEs where it reduced costs and/or improved outcomes.**

**Ninety-five per cent of all FTEs added through the program were contractor conversions. Overall there were 706 FTEs added through the Program, resulting in annual savings of approximately $18.5 million.**

**While contractor conversions were the focus, the Program was used to manage all regular time FTE additions. This consistent governance model was used so that optimal labour resourcing decisions were made in all situations and not just for work previously done by contractors.**

**Where FTE additions were required due to new work or increasing workloads, there were no existing contractor savings that could be used to fund the additional FTEs. In these cases, the FTE additions were funded either by repurposing vacancies or reducing other expenditures.**

**Three categories were used to track funding sources for FTEs added through the Workforce Optimization Program:**

- **Reductions to External Contractors;**
- **Re-Purposing Vacancies; and**
- **Reductions to Other Expenditures.**

**There were only nine FTE funded through the reduction of other expenditures. Most of these (seven FTEs) were added in fiscal 2019 to manage the Customer Crisis Fund. These FTEs were funded through the rate rider approved by BCUC Order No. G-166-17 to recover the overall costs of this fund. While these FTEs were funded through an increase in revenue, rather than a reduction in expenditures, they were captured within this category as it provided the best fit of the three category options.**

**225.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-1, Section 5.6, p. 5-28; Section 5.6.1.3, Footnote 161, p. 5-34; Exhibit B-5, BCUC IR 35.1, 46.3, 46.5, 47.1, 47.3, 47.4, 47.4.1, 47.5, 48.1; Exhibit B-6, AMPC IR 3.7; BC Hydro F2017-F2019 RRA proceeding, Exhibit B-1-1, Section 5.3.1.3, p. 5-16**
**Workforce Optimization Program – contractor conversions to internal FTEs**

In response to BCUC IR 47.1, BC Hydro stated:

> Equivalent cost reduction is the reduction to external contractor costs as well as other cost reductions, if required, to fully offset the cost of the additional FTE.
>
> […]
>
> Billings from external contractors include other costs such as their profit and professional development/training costs.

In Footnote 161 on page 5-34 of the Application, BC Hydro states:

> FTE additions through the Workforce Optimization Program Plan must be fully funded through an equivalent cost reduction. In most cases, this means a reduction in funding for external contractors; however, in some cases, FTE additions may be funded through reductions to other expenditures (e.g., materials, building and equipment, etc.), or by re-purposing other vacant positions.

Further in response to BCUC IR 47.3, BC Hydro stated that “less than 1 per cent of the total Workforce Optimization FTEs were funded through a reduction to other expenditures.” As part of this response, BC Hydro also provides examples of this type of funding as part of the Workforce Optimization program.

2.225.2.1 Please explain whether FTE additions funded through reductions to other expenditures may include costs such as contractor profit and professional development/training costs.

**RESPONSE:**

**FTE additions funded through reduction to other expenditures did not include contractor savings or professional development/training costs.**

**Please refer to BC Hydro's response to BCUC IR 2.225.2 where we explain that seven of the nine FTEs added in this category were for the Customer Crisis Fund and are funded via a rate rider.**

**225.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-1, Section 5.6, p. 5-28; Section 5.6.1.3, Footnote 161, p. 5-34; Exhibit B-5, BCUC IR 35.1, 46.3, 46.5, 47.1, 47.3, 47.4, 47.4.1, 47.5, 48.1; Exhibit B-6, AMPC IR 3.7; BC Hydro F2017-F2019 RRA proceeding, Exhibit B-1-1, Section 5.3.1.3, p. 5-16**
**Workforce Optimization Program – contractor conversions to internal FTEs**

In response to BCUC IR 47.4, BC Hydro stated:

> Re-purposing other vacant positions to fund FTE additions through the Workforce Optimization Program refers to either:
>
> - the conversion of vacant FTE positions no longer required;
> - the conversion of funding from vacancy factor positions to fund additional FTEs.

Further in response to BCUC IR 46.3, BC Hydro stated: "[t]here were no instances where FTEs were hired in lieu of contractors when it was less cost-effective to hire FTEs on a long-term basis."

2.225.3 Please explain why re-purposing other vacant positions to fund FTE additions is not considered to be a new hire. Please discuss how this is considered to be part of the Workforce Optimization program.

**RESPONSE:**

**As discussed in BC Hydro's response to BCUC IR 2.225.2, the Workforce Optimization Program was developed to optimally manage the labour resources required to execute our work plan. While contractor conversions were the focus, all regular time FTE additions were managed as part of the Program. This consistent governance model was used so that optimal labour resourcing decisions were made in all situations, not just work previously done by contractors.**

**When positions became vacant, they were reviewed to determine the best use of the labour budget, taking into consideration factors such as the priority of work and shifting workloads across the company. In some cases, this resulted in positions being repurposed to fund a higher priority position or area where increasing workloads required additional resourcing.**

**Only 24 additional FTEs, or approximately 3 per cent of all FTEs added through the Workforce Optimization Program, were funded by repurposing vacancies. For further information on how these FTEs were funded, please refer to BC Hydro's response to BCUC IR 2.225.5.**

**225.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-1, Section 5.6, p. 5-28; Section 5.6.1.3, Footnote 161, p. 5-34; Exhibit B-5, BCUC IR 35.1, 46.3, 46.5, 47.1, 47.3, 47.4, 47.4.1, 47.5, 48.1; Exhibit B-6, AMPC IR 3.7; BC Hydro F2017-F2019 RRA proceeding, Exhibit B-1-1, Section 5.3.1.3, p. 5-16**
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> Re-purposing other vacant positions to fund FTE additions through the Workforce Optimization Program refers to either:
>
> - the conversion of vacant FTE positions no longer required;
> - the conversion of funding from vacancy factor positions to fund additional FTEs.

Further in response to BCUC IR 46.3, BC Hydro stated: “[t]here were no instances where FTEs were hired in lieu of contractors when it was less cost-effective to hire FTEs on a long-term basis.”

2.225.4 Please explain why a vacant FTE position is available for conversion if it is no longer required. Please also comment on how this conversion is considered cost-effective given that the vacant position was no longer needed and had no associated FTE costs (i.e. no salary being paid).

**RESPONSE:**

**As discussed in BC Hydro’s response to BCUC IR 2.225.3, when positions become vacant they are reviewed to determine the best use of that labour budget taking into consideration factors such as the priority of work and shifting workloads across the company.**

**While the existing position becomes vacant, it is still fully budgeted for and therefore that budget is able to be repurposed for the new FTE. This is considered cost effective as the new FTE is funded within the existing labour budget, rather than through an increase to the labour budget.**

**225.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-1, Section 5.6, p. 5-28; Section 5.6.1.3, Footnote 161, p. 5-34; Exhibit B-5, BCUC IR 35.1, 46.3, 46.5, 47.1, 47.3, 47.4, 47.4.1, 47.5, 48.1; Exhibit B-6, AMPC IR 3.7; BC Hydro F2017-F2019 RRA proceeding, Exhibit B-1-1, Section 5.3.1.3, p. 5-16**
**Workforce Optimization Program – contractor conversions to internal FTEs**

In response to BCUC IR 47.4, BC Hydro stated:

> Re-purposing other vacant positions to fund FTE additions through the Workforce Optimization Program refers to either:
>
> - the conversion of vacant FTE positions no longer required;
> - the conversion of funding from vacancy factor positions to fund additional FTEs.

Further in response to BCUC IR 46.3, BC Hydro stated: “[t]here were no instances where FTEs were hired in lieu of contractors when it was less cost-effective to hire FTEs on a long-term basis.”

2.225.5 Please explain what is meant by the “conversion of funding from vacancy factor positions.” Please discuss how this is different from filling the vacant position (i.e. new hire), or the conversion of vacant FTE positions that are no longer required.

**RESPONSE:**

**As discussed in BC Hydro’s response to BCUC IR 2.225.2, the Workforce Optimization Program was developed to optimally manage the labour resources required to execute our work plan. When new work or increasing workload required the addition of FTEs, BC Hydro assessed whether it could be funded by reducing vacancies. This was done to make the best use of available labour budgets.**

**Vacancy factor positions related to the Workforce Optimization Program refer to additional FTE(s) that were added in a group without increasing or decreasing the labour budget. The additional FTE(s) were absorbed within the existing labour budget by taking into account temporary vacancy periods for the existing FTEs within the group.**

**This differs from filling or re-purposing a vacant position, which results in no change to the overall number of FTEs.**

**225.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-1, Section 5.6, p. 5-28; Section 5.6.1.3, Footnote 161, p. 5-34; Exhibit B-5, BCUC IR 35.1, 46.3, 46.5, 47.1, 47.3, 47.4, 47.4.1, 47.5, 48.1; Exhibit B-6, AMPC IR 3.7; BC Hydro F2017-F2019 RRA proceeding, Exhibit B-1-1, Section 5.3.1.3, p. 5-16**
**Workforce Optimization Program – contractor conversions to internal FTEs**

In response to BCUC IR 47.4, BC Hydro stated:

> Re-purposing other vacant positions to fund FTE additions through the Workforce Optimization Program refers to either:
>
> - the conversion of vacant FTE positions no longer required;
> - the conversion of funding from vacancy factor positions to fund additional FTEs.

Further in response to BCUC IR 46.3, BC Hydro stated: “[t]here were no instances where FTEs were hired in lieu of contractors when it was less cost-effective to hire FTEs on a long-term basis.”

2.225.6 Please explain, how the cost-effectiveness/savings of “re-purposing other vacant positions” is measured, and how this contributes to the cost savings of the Workforce Optimization program. Please provide details of the calculation.

**RESPONSE:**

**BC Hydro follows the same principles and analysis for re-purposing vacant positions as followed for the conversion of external contractors to internal FTEs. This includes calculating the cost reduction of the vacancy compared to the labour cost of the additional FTE(s).**

**As discussed in BC Hydro’s response to BCUC IR 2.225.10, because these additional FTEs were required for new work, there were no net savings.**

**225.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-1, Section 5.6, p. 5-28; Section 5.6.1.3, Footnote 161, p. 5-34; Exhibit B-5, BCUC IR 35.1, 46.3, 46.5, 47.1, 47.3, 47.4, 47.4.1, 47.5, 48.1; Exhibit B-6, AMPC IR 3.7; BC Hydro F2017-F2019 RRA proceeding, Exhibit B-1-1, Section 5.3.1.3, p. 5-16**
**Workforce Optimization Program – contractor conversions to internal FTEs**

In response to BCUC IR 47.4, BC Hydro stated:

> Re-purposing other vacant positions to fund FTE additions through the Workforce Optimization Program refers to either:
>
> - the conversion of vacant FTE positions no longer required;
> - the conversion of funding from vacancy factor positions to fund additional FTEs.

Further in response to BCUC IR 46.3, BC Hydro stated: “[t]here were no instances where FTEs were hired in lieu of contractors when it was less cost-effective to hire FTEs on a long-term basis.”

2.225.7 Please explain how the re-purposing of vacant positions impacts the vacancy factor savings. Please quantify the impact on the vacancy factor savings for those positions that were re-purposed in this manner.

**RESPONSE:**

**The re-purposing of vacant positions to fund additions through the Workforce Optimization Program did not have an impact on the vacancy factor savings of $5.6 million operating cost savings for the test period. As described in BC Hydro’s response to BCUC IR 2.225.2, only 24 additional FTEs were funded by repurposing vacancies and as shown in Attachment 1 to BC Hydro’s response to BCUC IR 1.47.5, the majority of these occurred in fiscal 2019 and fiscal 2020.**

**Given the small number and timing of these FTE additions, they were not considered when assessing the historical operating labour expenditures to determine the $5.6 million vacancy factor savings for the test period.**

**225.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-1, Section 5.6, p. 5-28; Section 5.6.1.3, Footnote 161, p. 5-34; Exhibit B-5, BCUC IR 35.1, 46.3, 46.5, 47.1, 47.3, 47.4, 47.4.1, 47.5, 48.1; Exhibit B-6, AMPC IR 3.7; BC Hydro F2017-F2019 RRA proceeding, Exhibit B-1-1, Section 5.3.1.3, p. 5-16**
**Workforce Optimization Program – contractor conversions to internal FTEs**

In the BC Hydro F2017-F2019 RRA, BC Hydro stated:

> At the end of October 2015, approximately 170 FTEs had been approved for hire through fiscal 2019 with offsetting reductions in the use of external resources.
>
> […]
>
> The Workforce Optimization Program will result in net savings, since increased labour costs will be more than offset by a reduction in contractor costs.

2.225.8 Please explain when the Workforce Optimization program changed focus from being funded through a reduction in contractor costs to being fully funded through an equivalent cost reduction (which includes funding through reductions to other expenditures [i.e., materials, building and equipment, etc.], or by re-purposing other vacant positions).

**RESPONSE:**

**The focus of the Workforce Optimization Program has remained the same since its inception in 2016. Please refer to BC Hydro's response to BCUC IR 2.225.2 where we explain that the primary focus of the Program was to convert work performed by contractors to internal FTEs where it reduced costs and/or improved outcomes and that 95 per cent of all FTEs added through the program were contractor conversions.**

**225.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-1, Section 5.6, p. 5-28; Section 5.6.1.3, Footnote 161, p. 5-34; Exhibit B-5, BCUC IR 35.1, 46.3, 46.5, 47.1, 47.3, 47.4, 47.4.1, 47.5, 48.1; Exhibit B-6, AMPC IR 3.7; BC Hydro F2017-F2019 RRA proceeding, Exhibit B-1-1, Section 5.3.1.3, p. 5-16**
**Workforce Optimization Program – contractor conversions to internal FTEs**

On page 5-28 of the current Application, BC Hydro states:

> By replacing contractors with internal FTEs, the Workforce Optimization Program has increased the number of FTEs while decreasing BC Hydro's total costs by an estimated $18.5 million annually.

2.225.9 Please explain where the annual net savings of $18.5 million for the Test Period can be found in Appendix A. If the net savings amounts cannot be traced to Appendix A, please explain how the net savings impacts the revenue requirement.

**RESPONSE:**

**The majority of the Workforce Optimization Program savings achieved are capital cost savings. The net savings on the capital side are included in Appendix A, Schedule 13 – Capital Expenditures and Additions; however, the savings are embedded in the total and are not specifically tracked.**

**225.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-1, Section 5.6, p. 5-28; Section 5.6.1.3, Footnote 161, p. 5-34; Exhibit B-5, BCUC IR 35.1, 46.3, 46.5, 47.1, 47.3, 47.4, 47.4.1, 47.5, 48.1; Exhibit B-6, AMPC IR 3.7; BC Hydro F2017-F2019 RRA proceeding, Exhibit B-1-1, Section 5.3.1.3, p. 5-16**
**Workforce Optimization Program – contractor conversions to internal FTEs**

On page 5-28 of the current Application, BC Hydro states:

> By replacing contractors with internal FTEs, the Workforce Optimization Program has increased the number of FTEs while decreasing BC Hydro's total costs by an estimated $18.5 million annually.

2.225.10 Of the $18.5 million in total annual cost savings, please provide the net annual savings attributable to those positions: i) funded through reductions to other expenditures (i.e., materials, building and equipment, etc.); and ii) funding through re-purposing other vacant positions.

**RESPONSE:**

**There were no net costs or savings for the FTE additions funded through re-purposing vacancies or reductions to other expenditures. In these cases, FTEs were required for new work and there were no existing contractors that could be converted to fund the additional FTEs. The additional FTEs were funded by re-purposing vacancies or reducing other expenditures so that there was no incremental cost.**

**225.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-1, Section 5.6, p. 5-28; Section 5.6.1.3, Footnote 161, p. 5-34; Exhibit B-5, BCUC IR 35.1, 46.3, 46.5, 47.1, 47.3, 47.4, 47.4.1, 47.5, 48.1; Exhibit B-6, AMPC IR 3.7; BC Hydro F2017-F2019 RRA proceeding, Exhibit B-1-1, Section 5.3.1.3, p. 5-16**
**Workforce Optimization Program – contractor conversions to internal FTEs**

In response to BCUC IR 47.4.1, BC Hydro provided a list of KBUs where FTE additions through the Workforce Optimization program were funded through the re-purposing of other vacant positions.

| Business Group | Key Business Unit |
|---|---|
| Integrated Planning | Engineering |
| Capital Infrastructure Project Delivery | Environment |
| Capital Infrastructure Project Delivery | Project Delivery |
| Capital Infrastructure Project Delivery | Properties |
| Operations | Distribution Design and Customer Connections |
| Operations | Stations Field Operations |
| Safety | Learning and Development |
| Finance Technology, Supply Chain | Finance |
| Finance Technology, Supply Chain | Supply Chain |
| People, Customer, Corporate Affairs | Communications and Community Engagement |
| People, Customer, Corporate Affairs | Ethics and Merit Office |
| People, Customer, Corporate Affairs | Human Resources |

Further in response to BCUC IR 35.1, BC Hydro provided a list of all vacancies approved for recruitment as of March 31, 2019.

2.225.11 Please explain if there is a correlation between the number of vacancies (including the KBUs the vacancies exist in) and re-purposing other vacant positions to fund FTE additions through the Workforce Optimization program.

**RESPONSE:**

**There is no correlation between the number of vacancies in a KBU and the number of FTEs added through the Workforce Optimization Program in a KBU by re-purposing vacancies.**

**This is because the Workforce Optimization Program is managed at a company-wide level. Vacancies are re-purposed to fund the highest priority needs and may be transferred from one KBU to another if there is a higher priority need for that FTE resource. For example, in BC Hydro's response to BCUC IR 2.225.13, we describe the transfer of FTEs from the Human Resources KBU to the Ethics and Merit Office KBU.**

**There is a correlation related to KBU size. As described in BC Hydro's response to BCUC IR 2.229.4, the largest KBUs have the highest number of vacancies. These KBUs would also be expected to have more FTEs added through the Workforce Optimization Program compared to a relatively smaller KBU.**

**225.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-1, Section 5.6, p. 5-28; Section 5.6.1.3, Footnote 161, p. 5-34; Exhibit B-5, BCUC IR 35.1, 46.3, 46.5, 47.1, 47.3, 47.4, 47.4.1, 47.5, 48.1; Exhibit B-6, AMPC IR 3.7; BC Hydro F2017-F2019 RRA proceeding, Exhibit B-1-1, Section 5.3.1.3, p. 5-16**
**Workforce Optimization Program – contractor conversions to internal FTEs**

In response to BCUC IR 48.1, BC Hydro stated: "[t]he majority of the workforce adjustment conversions replaced work or functions performed by external contractors… 95 per cent are external contractor conversions."

2.225.12 Please confirm, or explain otherwise, that the remaining 5 percent of workforce adjustment conversions were funded through reduction to other expenditures or re-purposing other vacant positions.

**RESPONSE:**

**Confirmed.**

**225.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-1, Section 5.6, p. 5-28; Section 5.6.1.3, Footnote 161, p. 5-34; Exhibit B-5, BCUC IR 35.1, 46.3, 46.5, 47.1, 47.3, 47.4, 47.4.1, 47.5, 48.1; Exhibit B-6, AMPC IR 3.7; BC Hydro F2017-F2019 RRA proceeding, Exhibit B-1-1, Section 5.3.1.3, p. 5-16**
**Workforce Optimization Program – contractor conversions to internal FTEs**

In response to BCUC IR 48.1, BC Hydro stated: "[t]he majority of the workforce adjustment conversions replaced work or functions performed by external contractors… 95 per cent are external contractor conversions."

2.225.12 Please confirm, or explain otherwise, that the remaining 5 percent of workforce adjustment conversions were funded through reduction to other expenditures or re-purposing other vacant positions.

2.225.12.1 If not confirmed, please elaborate on how these workforce adjustment conversions were funded.

**RESPONSE:**

**Please refer to BC Hydro's response to BCUC IR 2.225.12 which confirms that the remaining 5 per cent of workforce adjustment conversions were funded through reductions to other expenditures or repurposing vacancies.**

**225.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-1, Section 5.6, p. 5-28; Section 5.6.1.3, Footnote 161, p. 5-34; Exhibit B-5, BCUC IR 35.1, 46.3, 46.5, 47.1, 47.3, 47.4, 47.4.1, 47.5, 48.1; Exhibit B-6, AMPC IR 3.7; BC Hydro F2017-F2019 RRA proceeding, Exhibit B-1-1, Section 5.3.1.3, p. 5-16**
**Workforce Optimization Program – contractor conversions to internal FTEs**

In response to BCUC IR 47.5, BC Hydro provided a table illustrating the breakdown of the FTEs added through the Workforce Optimization program by Business Group and by funding source. Presented in F2018 (Finance Technology and Supply Chain and People, Customer, Corporate Affairs Business Groups) and F2020 (People, Customer, Corporate Affairs Business Group) are positive figures where funding FTE additions was completed by re-purposing vacant positions, and all other FTE additions are negative.

2.225.13 Please explain why positive values are listed in the re-purposing vacant positions column for the Finance Technology and Supply Chain Business Group in F2018 and the People, Customer, Corporate Affairs Business Group in F2018 and F2020.

**RESPONSE:**

**The positive values listed in the Re-Purposing Vacant Positions column represent cases where:**

1. **More FTEs at a lower Standard Labour Rate were re-purposed to fund the new FTE(s) at a higher Standard Labour Rate; or**
2. **The re-purposed position(s) were at a lower Standard Labour Rate than the new FTE position(s) and the remaining difference was funded through reductions to contractor spending.**

**The table provided in BC Hydro's response to BCUC IR 1.47.5 represents the funding source of net FTEs added since the inception of the Workforce Optimization program. In the cases of re-purposed vacant positions described above, a higher number of FTE(s) were re-purposed than the funding source required for the new FTE(s), resulting in a positive value in the re-purposing vacant positions column.**

**For example, in the People, Customer, Corporate Affairs Business Group in fiscal 2020, the positive 1 reflects a case which re-purposed two FTEs from the Human Resources KBU at lower Standard Labour Rates, to fund the addition of one FTE in the Ethics and Merit Office KBU at a higher Standard Labour Rate.**

**225.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-1, Section 5.6, p. 5-28; Section 5.6.1.3, Footnote 161, p. 5-34; Exhibit B-5, BCUC IR 35.1, 46.3, 46.5, 47.1, 47.3, 47.4, 47.4.1, 47.5, 48.1; Exhibit B-6, AMPC IR 3.7; BC Hydro F2017-F2019 RRA proceeding, Exhibit B-1-1, Section 5.3.1.3, p. 5-16**
**Workforce Optimization Program – contractor conversions to internal FTEs**

In response to BCUC IR 47.5, BC Hydro provided a table illustrating the breakdown of the FTEs added through the Workforce Optimization program by Business Group and by funding source. Presented in F2018 (Finance Technology and Supply Chain and People, Customer, Corporate Affairs Business Groups) and F2020 (People, Customer, Corporate Affairs Business Group) are positive figures where funding FTE additions was completed by re-purposing vacant positions, and all other FTE additions are negative.

2.225.13 Please explain why positive values are listed in the re-purposing vacant positions column for the Finance Technology and Supply Chain Business Group in F2018 and the People, Customer, Corporate Affairs Business Group in F2018 and F2020.

2.225.13.1 Please clarify whether this indicates vacant positions were re-purposed to add contractor positions. Please also comment on the impact on the annual net savings in these instances.

**RESPONSE:**

**Positive values do not indicate that vacant positions were re-purposed to add contractor positions. Please refer to BC Hydro's response to BCUC IR 2.225.13 for further details.**

**225.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-1, Section 5.6, p. 5-28; Section 5.6.1.3, Footnote 161, p. 5-34; Exhibit B-5, BCUC IR 35.1, 46.3, 46.5, 47.1, 47.3, 47.4, 47.4.1, 47.5, 48.1; Exhibit B-6, AMPC IR 3.7; BC Hydro F2017-F2019 RRA proceeding, Exhibit B-1-1, Section 5.3.1.3, p. 5-16**
**Workforce Optimization Program – contractor conversions to internal FTEs**

In response to AMPC IR 3.7, BC Hydro stated:

> Generally, the contractor to FTE conversions from the Workforce Optimization Program have resulted in lower average operating costs per FTE than existing FTEs. As discussed further in section 5.6 of Chapter 5 of the Application, this is because many of the conversions are driven by capital investment and the majority of the labour costs associated with these FTEs are charged to capital projects.
>
> The average labour operating costs for FTEs approved through the Workforce Optimization Program are higher than the average labour operating costs for existing FTEs in the Indigenous Relations, T&D System Operations and Customer Service KBUs, for the following reasons:
>
> - Indigenous Relations KBU – The contractor to FTE conversions charge less of their time to capital projects than existing FTEs.
>
> […]
>
> - Customer Service KBU – The contractor to FTE conversions have comparatively higher operating labour costs than the FTEs in the Contact Centre, which make up a significant portion of the overall existing FTEs in the Customer Service KBU.

2.225.14 Please confirm, or otherwise explain, that the role completed by a contractor is fully replaced by an internal FTE in the Workforce Optimization program.

**RESPONSE:**

**Confirmed. Through the Workforce Optimization Program, the work previously contracted is fully replaced by internal FTEs.**

**225.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-1, Section 5.6, p. 5-28; Section 5.6.1.3, Footnote 161, p. 5-34; Exhibit B-5, BCUC IR 35.1, 46.3, 46.5, 47.1, 47.3, 47.4, 47.4.1, 47.5, 48.1; Exhibit B-6, AMPC IR 3.7; BC Hydro F2017-F2019 RRA proceeding, Exhibit B-1-1, Section 5.3.1.3, p. 5-16**
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>
> The average labour operating costs for FTEs approved through the Workforce Optimization Program are higher than the average labour operating costs for existing FTEs in the Indigenous Relations, T&D System Operations and Customer Service KBUs, for the following reasons:
>
> - Indigenous Relations KBU – The contractor to FTE conversions charge less of their time to capital projects than existing FTEs.
>
> […]
>
> - Customer Service KBU – The contractor to FTE conversions have comparatively higher operating labour costs than the FTEs in the Contact Centre, which make up a significant portion of the overall existing FTEs in the Customer Service KBU.

2.225.15 Please explain whether the contractor to FTE conversions for the Indigenous Relations KBU have reductions to their capital costs (per FTE) offsetting the increase in operating costs (per FTE). If not, why not?

**RESPONSE:**

**The contractor to FTE conversions in the Indigenous Relations KBU have result in a net capital savings of $0.2 million per year.**

**BC Hydro's response to AMPC IR 1.3.7 provided a comparison of the average labour operating cost per FTE for existing FTEs in a KBU to the average labour operating cost per FTEs approved through the Workforce Optimization Program.**

**The table below provides the same comparison for the Indigenous Relations KBU, accounting for both operating and capital costs. As shown, when capital costs are taken into account, the average labour cost per FTE approved through the Workforce Optimization Program is lower than the average labour cost per FTE for all FTEs in the Indigenous Relations KBU, based on fiscal 2019 forecast.**

**Indigenous Relations - Average Labour Cost per FTE**

| Expense Type | F2019 Forecast Total Cost $000 per FTE | Workforce Optimization Program Total Cost $000 Per FTE |
|---|---|---|
| Operating | 73.7 | 79.0 |
| Capital | 63.0 | 50.4 |
| Total | 136.7 | 129.4 |

**225.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
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**Workforce Optimization Program – contractor conversions to internal FTEs**

In response to AMPC IR 3.7, BC Hydro stated:

> Generally, the contractor to FTE conversions from the Workforce Optimization Program have resulted in lower average operating costs per FTE than existing FTEs. As discussed further in section 5.6 of Chapter 5 of the Application, this is because many of the conversions are driven by capital investment and the majority of the labour costs associated with these FTEs are charged to capital projects.
>
> The average labour operating costs for FTEs approved through the Workforce Optimization Program are higher than the average labour operating costs for existing FTEs in the Indigenous Relations, T&D System Operations and Customer Service KBUs, for the following reasons:
>
> - Indigenous Relations KBU – The contractor to FTE conversions charge less of their time to capital projects than existing FTEs.
>
> […]
>
> - Customer Service KBU – The contractor to FTE conversions have comparatively higher operating labour costs than the FTEs in the Contact Centre, which make up a significant portion of the overall existing FTEs in the Customer Service KBU.

2.225.16 Please clarify why contractor to FTE conversion in the Customer Service KBU have comparatively higher operating labour costs than the FTEs in the contract centre.

**RESPONSE:**

**The majority of the FTEs in the Contact Centre are Customer Service Account Rep 7 (also referred to as Customer Service Representatives) and are in a lower job grouping than the average job grouping of the 14 contractor to FTE conversions completed in the Customer Service KBU.**

**225.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-1, Section 5.6, p. 5-28; Section 5.6.1.3, Footnote 161, p. 5-34; Exhibit B-5, BCUC IR 35.1, 46.3, 46.5, 47.1, 47.3, 47.4, 47.4.1, 47.5, 48.1; Exhibit B-6, AMPC IR 3.7; BC Hydro F2017-F2019 RRA proceeding, Exhibit B-1-1, Section 5.3.1.3, p. 5-16**
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> Generally, the contractor to FTE conversions from the Workforce Optimization Program have resulted in lower average operating costs per FTE than existing FTEs. As discussed further in section 5.6 of Chapter 5 of the Application, this is because many of the conversions are driven by capital investment and the majority of the labour costs associated with these FTEs are charged to capital projects.
>
> The average labour operating costs for FTEs approved through the Workforce Optimization Program are higher than the average labour operating costs for existing FTEs in the Indigenous Relations, T&D System Operations and Customer Service KBUs, for the following reasons:
>
> - Indigenous Relations KBU – The contractor to FTE conversions charge less of their time to capital projects than existing FTEs.
>
> […]
>
> - Customer Service KBU – The contractor to FTE conversions have comparatively higher operating labour costs than the FTEs in the Contact Centre, which make up a significant portion of the overall existing FTEs in the Customer Service KBU.

2.225.16.1 Please explain if the increased labour costs as a result of the FTE conversion was more than offset by a reduction in contractor costs. If not, please explain why and discuss whether there were additional cost savings derived elsewhere, and whether these savings are to be incurred annually.

**RESPONSE:**

**Of the 14 FTEs added to the Customer Service KBU, seven were fully offset by reductions to contractor costs. The remaining seven were added to manage the the Customer Crisis Fund and are funded through the rate rider approved by BCUC Order No. G-166-17. Please refer to BC Hydro's response to BCUC IR 2.225.2 for additional details.**

**226.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-1 Section 5.6.2.2, Table 5-11, pp. 5-40–5-41;**
**Exhibit B-5, BCUC IR 49.3, 49.6, 49.10, 49.11, 49.11.2**
**Accenture repatriation**

In Table 5-11 in the Application, BC Hydro presents the forecast annual net savings from the Accenture Repatriations:

**Table 5-11 Summary of Accenture Repatriation Savings and FTE Impact**

| KBU/Function | Services - ABS F2019 RRA ($ million) (1) | Services - ABS Reduction ($ million) | Incremental Operating Costs ($ million) (2) | Annual Operating (Costs) Savings ($ million) (3 = 1 - 2) | FTEs |
|---|---|---|---|---|---|
| Customer Service | 27.8 | (27.8) | 21.9 | 5.9 | 281 |
| Human Resources | 5.1 | (5.1) | 3.5 | 1.6 | 32 |
| Properties | 1.8 | (1.8) | 0.4 | 1.4 | 7 |
| Supply Chain | 2.5 | (2.5) | 2.4 | 0.1 | 23 |
| Technology | 0.0 | 0.0 | 0.5 | (0.5) | 5 |
| Communications and Community Engagement | 0.0 | 0.0 | 0.7 | (0.7) | 7 |
| Finance | 0.0 | 0.0 | 0.3 | (0.3) | 2 |
| **Sub-Total** | **37.2** | **(37.2)** | **29.8** | **7.4** | **357** |
| Tempworks[164] | 4.2 | (4.2) | 4.2 | 0.0 | 0 |
| Field Service Representatives[165] | 7.9[166] | (7.9) | 7.1 | 0.8 | 66 |
| **Total** | **49.3** | **(49.3)** | **41.1** | **8.2** | **423** |

In response to BCUC IR 49.3, BC Hydro provided a table illustrating the total Services - ABS operating costs for F2016 to F2018 by KBU/function:

| KBU/Function | Services - ABS F2016 Actuals ($ million) | Services - ABS F2017 Actuals ($ million) | Services - ABS F2018 Actuals ($ million) |
|---|---|---|---|
| Customer Service | 31.4 | 27.4 | 28.0 |
| Human Resources | 4.7 | 4.9 | 5.1 |
| Properties | 1.7 | 1.7 | 1.8 |
| Supply Chain | 2.6 | 2.3 | 2.4 |
| Technology | 0.0 | 0.0 | 0.0 |
| Communications and Community Engagement | 0.0 | 0.0 | 0.0 |
| Finance | 0.0 | 0.0 | 0.0 |
| Sub-Total | 40.4 | 36.4 | 37.2 |
| Tempworks | 7.9 | 6.9 | 4.7 |
| Field Service Representatives | 18.8 | 4.7 | 0.0 |
| Total | 67.1 | 48.0 | 41.9 |

2.226.1 Please provide the F2019 actuals for Services – ABS.

**RESPONSE:**

**The table below has been expanded to include the fiscal 2019 actuals for Services – ABS. Fiscal 2019 only includes one month of services from Accenture as the repatriation of these services back to BC Hydro was effective May 1, 2018.**

| KBU/Function | Services - ABS F2016 Actuals ($ million) | Services - ABS F2017 Actuals ($ million) | Services - ABS F2018 Actuals ($ million) | Services - ABS F2019 Actuals ($ million) |
|---|---|---|---|---|
| Customer Service | 31.4 | 27.4 | 28.0 | 2.5 |
| Human Resources | 4.7 | 4.9 | 5.1 | 0.5 |
| Properties | 1.7 | 1.7 | 1.8 | 0.2 |
| Supply Chain | 2.6 | 2.3 | 2.4 | 0.2 |
| Technology | 0.0 | 0.0 | 0.0 | 0.0 |
| Communications | 0.0 | 0.0 | 0.0 | 0.0 |
| Finance | 0.0 | 0.0 | 0.0 | 0.0 |
| Sub-Total | 40.4 | 36.4 | 37.2 | 3.3 |
| Tempworks | 7.9 | 7.0 | 4.7 | 0.3 |

| KBU/Function | Services - ABS F2016 Actuals ($ million) | Services - ABS F2017 Actuals ($ million) | Services - ABS F2018 Actuals ($ million) | Services - ABS F2019 Actuals ($ million) |
|---|---|---|---|---|
| Field Service Representatives | 18.8 | 4.7 | 0.0 | 0.0 |
| **Total** | **67.2** | **48.1** | **42.0** | **3.6** |

**226.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-1 Section 5.6.2.2, Table 5-11, pp. 5-40–5-41;**
**Exhibit B-5, BCUC IR 49.3, 49.6, 49.10, 49.11, 49.11.2**
**Accenture repatriation**

In Table 5-11 in the Application, BC Hydro presents the forecast annual net savings from the Accenture Repatriations:

**Table 5-11 Summary of Accenture Repatriation Savings and FTE Impact**

| KBU/Function | Services - ABS F2019 RRA ($ million) (1) | Services - ABS Reduction ($ million) | Incremental Operating Costs ($ million) (2) | Annual Operating (Costs) Savings ($ million) (3 = 1 - 2) | FTEs |
|---|---|---|---|---|---|
| Customer Service | 27.8 | (27.8) | 21.9 | 5.9 | 281 |
| Human Resources | 5.1 | (5.1) | 3.5 | 1.6 | 32 |
| Properties | 1.8 | (1.8) | 0.4 | 1.4 | 7 |
| Supply Chain | 2.5 | (2.5) | 2.4 | 0.1 | 23 |
| Technology | 0.0 | 0.0 | 0.5 | (0.5) | 5 |
| Communications and Community Engagement | 0.0 | 0.0 | 0.7 | (0.7) | 7 |
| Finance | 0.0 | 0.0 | 0.3 | (0.3) | 2 |
| **Sub-Total** | **37.2** | **(37.2)** | **29.8** | **7.4** | **357** |
| Tempworks[164] | 4.2 | (4.2) | 4.2 | 0.0 | 0 |
| Field Service Representatives[165] | 7.9[166] | (7.9) | 7.1 | 0.8 | 66 |
| **Total** | **49.3** | **(49.3)** | **41.1** | **8.2** | **423** |

In response to BCUC IR 49.3, BC Hydro provided a table illustrating the total Services - ABS operating costs for F2016 to F2018 by KBU/function:

| KBU/Function | Services - ABS F2016 Actuals ($ million) | Services - ABS F2017 Actuals ($ million) | Services - ABS F2018 Actuals ($ million) |
|---|---|---|---|
| Customer Service | 31.4 | 27.4 | 28.0 |
| Human Resources | 4.7 | 4.9 | 5.1 |
| Properties | 1.7 | 1.7 | 1.8 |
| Supply Chain | 2.6 | 2.3 | 2.4 |
| Technology | 0.0 | 0.0 | 0.0 |
| Communications and Community Engagement | 0.0 | 0.0 | 0.0 |
| Finance | 0.0 | 0.0 | 0.0 |
| Sub-Total | 40.4 | 36.4 | 37.2 |
| Tempworks | 7.9 | 6.9 | 4.7 |
| Field Service Representatives | 18.8 | 4.7 | 0.0 |
| Total | 67.1 | 48.0 | 41.9 |

2.226.2 Please explain why Table 5-11 calculates the annual operating (costs) savings based on the 2019 RRA figure instead of the actual F2018 costs given that the F2018 actual provides the last full year of Accenture costs prior to the repatriation.

**RESPONSE:**

**Table 5-11 was prepared to show the impact on the revenue requirements as a result of the repatriation. The impact on the revenue requirements is the difference between the fiscal 2019 RRA plan (which assumed a full year of Services – ABS costs if the contract with Accenture had been extended) and the amounts included in the fiscal 2020 RRA plan.**

## 226.0 C. CHAPTER 5 – OPERATING COSTS

**Reference: OPERATING COSTS**
**Exhibit B-1 Section 5.6.2.2, Table 5-11, pp. 5-40–5-41;**
**Exhibit B-5, BCUC IR 49.3, 49.6, 49.10, 49.11, 49.11.2**
**Accenture repatriation**

In Table 5-11 in the Application, BC Hydro presents the forecast annual net savings from the Accenture Repatriations:

**Table 5-11 Summary of Accenture Repatriation Savings and FTE Impact**

| KBU/Function | Services - ABS F2019 RRA ($ million) (1) | Services - ABS Reduction ($ million) | Incremental Operating Costs ($ million) (2) | Annual Operating (Costs) Savings ($ million) (3 = 1 - 2) | FTEs |
|---|---|---|---|---|---|
| Customer Service | 27.8 | (27.8) | 21.9 | 5.9 | 281 |
| Human Resources | 5.1 | (5.1) | 3.5 | 1.6 | 32 |
| Properties | 1.8 | (1.8) | 0.4 | 1.4 | 7 |
| Supply Chain | 2.5 | (2.5) | 2.4 | 0.1 | 23 |
| Technology | 0.0 | 0.0 | 0.5 | (0.5) | 5 |
| Communications and Community Engagement | 0.0 | 0.0 | 0.7 | (0.7) | 7 |
| Finance | 0.0 | 0.0 | 0.3 | (0.3) | 2 |
| **Sub-Total** | **37.2** | **(37.2)** | **29.8** | **7.4** | **357** |
| Tempworks[164] | 4.2 | (4.2) | 4.2 | 0.0 | 0 |
| Field Service Representatives[165] | 7.9[166] | (7.9) | 7.1 | 0.8 | 66 |
| **Total** | **49.3** | **(49.3)** | **41.1** | **8.2** | **423** |

In response to BCUC IR 49.3, BC Hydro provided a table illustrating the total Services - ABS operating costs for F2016 to F2018 by KBU/function:

| KBU/Function | Services - ABS F2016 Actuals ($ million) | Services - ABS F2017 Actuals ($ million) | Services - ABS F2018 Actuals ($ million) |
|---|---|---|---|
| Customer Service | 31.4 | 27.4 | 28.0 |
| Human Resources | 4.7 | 4.9 | 5.1 |
| Properties | 1.7 | 1.7 | 1.8 |
| Supply Chain | 2.6 | 2.3 | 2.4 |
| Technology | 0.0 | 0.0 | 0.0 |
| Communications and Community Engagement | 0.0 | 0.0 | 0.0 |
| Finance | 0.0 | 0.0 | 0.0 |
| Sub-Total | 40.4 | 36.4 | 37.2 |
| Tempworks | 7.9 | 6.9 | 4.7 |
| Field Service Representatives | 18.8 | 4.7 | 0.0 |
| Total | 67.1 | 48.0 | 41.9 |

2.226.2.1 Please update Table 5-11 using the actual F2018 figures.

**RESPONSE:**

**Table 5-11 of Chapter 5 of the Application has been updated below to replace the fiscal 2019 RRA plan with fiscal 2018 actuals.**

| KBU/Function | Services - ABS F2018 Actuals ($ million) (1) | Services - ABS Reduction ($ million) | Incremental Operating Costs ($ million) (2) | Annual Operating (Costs) Savings (3 = 1 - 2) | FTEs |
|---|---|---|---|---|---|
| Customer Service | 28.0 | (28.0) | 21.9 | 6.0 | 281 |
| Human Resources | 5.1 | (5.1) | 3.5 | 1.6 | 32 |
| Properties | 1.8 | (1.8) | 0.4 | 1.3 | 7 |
| Supply Chain | 2.4 | (2.4) | 2.4 | (0.1) | 23 |
| Technology | 0.0 | 0.0 | 0.5 | (0.5) | 5 |
| Communications | 0.0 | 0.0 | 0.7 | (0.7) | 7 |
| Finance | 0.0 | 0.0 | 0.3 | (0.3) | 2 |
| Sub-Total | 37.2 | (37.2) | 29.8 | 7.4 | 357 |

| KBU/Function | Services - ABS F2018 Actuals ($ million) | Services - ABS Reduction ($ million) | Incremental Operating Costs ($ million) | Annual Operating (Costs) Savings | FTEs |
|---|---|---|---|---|---|
| Tempworks | 4.7 | (4.7) | 4.2 | 0.5 | 0 |
| Field Service Representatives* | 0.0 | 0.0 | 0.0 | 0.0 | 0 |
| Total | 41.9 | (41.9) | 34.0 | 7.9 | 357 |

***The Field Service Representatives line represents meter reading services repatriated in fiscal 2017**

**As described in BC Hydro's response to BCUC IR 2.226.2, Table 5-11 of Chapter 5 of the Application was prepared to show the impact on the revenue requirements as a result of the Accenture Repatriation. The repatriation did not occur in fiscal 2018 and therefore the incremental operating costs and resulting annual operating (cost) savings columns in the table above do not accurately reflect the savings BC Hydro has planned in respect of the Accenture Repatriation.**

**Rather, the impact on the revenue requirements is the difference between the fiscal 2019 RRA plan and the amounts included in the fiscal 2020 RRA plan shown in Table 5-11 of Chapter 5 of the Application.**

**226.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-1 Section 5.6.2.2, Table 5-11, pp. 5-40–5-41;**
**Exhibit B-5, BCUC IR 49.3, 49.6, 49.10, 49.11, 49.11.2**
**Accenture repatriation**

BC Hydro states in Footnote 164 on page 5-41 of the Application:

> Accenture previously provided Tempworks (i.e., temporary administrative and clerical support) services to BC Hydro. Rather than repatriating this function, BC Hydro decided to manage this function as part of its overall Contingent Labour Resource Augmentation Solution which will provide BC Hydro with a centralized, automated and standardized process for securing all contingent labour resource augmentation services and will provide greater visibility into the use of contingent labour across the whole organization.

Further in response to BCUC IR 49.6, BC Hydro stated:

> Contingent labour resource augmentation is defined as an individual who does work under BC Hydro supervision on a non-permanent basis. The main drivers of BC Hydro's use of contingent labour are to help deliver on projects, to provide short-term specialized skills and to meet variable work volumes.

2.226.3 Please explain why Tempworks has an incremental operating cost in Table 5-11 when no FTEs were repatriated.

**RESPONSE:**

**The $4.2 million in incremental operating costs reflected in the Tempworks line in Table 5-11 of Chapter 5 of the Application are fully offset by a reduction of $4.2 million to Services – ABS. The $4.2 million funds temporary labour resources through BC Hydro's Contingent Labour Resource Augmentation Solution.**

**BC Hydro's solution provides a similar service as the former Tempworks program provided by Accenture, but uses a different business model.**

**While Accenture relied on its own pool of temporary employees to assign to BC Hydro for contract work, BC Hydro's solution mainly relies on resource augmentation firms to provide temporary external labour. As such, BC Hydro did not need to repatriate Accenture's pool employees that were part of the Tempworks program and there is no associated FTE increase.**

**226.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-1 Section 5.6.2.2, Table 5-11, pp. 5-40–5-41;**
**Exhibit B-5, BCUC IR 49.3, 49.6, 49.10, 49.11, 49.11.2**
**Accenture repatriation**

BC Hydro states in Footnote 164 on page 5-41 of the Application:

> Accenture previously provided Tempworks (i.e., temporary administrative and clerical support) services to BC Hydro. Rather than repatriating this function, BC Hydro decided to manage this function as part of its overall Contingent Labour Resource Augmentation Solution which will provide BC Hydro with a centralized, automated and standardized process for securing all contingent labour resource augmentation services and will provide greater visibility into the use of contingent labour across the whole organization.

Further in response to BCUC IR 49.6, BC Hydro stated:

> Contingent labour resource augmentation is defined as an individual who does work under BC Hydro supervision on a non-permanent basis. The main drivers of BC Hydro's use of contingent labour are to help deliver on projects, to provide short-term specialized skills and to meet variable work volumes.

2.226.4 Please discuss if the contingent labour resource augmentation solution reduces overtime (i.e. unplanned, planned, budgeted, or targeted).

**RESPONSE:**

**BC Hydro believes the Contingent Labour Augmentation Solution will provide a faster, more timely and efficient mechanism for acquiring temporary labour resources. As a result, overtime may be lower than it otherwise would be.**

**226.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-1 Section 5.6.2.2, Table 5-11, pp. 5-40–5-41;**
**Exhibit B-5, BCUC IR 49.3, 49.6, 49.10, 49.11, 49.11.2**
**Accenture repatriation**

On page 5-40 of the Application, BC Hydro states: "[r]epatriation also eliminated the requirement to share with Accenture future operational savings achieved through efficiency initiatives and eliminated the need for day to day management of Accenture."

2.226.5 Please quantify the savings achieved through the elimination of the day-to-day management of Accenture. Please clarify if these savings are included in the annual cost savings of the Accenture repatriation in Table 5-11.

**RESPONSE:**

**BC Hydro cannot isolate the savings achieved through the elimination of the day-to-day management of Accenture.**

**The $8.2 million in savings shown in Table 5-11 of Chapter 5 of the Application was determined by taking the difference between:**

- **The cost charged by Accenture for its services; and**
- **The cost of the people, process and technology that BC Hydro believes it requires to provide similar services after repatriation.**

**Please also refer to BC Hydro's response to BCUC IR 1.49.4 which explains the process BC Hydro used to ensure that the services being repatriated were necessary.**

**226.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-1 Section 5.6.2.2, Table 5-11, pp. 5-40–5-41;**
**Exhibit B-5, BCUC IR 49.3, 49.6, 49.10, 49.11, 49.11.2**
**Accenture repatriation**

On page 5-40 of the Application, BC Hydro states: "[r]epatriation also eliminated the requirement to share with Accenture future operational savings achieved through efficiency initiatives and eliminated the need for day to day management of Accenture."

2.226.6 Please discuss the efficiency initiatives that have been undertaken, and quantify any operational savings achieved or planned to be achieved. Please clarify if these savings are included in the annual cost savings of the Accenture repatriation in Table 5-11.

**RESPONSE:**

**BC Hydro did not identify or plan for future operational savings (i.e., beyond those already identified in the Application) arising from the Accenture repatriation. As explained in BC Hydro's response to BCUC IR 1.49.9, BC Hydro's primary objective for the transfer from Accenture was to repatriate services on a "like-for-like" basis to mitigate the risks that could be caused by wide-scale process and organizational changes. In addition, as explained in BC Hydro's response to BCUC IR 1.49.4, Accenture was financially motivated to minimize the costs of delivering its services, and therefore had a strong focus on process improvement and cost reduction. Accordingly, there are no future cost savings from efficiency initiatives included in Table 5-11 of Chapter 5 of the Application.**

**With post-repatriation operations now stabilized, the Contact Centre and Billing Operations department in the Customer Service Key Business Unit has several operational reviews underway to identify areas for process improvements that could lead to cost savings. These include:**

- **Analyzing technical and process barriers to the successful completion of online move-in applications, to reduce the volume of customer account set-up calls to the contact centre;**
- **Analyzing billing control thresholds to reduce the number of bills stopped for manual review but released without adjustment. Any eventual cost savings would be in addition to the cost savings already achieved through the initiative described on page 5F-27 of the Application;**

- **Modifying approval guidelines for Installment Plans, to increase success rates for customers and, in turn, potentially reduce calls to the contact centre; and**
- **Modifying collections processes to improve operating efficiency during the winter disconnection moratorium, now that BC Hydro has committed to the winter disconnection moratorium being a standard business practice.**

**These initiatives started only recently so it is premature to estimate the potential cost savings that may be achieved or the enhancements to IT systems that may be necessary to implement them.**

**226.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-1 Section 5.6.2.2, Table 5-11, pp. 5-40–5-41;**
**Exhibit B-5, BCUC IR 49.3, 49.6, 49.10, 49.11, 49.11.2**
**Accenture repatriation**

In response to BCUC IR 49.10, BC Hydro stated that "BC Hydro also identified a number of areas where additional resources were required because Accenture performed tasks with employees not included in the staffing snapshot or because Accenture's staffing approach didn't align with how BC Hydro wanted to operate the function."

2.226.7 Please provide the number and type of additional resources required. Please breakdown the information by KBU and also by affiliation.

**RESPONSE:**

**The following table lists the additional resources identified in BC Hydro's response to BCUC IR 1.49.10:**

| Position | Number | Affiliation |
|---|---|---|
| **Contact Centre Workleader** | **4** | **MoveUP** |
| **Process and Learning Specialist** | **3** | **MoveUP** |
| **Reporting Analyst** | **1** | **MoveUP** |
| **Payments Clerk** | **1** | **MoveUP** |
| **Billing Controls Advisor** | **1** | **Management and Professional** |

**All of these resources were added to the Contact Centre and Billing Operations Department in the Customer Service KBU.**

**As explained further in BC Hydro's response to BCUC IR 2.226.8, there were no impacts to the overall savings from the Accenture repatriation from these additions.**

**226.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-1 Section 5.6.2.2, Table 5-11, pp. 5-40–5-41;**
**Exhibit B-5, BCUC IR 49.3, 49.6, 49.10, 49.11, 49.11.2**
**Accenture repatriation**

In response to BCUC IR 49.10, BC Hydro stated that "BC Hydro also identified a number of areas where additional resources were required because Accenture performed tasks with employees not included in the staffing snapshot or because Accenture's staffing approach didn't align with how BC Hydro wanted to operate the function."

2.226.8 Please explain how the added resources impact the overall savings to the Accenture repatriation.

**RESPONSE:**

**There were no impacts to the overall savings of the Accenture repatriation from the following additional resources identified in BC Hydro's response to BCUC IR 1.49.10.**

**Billing Controls Advisor**

**The need for the additional Billing Controls Advisor position noted in BC Hydro's response to BCUC IR 1.49.10 had been identified during the initial assessment of staffing needs when the business case for repatriation was being developed. As a result, this position was included in the calculation of annual cost savings.**

**Other Resource Additions**

**The staffing snapshot provided by Accenture was used as a guideline for labour requirements after repatriation. However, as discussed in BC Hydro's response to BCUC IR 1.49.8, BC Hydro had limited opportunities to assess operations prior to the transition period. Accordingly, BC Hydro expected that some staffing adjustments might be necessary once it repatriated the services, and that the adjustments could be accommodated within the overall FTEs planned within the repatriation business case.**

**BC Hydro found that the staffing snapshot identified more Customer Service Representatives than BC Hydro felt were needed to maintain target contact centre**

**performance levels and reallocated those FTEs to the nine other resources identified in BC Hydro's response to BCUC IR 1.49.10 (i.e., not including the Billing Controls Advisor). Therefore, the additions did not impact savings from the Accenture repatriation.**

**226.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-1 Section 5.6.2.2, Table 5-11, pp. 5-40–5-41;**
**Exhibit B-5, BCUC IR 49.3, 49.6, 49.10, 49.11, 49.11.2**
**Accenture repatriation**

In response to BCUC IR 49.10, BC Hydro stated that "BC Hydro also identified a number of areas where additional resources were required because Accenture performed tasks with employees not included in the staffing snapshot or because Accenture's staffing approach didn't align with how BC Hydro wanted to operate the function."

2.226.8 Please explain how the added resources impact the overall savings to the Accenture repatriation.

2.226.8.1 If there is no impact, please explain why the additional resources were not included in the calculation of the annual cost savings.

**RESPONSE:**

**Please refer to BC Hydro's response to BCUC IR 2.226.8 which explains that:**

- **One additional resource (the Billing Controls Advisor) had been included in the original resource estimate for the repatriation business case; and**
- **The remaining additional resources were a reallocation of resources from anticipated Customer Service Representatives roles and did not result in a net impact to savings from the Accenture repatriation.**

**226.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-1 Section 5.6.2.2, Table 5-11, pp. 5-40–5-41;**
**Exhibit B-5, BCUC IR 49.3, 49.6, 49.10, 49.11, 49.11.2**
**Accenture repatriation**

In response to BCUC IR 49.11, BC Hydro provided the following table breaking down the FTE additions associated with the repatriation of services from Accenture:

| KBU/Function | Management and Professional | MoveUP | Total |
|---|---|---|---|
| Customer Service | 20 | 261 | 281 |
| Human Resources | 18 | 14 | 32 |
| Properties | 0 | 7 | 7 |
| Supply Chain | 2 | 21 | 23 |
| Technology | 1 | 4 | 5 |
| Communications and Community Engagement | 1 | 6 | 7 |
| Finance | 1 | 1 | 2 |
| Sub-Total | 43 | 314 | 357 |
| Field Service Representatives | 4 | 62 | 66 |
| Total | 47 | 376 | 423 |

2.226.9 Please confirm, or explain otherwise, that the management and professional employees repatriated primarily provide managerial oversight to the MoveUP employees in the above table.

**RESPONSE:**

**Managerial oversight of the MoveUp employees is the primary role of the management and professional FTEs included in the table above, with the exception of the Human Resources and Finance KBUs.**

**Only two of the 18 management and professional FTEs in the Human Resources KBU provide managerial oversight. The others are exempt professional positions such as Recruitment Coordinators.**

**The one management and professional FTE in the Finance KBU is for an additional position required in the Finance Business Support Department. This position is required to continue providing ongoing financial services and support to the KBUs with internal staff increases resulting from the Accenture repatriation.**

**226.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-1 Section 5.6.2.2, Table 5-11, pp. 5-40–5-41;**
**Exhibit B-5, BCUC IR 49.3, 49.6, 49.10, 49.11, 49.11.2**
**Accenture repatriation**

In response to BCUC IR 49.11, BC Hydro provided the following table breaking down the FTE additions associated with the repatriation of services from Accenture:

| KBU/Function | Management and Professional | MoveUP | Total |
| --- | --- | --- | --- |
| Customer Service | 20 | 261 | 281 |
| Human Resources | 18 | 14 | 32 |
| Properties | 0 | 7 | 7 |
| Supply Chain | 2 | 21 | 23 |
| Technology | 1 | 4 | 5 |
| Communications and Community Engagement | 1 | 6 | 7 |
| Finance | 1 | 1 | 2 |
| Sub-Total | 43 | 314 | 357 |
| Field Service Representatives | 4 | 62 | 66 |
| Total | 47 | 376 | 423 |

2.226.9 Please confirm, or explain otherwise, that the management and professional employees repatriated primarily provide managerial oversight to the MoveUP employees in the above table.

2.226.9.1 If confirmed, please explain why the Human Resource and Finance KBU/Function have the same or more management and professional employees repatriated as compared to MoveUP employees repatriated.

**RESPONSE:**

**Please refer to BC Hydro's response to BCUC IR 2.226.9 which explains the management and professional FTE increases in the Human Resources and Finance KBUs.**

**226.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-1 Section 5.6.2.2, Table 5-11, pp. 5-40–5-41;**
**Exhibit B-5, BCUC IR 49.3, 49.6, 49.10, 49.11, 49.11.2**
**Accenture repatriation**

In response to BCUC IR 49.11, BC Hydro provided the following table breaking down the FTE additions associated with the repatriation of services from Accenture:

| KBU/Function | Management and Professional | MoveUP | Total |
|---|---|---|---|
| Customer Service | 20 | 261 | 281 |
| Human Resources | 18 | 14 | 32 |
| Properties | 0 | 7 | 7 |
| Supply Chain | 2 | 21 | 23 |
| Technology | 1 | 4 | 5 |
| Communications and Community Engagement | 1 | 6 | 7 |
| Finance | 1 | 1 | 2 |
| Sub-Total | 43 | 314 | 357 |
| Field Service Representatives | 4 | 62 | 66 |
| Total | 47 | 376 | 423 |

2.226.9 Please confirm, or explain otherwise, that the management and professional employees repatriated primarily provide managerial oversight to the MoveUP employees in the above table.

2.226.9.2 If not confirmed, please discuss the role of the repatriated management and professional employees in the Human Resource and Finance KBU/Function.

**RESPONSE:**

**Please refer to BC Hydro's response to BCUC IR 2.226.9 which explains the management and professional FTE increases in the Human Resources and Finance KBUs.**

**226.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-1 Section 5.6.2.2, Table 5-11, pp. 5-40–5-41;**
**Exhibit B-5, BCUC IR 49.3, 49.6, 49.10, 49.11, 49.11.2**
**Accenture repatriation**

In response to BCUC IR 49.11.2, BC Hydro stated:

> …there was a memorandum of understanding (MOU85) that was negotiated with MoveUP that provides some different terms and conditions that apply only to the repatriated MoveUP positions. These were primarily terms and conditions that were contained within the Accenture and MoveUP collective agreement and carried over to BC Hydro. For example, MOU85 contains separate wage scales, and an 'hours of work' and 'scheduling' section for the Contact Center.

2.226.10 Please provide the date of when MOU85 expires and comment on whether the terms and conditions within MOU85 can be re-negotiated following its expiration.

**RESPONSE:**

**MOU85 expires on March 31, 2024. Like any other agreement, the terms and conditions within MOU85 can be re-negotiated with MoveUP following its expiration as part of the collective bargaining process.**

**226.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-1 Section 5.6.2.2, Table 5-11, pp. 5-40–5-41;**
**Exhibit B-5, BCUC IR 49.3, 49.6, 49.10, 49.11, 49.11.2**
**Accenture repatriation**

In response to BCUC IR 49.11.2, BC Hydro stated:

> …there was a memorandum of understanding (MOU85) that was negotiated with MoveUP that provides some different terms and conditions that apply only to the repatriated MoveUP positions. These were primarily terms and conditions that were contained within the Accenture and MoveUP collective agreement and carried over to BC Hydro. For example, MOU85 contains separate wage scales, and an 'hours of work' and 'scheduling' section for the Contact Center.

2.226.10 Please provide the date of when MOU85 expires and comment on whether the terms and conditions within MOU85 can be re-negotiated following its expiration.

2.226.10.1 If MOU85 expires in the Test Period and the terms and conditions within MOU85 can be re-negotiated, please discuss if this has been accounted for in the current RRA. If not, why not? If so, please indicate where it has been accounted for.

**RESPONSE:**

**As discussed in BC Hydro's response to BCUC IR 2.226.10, MOU 85 expires on March 31, 2024 and therefore falls outside the test period.**

**227.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-5, BCUC IR 52.1; Exhibit B-6-1, BCOAPO IR 6.1, Attachment 1, p. 9; Attachment 2**
**Benchmarking – Morneau Shepell**

In response to BCUC IR 52.1, BC Hydro provided Attachment 2 listing the participants of the Willis Towers Watson salary survey used for salary information for MoveUP and management and professionals.

2.227.1 Please confirm, or explain otherwise, that only salary information from the Canadian participants, or the Canadian offices of the participants, was used to determine median salary for MoveUP and management and professional employees.

**RESPONSE:**

**Confirmed. Companies are only to report information for Canadian employees in this survey.**

**227.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-5, BCUC IR 52.1; Exhibit B-6-1, BCOAPO IR 6.1, Attachment 1, p. 9; Attachment 2**
**Benchmarking – Morneau Shepell**

In response to BCUC IR 52.1, BC Hydro provided Attachment 2 listing the participants of the Willis Towers Watson salary survey used for salary information for MoveUP and management and professionals.

2.227.1 Please confirm, or explain otherwise, that only salary information from the Canadian participants, or the Canadian offices of the participants, was used to determine median salary for MoveUP and management and professional employees.

2.227.1.1 If not confirmed, please explain how salary information from foreign participants considered inherent differences, including, but not limited to: socio-economic; currency; and cost of living factors.

**RESPONSE:**

**Please refer to BC Hydro's response to BCUC IR 2.227.1 which confirms that only Canadian data is included in the survey.**

**227.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-5, BCUC IR 52.1; Exhibit B-6-1, BCOAPO IR 6.1, Attachment 1, p. 9; Attachment 2**
**Benchmarking – Morneau Shepell**

In response to BCUC IR 52.1, BC Hydro provided Attachment 2 listing the participants of the Willis Towers Watson salary survey used for salary information for MoveUP and management and professionals.

2.227.1 Please confirm, or explain otherwise, that only salary information from the Canadian participants, or the Canadian offices of the participants, was used to determine median salary for MoveUP and management and professional employees.

2.227.1.2 If not confirmed, please discuss the weight the Willis Towers Watson salary survey had in determining the median salary in the Morneau Shepell benchmarking study, and the general wage increases over the Test Period.

**RESPONSE:**

**Please refer to BC Hydro's response to BCUC IR 2.227.1 which confirms that only Canadian data is included in the survey.**

**227.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-5, BCUC IR 52.1; Exhibit B-6-1, BCOAPO IR 6.1, Attachment 1, p. 9; Attachment 2**
**Benchmarking – Morneau Shepell**

In the confidential response to BCOAPO IR 6.1, BC Hydro provided the 2017 Morneau Shepell assessment in Attachment 1 and a summary of the total rewards comparison by job in Attachment 2.

2.227.2 Please confirm, or explain otherwise, that all job titles (positions) were included in the summary of the total rewards comparison by job in Attachment 2.

**RESPONSE:**

**There were 92 jobs included in the Morneau Shepell assessment in Attachment 1 and 91 jobs included in the summary total rewards comparison by job in Attachment 2 provided in BC Hydro's confidential response to BCOAPO IR 1.6.1.**

**The summary total rewards comparison by job was an internal document prepared by BC Hydro which excluded the position of General Counsel. This position was excluded as it was considered an outlier, given the degree to which the market data exceeded BC Hydro's compensation and given BC Hydro's own knowledge of compensation provided by similar companies for this position.**

**An updated summary of the total rewards comparison by job, including the position of General Counsel, is provided as Attachment 1 to this response. BC Hydro is filing this attachment in confidence with the BCUC.**

**The inclusion of the General Counsel position in the summary of the total rewards comparison doesn't change the overall conclusion that BC Hydro's compensation is less than the market median rate by 11 per cent on a total cash basis and by 2 per cent on a total rewards basis.**

# CONFIDENTIAL ATTACHMENT

# FILED WITH BCUC ONLY

**227.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-5, BCUC IR 52.1; Exhibit B-6-1, BCOAPO IR 6.1, Attachment 1, p. 9; Attachment 2**
**Benchmarking – Morneau Shepell**

In the confidential response to BCOAPO IR 6.1, BC Hydro provided the 2017 Morneau Shepell assessment in Attachment 1 and a summary of the total rewards comparison by job in Attachment 2.

2.227.2 Please confirm, or explain otherwise, that all job titles (positions) were included in the summary of the total rewards comparison by job in Attachment 2.

2.227.2.1 If confirmed, please explain why the number of employees that participated in the 2017 Morneau Shepell assessment in Attachment 1 does not agree with the number of BC Hydro job titles (positions) in the summary of the total rewards comparison by job in Attachment 2. Please provide an updated summary, as necessary.

**RESPONSE:**

**Please refer to BC Hydro's response to BCUC IR 2.227.2.**

**228.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-5, BCUC IR 62.1, 62.4, 62.10**
**Benchmarking – operating and maintenance costs**

In response to BCUC IR 62.1, BC Hydro provided a list of performance measurements currently included on the dashboard for each Business Group.

2.228.1 Please confirm, or explain otherwise, that each KBU has a performance measure on operating expenditures.

**RESPONSE:**

**This answer also responds to BCUC IRs 2.228.1.1, 2.228.1.2 and 2.228.1.3.**

**Confirmed. A positive outcome for each KBU is defined as actual annual expenditures at or below the annual operating plans while completing the related annual KBU work plans. This criterion is set in advance of the fiscal year by senior and executive management and is tracked on business group dashboards, business group performance packages, or KBU scorecards.**

**For a summary of the actuals vs plan operating expenditure metric please refer to Schedules 5.1 to 5.7 of Appendix A to the Evidentiary Update with regards to operating costs fiscal 2015 to fiscal 2019 and fiscal 2020 to fiscal 2021 plans.**
**BC Hydro has provided the financial information back to fiscal 2015 as a relevant comparator for the test period.**

**Please refer to BC Hydro's response to CEC IR 2.92.2 where we discuss the use of BC Hydro's Service Plan to determine cost effectiveness.**

**228.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-5, BCUC IR 62.1, 62.4, 62.10**
**Benchmarking – operating and maintenance costs**

In response to BCUC IR 62.1, BC Hydro provided a list of performance measurements currently included on the dashboard for each Business Group.

2.228.1 Please confirm, or explain otherwise, that each KBU has a performance measure on operating expenditures.

2.228.1.1 If confirmed, please elaborate on the performance measure and how it measures efficiency of operating costs.

**RESPONSE:**

**Please refer to BC Hydro's response to BCUC IR 2.228.1 where we provide the details on this performance measure.**

**228.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-5, BCUC IR 62.1, 62.4, 62.10**
**Benchmarking – operating and maintenance costs**

In response to BCUC IR 62.1, BC Hydro provided a list of performance measurements currently included on the dashboard for each Business Group.

2.228.1 Please confirm, or explain otherwise, that each KBU has a performance measure on operating expenditures.

2.228.1.2 If confirmed, please provide the actual results of the performance measure for F2012 to F2019 actuals and F2020 to F2021 planned. Please also compare the actual results with the performance measure targets, if applicable.

**RESPONSE:**

**Please refer to BC Hydro's response to BCUC IR 2.228.1 where we provide actual results of this performance measure.**

**228.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-5, BCUC IR 62.1, 62.4, 62.10**
**Benchmarking – operating and maintenance costs**

In response to BCUC IR 62.1, BC Hydro provided a list of performance measurements currently included on the dashboard for each Business Group.

2.228.1 Please confirm, or explain otherwise, that each KBU has a performance measure on operating expenditures.

2.228.1.3 If not confirmed, please explain why.

**RESPONSE:**

**Please refer to BC Hydro's response to BCUC IR 2.228.1.**

**228.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-5, BCUC IR 62.1, 62.4, 62.10**
**Benchmarking – operating and maintenance costs**

In response to BCUC IR 62.1, BC Hydro provided a list of performance measurements currently included on the dashboard for each Business Group.

2.228.2 The Capital Infrastructure Project Delivery Business Group has a performance measure of "Operating Costs Before Capital Overhead." Please explain if there is a performance measure for capital overhead expenditures and whether all Business Groups (KBUs) have a similar performance measure. If not, why not?

**RESPONSE:**

**There is not a specific performance measure for capital overhead expenditures for any Business Group. However, Business Groups are responsible for managing all the costs of activities that they perform. In addition, all projects have a budget that includes capital overhead costs. All projects are reviewed against budget and thus capital overhead cost must be controlled within budget. Please also refer to BC Hydro's response to BCUC IRs 2.228.3 and 2.228.3.1 for further information on performance measures on BC Hydro's capital expenditures.**

**The amount of capital overhead is an accounting determination that is an outcome of the nature, volume and cost of the work performed by the Business Groups. The amount of Capital overhead does not measure how the Business Groups have performed in terms of completing the necessary volumes of work and the cost effectiveness of performing the work.**

**228.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-5, BCUC IR 62.1, 62.4, 62.10**
**Benchmarking – operating and maintenance costs**

In response to BCUC IR 62.1, BC Hydro provided a list of performance measurements currently included on the dashboard for each Business Group.

2.228.2 The Capital Infrastructure Project Delivery Business Group has a performance measure of "Operating Costs Before Capital Overhead." Please explain if there is a performance measure for capital overhead expenditures and whether all Business Groups (KBUs) have a similar performance measure. If not, why not?

2.228.2.1 If yes, please provide the actual results of the performance measure for F2012 to F2019 actuals and F2020 to F2021 planned. Please also compare the actual results with the performance measure targets, if applicable.

**RESPONSE:**

**Please refer to BC Hydro's response to BCUC IR 2.228.2.**

**228.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-5, BCUC IR 62.1, 62.4, 62.10**
**Benchmarking – operating and maintenance costs**

In response to BCUC IR 62.1, BC Hydro provided a list of performance measurements currently included on the dashboard for each Business Group.

2.228.3 Please confirm, or explain otherwise, that each KBU has a performance measure on capital expenditures.

**RESPONSE:**

**Each KBU that plans or delivers capital expenditures has KBU-specific capital metrics on their monthly performance reports. In addition, the Capital Delivery Management Committee also reviews and manages the planning and delivery of the capital plan by the different KBUs.**

**Overall, a key performance metric that BC Hydro uses to evaluate the performance of delivering capital projects is the comparison of the actual project costs for in-service projects to the original approved expected cost, also referred to as first full funding, over an aggregated five-year period. This metric includes projects that are managed by different KBUs. Please see Table 6-3 in the Application, which summarizes the aggregated results over the past five years.**

**228.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-5, BCUC IR 62.1, 62.4, 62.10**
**Benchmarking – operating and maintenance costs**

In response to BCUC IR 62.1, BC Hydro provided a list of performance measurements currently included on the dashboard for each Business Group.

2.228.3 Please confirm, or explain otherwise, that each KBU has a performance measure on capital expenditures.

2.228.3.1 If confirmed, please elaborate on the performance measure and how it measures efficiency of capital (direct and indirect) costs.

**RESPONSE:**

**BC Hydro's capital plan is made up of a large number of individual projects, many of which are delivered over multi-year periods. The Project Budget to Actual Cost metric, which is included in the Service Plan, was designed to measure our cost performance in delivering this portfolio of projects.**

**The Project Budget amount included in the metric is the Expected Amount at the start of the implementation phase, which would include the full scope of the project. The Expected Amount is:**

- **Estimated project costs including contingencies and appropriate loadings, but not including any Project Reserve; and**
- **A P50 cost estimate for most projects, which means that there is an expectation that the estimate would be exceeded 50 per cent of the time.**

**Therefore, if BC Hydro is delivering its portfolio of projects within the capital performance metric targets, it is an indication that BC Hydro is prudently managing capital expenditures on a portfolio basis.**

**The Project Delivery, Technology and Properties KBUs deliver a majority of BC Hydro's capital plan and have the following KBU specific capital expenditure performance measures:**

- **Project Delivery - Number of projects placed in-service less than or equal to First Full Funding expected amount;**

- **Technology - Percentage of Technology projects completed within total approved First Full Funding Amount; and**
- **Properties - Percentage of completed projects with total spend less than or equal to the expected amount.**

**Please refer to BC Hydro's response to BCUC IR 2.228.3.2 for the plan / targets and actual results for these capital performance measures.**

**The Program and Contract Management KBU is currently establishing a similar capital performance measure and will start reporting results by the end of fiscal 2020.**

**228.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-5, BCUC IR 62.1, 62.4, 62.10**
**Benchmarking – operating and maintenance costs**

In response to BCUC IR 62.1, BC Hydro provided a list of performance measurements currently included on the dashboard for each Business Group.

2.228.3 Please confirm, or explain otherwise, that each KBU has a performance measure on capital expenditures.

2.228.3.2 If confirmed, please provide the actual results of the performance measure for F2012 to F2019 actuals and F2020 to F2021 planned. Please also compare the actual results with the performance measure targets, if applicable.

**RESPONSE:**

**As discussed in BC Hydro's response to BCUC IR 2.228.3, the key performance metric BC Hydro uses to evaluate the performance of delivering capital projects is to compare the actual project costs for in-service projects to the original approved expected cost (also referred to as first full funding), over an aggregated five-year period. In addition, the Project Delivery, Technology and Properties KBUs, which deliver a majority of BC Hydro's capital plan, have KBU specific capital expenditure performance measures.**

**The table below provides the actual project costs for in-service projects to the original approved expected cost for fiscal 2013 to fiscal 2019. BC Hydro started to report results on this metric in fiscal 2013.**

| Project Budget to Actual Cost | F2013 | F2014 | F2015 | F2016 | F2017 | F2018 | F2019 |
|---|---|---|---|---|---|---|---|
| Actuals | +0.83% on $3.29 billion | -4.75% on $3.33 billion | -1.83% on $3.94 billion | -0.18% on $6.49 billion | -0.94% on $6.36 billion | +0.40% on $6.9 billion | -0.34% on $8.03 billion |
| Plan | Within +5% to -5% of budget excluding project reserve amounts | | | | | | |

**The fiscal 2020 and fiscal 2021 plan / target is to be within +5 per cent to -5 per cent of budget excluding project reserve amounts.**

**KBU specific capital expenditure performance measures are provided below.**

**Project Delivery KBU**

| Metric | F2016 Actual | F2017 Actual | F2016 / F2017 Plan | F2018 Actual | F2019 Actual | F2019 / F2020 Plan | F2020 Plan |
|---|---|---|---|---|---|---|---|
| **Projects cost ≤ Expected Amount (Number and %)** | **74 of 95 (78%)** | **53 of 82 (64%)** | **N/A** | **32 of 51 (63%)** | **37 of 44 (84%)** | **≥ 50%** | **≥ 50%** |

**BC Hydro started to track and report on the above capital performance measure in fiscal 2016. A plan amount was not established for fiscal 2016 and fiscal 2017.**

**Technology KBU**

| Metric | F2017 Actual | F2017 Plan | F2018 Actual | F2018 Plan | F2019 Actual | F2019 Plan | F2020 Plan |
|---|---|---|---|---|---|---|---|
| **Project Implementation Cost Met - % closed projects within budget** | **81%** | **N/A** | **91%** | **≥ 80%** | **95%** | **≥ 80%** | **≥ 80%** |

**BC Hydro started to track and report on the above capital performance measure in fiscal 2017.**

**Properties KBU**

| Metric | F2017 Actual | F2017 Plan | F2018 Actual | F2018 Plan | F2019 Actual | F2019 Plan | F2020 Plan |
|---|---|---|---|---|---|---|---|
| **Project costs ≤ Expected Amount (Number and %)** | **34 of 34 100%** | **95%** | **32 of 34 94%** | **95%** | **56 of 59 95%** | **95%** | **95%** |

**BC Hydro started to track and report on the above capital performance measure in fiscal 2017.**

**228.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-5, BCUC IR 62.1, 62.4, 62.10**
**Benchmarking – operating and maintenance costs**

In response to BCUC IR 62.1, BC Hydro provided a list of performance measurements currently included on the dashboard for each Business Group.

2.228.3 Please confirm, or explain otherwise, that each KBU has a performance measure on capital expenditures.

2.228.3.3 If not confirmed, please explain why.

**RESPONSE:**

**Please refer to BC Hydro's response to BCUC IR 2.228.3.**

**228.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-5, BCUC IR 62.1, 62.4, 62.10**
**Benchmarking – operating and maintenance costs**

In response to BCUC IR 62.4, BC Hydro provided the labour costs as a percentage of overall revenues as provided below:

| Labour operating costs as % of Revenue<br>$ millions | F17<br>Actual | F18<br>Actual | F19<br>Forecast |
|---|---|---|---|
| Labour operating costs | 487.8 | 522.2 | 557.5 |
| Total revenues | 5,874.0 | 6,237.0 | 6,095.0 |
| Labour operating costs as % of revenue | 8% | 8% | 9% |

2.228.4 Please confirm, or explain otherwise, that the increase in labour operating costs from F2018 to F2019 forecast is primarily a result of the Workforce Optimization program and the Accenture Repatriation.

**RESPONSE:**

**Confirmed. While the Workforce Optimization Program and the Accenture Repatriation are the primary contributors to the increase in labour operating cost between fiscal 2018 actual and fiscal 2019 forecast, these increases are fully offset by equivalent cost reductions. Standard Labour Rate increases also contributed to the labour operating costs increase.**

## 228.0 C. CHAPTER 5 – OPERATING COSTS

**Reference: OPERATING COSTS**
**Exhibit B-5, BCUC IR 62.1, 62.4, 62.10**
**Benchmarking – operating and maintenance costs**

In response to BCUC IR 62.10, BC Hydro provided a table presenting the total human resources (HR) operating costs divided by total FTEs:

| **Total HR operating costs divided by total FTEs** | **Actual F2012** | **Actual F2013** | **Actual F2014** | **Actual F2015** | **Actual F2016** | **Actual F2017** | **Actual F2018** |
|---|---|---|---|---|---|---|---|
| Total HR operating costs ($ million) | 22.6 | 23.4 | 23.8 | 22.9 | 21.4 | 21.6 | 22.1 |
| Total BC Hydro FTEs | 5,738 | 5,511 | 5,571 | 5,690 | 5,635 | 5,735 | 6,004 |
| **Operating costs per FTE** | **$3,935** | **$4,247** | **$4,266** | **$4,019** | **$3,799** | **$3,768** | **$3,688** |

| | **Forecast F2019** | **Plan F2020** | **Plan F2021** |
|---|---|---|---|
| Total HR operating costs ($ million) | 21.1 | 21.1 | 21.4 |
| Total BC Hydro FTEs | 6,789 | 6,884 | 6,880 |
| **Operating costs per FTE** | **$3,111** | **$3,067** | **$3,108** |

In addition, BC Hydro provided a table illustrating the total HR operating costs divided by total operating expenses:

| **Total HR operating costs divided by total BC Hydro operating costs $ million** | **Actual F2012** | **Actual F2013** | **Actual F2014** | **Actual F2015** | **Actual F2016** | **Actual F2017** | **Actual F2018** |
|---|---|---|---|---|---|---|---|
| Total HR operating costs | 22.6 | 23.4 | 23.8 | 22.9 | 21.4 | 21.6 | 22.1 |
| BC Hydro net operating costs | 779.2 | 754.7 | 755.1 | 797.6 | 829.3 | 867.6 | 931.9 |
| **HR costs / BC Hydro operating costs** | **2.9%** | **3.1%** | **3.2%** | **2.9%** | **2.6%** | **2.5%** | **2.4%** |

| | **Forecast F2019** | **Plan F2020** | **Plan F2021** |
|---|---|---|---|
| Total HR operating costs | 21.1 | 21.1 | 21.4 |
| BC Hydro net operating costs | 979.3 | 959.0 | 991.4 |
| **HR costs / BC Hydro operating costs** | **2.2%** | **2.2%** | **2.2%** |

2.228.5 Considering the Workforce Optimization program and the Accenture repatriation, including the repatriated human resources employees, please discuss the reduction in operating costs per FTE as well as the reduction in HR costs as a percentage of operating costs between F2018 actual and F2019 forecast.

**RESPONSE:**

**The reduction in Human Resources operating costs from fiscal 2018 actual to fiscal 2019 forecast is primarily due to savings from the repatriation of work from**

**Accenture. As shown in Table 5-11 of Chapter 5 of the Application, the Accenture repatriation resulted in annual operating cost savings of $1.6 million for the Human Resources KBU.**

**The total number of FTEs increased from fiscal 2018 to fiscal 2019 primarily as a result of the Workforce Optimization program and the Accenture repatriation.**

**The combination of these two factors resulted in a reduction to Human Resources costs per FTE from fiscal 2018 to fiscal 2019.**

**The reduction in Human Resources operating costs resulted in a reduction to Human Resources costs as a percentage of operating costs from fiscal 2018 to fiscal 2019.**

**229.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-1, Section 5.6.1.4, Table 5-10, pp. 5-36–5-38;**
**Exhibit B-5, BCUC IR 35.1**
**Vacancy management governance process**

In response to BCUC IR 35.1, BC Hydro provided a list of all vacancies approved for recruitment as of March 31, 2019. The list includes 433 vacancies from various KBUs, including: Customer Service (86 vacancies, of which 68 are Customer Service Accounts Rep 7 and 7 are Customer Service Billing Agents); Engineering (20 vacancies); Learning & Development (29 vacancies); line Field Operations (21 vacancies); Project Delivery (45 vacancies); Stations Field Operations (21 vacancies); and Supply Chain (38 vacancies).

2.229.1 Please discuss whether BC Hydro is currently actively recruiting for all 433 vacant positions. If not, why not?

**RESPONSE:**

**BC Hydro was/is recruiting for all 433 vacant positions. As the list was effective March 31, 2019, vacancies listed may have since been filled.**

**229.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-1, Section 5.6.1.4, Table 5-10, pp. 5-36–5-38;**
**Exhibit B-5, BCUC IR 35.1**
**Vacancy management governance process**

In response to BCUC IR 35.1, BC Hydro provided a list of all vacancies approved for recruitment as of March 31, 2019. The list includes 433 vacancies from various KBUs, including: Customer Service (86 vacancies, of which 68 are Customer Service Accounts Rep 7 and 7 are Customer Service Billing Agents); Engineering (20 vacancies); Learning & Development (29 vacancies); line Field Operations (21 vacancies); Project Delivery (45 vacancies); Stations Field Operations (21 vacancies); and Supply Chain (38 vacancies).

2.229.2 Please confirm, or explain otherwise, that the list of all vacancies approved for recruitment are included in the number of the FTEs in the Test Period (Appendix A, Schedule 16, line 52). If not, please explain why not.

**RESPONSE:**

**Confirmed. All 433 vacant positions included in BC Hydro's response to BCUC IR 1.35.1 were approved for recruitment and as such, are included in the FTE count and budget in the Test Period. Please refer to section 5.4.3 of Chapter 5 of the Application for additional details on the vacancy management governance process and the requirements needed for a position to be approved for recruitment.**

**As discussed further in Table 5-6 of Chapter 5 of the Application, to account for labour cost savings that may be incurred while a position is vacant, vacancy factor savings are applied to labour budgets, which reduces BC Hydro's overall operating cost budget. In some cases, BC Hydro may incur additional contractor or overtime labour costs while a position remains vacant.**

**229.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-1, Section 5.6.1.4, Table 5-10, pp. 5-36–5-38;**
**Exhibit B-5, BCUC IR 35.1**
**Vacancy management governance process**

In response to BCUC IR 35.1, BC Hydro provided a list of all vacancies approved for recruitment as of March 31, 2019. The list includes 433 vacancies from various KBUs, including: Customer Service (86 vacancies, of which 68 are Customer Service Accounts Rep 7 and 7 are Customer Service Billing Agents); Engineering (20 vacancies); Learning & Development (29 vacancies); line Field Operations (21 vacancies); Project Delivery (45 vacancies); Stations Field Operations (21 vacancies); and Supply Chain (38 vacancies).

2.229.3 Please clarify whether all 433 vacant positions approved for recruitment have been included in the current Test Period revenue requirement.

**RESPONSE:**

**Confirmed. Please refer to BC Hydro's response to BCUC IR 2.229.2 for further details.**

**229.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-1, Section 5.6.1.4, Table 5-10, pp. 5-36–5-38;**
**Exhibit B-5, BCUC IR 35.1**
**Vacancy management governance process**

In response to BCUC IR 35.1, BC Hydro provided a list of all vacancies approved for recruitment as of March 31, 2019. The list includes 433 vacancies from various KBUs, including: Customer Service (86 vacancies, of which 68 are Customer Service Accounts Rep 7 and 7 are Customer Service Billing Agents); Engineering (20 vacancies); Learning & Development (29 vacancies); line Field Operations (21 vacancies); Project Delivery (45 vacancies); Stations Field Operations (21 vacancies); and Supply Chain (38 vacancies).

2.229.3.1 Please discuss whether the labour costs included in the Test Period revenue requirement only includes the period that the vacant position is expected to be filled. For example, if the vacancy is expected to be filled in October of 2019, then the revenue requirement only includes labour costs from October 2019 onwards.

**RESPONSE:**

**It is recognized that positions will be temporarily vacant at times. For example, it takes time to fill a position after an employee leaves. How much time is needed to fill a particular vacancy depends on a number of factors and is typically not known ahead of time.**

**To account for labour cost savings during these vacancy periods, a vacancy factor is applied to reduce overall labour budgets. Please refer to Table 5-6 of Chapter 5 of the Application which further describes vacancy factor savings during the Test Period.**

**229.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-1, Section 5.6.1.4, Table 5-10, pp. 5-36–5-38;**
**Exhibit B-5, BCUC IR 35.1**
**Vacancy management governance process**

In Table 5-10 of the Application, BC Hydro provides details on the additional Workforce Optimization FTEs confirmed since the previous RRA, by KBU.

2.229.4 Please comment on the number of vacant positions in the KBUs provided below. If any of the vacancies are attributed to expected contractor conversions to internal FTEs as part of the Workforce Optimization program, please confirm the conversions are included in Table 5-10 of the Application.

- Customer Service (86)
- Engineering (20)
- Learning and Development (29)
- Line Field Operations (21)
- Project Delivery (45)
- Stations Field Operations (21)
- Supply Chain (38)

**RESPONSE:**

**Confirmed. The vacancies due to planned contractor conversions to internal FTEs as part of the Workforce Optimization program are included in Table 5-10 of the Application.**

**The number of vacancies, as provided in the attachment to BC Hydro’s response to BCUC IR 1.35.1, was as of March 31, 2019. The number of vacancies within each KBU fluctuates over the course of the year, due to various factors, which are further discussed in BC Hydro’s response to BCUC IR 1.35.1.2.**

**With the exception of the Learning and Development KBU, which had a relatively high number of vacancies as at March 31, 2019, due to apprentice and trainee intakes that were in progress at that time, the KBUs referenced in the question are BC Hydro’s largest KBUs by FTE and would therefore be expected to have a relatively higher number of vacancies.**

**Sixty-eight of the 86 vacancies in the Customer Service KBU as at March 31, 2019 were for Customer Service Account Rep 7 positions. For further discussion on these vacancies, please refer to BC Hydro’s response to BCUC IR 2.229.5.**

**229.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-1, Section 5.6.1.4, Table 5-10, pp. 5-36–5-38;**
**Exhibit B-5, BCUC IR 35.1**
**Vacancy management governance process**

In Table 5-10 of the Application, BC Hydro provides details on the additional Workforce Optimization FTEs confirmed since the previous RRA, by KBU.

2.229.5 Please explain why there are approximately 68 vacancies for "Customer Service Accounts Rep 7" and approximately 7 vacancies for "Customer Service Billing Agent" within the Customer Service KBU, considering the recent repatriation of Accenture. Please discuss how filling these vacancies impacts the annual savings from the Accenture repatriation.

**RESPONSE:**

**The Customer Service Account Rep 7 and Customer Service Billing Agent roles being hired on March 31, 2019 were to fill positions within the labour forecast of the Contact Centre and Billing Operations department in the Customer Service KBU. They were not additional FTEs and so did not impact annual savings from the Accenture repatriation.**

**For context, BC Hydro requires staffing flexibility in our contact centre so that Customer Service Account Rep 7 roles (also referred to as Customer Service Representatives) can be optimally scheduled to meet hourly, daily, and seasonal variations in forecast call volumes. BC Hydro meets this need through a combination of full time and part-time positions that are filled by both regular and temporary employees. Regular and full-time temporary employees are used to fulfill base staffing needs while part-time temporary employees are scheduled as necessary to supply additional resources during peak call periods or to backfill for regular employees on vacation, for example. Importantly, part time temporary employees are only paid for time worked. Therefore, Contact Centre and Billing Operations' labour costs are largely influenced by the number of hours worked by part-time temporary employees rather than by headcount associated with part-time temporary employees.**

**Contact centre hiring needs are also impacted by the Customer Service Account Rep 7 being an entry level role into BC Hydro. It is common for new Customer Service Account Rep 7 employees to transfer into other positions within BC Hydro after a short period, creating higher than usual vacancy levels. This was exacerbated after repatriation because MoveUP employees maintained their**

**seniority from their time worked at Accenture, thereby improving their ability to obtain roles elsewhere in BC Hydro. Further, there is a higher rate of attrition among Customer Service Account Rep 7 roles than is typical in BC Hydro, as is a common trend throughout contact centres.**

**With respect to the 68 vacancies on March 31, 2019 for Customer Service Account Rep 7 positions, 36 vacancies were posted to change the status of 36 part-time temporary positions to full time temporary positions. This change of status increased the hours these employees could work under the MoveUP collective agreement. Filling these vacancies did not increase headcount.**

**The additional 32 part-time temporary Customer Service Account Rep 7 positions were posted to recruit new contact centre resources, most likely externally, to address actual and forecast employee movement and attrition. Customer Service Account Rep 7 employees are recruited in 'hiring classes' rather than as individual vacancies arise because of training requirements. Labour forecasts for the Accenture repatriation included the need for ongoing recruitment to address attrition so hiring these positions doesn't affect annual savings from the Accenture repatriation.**

**BC Hydro also notes that although we attempted to recruit 32 part-time temporary Customer Service Account Rep 7 positions, we actually hired only 22 individuals based on the skills and experience of the candidates applying.**

**With respect to the seven vacancies on March 31, 2019 for Customer Service Billing Agent positions, one was a full-time temporary position to backfill an employee going on maternity leave. There was no impact to annual savings as a result of hiring this position. The other six vacancies were for part time temporary positions to supplement core staffing for periods of higher work volumes and provide vacation backfill. There would not have been an impact to annual savings because utilizing part time temporary employees was an alternative to assigning overtime to existing staff; an allowance for overtime had been included in labour forecasts. However, these positions were not filled because suitable candidates did not apply.**

**230.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-1, Section 5.5.2.3, Table 5-6, p. 5-25; Appendix A, Schedule 5, 16; Exhibit B-5, BCUC IR 35.1.2, 43.1, 43.3.2, 68.1**
**Vacancy factor savings**

In response to BCUC IR 43.1, BC Hydro stated:

> Vacancy factor savings are budget adjustments which take into account the fact that positions will not remain filled 100 per cent of the time.
>
> […]
>
> Filling vacancies is part of the vacancy management governance process discussed in section 5.4.3 of Chapter 5 of the Application.
>
> […]
>
> Vacancy factor savings also includes an increased proportion of time and costs charged out to capital work than previous budgets.
>
> The savings of $5.6 million for each of fiscal 2020 and fiscal 2021 is our estimated operating savings as a result of applying a consistent approach to labour analysis for all key business units. The approach entailed a review of historical operating labour expenditures, estimated future vacancies, and charge out expectations for each key business unit. Adjustments, as appropriate, were made to each key business unit's budget based on the resulting data.

2.230.1 Please explain whether vacancy factor savings are treated as a reduction to labour costs in the RRA for the positions that BC Hydro does not expect to have filled 100 percent of the time.

**RESPONSE:**

**BC Hydro clarifies that vacancy factor savings are not attributed to any specific positions. Vacancy factor savings are treated as a reduction to labour costs in the Application and are estimated based on the approach described in BC Hydro's response to BCUC IR 1.43.1.**

**230.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-1, Section 5.5.2.3, Table 5-6, p. 5-25; Appendix A, Schedule 5, 16; Exhibit B-5, BCUC IR 35.1.2, 43.1, 43.3.2, 68.1**
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2.230.1.1 Please discuss whether a full complement of staff for the full F2020 plan year (i.e. all positions are filled 100 percent of the time) would have the same labour costs as presented in the current RRA for F2020 (Appendix A, Schedule 5, line 16).

**RESPONSE:**

**A full complement of staff for the full fiscal 2020 plan year would have higher operating costs of $5.6 million. In other words, in the absence of the planned vacancy factor savings of $5.6 million, the revenue requirements would be higher for the test period by that amount in each fiscal year.**

**230.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-1, Section 5.5.2.3, Table 5-6, p. 5-25; Appendix A, Schedule 5, 16; Exhibit B-5, BCUC IR 35.1.2, 43.1, 43.3.2, 68.1**
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2.230.1.1 Please discuss whether a full complement of staff for the full F2020 plan year (i.e. all positions are filled 100 percent of the time) would have the same labour costs as presented in the current RRA for F2020 (Appendix A, Schedule 5, line 16).

2.230.1.1.1 If so, please explain where the vacancy factor savings is located in the Application; specifically, Appendix A.

**RESPONSE:**

**Vacancy factor savings are embedded into BC Hydro's forecast labour costs for the test period. Accordingly, the amounts shown in Appendix A, Schedules 5.0 to 5.7 are net of the $5.6 million vacancy factor savings for the test period.**

**230.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-1, Section 5.5.2.3, Table 5-6, p. 5-25; Appendix A, Schedule 5, 16; Exhibit B-5, BCUC IR 35.1.2, 43.1, 43.3.2, 68.1**
**Vacancy factor savings**

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> Vacancy factor savings are budget adjustments which take into account the fact that positions will not remain filled 100 per cent of the time.
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> Vacancy factor savings also includes an increased proportion of time and costs charged out to capital work than previous budgets.
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> The savings of $5.6 million for each of fiscal 2020 and fiscal 2021 is our estimated operating savings as a result of applying a consistent approach to labour analysis for all key business units. The approach entailed a review of historical operating labour expenditures, estimated future vacancies, and charge out expectations for each key business unit. Adjustments, as appropriate, were made to each key business unit's budget based on the resulting data.

2.230.1.1 Please discuss whether a full complement of staff for the full F2020 plan year (i.e. all positions are filled 100 percent of the time) would have the same labour costs as presented in the current RRA for F2020 (Appendix A, Schedule 5, line 16).

2.230.1.1.2 If no, and the F2020 plan labour costs include the $5.6 million savings, please clarify where additional savings will be applied if the expected vacancy factor savings are exceeded.

**RESPONSE:**

**If the labour costs are lower than planned in the test period, similar to other variances, these variances would be managed within BC Hydro's overall operating cost budget and may be used to manage unanticipated cost pressures as they arise over the course of a fiscal year. Please refer to BC Hydro's response to BCUC IR 1.36.2.1 for further information on how BC Hydro manages to its overall operating cost budget.**

**230.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-1, Section 5.5.2.3, Table 5-6, p. 5-25; Appendix A, Schedule 5, 16; Exhibit B-5, BCUC IR 35.1.2, 43.1, 43.3.2, 68.1**
**Vacancy factor savings**

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2.230.2 Please provide the vacancy factor savings applied during the Test Period for capital and deferred FTEs. Please discuss the cost pressures these savings address.

**RESPONSE:**

**This answer also responds to BCUC IRs 2.230.2.1 and 2.230.3.**

**Vacancy factor savings were not specifically applied during the test period for capital and deferred labour costs and FTEs. Internal labour vacancies for capital and deferred projects and programs are balanced and managed through the deployment of external contractors.**

**230.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-1, Section 5.5.2.3, Table 5-6, p. 5-25; Appendix A, Schedule 5, 16; Exhibit B-5, BCUC IR 35.1.2, 43.1, 43.3.2, 68.1**
**Vacancy factor savings**

In response to BCUC IR 43.1, BC Hydro stated:

> Vacancy factor savings are budget adjustments which take into account the fact that positions will not remain filled 100 per cent of the time.
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> […]
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> Filling vacancies is part of the vacancy management governance process discussed in section 5.4.3 of Chapter 5 of the Application.
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> […]
>
> Vacancy factor savings also includes an increased proportion of time and costs charged out to capital work than previous budgets.
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> The savings of $5.6 million for each of fiscal 2020 and fiscal 2021 is our estimated operating savings as a result of applying a consistent approach to labour analysis for all key business units. The approach entailed a review of historical operating labour expenditures, estimated future vacancies, and charge out expectations for each key business unit. Adjustments, as appropriate, were made to each key business unit's budget based on the resulting data.

2.230.2.1 Please confirm, or explain otherwise, that the approach for estimating the vacancy factor savings for capital and deferred FTEs was the same for operating FTEs. If not confirmed, please discuss the approach.

**RESPONSE:**

**Please refer to BC Hydro's response to BCUC IR 2.230.2.**

**230.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-1, Section 5.5.2.3, Table 5-6, p. 5-25; Appendix A, Schedule 5, 16; Exhibit B-5, BCUC IR 35.1.2, 43.1, 43.3.2, 68.1**
**Vacancy factor savings**

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> […]
>
> Filling vacancies is part of the vacancy management governance process discussed in section 5.4.3 of Chapter 5 of the Application.
>
> […]
>
> Vacancy factor savings also includes an increased proportion of time and costs charged out to capital work than previous budgets.
>
> The savings of $5.6 million for each of fiscal 2020 and fiscal 2021 is our estimated operating savings as a result of applying a consistent approach to labour analysis for all key business units. The approach entailed a review of historical operating labour expenditures, estimated future vacancies, and charge out expectations for each key business unit. Adjustments, as appropriate, were made to each key business unit's budget based on the resulting data.

2.230.3 Please explain why the vacancy factor savings would impact the proportion of time/costs charged to capital work.

**RESPONSE:**

**Please refer to BC Hydro's response to BCUC IR 2.230.2.**

**230.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-1, Section 5.5.2.3, Table 5-6, p. 5-25; Appendix A, Schedule 5, 16; Exhibit B-5, BCUC IR 35.1.2, 43.1, 43.3.2, 68.1**
**Vacancy factor savings**

In response to BCUC IR 43.1, BC Hydro stated:

> Vacancy factor savings are budget adjustments which take into account the fact that positions will not remain filled 100 per cent of the time.
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> […]
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> Filling vacancies is part of the vacancy management governance process discussed in section 5.4.3 of Chapter 5 of the Application.
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> Vacancy factor savings also includes an increased proportion of time and costs charged out to capital work than previous budgets.
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2.230.4 Please confirm, or explain otherwise, whether vacancy factor savings were included in previous revenue requirement applications.

**RESPONSE:**

**Confirmed. As described in Table 5-6 on page 5-25 of Chapter 5 of the Application, in previous years, some KBUs reduced their labour budgets to recognize that positions would not remain filled 100 per cent of the time.**

**230.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-1, Section 5.5.2.3, Table 5-6, p. 5-25; Appendix A, Schedule 5, 16; Exhibit B-5, BCUC IR 35.1.2, 43.1, 43.3.2, 68.1**
**Vacancy factor savings**

In response to BCUC IR 43.1, BC Hydro stated:

> Vacancy factor savings are budget adjustments which take into account the fact that positions will not remain filled 100 per cent of the time.
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> […]
>
> Filling vacancies is part of the vacancy management governance process discussed in section 5.4.3 of Chapter 5 of the Application.
>
> […]
>
> Vacancy factor savings also includes an increased proportion of time and costs charged out to capital work than previous budgets.
>
> The savings of $5.6 million for each of fiscal 2020 and fiscal 2021 is our estimated operating savings as a result of applying a consistent approach to labour analysis for all key business units. The approach entailed a review of historical operating labour expenditures, estimated future vacancies, and charge out expectations for each key business unit. Adjustments, as appropriate, were made to each key business unit's budget based on the resulting data.

2.230.4 Please confirm, or explain otherwise, whether vacancy factor savings were included in previous revenue requirement applications.

2.230.4.1 If confirmed, please provide reference to where these savings were included in the previous applications, and calculate the actual annual savings achieved.

**RESPONSE:**

**Labour cost reductions in previous revenue requirements were embedded within the Operating Costs by Resource – Labour line in Schedule 5.0 of Appendix A of the previous revenue requirements applications. As described in Table 5-6 on page 5-25 of Chapter 5 of the Application, the exact approach for identifying these reductions for each KBU has varied. These amounts were not specifically tracked and therefore the actual annual savings achieved cannot be calculated.**

**230.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-1, Section 5.5.2.3, Table 5-6, p. 5-25; Appendix A, Schedule 5, 16; Exhibit B-5, BCUC IR 35.1.2, 43.1, 43.3.2, 68.1**
**Vacancy factor savings**

In response to BCUC IR 43.1, BC Hydro stated:

> Vacancy factor savings are budget adjustments which take into account the fact that positions will not remain filled 100 per cent of the time.
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> Filling vacancies is part of the vacancy management governance process discussed in section 5.4.3 of Chapter 5 of the Application.
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> The savings of $5.6 million for each of fiscal 2020 and fiscal 2021 is our estimated operating savings as a result of applying a consistent approach to labour analysis for all key business units. The approach entailed a review of historical operating labour expenditures, estimated future vacancies, and charge out expectations for each key business unit. Adjustments, as appropriate, were made to each key business unit's budget based on the resulting data.

2.230.5 Please discuss the relationship between the vacancy factor savings and the vacancies approved for recruitment.

**RESPONSE:**

**Although there is no direct correlation between the current vacancies approved for recruitment provided in Attachment 1 to BC Hydro's response to BCUC IR 1.35.1 and the vacancy factor savings of $5.6 million, these vacancies will contribute to the vacancy factor savings planned in the test period.**

**While BC Hydro expects that there will be savings from future vacancies, the exact nature and timing of these vacancies is not known. As discussed in BC Hydro's response to BCUC IR 1.43.1, the vacancy factor savings of $5.6 million for each of fiscal 2020 and fiscal 2021 is our estimated operating savings as a**

**result of applying a consistent approach for all Key Business Units, considering factors such as a review of historical operating labour expenditures, estimated future vacancies and charge out expectations.**

**As noted in BC Hydro’s response to BCUC IR 2.229.3.1, the length of time required to fill a particular vacancy depends on a number of factors and is typically not known ahead of time.**

**230.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-1, Section 5.5.2.3, Table 5-6, p. 5-25; Appendix A, Schedule 5, 16; Exhibit B-5, BCUC IR 35.1.2, 43.1, 43.3.2, 68.1**
**Vacancy factor savings**

In response to BCUC IR 43.1, BC Hydro stated:

> Vacancy factor savings are budget adjustments which take into account the fact that positions will not remain filled 100 per cent of the time.
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> […]
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> Filling vacancies is part of the vacancy management governance process discussed in section 5.4.3 of Chapter 5 of the Application.
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> Vacancy factor savings also includes an increased proportion of time and costs charged out to capital work than previous budgets.
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> The savings of $5.6 million for each of fiscal 2020 and fiscal 2021 is our estimated operating savings as a result of applying a consistent approach to labour analysis for all key business units. The approach entailed a review of historical operating labour expenditures, estimated future vacancies, and charge out expectations for each key business unit. Adjustments, as appropriate, were made to each key business unit's budget based on the resulting data.

2.230.6 Please explain how $5.6 million in vacancy factor savings will be sustained into F2021.

**RESPONSE:**

**The vacancy factor savings for fiscal 2020 and fiscal 2021 were estimated based on the same information and approach as set out in BC Hydro's response to BCUC IR 1.43.1. BC Hydro expects the level of vacancies in fiscal 2020 and fiscal 2021 to be similar.**

**230.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-1, Section 5.5.2.3, Table 5-6, p. 5-25; Appendix A, Schedule 5, 16; Exhibit B-5, BCUC IR 35.1.2, 43.1, 43.3.2, 68.1**
**Vacancy factor savings**

In response to BCUC IR 43.3.2, BC Hydro stated: “our approach to vacancy factor savings is cost based rather than position by position vacancy duration estimates and that while there may be a number of positions that are not filled 100 percent of the time… the vacancy factor is an estimated aggregation of all partial year vacancies.”

2.230.7 Please elaborate on the methodology applied to derive the estimated annual vacancy factor savings. Specifically address how this was accomplished without considering the number and type of vacant positions.

**RESPONSE:**

**As described in BC Hydro’s response to BCUC IR 1.43.1, the $5.6 million of vacancy factor savings was determined by reviewing the historical operating labour expenditures, estimated future vacancies and charge out expectations (i.e., operating labour costs excluding labour costs charged to capital or maintenance work programs) for each KBU. The information obtained through this review informed a judgement-based estimate of the vacancy factor savings applied to each KBU, totalling $5.6 million in operating cost savings for fiscal 2020 and fiscal 2021.**

**As noted above, this process did consider estimated future vacancies, based on historical information for each KBU. This is a more appropriate approach than solely examining the number and type of vacancies at any particular point in time, as the latter is unlikely, on its own, to be indicative of future results.**

**230.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-1, Section 5.5.2.3, Table 5-6, p. 5-25; Appendix A, Schedule 5, 16; Exhibit B-5, BCUC IR 35.1.2, 43.1, 43.3.2, 68.1**
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In response to BCUC IR 43.3.2, BC Hydro stated: "our approach to vacancy factor savings is cost based rather than position by position vacancy duration estimates and that while there may be a number of positions that are not filled 100 percent of the time… the vacancy factor is an estimated aggregation of all partial year vacancies."

2.230.8 Please explain how the estimated aggregation of all partial year vacancies was determined. Please provide an illustrative example and calculation of the vacancy factor savings.

**RESPONSE:**

**The estimated aggregation of all partial year vacancies to determine the vacancy factor savings for each KBU was assessed taking into account historical operating labour expenditures, estimated future vacancies, and charge out expectations. As a result, the vacancy factor savings applied to each KBU varied based on a judgement-based assessment of the factors noted above.**

**For example, vacancy factor savings of $0.05 million were applied to the Regulatory and Rates KBU for fiscal 2020 and fiscal 2021. While Regulatory and Rates is a small KBU (28 FTEs), due to the complex and technical nature of the positions, recruitment for vacancies, when they arise, can take some time to fill. The vacancy factor savings applied to the KBU reflect these circumstances and are informed by a review of the historical vacancy trends within the KBU.**

**230.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-1, Section 5.5.2.3, Table 5-6, p. 5-25; Appendix A, Schedule 5, 16; Exhibit B-5, BCUC IR 35.1.2, 43.1, 43.3.2, 68.1**
**Vacancy factor savings**

In Table 5-6 of the Application, BC Hydro provides a vacancy factor savings of $5.6 million and states that "[i]n the test period, BC Hydro has taken a consistent approach to assessing each KBU and identifying any budget reductions associated with unfilled positions."

In response to BCUC IR 68.1, BC Hydro stated that the Engineering and Project Delivery KBUs have vacancy factor adjustments.

2.230.9 Please confirm, or explain otherwise, that the $5.6 million vacancy factor savings includes the vacancy factor adjustments.

**RESPONSE:**

**This answer also responds to BCUC IRs 2.230.9.1, 2.230.9.2 and 2.230.10.**

**Not confirmed. As described in BC Hydro's response to BCUC IR 1.43.1, the $5.6 million vacancy factor savings was determined by reviewing the historical operating labour expenditures, estimated future vacancies and charge out expectations for each KBU. The information obtained through this review was used to estimate the operating cost savings for each KBU, totalling $5.6 million.**

**Vacancy factor adjustments are separate from vacancy factor savings and are used in the Engineering and Project Delivery KBUs. Vacancy factor adjustments are additional FTEs planned at the individual department level, with offsetting negative FTEs in the General Manager, Engineering department (in the case of the Engineering KBU) or VP, Project Delivery department (in the case of the Project Delivery KBU). 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.**

**230.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-1, Section 5.5.2.3, Table 5-6, p. 5-25; Appendix A, Schedule 5, 16; Exhibit B-5, BCUC IR 35.1.2, 43.1, 43.3.2, 68.1**
**Vacancy factor savings**

In Table 5-6 of the Application, BC Hydro provides a vacancy factor savings of $5.6 million and states that "[i]n the test period, BC Hydro has taken a consistent approach to assessing each KBU and identifying any budget reductions associated with unfilled positions."

In response to BCUC IR 68.1, BC Hydro stated that the Engineering and Project Delivery KBUs have vacancy factor adjustments.

2.230.9 Please confirm, or explain otherwise, that the $5.6 million vacancy factor savings includes the vacancy factor adjustments.

2.230.9.1 If confirmed, please explain how the vacancy factor adjustments are incorporated into the vacancy factor savings calculation.

**RESPONSE:**

**As described in BC Hydro's response to BCUC IR 2.230.9, the vacancy factor adjustments are not incorporated into the vacancy factor savings calculation.**

**230.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-1, Section 5.5.2.3, Table 5-6, p. 5-25; Appendix A, Schedule 5, 16; Exhibit B-5, BCUC IR 35.1.2, 43.1, 43.3.2, 68.1**
**Vacancy factor savings**

In Table 5-6 of the Application, BC Hydro provides a vacancy factor savings of $5.6 million and states that "[i]n the test period, BC Hydro has taken a consistent approach to assessing each KBU and identifying any budget reductions associated with unfilled positions."

In response to BCUC IR 68.1, BC Hydro stated that the Engineering and Project Delivery KBUs have vacancy factor adjustments.

2.230.9 Please confirm, or explain otherwise, that the $5.6 million vacancy factor savings includes the vacancy factor adjustments.

2.230.9.2 If not confirmed, please explain if there are cost savings achieved through the vacancy factor adjustments, and if so, where these savings can be located in the Application, specifically, Appendix A.

**RESPONSE:**

**There are no cost savings through vacancy factor adjustments. Please refer to BC Hydro's response to BCUC IR 2.230.9 where we describe when vacancy factor adjustments are utilized.**

**230.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-1, Section 5.5.2.3, Table 5-6, p. 5-25; Appendix A, Schedule 5, 16; Exhibit B-5, BCUC IR 35.1.2, 43.1, 43.3.2, 68.1**
**Vacancy factor savings**

In Table 5-6 of the Application, BC Hydro provides a vacancy factor savings of $5.6 million and states that "[i]n the test period, BC Hydro has taken a consistent approach to assessing each KBU and identifying any budget reductions associated with unfilled positions."

In response to BCUC IR 68.1, BC Hydro stated that the Engineering and Project Delivery KBUs have vacancy factor adjustments.

2.230.10 Please explain why the Engineering and Project Delivery KBUs are the only KBUs that appear to have vacancy factor adjustments.

**RESPONSE:**

**Please refer to BC Hydro's response to BCUC IR 2.230.9.**

**230.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-1, Section 5.5.2.3, Table 5-6, p. 5-25; Appendix A, Schedule 5, 16; Exhibit B-5, BCUC IR 35.1.2, 43.1, 43.3.2, 68.1**
**Vacancy factor savings**

Schedule 16 in Appendix A of the Application shows the FTEs.

2.230.11 Please explain whether the FTEs presented in Schedule 16 are net of vacancies (i.e. total FTEs less vacancies approved for recruitment).

**RESPONSE:**

**The vacancy factor savings of $5.6 million in the test period relate to labour costs only and not FTEs. As a result, vacancy factor savings did not result in FTE reductions and are therefore not included in Appendix A, Schedule 16.0.**

**230.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-1, Section 5.5.2.3, Table 5-6, p. 5-25; Appendix A, Schedule 5, 16; Exhibit B-5, BCUC IR 35.1.2, 43.1, 43.3.2, 68.1**
**Vacancy factor savings**

In response to BCUC IR 35.1.2, BC Hydro stated that the list of vacant positions actively being recruited for are vacant due to one of four reasons: replacement, leave, new position and seasonal position.

2.230.12 Please confirm, or explain otherwise, the portion of the year that a seasonal position is not required to be filled is included in the estimated annual vacancy factor savings.

**RESPONSE:**

**Not confirmed. Seasonal positions are only budgeted for in the months that they are expected to be filled. For example, the Visitor Center Representatives are estimated to be active employees for six months per year on average and as such, the FTE and associated labour budget is based on 0.5 FTE.**

**230.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-1, Section 5.5.2.3, Table 5-6, p. 5-25; Appendix A, Schedule 5, 16; Exhibit B-5, BCUC IR 35.1.2, 43.1, 43.3.2, 68.1**
**Vacancy factor savings**

In response to BCUC IR 35.1.2, BC Hydro stated that the list of vacant positions actively being recruited for are vacant due to one of four reasons: replacement, leave, new position and seasonal position.

2.230.12 Please confirm, or explain otherwise, the portion of the year that a seasonal position is not required to be filled is included in the estimated annual vacancy factor savings.

2.230.12.1 If confirmed, please explain why seasonal positions should be included in the estimated annual vacancy factor savings given that by the nature of the position, these positions not expected to be filled the entire year.

**RESPONSE:**

**Please refer to BC Hydro's response to BCUC IR 2.230.12 where we explain that seasonal positions are only budgeted for in the months that they are expected to be filled and accordingly, are not included in the vacancy factor savings.**

**230.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-1, Section 5.5.2.3, Table 5-6, p. 5-25; Appendix A, Schedule 5, 16; Exhibit B-5, BCUC IR 35.1.2, 43.1, 43.3.2, 68.1**
**Vacancy factor savings**

In response to BCUC IR 35.1.2, BC Hydro stated that the list of vacant positions actively being recruited for are vacant due to one of four reasons: replacement, leave, new position and seasonal position.

2.230.12 Please confirm, or explain otherwise, the portion of the year that a seasonal position is not required to be filled is included in the estimated annual vacancy factor savings.

2.230.12.2 If confirmed, please provide the amount that seasonal positions contribute to the estimated $5.6 million in vacancy factor savings.

**RESPONSE:**

**Please refer to BC Hydro's response to BCUC IR 2.230.12 where we explain that seasonal positions are only budgeted for in the months that they are expected to be filled and accordingly, are not included in the vacancy factor savings.**

**231.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-1, Section 5.5.2.2, Table 5-5, pp. 5-23–5-24;**
**Section 5G.7.2, p. 5G-12;**
**Exhibit B-5, BCUC IR 36.2.1, 36.3, 63.2, 63.6, 63.7**
**Unallocated funds**

In Table 5-5 of the Application, BC Hydro provides a detailed breakdown of Test Period cost increases and includes a $7.0 million incremental savings in F2020 from the reduction of unallocated funds.

In response to BCUC IR 63.2, BC Hydro stated:

> The unallocated funds budget was held centrally in Corporate Costs in order to effectively manage the funding of unplanned work demands and unanticipated cost pressures that arise throughout the fiscal year.
>
> In the Previous Application, an unallocated funds budget of $6.5 million was included for fiscal 2019 in Corporate Costs. …Over the course of the fiscal 2017 to fiscal 2019 test period, additional net savings of $8.5 million were identified and added to the unallocated funds budget, increasing it to $15.0 million...
>
> …forecasts are prepared for and reviewed by the Executive Team on a monthly basis to identify emerging cost pressures and potential areas of savings. In the event that adequate savings could not be identified by the Business Groups to absorb unanticipated cost pressures, the unallocated funds budget would have been considered as a possible funding source.
>
> During the fiscal 2020 and fiscal 2021 test period, there is no unallocated funds budget.

2.231.1 Please explain how BC Hydro will manage the funding of unplanned work demands and unanticipated cost pressures that arise during the Test Period.

**RESPONSE:**

**As described in BC Hydro's response to BCUC IR 1.36.3, budget owners are accountable for their budgets and may take corrective actions to remain on track throughout the fiscal year. Each Executive Team member is accountable for achieving their overall operating cost budget (i.e., the sum of their KBUs within their Business Group).**

**Any unplanned work demands and unanticipated cost pressures that cannot be absorbed within the Business Group will be raised to the Executive Team as part of the monthly review process for discussion of corrective action options such as advancing or delaying work and may result in target adjustments between Business Groups, while keeping BC Hydro's operating budget net neutral.**

**As there is no unallocated funds budget available in the current test period, all funding of unplanned work demands and unanticipated cost pressures will need to come through target adjustments that equal zero on a net basis or will result in a direct impact to the shareholder, all else equal. Without the unallocated funds budget, BC Hydro recognizes it will be a significant challenge to manage within the overall operating budget during the test period.**

**231.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-1, Section 5.5.2.2, Table 5-5, pp. 5-23–5-24;**
**Section 5G.7.2, p. 5G-12;**
**Exhibit B-5, BCUC IR 36.2.1, 36.3, 63.2, 63.6, 63.7**
**Unallocated funds**

In Table 5-5 of the Application, BC Hydro provides a detailed breakdown of Test Period cost increases and includes a $7.0 million incremental savings in F2020 from the reduction of unallocated funds.

In response to BCUC IR 63.2, BC Hydro stated:

> The unallocated funds budget was held centrally in Corporate Costs in order to effectively manage the funding of unplanned work demands and unanticipated cost pressures that arise throughout the fiscal year.
>
> In the Previous Application, an unallocated funds budget of $6.5 million was included for fiscal 2019 in Corporate Costs. …Over the course of the fiscal 2017 to fiscal 2019 test period, additional net savings of $8.5 million were identified and added to the unallocated funds budget, increasing it to $15.0 million...
>
> …forecasts are prepared for and reviewed by the Executive Team on a monthly basis to identify emerging cost pressures and potential areas of savings. In the event that adequate savings could not be identified by the Business Groups to absorb unanticipated cost pressures, the unallocated funds budget would have been considered as a possible funding source.
>
> During the fiscal 2020 and fiscal 2021 test period, there is no unallocated funds budget.

2.231.2 Given that there are no unallocated funds planned for the Test Period, please explain if there is another fund planned for the Test Period with a similar purpose.

**RESPONSE:**

**BC Hydro confirms that there are no other unallocated funds budget(s) planned in the test period to fund unplanned work demands and unanticipated cost pressures that arise throughout the fiscal year. As described in BC Hydro's response to BCUC IR 2.231.1, the funding of unplanned work demands and unanticipated cost pressures will need to come through management of Business Group budgets and/or target adjustments which net to zero in order to remain within BC Hydro's overall operating budget.**

**231.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-1, Section 5.5.2.2, Table 5-5, pp. 5-23–5-24;**
**Section 5G.7.2, p. 5G-12;**
**Exhibit B-5, BCUC IR 36.2.1, 36.3, 63.2, 63.6, 63.7**
**Unallocated funds**

In response to BCUC IR 36.2.1, BC Hydro stated: "As part of the review process, the Executive Team may approve funding reallocations between Business Groups or KBUs. These approved funding reallocations then form the target for the fiscal year."

Further, in response to BCUC IR 36.3, BC Hydro stated: "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 and may result in target adjustments for a KBU, while keeping BC Hydro's overall budget the same."

2.231.3 In reference to BC Hydro's methodology of making "adjustments for a KBU, while keeping BC Hydro's overall budget the same," please discuss whether this is comparable to operating within an approved spending envelope for operating expenses under a performance based regulation regime. Please discuss the similarities and differences.

**RESPONSE:**

**BC Hydro has not proposed a PBR plan in this proceeding. The extent to which cost of service regulation and performance based regulation (PBR) are similar or different with regards to operating within an approved spending envelope for operating expenditures, depends on the design of a potential PBR plan for BC Hydro.**

**Under both approaches, BC Hydro expects that its revenue requirements would be set for a period of time and BC Hydro would need to manage any cost pressures that could not be deferred within those constraints. However, there are two key potential differences:**

- **First, as discussed in section 11.4.1 of Chapter 11 of the Application, under PBR, rates are typically set for a longer period of time. As a result, BC Hydro would assume greater risk with regards to cost pressures that cannot be deferred, given the longer period of time before rates are re-based. As noted by Dr. Weisman in BC Hydro's response to BCUC IR 1.193.1, this increased**

**risk would be reflected in an increased cost of capital and therefore, higher rates for consumers, holding all other factors constant; and**

- **Second, whether certain cost pressures can be deferred under PBR depends on the criteria established for the Y factor (uncontrollable factor) and Z factor (unforeseen factor). If PBR were adopted for BC Hydro and the criteria for these factors were different from BC Hydro's current cost of service framework, BC Hydro may assume more or less risk with regards to operating within an approved spending envelope for operating expenditures.**

**231.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-1, Section 5.5.2.2, Table 5-5, pp. 5-23–5-24;**
**Section 5G.7.2, p. 5G-12;**
**Exhibit B-5, BCUC IR 36.2.1, 36.3, 63.2, 63.6, 63.7**
**Unallocated funds**

In response to BCUC IR 36.2.1, BC Hydro stated: "As part of the review process, the Executive Team may approve funding reallocations between Business Groups or KBUs. These approved funding reallocations then form the target for the fiscal year."

Further, in response to BCUC IR 36.3, BC Hydro stated: "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 and may result in target adjustments for a KBU, while keeping BC Hydro's overall budget the same."

2.231.4 Please discuss whether emerging cost pressures and potential areas of savings will be evaluated over the Test Period, and where adequate savings are not identified in the Business Group experiencing cost pressures, cost savings from another Business Group may be applied, similar to the unallocated funds.

**RESPONSE:**

**BC Hydro is continually evaluating and reviewing emerging cost pressures and potential areas of savings in order to manage within the overall operating budget. Please refer to BC Hydro's response to BCUC IR 2.231.1, where we note that as unplanned work demands and unanticipated cost pressures that cannot be absorbed within a Business Group are raised to the Executive Team as part of the monthly review process, there could be target adjustments made between the Business Groups. Such adjustments net to zero and hence do not increase BC Hydro's overall operating cost budget.**

**231.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-1, Section 5.5.2.2, Table 5-5, pp. 5-23–5-24;**
**Section 5G.7.2, p. 5G-12;**
**Exhibit B-5, BCUC IR 36.2.1, 36.3, 63.2, 63.6, 63.7**
**Unallocated funds**

In response to BCUC IR 36.2.1, BC Hydro stated: "As part of the review process, the Executive Team may approve funding reallocations between Business Groups or KBUs. These approved funding reallocations then form the target for the fiscal year."

Further, in response to BCUC IR 36.3, BC Hydro stated: "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 and may result in target adjustments for a KBU, while keeping BC Hydro's overall budget the same."

2.231.5 Please explain how the reallocation/repurposing of funds between Business Groups drives process improvements and conveys an expectation for the efficient use of existing budgets.

**RESPONSE:**

**Each Business Group is expected to manage within their operating budget and the Executive Team members do so by managing the KBUs within their Business Group to stay on track with the Business Group total operating budget.**

**As stated in section 5.4.2 of Chapter 5 of the Application, "During the budgeting process for this Application, which occurred in conjunction with the Comprehensive Review, the Executive Team determined that, with the exception of certain uncontrollable costs and Standard Labour Rate increases, all cost pressures would be managed within the existing (i.e., fiscal 2019 forecast) operating cost budget."**

**In order to manage the cost pressures that arose before the test period and were not able to be funded, and that arise during the test period, Business Groups are always working to ensure efficient use of existing operating budgets, as well as identifying potential areas of savings. Both the efficient use of existing budgets and savings identified are used to offset cost pressures and manage within the Business Group's total operating budget.**

**231.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-1, Section 5.5.2.2, Table 5-5, pp. 5-23–5-24;**
**Section 5G.7.2, p. 5G-12;**
**Exhibit B-5, BCUC IR 36.2.1, 36.3, 63.2, 63.6, 63.7**
**Unallocated funds**

In response to BCUC IR 63.6, BC Hydro confirmed it collected $16.9 million in F2019 rates related to unallocated funds and trailing costs for the Accenture repatriation, and is now proposing to reallocate these funds in the Test Period.

Further in response to BCUC IR 63.7, BC Hydro stated:

> Provided below is a table of the unallocated funds budget, the expenditures incurred and the balance available in each fiscal year for unplanned work demands and unanticipated cost pressures incurred in the KBUs. Unspent amounts do not carry forward; the unallocated funds budget is determined each year….

| | Fiscal 2015 | Fiscal 2016 | Fiscal 2017 | Fiscal 2018 |
| --- | --- | --- | --- | --- |
| RRA Plan | 4.9 | 10.1 | 4.0 | 5.2 |
| Annual Planning Adjustments | - | (3.6) | - | 4.8 |
| Unallocated Funds Usage | | | | |
| Acquisition of 2/3 Waneta | - | - | (1.5) | (1.6) |
| Accenture Repatriation | - | - | - | (1.7) |
| PST Self-Assessment | - | - | (1.4) | - |
| Various Other | (1.1) | (0.1) | - | - |
| Unallocated Funds Available for Other Cost Pressures during the Year | 3.8 | 6.4 | 1.2 | 6.7 |

2.231.6 Please provide a similar breakdown for F2019.

**RESPONSE:**

**The table provided below has been expanded to include fiscal 2019. As shown in the attachments provided to BC Hydro's response to BCUC IR 1.63.5, BC Hydro provided information regarding the unallocated funds budget included in Corporate Costs from fiscal 2015 to fiscal 2019 in responding to questions during the Previous Application proceeding.**

| | Fiscal 2015 | Fiscal 2016 | Fiscal 2017 | Fiscal 2018 | Fiscal 2019 |
|---|---|---|---|---|---|
| RRA Plan | 4.9 | 10.1 | 4.0 | 5.2 | 6.5 |
| Annual Planning Adjustments | - | (3.6) | - | 4.8 | 8.5 |
| Unallocated Funds Budget Expenditures | | | | | |
| Acquisition of 2/3 Waneta | - | - | (1.5) | (1.6) | - |
| Accenture Repatriation | - | - | - | (1.7) | - |
| PST Self-Assessment | - | - | (1.4) | - | - |
| NEB and BCUC Cost Recovery Levies | - | - | - | - | (3.0) |
| ARC Generator Rental | - | - | - | - | (1.0) |
| Various Other | (1.1) | (0.1) | - | - | (0.2) |
| Unallocated Funds Available for Other Cost Pressures during the Year | 3.8 | 6.4 | 1.2 | 6.7 | 10.8 |

**The 231.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-1, Section 5.5.2.2, Table 5-5, pp. 5-23–5-24;**
**Section 5G.7.2, p. 5G-12;**
**Exhibit B-5, BCUC IR 36.2.1, 36.3, 63.2, 63.6, 63.7**
**Unallocated funds**

In response to BCUC IR 63.6, BC Hydro confirmed it collected $16.9 million in F2019 rates related to unallocated funds and trailing costs for the Accenture repatriation, and is now proposing to reallocate these funds in the Test Period.

Further in response to BCUC IR 63.7, BC Hydro stated:

> Provided below is a table of the unallocated funds budget, the expenditures incurred and the balance available in each fiscal year for unplanned work demands and unanticipated cost pressures incurred in the KBUs. Unspent amounts do not carry forward; the unallocated funds budget is determined each year….

| | Fiscal 2015 | Fiscal 2016 | Fiscal 2017 | Fiscal 2018 |
| --- | --- | --- | --- | --- |
| RRA Plan | 4.9 | 10.1 | 4.0 | 5.2 |
| Annual Planning Adjustments | - | (3.6) | - | 4.8 |
| Unallocated Funds Usage | | | | |
| Acquisition of 2/3 Waneta | - | - | (1.5) | (1.6) |
| Accenture Repatriation | - | - | - | (1.7) |
| PST Self-Assessment | - | - | (1.4) | - |
| Various Other | (1.1) | (0.1) | - | - |
| Unallocated Funds Available for Other Cost Pressures during the Year | 3.8 | 6.4 | 1.2 | 6.7 |

2.231.7 Given that unallocated funds were historically meant to manage the funding of unplanned work and unanticipated cost pressures, please explain how the unallocated funds budget included in the RRA plan for F2015 to F2019 was determined or forecasted.

**RESPONSE:**

**The unallocated funds budget was not for a forecast amount of unplanned work or unanticipated cost pressures. Rather, the unallocated funds budget was the residual amount remaining between the annual bottom-up budgeting process followed by the KBUs/Business Groups and the top-down target set by the**

**Executive Team. The annual budgeting approach is described in more detail in section 5.4.2 of Chapter 5 of the Application.**

**Business Groups identified cost pressures and savings opportunities during the annual budgeting process. These items were raised to the Executive Team for review and any approved net cost pressures or savings were reflected in the Annual Planning Adjustments line (specifically, as shown in the table in BC Hydro's response to BCUC IR 2.231.6, these occurred in fiscal 2016, fiscal 2018 and fiscal 2019).**

**231.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-1, Section 5.5.2.2, Table 5-5, pp. 5-23–5-24;**
**Section 5G.7.2, p. 5G-12;**
**Exhibit B-5, BCUC IR 36.2.1, 36.3, 63.2, 63.6, 63.7**
**Unallocated funds**

In response to BCUC IR 63.6, BC Hydro confirmed it collected $16.9 million in F2019 rates related to unallocated funds and trailing costs for the Accenture repatriation, and is now proposing to reallocate these funds in the Test Period.

Further in response to BCUC IR 63.7, BC Hydro stated:

> Provided below is a table of the unallocated funds budget, the expenditures incurred and the balance available in each fiscal year for unplanned work demands and unanticipated cost pressures incurred in the KBUs. Unspent amounts do not carry forward; the unallocated funds budget is determined each year….

| | Fiscal 2015 | Fiscal 2016 | Fiscal 2017 | Fiscal 2018 |
|---|---|---|---|---|
| RRA Plan | 4.9 | 10.1 | 4.0 | 5.2 |
| Annual Planning Adjustments | - | (3.6) | - | 4.8 |
| Unallocated Funds Usage | | | | |
| Acquisition of 2/3 Waneta | - | - | (1.5) | (1.6) |
| Accenture Repatriation | - | - | - | (1.7) |
| PST Self-Assessment | - | - | (1.4) | - |
| Various Other | (1.1) | (0.1) | - | - |
| Unallocated Funds Available for Other Cost Pressures during the Year | 3.8 | 6.4 | 1.2 | 6.7 |

2.231.8 Please explain how the $16.9 million incremental savings from repurposing unallocated funds in F2019 to F2020 impacts F2021 planned costs, if any.

**RESPONSE:**

**The repurposing of the unallocated funds and trailing costs for the Accenture repatriation will have the same effect in fiscal 2021 as it does in fiscal 2020. The re-purposed budget carries forward through the test period to assist with the labour, maintenance and John Hart cost pressures described on page 5G-12 of Chapter 5G of the Application.**

**231.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-1, Section 5.5.2.2, Table 5-5, pp. 5-23–5-24;**
**Section 5G.7.2, p. 5G-12;**
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**Unallocated funds**

In response to BCUC IR 63.6, BC Hydro confirmed it collected $16.9 million in F2019 rates related to unallocated funds and trailing costs for the Accenture repatriation, and is now proposing to reallocate these funds in the Test Period.

Further in response to BCUC IR 63.7, BC Hydro stated:

> Provided below is a table of the unallocated funds budget, the expenditures incurred and the balance available in each fiscal year for unplanned work demands and unanticipated cost pressures incurred in the KBUs. Unspent amounts do not carry forward; the unallocated funds budget is determined each year….

| | Fiscal 2015 | Fiscal 2016 | Fiscal 2017 | Fiscal 2018 |
|---|---|---|---|---|
| RRA Plan | 4.9 | 10.1 | 4.0 | 5.2 |
| Annual Planning Adjustments | - | (3.6) | - | 4.8 |
| Unallocated Funds Usage | | | | |
| Acquisition of 2/3 Waneta | - | - | (1.5) | (1.6) |
| Accenture Repatriation | - | - | - | (1.7) |
| PST Self-Assessment | - | - | (1.4) | - |
| Various Other | (1.1) | (0.1) | - | - |
| Unallocated Funds Available for Other Cost Pressures during the Year | 3.8 | 6.4 | 1.2 | 6.7 |

2.231.9 Please clarify how $16.9 million of unallocated funds and trailing costs for the Accenture repatriation from F2019 can be reallocated in the Test Period if unspent amounts do not carry forward.

**RESPONSE:**

**The unspent amounts that do not carry forward (described in BC Hydro's response to BCUC IR 1.63.7) refer to operating budgets that are not spent in a specific fiscal year. While the unspent amount from the prior fiscal cannot be carried forward, this does not impact the annual budget for the subsequent fiscal year.**

**231.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-1, Section 5.5.2.2, Table 5-5, pp. 5-23–5-24;**
**Section 5G.7.2, p. 5G-12;**
**Exhibit B-5, BCUC IR 36.2.1, 36.3, 63.2, 63.6, 63.7**
**Unallocated funds**

In response to BCUC IR 63.6, BC Hydro confirmed it collected $16.9 million in F2019 rates related to unallocated funds and trailing costs for the Accenture repatriation, and is now proposing to reallocate these funds in the Test Period.

Further in response to BCUC IR 63.7, BC Hydro stated:

> Provided below is a table of the unallocated funds budget, the expenditures incurred and the balance available in each fiscal year for unplanned work demands and unanticipated cost pressures incurred in the KBUs. Unspent amounts do not carry forward; the unallocated funds budget is determined each year….

| | Fiscal 2015 | Fiscal 2016 | Fiscal 2017 | Fiscal 2018 |
|---|---|---|---|---|
| RRA Plan | 4.9 | 10.1 | 4.0 | 5.2 |
| Annual Planning Adjustments | - | (3.6) | - | 4.8 |
| Unallocated Funds Usage | | | | |
| Acquisition of 2/3 Waneta | - | - | (1.5) | (1.6) |
| Accenture Repatriation | - | - | - | (1.7) |
| PST Self-Assessment | - | - | (1.4) | - |
| Various Other | (1.1) | (0.1) | - | - |
| Unallocated Funds Available for Other Cost Pressures during the Year | 3.8 | 6.4 | 1.2 | 6.7 |

2.231.10 Please explain what happened to the $16.9 million collected in rates in F2019. If unspent, please clarify if the $16.9 million becomes part of retained earnings at fiscal year end. If spent, please specify the expenditures/cost pressures.

**RESPONSE:**

**As shown in BC Hydro's response to BCUC IR 2.231.6, a portion of the unallocated funds budget in fiscal 2019 was used to fund operating cost pressures charged directly to Corporate Costs (e.g., NEB and BCUC Cost Recovery Levies increases).**

**After funding these cost pressures, there was $10.8 million Unallocated Funds Available for Other Cost Pressures during the Year. These funds were used to offset operating cost pressures in the Business Groups (i.e., additional line and stations maintenance work in the Line Asset Planning and Stations Asset Planning KBUs). For BC Hydro's overall operating cost variances, please refer to section 4 of Appendix G of the Evidentiary Update.**

**Any net variance remaining in BC Hydro's overall base operating cost actuals was used to fund other non-operating, non-deferrable cost pressures.**

**As described in BC Hydro's response to CEC IR 2.128.3, the fiscal 2019 actual net income (excluding the impact of the write-off of the Rate Smoothing Account) was $4.0 million lower than plan. Accordingly, unspent operating costs did not become part of retained earnings at year end.**

**231.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-1, Section 5.5.2.2, Table 5-5, pp. 5-23–5-24;**
**Section 5G.7.2, p. 5G-12;**
**Exhibit B-5, BCUC IR 36.2.1, 36.3, 63.2, 63.6, 63.7**
**Unallocated funds**

In response to BCUC IR 63.6, BC Hydro confirmed it collected $16.9 million in F2019 rates related to unallocated funds and trailing costs for the Accenture repatriation, and is now proposing to reallocate these funds in the Test Period.

Further in response to BCUC IR 63.7, BC Hydro stated:

> Provided below is a table of the unallocated funds budget, the expenditures incurred and the balance available in each fiscal year for unplanned work demands and unanticipated cost pressures incurred in the KBUs. Unspent amounts do not carry forward; the unallocated funds budget is determined each year….

| | Fiscal 2015 | Fiscal 2016 | Fiscal 2017 | Fiscal 2018 |
|---|---|---|---|---|
| RRA Plan | 4.9 | 10.1 | 4.0 | 5.2 |
| Annual Planning Adjustments | - | (3.6) | - | 4.8 |
| Unallocated Funds Usage | | | | |
| Acquisition of 2/3 Waneta | - | - | (1.5) | (1.6) |
| Accenture Repatriation | - | - | - | (1.7) |
| PST Self-Assessment | - | - | (1.4) | - |
| Various Other | (1.1) | (0.1) | - | - |
| Unallocated Funds Available for Other Cost Pressures during the Year | 3.8 | 6.4 | 1.2 | 6.7 |

2.231.11 Please explain what is meant by “unallocated funds available for other cost pressures during the year.” Please discuss if this refers to unallocated funds that were not used (i.e. unused amounts).

**RESPONSE:**

**As described in section 5G.7.2 of Chapter 5G of the Application, the unallocated funds budget was held in Corporate Costs. The table in the preamble reflects the annual operating budget and the costs in Corporate Costs that utilized the unallocated funds budget.**

**The Unallocated Funds Available for Other Cost Pressures during the Year line item is the remaining amount available to offset other cost pressures in the business that arise during the fiscal year. An example was additional line and stations maintenance work in the Line Asset Planning and Stations Asset Planning KBUs. In this example, the Line Asset Planning and Stations Asset Planning KBUs would be over budget to offset Corporate Costs' under budget.**

**For additional information on how the Unallocated Funds Available for Other Cost Pressures during the Year is used, please refer to BC Hydro's response to BCUC IR 2.231.10.**

**231.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-1, Section 5.5.2.2, Table 5-5, pp. 5-23–5-24;**
**Section 5G.7.2, p. 5G-12;**
**Exhibit B-5, BCUC IR 36.2.1, 36.3, 63.2, 63.6, 63.7**
**Unallocated funds**

In response to BCUC IR 63.6, BC Hydro confirmed it collected $16.9 million in F2019 rates related to unallocated funds and trailing costs for the Accenture repatriation, and is now proposing to reallocate these funds in the Test Period.

Further in response to BCUC IR 63.7, BC Hydro stated:

> Provided below is a table of the unallocated funds budget, the expenditures incurred and the balance available in each fiscal year for unplanned work demands and unanticipated cost pressures incurred in the KBUs. Unspent amounts do not carry forward; the unallocated funds budget is determined each year….

| | Fiscal 2015 | Fiscal 2016 | Fiscal 2017 | Fiscal 2018 |
| --- | --- | --- | --- | --- |
| RRA Plan | 4.9 | 10.1 | 4.0 | 5.2 |
| Annual Planning Adjustments | - | (3.6) | - | 4.8 |
| Unallocated Funds Usage | | | | |
| Acquisition of 2/3 Waneta | - | - | (1.5) | (1.6) |
| Accenture Repatriation | - | - | - | (1.7) |
| PST Self-Assessment | - | - | (1.4) | - |
| Various Other | (1.1) | (0.1) | - | - |
| Unallocated Funds Available for Other Cost Pressures during the Year | 3.8 | 6.4 | 1.2 | 6.7 |

2.231.12 Please explain what happened to the F2015 to F2018 "unallocated funds available for other cost pressures during the year." Were any of the funds to the account of the shareholder or spent on other cost pressures during the year? If spent on other cost pressures, please identify the cost pressures and the amount spent on each.

**RESPONSE:**

**As described in BC Hydro's response to BCUC IR 2.231.10, the Unallocated Funds Available for Other Cost Pressures during the Year were first used to offset**

**operating cost pressures in the Business Groups. For BC Hydro's overall operating cost variances, please refer to section 4 of Appendix G of the Application (for fiscal 2017 and fiscal 2018) and to section 4 of Appendix G of the Evidentiary Update (for fiscal 2019).**

**Any net variance remaining in BC Hydro's overall base operating cost actuals was used to fund other non-operating, non-deferrable cost pressures.**

**As described in BC Hydro's response to CEC IR 2.128.3, the actual net income has been at or below the approved RRA net income in four of the last five years. Accordingly, as discussed in BC Hydro's response to BCUC IR 2.231.10, any unspent operating costs did not become part of retained earnings at year-end.**

**231.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-1, Section 5.5.2.2, Table 5-5, pp. 5-23–5-24;**
**Section 5G.7.2, p. 5G-12;**
**Exhibit B-5, BCUC IR 36.2.1, 36.3, 63.2, 63.6, 63.7**
**Unallocated funds**

In response to BCUC IR 63.6, BC Hydro confirmed it collected $16.9 million in F2019 rates related to unallocated funds and trailing costs for the Accenture repatriation, and is now proposing to reallocate these funds in the Test Period.

Further in response to BCUC IR 63.7, BC Hydro stated:

> Provided below is a table of the unallocated funds budget, the expenditures incurred and the balance available in each fiscal year for unplanned work demands and unanticipated cost pressures incurred in the KBUs. Unspent amounts do not carry forward; the unallocated funds budget is determined each year….

| | Fiscal 2015 | Fiscal 2016 | Fiscal 2017 | Fiscal 2018 |
| --- | --- | --- | --- | --- |
| RRA Plan | 4.9 | 10.1 | 4.0 | 5.2 |
| Annual Planning Adjustments | - | (3.6) | - | 4.8 |
| Unallocated Funds Usage | | | | |
| Acquisition of 2/3 Waneta | - | - | (1.5) | (1.6) |
| Accenture Repatriation | - | - | - | (1.7) |
| PST Self-Assessment | - | - | (1.4) | - |
| Various Other | (1.1) | (0.1) | - | - |
| Unallocated Funds Available for Other Cost Pressures during the Year | 3.8 | 6.4 | 1.2 | 6.7 |

2.231.13 Assuming the "unallocated funds available for other cost pressures during the year" did not address other cost pressures in the year, please explain why these amounts are not alleviating cost pressures in the subsequent year, similar to how the $16.9 million of unallocated funds from F2019 is reallocate to the Test Period.

**RESPONSE:**

**As described in BC Hydro's response to BCUC IRs 2.231.10 and 2.231.12, the Unallocated Funds Available for Other Cost Pressures during the Year were used**

**in previous years to offset operating cost pressures in the business, and non-operating, non-deferrable cost pressures.**

**As described in BC Hydro's response to BCUC IR 2.231.1, because the unallocated funds budget has been re-purposed, it will be a significant challenge to manage within the overall operating budget and the approved RRA Net Income during the test period.**

**231.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-1, Section 5.5.2.2, Table 5-5, pp. 5-23–5-24;**
**Section 5G.7.2, p. 5G-12;**
**Exhibit B-5, BCUC IR 36.2.1, 36.3, 63.2, 63.6, 63.7**
**Unallocated funds**

In response to BCUC IR 63.6, BC Hydro confirmed it collected $16.9 million in F2019 rates related to unallocated funds and trailing costs for the Accenture repatriation, and is now proposing to reallocate these funds in the Test Period.

Further in response to BCUC IR 63.7, BC Hydro stated:

> Provided below is a table of the unallocated funds budget, the expenditures incurred and the balance available in each fiscal year for unplanned work demands and unanticipated cost pressures incurred in the KBUs. Unspent amounts do not carry forward; the unallocated funds budget is determined each year….

| | Fiscal 2015 | Fiscal 2016 | Fiscal 2017 | Fiscal 2018 |
|---|---|---|---|---|
| RRA Plan | 4.9 | 10.1 | 4.0 | 5.2 |
| Annual Planning Adjustments | - | (3.6) | - | 4.8 |
| Unallocated Funds Usage | | | | |
| Acquisition of 2/3 Waneta | - | - | (1.5) | (1.6) |
| Accenture Repatriation | - | - | - | (1.7) |
| PST Self-Assessment | - | - | (1.4) | - |
| Various Other | (1.1) | (0.1) | - | - |
| Unallocated Funds Available for Other Cost Pressures during the Year | 3.8 | 6.4 | 1.2 | 6.7 |

2.231.14 Please explain what is meant by "Annual Planning Adjustments."

**RESPONSE:**

**As noted in BC Hydro's response to BCUC IR 2.231.7, the Annual Planning Adjustments line relates to any approved net cost pressures or savings approved during the annual budgeting process for the upcoming fiscal year.**

**231.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-1, Section 5.5.2.2, Table 5-5, pp. 5-23–5-24;**
**Section 5G.7.2, p. 5G-12;**
**Exhibit B-5, BCUC IR 36.2.1, 36.3, 63.2, 63.6, 63.7**
**Unallocated funds**

In response to BCUC IR 63.6, BC Hydro confirmed it collected $16.9 million in F2019 rates related to unallocated funds and trailing costs for the Accenture repatriation, and is now proposing to reallocate these funds in the Test Period.

Further in response to BCUC IR 63.7, BC Hydro stated:

> Provided below is a table of the unallocated funds budget, the expenditures incurred and the balance available in each fiscal year for unplanned work demands and unanticipated cost pressures incurred in the KBUs. Unspent amounts do not carry forward; the unallocated funds budget is determined each year….

| | Fiscal 2015 | Fiscal 2016 | Fiscal 2017 | Fiscal 2018 |
| --- | --- | --- | --- | --- |
| RRA Plan | 4.9 | 10.1 | 4.0 | 5.2 |
| Annual Planning Adjustments | - | (3.6) | - | 4.8 |
| Unallocated Funds Usage | | | | |
| Acquisition of 2/3 Waneta | - | - | (1.5) | (1.6) |
| Accenture Repatriation | - | - | - | (1.7) |
| PST Self-Assessment | - | - | (1.4) | - |
| Various Other | (1.1) | (0.1) | - | - |
| Unallocated Funds Available for Other Cost Pressures during the Year | 3.8 | 6.4 | 1.2 | 6.7 |

2.231.15 Please elaborate on what the $1.7 million cost pressure in F2018 relates to, and whether this amount is included in the Accenture repatriation savings.

**RESPONSE:**

**The $1.7 million cost pressure in fiscal 2018 for Accenture Repatriation reflects one-time costs incurred for the transition of the services previously performed by Accenture back into BC Hydro. Examples of costs included in the $1.7 million are internal resources assigned to the transition team as well as information technology and legal costs. As these were one-time costs in fiscal 2018, they are not included in the Accenture Repatriation savings as calculated in Table 5-11 of Chapter 5 of the Application.**

**231.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-1, Section 5.5.2.2, Table 5-5, pp. 5-23–5-24;**
**Section 5G.7.2, p. 5G-12;**
**Exhibit B-5, BCUC IR 36.2.1, 36.3, 63.2, 63.6, 63.7**
**Unallocated funds**

In response to BCUC IR 63.6, BC Hydro confirmed it collected $16.9 million in F2019 rates related to unallocated funds and trailing costs for the Accenture repatriation, and is now proposing to reallocate these funds in the Test Period.

Further in response to BCUC IR 63.7, BC Hydro stated:

> Provided below is a table of the unallocated funds budget, the expenditures incurred and the balance available in each fiscal year for unplanned work demands and unanticipated cost pressures incurred in the KBUs. Unspent amounts do not carry forward; the unallocated funds budget is determined each year….

| | Fiscal 2015 | Fiscal 2016 | Fiscal 2017 | Fiscal 2018 |
|---|---|---|---|---|
| RRA Plan | 4.9 | 10.1 | 4.0 | 5.2 |
| Annual Planning Adjustments | - | (3.6) | - | 4.8 |
| Unallocated Funds Usage | | | | |
| Acquisition of 2/3 Waneta | - | - | (1.5) | (1.6) |
| Accenture Repatriation | - | - | - | (1.7) |
| PST Self-Assessment | - | - | (1.4) | - |
| Various Other | (1.1) | (0.1) | - | - |
| Unallocated Funds Available for Other Cost Pressures during the Year | 3.8 | 6.4 | 1.2 | 6.7 |

2.231.16 Please explain what is meant by "PST Self-Assessment" and provide details of this cost pressure.

**RESPONSE:**

**The PST-Self Assessment line item referred to in the table provided in BC Hydro's response to BCUC IR 1.63.7 is in relation to a voluntary disclosure procedure BC Hydro performed in fiscal 2017 to remit PST self-assessments to the BC Ministry of Finance, dating back to April 1, 2013. The $1.4 million recorded in operating costs is an accrual for the estimated PST self-assessments not related to capital projects.**

**231.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-1, Section 5.5.2.2, Table 5-5, pp. 5-23–5-24;**
**Section 5G.7.2, p. 5G-12;**
**Exhibit B-5, BCUC IR 36.2.1, 36.3, 63.2, 63.6, 63.7**
**Unallocated funds**

On page 5G-12 of the Application, BC Hydro states:

> The 2013 10 Year Rates Plan prescribed certain operating cost and rate increase targets, to manage unanticipated cost pressures within these targets, BC Hydro maintained a budget of unallocated funds.

2.231.17 Please explain why there are no unallocated funds for F2013 and F2014 in the above table.

**RESPONSE:**

**The table provided in BC Hydro's response to BCUC IR 1.63.7 did not include fiscal 2013 and fiscal 2014 as there was no unallocated funds budget during these years.**

**232.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-1, Section 6.4.15, Table 6-43, p. 6-123;**
**Section 6.4.15.2, p. 6-134;**
**Exhibit B-5, BCUC IR 63.11, 63.12, 63.13.3.3**
**Power system assets/vegetation management and storm restoration**

In response to BCUC IR 63.11, BC Hydro stated: "The December 2018 storm remediation expenditures were approximately $22.9 million. Of these expenditures, approximately $5.1 million were capitalized for asset replacements, and $17.8 million were related to repairs and charged to the Storm Restoration budget."

In this same response, BC Hydro provided the actual costs of the three most costly storms that it has record of, which included the December 2018 windstorm at a cost of $22.9 million and the August 2018 wildfire at a cost of $8.9 million.

Further in response to BCUC IR 63.12, BC Hydro stated: "Audited financial results for fiscal 2019 are not yet available. The recalculation of the five-year average, using the fiscal 2019 forecast, which excludes the December 2018 storm impact… would be as follows:"

| Based on F19 Forecast included in F20-21 RRA | F2015 ($ million) | F2016 ($ million) | F2017 ($ million) | F2018 ($ million) | F2019 ($ million) | F2015-F2019 Average ($ million) |
|---|---|---|---|---|---|---|
| Storm Restoration Costs | 12.9 | 23.5 | 25.3 | 22.9 | 6.7 | 18.3 |

2.232.1 Please confirm, or explain otherwise, that the $6.7 million storm restoration costs in F2019 include all operating costs associated with the August 2018 wildfire. If not confirmed, please provide a breakdown of the storm restoration costs included in the $6.7 million.

**RESPONSE:**

**This answer also responds to BCUC IRs 2.232.2 and 2.232.3.**

**Not confirmed. In responding to this question, BC Hydro identified a typographical error in BC Hydro's response to BCUC IR 1.63.11. The third most expensive storm was listed as the "August 2018 wildfire: $8.9 million." This storm event should be**

**listed as the "August 2017 wildfire: $8.9 million." This correction has no impact on the financial information presented in the Application.**

**The August 2017 wildfire expenditures of $8.9 million were incurred in fiscal 2018 and were accounted for as follows: $5.1 million was related to repairs and charged to the Storm Restoration operating costs budget and $3.8 million was capitalized for asset replacements. Therefore, noting the error above, BC Hydro can confirm that all operating costs ($5.1 million) related to the August 2017 wildfire were included in fiscal 2018 actual costs (i.e., they are included in the $22.9 million shown in the table above).**

**The fiscal 2019 forecast Storm Restoration operating costs of $6.7 million in the table provided in BC Hydro's response to BCUC IR 1.63.12 is the fiscal 2019 forecast amount included in the Previous Application.**

**Fiscal 2019 actual Storm Restoration operating costs were $25.6 million. The five-year average of actual Storm Restoration operating costs from fiscal 2015 to fiscal 2019 is $22.0 million, as follows:**

**Storm Restoration Operating Costs Fiscal 2015 to Fiscal 2019 Actual**

| **($ million)** | **F2015 Actual** | **F2016 Actual** | **F2017 Actual** | **F2018 Actual** | **F2019 Actual** | **F2015-F2019 Average** |
|---|---|---|---|---|---|---|
| | 1 | 2 | 3 | 4 | 5 | 6 |
| Storm Restoration Operating Costs | 12.9 | 23.5 | 25.3 | 22.9 | 25.6 | **22.0** |

**232.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-1, Section 6.4.15, Table 6-43, p. 6-123;**
**Section 6.4.15.2, p. 6-134;**
**Exhibit B-5, BCUC IR 63.11, 63.12, 63.13.3.3**
**Power system assets/vegetation management and storm restoration**

In response to BCUC IR 63.11, BC Hydro stated: "The December 2018 storm remediation expenditures were approximately $22.9 million. Of these expenditures, approximately $5.1 million were capitalized for asset replacements, and $17.8 million were related to repairs and charged to the Storm Restoration budget."

In this same response, BC Hydro provided the actual costs of the three most costly storms that it has record of, which included the December 2018 windstorm at a cost of $22.9 million and the August 2018 wildfire at a cost of $8.9 million.

Further in response to BCUC IR 63.12, BC Hydro stated: "Audited financial results for fiscal 2019 are not yet available. The recalculation of the five-year average, using the fiscal 2019 forecast, which excludes the December 2018 storm impact… would be as follows:"

| Based on F19 Forecast included in F20-21 RRA | F2015 ($ million) | F2016 ($ million) | F2017 ($ million) | F2018 ($ million) | F2019 ($ million) | F2015-F2019 Average ($ million) |
|---|---|---|---|---|---|---|
| Storm Restoration Costs | 12.9 | 23.5 | 25.3 | 22.9 | 6.7 | 18.3 |

2.232.2 Please confirm, or explain otherwise, that capital costs associated with the August 2018 wildfire were $2.2 million ($8.9 million less $6.7 million).

**RESPONSE:**

**Not confirmed. Please refer to BC Hydro's response to BCUC IR 2.232.1 where we acknowledge a typographical error and note that the capitalized costs related to the August 2017 wildfire were $3.8 million.**

**232.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-1, Section 6.4.15, Table 6-43, p. 6-123;**
**Section 6.4.15.2, p. 6-134;**
**Exhibit B-5, BCUC IR 63.11, 63.12, 63.13.3.3**
**Power system assets/vegetation management and storm restoration**

In response to BCUC IR 63.11, BC Hydro stated: "The December 2018 storm remediation expenditures were approximately $22.9 million. Of these expenditures, approximately $5.1 million were capitalized for asset replacements, and $17.8 million were related to repairs and charged to the Storm Restoration budget."

In this same response, BC Hydro provided the actual costs of the three most costly storms that it has record of, which included the December 2018 windstorm at a cost of $22.9 million and the August 2018 wildfire at a cost of $8.9 million.

Further in response to BCUC IR 63.12, BC Hydro stated: "Audited financial results for fiscal 2019 are not yet available. The recalculation of the five-year average, using the fiscal 2019 forecast, which excludes the December 2018 storm impact… would be as follows:"

| Based on F19 Forecast included in F20-21 RRA | F2015 ($ million) | F2016 ($ million) | F2017 ($ million) | F2018 ($ million) | F2019 ($ million) | F2015-F2019 Average ($ million) |
|---|---|---|---|---|---|---|
| Storm Restoration Costs | 12.9 | 23.5 | 25.3 | 22.9 | 6.7 | 18.3 |

2.232.3 Please update the above table provided in response to BCUC IR 63.12 to include the December 2018 storm if the F2019 audited financial results are available.

**RESPONSE:**

**Please refer to BC Hydro's response to BCUC IR 2.232.1 where we provide the actual Storm Restoration operating costs for each of fiscal 2015 to fiscal 2019, as well as the five-year average of $22.0 million during that period.**

**232.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-1, Section 6.4.15, Table 6-43, p. 6-123;**
**Section 6.4.15.2, p. 6-134;**
**Exhibit B-5, BCUC IR 63.11, 63.12, 63.13.3.3**
**Power system assets/vegetation management and storm restoration**

In response to BCUC IR 63.11, BC Hydro stated: "The December 2018 storm remediation expenditures were approximately $22.9 million. Of these expenditures, approximately $5.1 million were capitalized for asset replacements, and $17.8 million were related to repairs and charged to the Storm Restoration budget."

In this same response, BC Hydro provided the actual costs of the three most costly storms that it has record of, which included the December 2018 windstorm at a cost of $22.9 million and the August 2018 wildfire at a cost of $8.9 million.

Further in response to BCUC IR 63.12, BC Hydro stated: "Audited financial results for fiscal 2019 are not yet available. The recalculation of the five-year average, using the fiscal 2019 forecast, which excludes the December 2018 storm impact… would be as follows:"

| Based on F19 Forecast included in F20-21 RRA | F2015 ($ million) | F2016 ($ million) | F2017 ($ million) | F2018 ($ million) | F2019 ($ million) | F2015-F2019 Average ($ million) |
|---|---|---|---|---|---|---|
| Storm Restoration Costs | 12.9 | 23.5 | 25.3 | 22.9 | 6.7 | 18.3 |

2.232.4 Considering two of the three most costly storms for BC Hydro occurred in F2019, please discuss whether using a five-year average approach to forecasting the Test Year storm restoration costs would potentially result in under forecasting storm restoration costs.

**RESPONSE:**

**Please refer to BC Hydro's response to BCUC IR 2.232.1 where we note that BC Hydro identified a typographical error in BC Hydro's response to BCUC IR 1.63.11. The third most expensive storm which was listed as the August 2018 wildfire should have been listed as the August 2017 wildfire (i.e., fiscal 2018). This means that one of the three most costly storms for BC Hydro occurred in fiscal 2019, rather than two storms as noted in the question above.**

**BC Hydro acknowledges the trend in storm costs in recent years and that, given this trend, the five-year average could result in under forecasting storm costs if recent trends continue. However, recent trends may not continue.**

**Using a five-year average to forecast storm restoration costs complies with the requirements of Directive 42 to BCUC's Decision on the Fiscal 2009 to Fiscal 2010 Revenue Requirements Application. Variances between forecast (based on an average of the actual storm restoration costs for the five most recent normal weather years) and actual storm restoration costs are deferred to the Storm Restoration Costs Regulatory Account, in accordance with that order (BCUC Order No. G-16-09):**

> **"The Commission Panel directs BC Hydro to include in its base OMA for the test period average storm-related restoration costs in 2009 dollars for F2009, and 2010 dollars for F2010, respectively, to be calculated as the average of actual costs for the five most recent "normal weather" years: e.g. F2003, F2004, F2005, F2006, and F2008 would be used for F2009; and to record any variance from the average amount for each test year in a separate regulatory account ("the Storm Damage Regulatory Account") to be dealt with in its next RRA."**

**Actual storm restoration costs could be higher or lower than forecast in a given year resulting in additions or reductions to the Storm Restoration Costs Regulatory Account. Amounts deferred to the account in a test period are recovered over the following test period. As a result, ratepayers only pay for the actual storm restoration costs incurred and these costs are recovered over a reasonably short period of time.**

**232.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-1, Section 6.4.15, Table 6-43, p. 6-123;**
**Section 6.4.15.2, p. 6-134;**
**Exhibit B-5, BCUC IR 63.11, 63.12, 63.13.3.3**
**Power system assets/vegetation management and storm restoration**

In response to BCUC IR 63.11, BC Hydro stated: "The December 2018 storm remediation expenditures were approximately $22.9 million. Of these expenditures, approximately $5.1 million were capitalized for asset replacements, and $17.8 million were related to repairs and charged to the Storm Restoration budget."

In this same response, BC Hydro provided the actual costs of the three most costly storms that it has record of, which included the December 2018 windstorm at a cost of $22.9 million and the August 2018 wildfire at a cost of $8.9 million.

Further in response to BCUC IR 63.12, BC Hydro stated: "Audited financial results for fiscal 2019 are not yet available. The recalculation of the five-year average, using the fiscal 2019 forecast, which excludes the December 2018 storm impact… would be as follows:"

| Based on F19 Forecast included in F20-21 RRA | F2015 ($ million) | F2016 ($ million) | F2017 ($ million) | F2018 ($ million) | F2019 ($ million) | F2015-F2019 Average ($ million) |
|---|---|---|---|---|---|---|
| Storm Restoration Costs | 12.9 | 23.5 | 25.3 | 22.9 | 6.7 | 18.3 |

2.232.4 Considering two of the three most costly storms for BC Hydro occurred in F2019, please discuss whether using a five-year average approach to forecasting the Test Year storm restoration costs would potentially result in under forecasting storm restoration costs.

2.232.4.1 If yes, please discuss alternative methods to forecasting storm restoration costs. As part of the response, please discuss forecasting methods used by other electrical utilities in North America.

**RESPONSE:**

**Other methods of forecasting storm restoration costs include using a shorter or longer period as the basis of the calculation for the average of actual storm restoration costs, (e.g., three years or 10 years). Alternatively, BC Hydro could base the forecast on the latest completed fiscal year of actuals at the time of the revenue requirements filing.**

**Storm restoration costs forecast amounts based on a five-year average of actual storm restoration costs as well as the alternatives described above are as follows:**

| ($ million) | 3 Year Average F2017-F2019 Average | 5 Year Average F2015-F2019 Average | 10 Year Average F2010-F2019 Average | Most Recent Fiscal Year Actual Fiscal 2019 Actual |
|---|---|---|---|---|
| Storm Restoration Costs Forecast | 24.6 | 22.0 | 13.4 | 25.6 |

**The calculations in the table above include fiscal 2019 actual storm restoration costs as these amounts are now available.**

**As noted in BC Hydro's response to BCUC IR 2.232.4, BC Hydro was directed to use a five-year average to forecast storm restoration costs.**

**Predicting storm restoration costs is inherently difficult and driven by uncontrollable factors. BC Hydro considers that using a three year average may give too much weight to recent years, while using a 10-year average gives too much weight to historical years that may not reflect recent trends. BC Hydro considers the current framework of using a five year average to be appropriate. The Storm Restoration Costs Regulatory Account results in ratepayers paying the actual costs over a reasonable period of time.**

**BC Hydro conducted a limited review of the publicly available annual reports and financial statements of five Canadian utilities (Hydro Quebec, Manitoba Hydro, Hydro One, FortisBC Inc. and SaskPower) to attempt to identify their forecasting method for storm restoration costs. BC Hydro found no references to forecasting storm restoration costs in these annual reports and was therefore unable to determine the approach used by these utilities.**

**232.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-1, Section 6.4.15, Table 6-43, p. 6-123;**
**Section 6.4.15.2, p. 6-134;**
**Exhibit B-5, BCUC IR 63.11, 63.12, 63.13.3.3**
**Power system assets/vegetation management and storm restoration**

In response to BCUC IR 63.11, BC Hydro stated: "The December 2018 storm remediation expenditures were approximately $22.9 million. Of these expenditures, approximately $5.1 million were capitalized for asset replacements, and $17.8 million were related to repairs and charged to the Storm Restoration budget."

In this same response, BC Hydro provided the actual costs of the three most costly storms that it has record of, which included the December 2018 windstorm at a cost of $22.9 million and the August 2018 wildfire at a cost of $8.9 million.

Further in response to BCUC IR 63.12, BC Hydro stated: "Audited financial results for fiscal 2019 are not yet available. The recalculation of the five-year average, using the fiscal 2019 forecast, which excludes the December 2018 storm impact… would be as follows:"

| Based on F19 Forecast included in F20-21 RRA | F2015 ($ million) | F2016 ($ million) | F2017 ($ million) | F2018 ($ million) | F2019 ($ million) | F2015-F2019 Average ($ million) |
|---|---|---|---|---|---|---|
| Storm Restoration Costs | 12.9 | 23.5 | 25.3 | 22.9 | 6.7 | 18.3 |

2.232.4 Considering two of the three most costly storms for BC Hydro occurred in F2019, please discuss whether using a five-year average approach to forecasting the Test Year storm restoration costs would potentially result in under forecasting storm restoration costs.

2.232.4.2 If applicable, please provide the storm restoration forecast using the alternative methods identified in the preceding IR.

**RESPONSE:**

**Please refer to BC Hydro's response to BCUC IR 2.232.4.1 where we provide an estimate of the storm restoration costs forecast using alternative methods identified in that response.**

**232.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-1, Section 6.4.15, Table 6-43, p. 6-123;**
**Section 6.4.15.2, p. 6-134;**
**Exhibit B-5, BCUC IR 63.11, 63.12, 63.13.3.3**
**Power system assets/vegetation management and storm restoration**

In response to BCUC IR 63.13.3.3, BC Hydro stated that "[t]he capital replacement expenditures due to wildfires are part of the $18 million Trouble capital expenditures budgeted in the test period, as shown in Table 6-43 of Chapter 6 of the Application."

In Table 6-43, BC Hydro provides the following actual and planned Trouble capital expenditures for F2017 to F2021:

- F2017: RRA $10.5 million; Actual $17.0 million
- F2018: RRA $10.8 million; Actual $21.5 million
- F2019: RRA $11.0 million; Forecast $17.3 million
- F2020: Plan $17.7 million
- F2021: Plan $18.0 million

Further on page 6-134 of the Application, BC Hydro states that Trouble capital expenditures are for equipment replacements that meet capitalization rules and resulting from: (1) routine trouble calls; (2) storms; or (3) damage to the plant.

2.232.5 Please discuss whether Trouble capital expenditures are correlated with storm restoration costs (i.e. if storm restoration costs increase, trouble capital expenditures would increase).

**RESPONSE:**

**A direct correlation cannot be made between Storm Restoration costs and Trouble capital expenditures.**

**Each routine trouble call, damage to plant incident, and storm event (e.g., wildfire, wind storm, flood) is unique and the damage inflicted on BC Hydro's infrastructure can vary from each incident. BC Hydro's response to each incident can have a varying combination of operating costs and/or capital expenditures. Due to the unpredictability and unique nature of these incidents, the varying impact and magnitude of the damage incurred, and the wide variability in the frequency of events, there is no direct correlation between storm restoration costs and Trouble capital expenditures.**

**232.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-1, Section 6.4.15, Table 6-43, p. 6-123;**
**Section 6.4.15.2, p. 6-134;**
**Exhibit B-5, BCUC IR 63.11, 63.12, 63.13.3.3**
**Power system assets/vegetation management and storm restoration**

In response to BCUC IR 63.13.3.3, BC Hydro stated that "[t]he capital replacement expenditures due to wildfires are part of the $18 million Trouble capital expenditures budgeted in the test period, as shown in Table 6-43 of Chapter 6 of the Application."

In Table 6-43, BC Hydro provides the following actual and planned Trouble capital expenditures for F2017 to F2021:

- F2017: RRA $10.5 million; Actual $17.0 million
- F2018: RRA $10.8 million; Actual $21.5 million
- F2019: RRA $11.0 million; Forecast $17.3 million
- F2020: Plan $17.7 million
- F2021: Plan $18.0 million

Further on page 6-134 of the Application, BC Hydro states that Trouble capital expenditures are for equipment replacements that meet capitalization rules and resulting from: (1) routine trouble calls; (2) storms; or (3) damage to the plant.

2.232.6 Please discuss how BC Hydro forecasts Trouble capital expenditures.

**RESPONSE:**

**An explanation of how BC Hydro forecasts Trouble expenditures was provided in BC Hydro's response to BCUC IR 1.128.2. An excerpt from the response is provided below for ease of reference:**

> **"The Trouble capital expenditures forecast follows the BC Hydro capital investment planning process, as described in section 6.3 of Chapter 6 of the Application.**
>
> **Historical trouble capital costs are used for forecasting, including the fiscal 2020 plan and the fiscal 2021 plan at the planning stage. The proposed forecasts are reviewed by the Integrated Planning Business Group and the investment**

**requests are prioritized across BC Hydro's Transmission and Distribution Capital investment portfolio.**

**The capital expenditure forecasts and investment requests are also reviewed, reprioritized and revised regularly throughout the fiscal year to facilitate flexibility and responsiveness to the investment needs of our system."**

**232.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-1, Section 6.4.15, Table 6-43, p. 6-123;**
**Section 6.4.15.2, p. 6-134;**
**Exhibit B-5, BCUC IR 63.11, 63.12, 63.13.3.3**
**Power system assets/vegetation management and storm restoration**

In response to BCUC IR 63.13.3.3, BC Hydro stated that "[t]he capital replacement expenditures due to wildfires are part of the $18 million Trouble capital expenditures budgeted in the test period, as shown in Table 6-43 of Chapter 6 of the Application."

In Table 6-43, BC Hydro provides the following actual and planned Trouble capital expenditures for F2017 to F2021:

- F2017: RRA $10.5 million; Actual $17.0 million
- F2018: RRA $10.8 million; Actual $21.5 million
- F2019: RRA $11.0 million; Forecast $17.3 million
- F2020: Plan $17.7 million
- F2021: Plan $18.0 million

Further on page 6-134 of the Application, BC Hydro states that Trouble capital expenditures are for equipment replacements that meet capitalization rules and resulting from: (1) routine trouble calls; (2) storms; or (3) damage to the plant.

2.232.7 Given the variance between forecast and actual Trouble capital expenditures in the above table, please discuss whether BC Hydro has considered alternative methods to forecasting the planned trouble capital expenditures. Please explain why or why not.

**RESPONSE:**

**Trouble events, by nature, are unpredictable and can be difficult to plan. BC Hydro forecasts Trouble capital expenditures based on historical amounts and has not explored alternative methods.**

**Planned amounts for fiscal 2020 and fiscal 2021 are higher than previous years, reflecting the fact that actual costs in past years were higher than the RRA plan amounts.**

**232.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-1, Section 6.4.15, Table 6-43, p. 6-123;**
**Section 6.4.15.2, p. 6-134;**
**Exhibit B-5, BCUC IR 63.11, 63.12, 63.13.3.3**
**Power system assets/vegetation management and storm restoration**

In response to BCUC IR 63.13.3.3, BC Hydro stated that "[t]he capital replacement expenditures due to wildfires are part of the $18 million Trouble capital expenditures budgeted in the test period, as shown in Table 6-43 of Chapter 6 of the Application."

In Table 6-43, BC Hydro provides the following actual and planned Trouble capital expenditures for F2017 to F2021:

- F2017: RRA $10.5 million; Actual $17.0 million
- F2018: RRA $10.8 million; Actual $21.5 million
- F2019: RRA $11.0 million; Forecast $17.3 million
- F2020: Plan $17.7 million
- F2021: Plan $18.0 million

Further on page 6-134 of the Application, BC Hydro states that Trouble capital expenditures are for equipment replacements that meet capitalization rules and resulting from: (1) routine trouble calls; (2) storms; or (3) damage to the plant.

2.232.7 Given the variance between forecast and actual Trouble capital expenditures in the above table, please discuss whether BC Hydro has considered alternative methods to forecasting the planned trouble capital expenditures. Please explain why or why not.

2.232.7.1 If yes, please discuss the alternative methods considered and the methods used by other electrical utilities in North America.

**RESPONSE:**

**Please refer to BC Hydro's response to BCUC IR 2.232.7 where we explain why BC Hydro has not explored alternative methods.**

**232.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-1, Section 6.4.15, Table 6-43, p. 6-123;**
**Section 6.4.15.2, p. 6-134;**
**Exhibit B-5, BCUC IR 63.11, 63.12, 63.13.3.3**
**Power system assets/vegetation management and storm restoration**

In response to BCUC IR 63.13.3.3, BC Hydro stated that "[t]he capital replacement expenditures due to wildfires are part of the $18 million Trouble capital expenditures budgeted in the test period, as shown in Table 6-43 of Chapter 6 of the Application."

In Table 6-43, BC Hydro provides the following actual and planned Trouble capital expenditures for F2017 to F2021:

- F2017: RRA $10.5 million; Actual $17.0 million
- F2018: RRA $10.8 million; Actual $21.5 million
- F2019: RRA $11.0 million; Forecast $17.3 million
- F2020: Plan $17.7 million
- F2021: Plan $18.0 million

Further on page 6-134 of the Application, BC Hydro states that Trouble capital expenditures are for equipment replacements that meet capitalization rules and resulting from: (1) routine trouble calls; (2) storms; or (3) damage to the plant.

2.232.7 Given the variance between forecast and actual Trouble capital expenditures in the above table, please discuss whether BC Hydro has considered alternative methods to forecasting the planned trouble capital expenditures. Please explain why or why not.

2.232.7.2 If applicable, please provide the Trouble capital expenditures forecast using the methods identified in the preceding IR.

**RESPONSE:**

**Please refer to BC Hydro's response to BCUC IR 2.232.7 where we explain why BC Hydro has not explored alternative methods.**

**233.0 C. CHAPTER 5 – OPERATING COSTS**
**Reference: OPERATING COSTS**
**Exhibit B-1, Section 5A.6.2, Table 5A-8, p. 5A-21; Exhibit B-5, BCUC IR 69.4, 71.3, 72.3**
**Power system assets/maintenance costs pressures**

In response to BCUC IR 71.3, BC Hydro presented the following table, which provides the actual/forecast costs for F2015 to F2019 and the planned costs for Stations Asset Maintenance:

| Stations Asset Maintenance ($ million) | F2015 Actual | F2016 Actual | F2017 Actual | F2018 Actual | F2019 Forecast | F2020 Plan | F2021 Plan |
|---|---|---|---|---|---|---|---|
| Labour | 40.3 | 40.8 | 40.0 | 42.0 | 42.6 | 44.5 | 45.0 |
| Services - Other | 27.4 | 24.3 | 26.3 | 27.6 | 24.4 | 34.1 | 34.5 |
| Material | 9.6 | 8.8 | 8.5 | 8.8 | 8.1 | 6.9 | 6.9 |
| Total | 77.2 | 73.9 | 74.7 | 78.4 | 75.1 | 85.5 | 86.4 |

2.233.1 Please provide a breakdown of the planned station asset maintenance projects that accounts for the increase in maintenance costs from F2019 forecast to F2020 plan.

**RESPONSE:**

**This answer also responds to BCOAPO IRs 2.127.1 and 2.127.3.**

**The $10.4 million increase ($75.1 million to $85.5 million) in Stations Asset Maintenance costs between fiscal 2019 forecast to fiscal 2020 plan consists of Standard Labour Rate Increases ($2.5 million), Net Re-organization impacts ($3.2 million) and re-purposing of unallocated funds ($4.7 million). Only the $4.7 million from re-purposing of unallocated funds is related to funding for additional planned preventative, condition-based and corrective maintenance work in BC Hydro's substations. The Standard Labour Rate increases are based on BC Hydro's Standard Labour Rate and the Re-organization impacts are cost neutral and are offset by reductions to the Business Unit Support KBU of the Operations Business Group and the Engineering KBU of the Integrated Planning Business Group.**

**The following table provides a breakdown of the $10.4 million increase by these drivers with Generation Maintenance, Substations Maintenance and Non-Integrated Area Maintenance costs shown separately.**

| ($ million)* | Generation Maintenance | Substation Maintenance | Non-Integrated Area Maintenance | Stations Asset Maintenance (Total) |
|---|---|---|---|---|
| Standard Labour Rate Increases | 1.8 | 0.6 | 0.2 | 2.5 |
| Net Re-organization impacts | 3.2 | 0 | 0 | 3.2 |
| Re-purposing of unallocated funds | 0.1 | 4.6 | 0 | 4.7 |
| Total | 5.1 | 5.2 | 0.2 | 10.4 |

* values rounded

**The following provides a breakdown of the additional planned preventative, condition-based and corrective maintenance work in BC Hydro's substations.**

**Condition based maintenance ($2.4 million):**

- **GM Shrum (GMS) – Transformer (T12) load tap changer A,B,C Overhaul;**
- **Meziadian (MEZ) – Transformer (T1) bushings replacement;**
- **Kelly Lake (KLY) - Circuit breaker (5CB33) rebuild;**
- **Strawberry Hill (SYH) – Transformer (T1) Bushing Replacement;**
- **Vancouver Island Terminal (VIT) – Synchronous condenser (SC4) cooling overhaul;**
- **Atchelitz (ALZ) - Transformer (T3) load tap changer overhaul;**
- **Douglas Street (DUG) – Transformer (T1) load tap changer overhaul; and**
- **Texada Island Reactor (TIR) – Replace temperature gauges.**

**Preventative maintenance for new in-service assets ($1.5 million).**

**Corrective maintenance ($0.8 million).**

**233.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-1, Section 5A.6.2, Table 5A-8, p. 5A-21; Exhibit B-5, BCUC IR 69.4, 71.3, 72.3**
**Power system assets/maintenance costs pressures**

In response to BCUC IR 71.3, BC Hydro presented the following table, which provides the actual/forecast costs for F2015 to F2019 and the planned costs for Stations Asset Maintenance:

| Stations Asset Maintenance ($ million) | F2015 Actual | F2016 Actual | F2017 Actual | F2018 Actual | F2019 Forecast | F2020 Plan | F2021 Plan |
|---|---|---|---|---|---|---|---|
| Labour | 40.3 | 40.8 | 40.0 | 42.0 | 42.6 | 44.5 | 45.0 |
| Services - Other | 27.4 | 24.3 | 26.3 | 27.6 | 24.4 | 34.1 | 34.5 |
| Material | 9.6 | 8.8 | 8.5 | 8.8 | 8.1 | 6.9 | 6.9 |
| Total | 77.2 | 73.9 | 74.7 | 78.4 | 75.1 | 85.5 | 86.4 |

2.233.2 Please explain the reduction in station asset maintenance costs from F2018 actual to F2019 forecast.

**RESPONSE:**

**As discussed in BC Hydro's response to BCUC IR 1.71.3, the reduction in Stations Asset Maintenance costs from fiscal 2018 Actual to fiscal 2019 Forecast was due to spending above plan in fiscal 2018 on additional priority maintenance work.**

**This work included an additional $2.2 million on substation corrective maintenance on existing assets in service and $1.5 million of additional preventative maintenance related to new assets that came into service.**

**While the $1.5 million of additional preventative maintenance was not included in the fiscal 2019 Forecast, it has been included in the fiscal 2020 Plan and fiscal 2021 Plan, as shown in BC Hydro's response to BCUC IR 2.233.1.**

**233.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-1, Section 5A.6.2, Table 5A-8, p. 5A-21; Exhibit B-5, BCUC IR 69.4, 71.3, 72.3**
**Power system assets/maintenance costs pressures**

In response to BCUC IR 71.3, BC Hydro presented the following table, which provides the actual/forecast costs for F2015 to F2019 and the planned costs for Stations Asset Maintenance:

| Stations Asset Maintenance ($ million) | F2015 Actual | F2016 Actual | F2017 Actual | F2018 Actual | F2019 Forecast | F2020 Plan | F2021 Plan |
|---|---|---|---|---|---|---|---|
| Labour | 40.3 | 40.8 | 40.0 | 42.0 | 42.6 | 44.5 | 45.0 |
| Services - Other | 27.4 | 24.3 | 26.3 | 27.6 | 24.4 | 34.1 | 34.5 |
| Material | 9.6 | 8.8 | 8.5 | 8.8 | 8.1 | 6.9 | 6.9 |
| Total | 77.2 | 73.9 | 74.7 | 78.4 | 75.1 | 85.5 | 86.4 |

2.233.3 Please explain the $10.4 million increase ($75.1 million to $85.5 million) in Stations Asset Maintenance costs presented from F2019 forecast to F2020 plan.

**RESPONSE:**

**Please refer to BC Hydro's response to BCUC IR 2.233.1 where we explain the increase in Stations Asset Maintenance costs from fiscal 2019 forecast to fiscal 2020 plan.**

## 233.0 C. CHAPTER 5 – OPERATING COSTS

**Reference: OPERATING COSTS**
**Exhibit B-1, Section 5A.6.2, Table 5A-8, p. 5A-21; Exhibit B-5, BCUC IR 69.4, 71.3, 72.3**
**Power system assets/maintenance costs pressures**

BC Hydro provides the F2019 forecast operating costs and FTEs for the Stations Asset Planning KBU in Table 5A-8 of the Application.

**Table 5A-8 Stations Asset Planning KBU Fiscal 2019 Forecast Operating Costs and FTEs by Department**

| | ($ million) | Labour | Services - ABSU | Services - Other | Materials | Building & Equipment | Capitalized Overhead | External Recoveries | Total Operating | Total FTEs |
|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Stations Asset Maintenance | 50.9 | 0.0 | 25.9 | 8.0 | 0.8 | 0.0 | 0.0 | 85.7 | - |
| 2 | Stations Asset Planning, Director | 0.3 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.3 | 1 |
| 3 | Substations Growth and Sustainment | 2.2 | 0.0 | 0.2 | 0.0 | 0.0 | 0.0 | 0.0 | 2.4 | 20 |
| 4 | Generation Asset Management | 1.5 | 0.0 | 0.3 | 0.0 | 0.0 | 0.0 | 0.0 | 1.8 | 8 |
| 5 | Generating Stations Maintenance Planning | 1.7 | 0.0 | 1.8 | 0.0 | 0.0 | 0.0 | 0.0 | 3.5 | 10 |
| 6 | NIA Planning | 0.2 | 0.0 | 0.1 | 0.0 | 0.0 | 0.0 | 0.0 | 0.3 | 7 |
| 7 | **Total (Sch 5.1 L3, Sch 16.0 L3)** | **56.9** | **0.0** | **28.3** | **8.0** | **0.8** | **0.0** | **0.0** | **94.0** | **46** |

2.233.4 Please explain why the table presented in response to BCUC IR 71.3 shows $75.1 million for the F2019 forecast Stations Asset Maintenance costs while Table 5A-8 of the Application shows $85.7 million. Please provide updated tables, if applicable.

**RESPONSE:**

**As discussed in BCUC IR 1.69.5, the $85.7 million in line 1 of Table 5A-8 includes $75.1 million for maintenance and $10.6 million related to operations. The $75.1 million corresponds to the fiscal 2019 Forecast value in the Stations Asset Maintenance line in the Table 5-20 of Chapter 5 of the Application, which is reproduced below.**

**Table 5-20 Stations Asset Maintenance Expenditures**

| ($ million) | F2017 RRA | F2017 Actual | F2018 RRA | F2018 Actual | F2019 RRA | F2019 Forecast | F2020 Plan | F2021 Plan |
|---|---|---|---|---|---|---|---|---|
| | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 |
| Generation Maintenance | 49.9 | 51.9 | 50.4 | 52.9 | 51.0 | 52.7 | 58.0 | 58.6 |
| Substations Maintenance | 17.6 | 18.5 | 17.6 | 20.3 | 17.6 | 17.2 | 22.4 | 22.6 |
| Non-Integrated Area Maintenance | 5.2 | 4.4 | 5.2 | 5.2 | 5.2 | 5.2 | 5.1 | 5.2 |
| Stations Asset Maintenance | 72.7 | 74.8 | 73.2 | 78.4 | 73.8 | 75.1 | 85.4 | 86.4 |

**233.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-1, Section 5A.6.2, Table 5A-8, p. 5A-21; Exhibit B-5, BCUC IR 69.4, 71.3, 72.3**
**Power system assets/maintenance costs pressures**

In response to BCUC IR 72.3, BC Hydro presented the following table which provides the actual/forecast costs for F2015 to F2019 and the planned costs for Lines Asset Maintenance:

| Lines Asset Maintenance ($ million) | F2015 Actual | F2016 Actual | F2017 Actual | F2018 Actual | F2019 Forecast | F2020 Plan | F2021 Plan |
|---|---|---|---|---|---|---|---|
| Labour | 23.3 | 24.3 | 26.3 | 27.7 | 23.6 | 26.5 | 27.7 |
| Services - Other | 75.4 | 71.2 | 71.1 | 78.4 | 82.4 | 84.3 | 78.4 |
| Materials | 4.1 | 3.9 | 3.5 | 4.0 | 3.1 | 2.8 | 4.0 |
| Recoveries | (7.2) | (8.3) | (8.5) | (8.7) | (8.5) | (8.5) | (8.7) |
| Total | 95.6 | 91.0 | 92.4 | 101.4 | 100.5 | 105.1 | 105.6 |

2.233.5 Please explain why the sum of the F2021 plan components does not equal the total. Please provide an updated table, as necessary.

**RESPONSE:**

**In responding to this question, BC Hydro noticed that the incorrect data was provided for fiscal 2021 in response to BCUC IR 1.72.3. A corrected table is provided below. The total of $105.6 million remains the same.**

| Lines Asset Maintenance ($ million) | F2015 Actual | F2016 Actual | F2017 Actual | F2018 Actual | F2019 Forecast | F2020 Plan | F2021 Plan |
|---|---|---|---|---|---|---|---|
| Labour | 23.3 | 24.3 | 26.3 | 27.7 | 23.6 | 26.5 | 26.8 |
| Services - Other | 75.4 | 71.2 | 71.1 | 78.4 | 82.4 | 84.3 | 84.5 |
| Materials | 4.1 | 3.9 | 3.5 | 4.0 | 3.1 | 2.8 | 2.8 |
| Recoveries | (7.2) | (8.3) | (8.5) | (8.7) | (8.5) | (8.5) | (8.5) |
| Total | 95.6 | 91.0 | 92.4 | 101.4 | 100.5 | 105.1 | 105.6 |

**233.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-1, Section 5A.6.2, Table 5A-8, p. 5A-21; Exhibit B-5, BCUC IR 69.4, 71.3, 72.3**
**Power system assets/maintenance costs pressures**

In response to BCUC IR 72.3, BC Hydro presented the following table which provides the actual/forecast costs for F2015 to F2019 and the planned costs for Lines Asset Maintenance:

| Lines Asset Maintenance ($ million) | F2015 Actual | F2016 Actual | F2017 Actual | F2018 Actual | F2019 Forecast | F2020 Plan | F2021 Plan |
| --- | --- | --- | --- | --- | --- | --- | --- |
| Labour | 23.3 | 24.3 | 26.3 | 27.7 | 23.6 | 26.5 | 27.7 |
| Services - Other | 75.4 | 71.2 | 71.1 | 78.4 | 82.4 | 84.3 | 78.4 |
| Materials | 4.1 | 3.9 | 3.5 | 4.0 | 3.1 | 2.8 | 4.0 |
| Recoveries | (7.2) | (8.3) | (8.5) | (8.7) | (8.5) | (8.5) | (8.7) |
| Total | 95.6 | 91.0 | 92.4 | 101.4 | 100.5 | 105.1 | 105.6 |

2.233.6 Please explain why there is a reduction in Services - Other by $5.9 million from F2020 plan to F2021 plan.

**RESPONSE:**

**Please refer to BC Hydro's response to BCUC IR 2.233.5 where we explain that BC Hydro's response to BCUC IR 1.72.3 provided incorrect data for fiscal 2021 and provide a corrected table. As shown in that response, the corrected Services – Other amount for fiscal 2021 is $84.5 million which is comparable to the fiscal 2020 amount of $84.3 million.**

**233.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-1, Section 5A.6.2, Table 5A-8, p. 5A-21; Exhibit B-5, BCUC IR 69.4, 71.3, 72.3**
**Power system assets/maintenance costs pressures**

Further in response to BCUC IR 69.4, BC Hydro stated that contributing to the increase from F2019 forecast to F2020 plan for Services – Other of the Integrated Planning Business Group is made up in part of:

> Approximately $10 million non-labour funding increase to Lines and Stations maintenance reflecting an aging and growing asset base, increased severe weather events, higher delivery costs, outstanding condition-based and corrective maintenance needs and additional regulatory and compliance requirements).

2.233.7 Please confirm, or otherwise explain, that the $10 million non-labour funding increase to lines and stations maintenance is fully accounted for in the tables provided in response to BCUC IR 71.3 (stations asset maintenance) and BCUC IR 72.3 (lines asset maintenance).

**RESPONSE:**

**Confirmed.**

**233.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-1, Section 5A.6.2, Table 5A-8, p. 5A-21; Exhibit B-5, BCUC IR 69.4, 71.3, 72.3**
**Power system assets/maintenance costs pressures**

Further in response to BCUC IR 69.4, BC Hydro stated that contributing to the increase from F2019 forecast to F2020 plan for Services – Other of the Integrated Planning Business Group is made up in part of:

> Approximately $10 million non-labour funding increase to Lines and Stations maintenance reflecting an aging and growing asset base, increased severe weather events, higher delivery costs, outstanding condition-based and corrective maintenance needs and additional regulatory and compliance requirements).

2.233.7 Please confirm, or otherwise explain, that the $10 million non-labour funding increase to lines and stations maintenance is fully accounted for in the tables provided in response to BCUC IR 71.3 (stations asset maintenance) and BCUC IR 72.3 (lines asset maintenance).

2.233.7.1 If not confirmed, please provide a breakdown of the work included in the $10 million non-labour funding.

**RESPONSE:**

**Please refer to BC Hydro’s response to BCUC IR 2.233.7.**

**234.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-1, Appendix A, Schedule 1**
**Revenue requirement summary**

Schedule 1 in Appendix A to the Application presents the revenue requirement summary from F2017 to F2021 plan.

2.234.1 If the Test Period revenue collected ends up being greater than the planned revenue requirement, please discuss how these differences would be accounted for. Please comment on whether the difference would accrue to an unallocated funds budget. Is the treatment different compared to the previous Test Period when there was a Rate Smoothing Deferral Account?

**RESPONSE:**

**If actual amounts relating to components of revenue requirements are higher or lower than the planned amounts, the treatment of such variances would depend on their eligibility for deferral to the regulatory accounts. The table below lists the items that are not eligible for deferral to regulatory accounts:**

| Forecast Item | Appendix A Reference |
|---|---|
| **Miscellaneous Revenues** | **Schedule 15.0, line 42 less lines 4 and 9** |
| **Operating costs** | **Schedule 5.0, line 15(1)** |
| **Provision and Other Costs** | **Schedule 5.0, lines 65 to 71(2)** |
| **Amortization (DSM and Existing Capital Assets) – Excludes Amortization on Capital Additions during the Test Period** | **Schedule 7.0, line 32**<br>**Less:**<br>**Schedule 7.0, line 28**<br>**Schedule 7.0, line 30**<br>**Schedule 13.0, line 35** |
| **First Nations Negotiations Costs** | **Schedule 5.0, line 54(3)** |
| **Taxes** | **Schedule 6.0, line 24** |
| **Asset Retirement Obligation Accretion** | **Schedule 8.0, line 16** |
| **Powertech Net Income** | **Schedule 1.0, line 18** |

1. **Except for the variances between forecast and actual Storm Restoration Costs and Current Service Costs.**
2. **Lines 65 to 71 include asset retirements and gains/losses on asset disposals.**

**3. First Nations negotiations costs are part of the total recoveries from the First Nations Costs Regulatory Account, shown on Schedule 2.2, line 12. The portion relating to First Nations negotiations costs are equal to the amounts shown on Schedule 5.0, Line 54.**

**Variances to plan related to the items shown in the table above are to the account of the shareholder.**

**This treatment of variances is unchanged from the treatment of variances in the Previous Application, and is not related to the Rate Smoothing Regulatory Account. The Rate Smoothing Regulatory Account was not a variance account. Instead, BC Hydro deferred a portion of its approved revenue requirement to the Rate Smoothing Regulatory Account for collection in rates in future fiscal years. No variances between actual results and the approved revenue requirements were transferred to the account.**

**No variances related to any component of the planned revenue requirement are transferred to an unallocated funds budget.**

## 235.0 C. CHAPTER 5 – OPERATING COSTS

**Reference: OPERATING COSTS**
**Exhibit B-1, Section 4.7.4, pp. 4-43–4-44; Appendix A, Schedule 15;**
**Exhibit B-6, BCOAPO IR 55.1**
**Waneta maintenance costs**

In response to BCOAPO IR 55.1, BC Hydro stated:

> The increase in operating costs for the Business Unit Support KBU of the Operations Business Group from fiscal 2018 actual to fiscal 2019 forecast is primarily due to the maintenance costs associated with BC Hydro's purchase of the remaining two-thirds interest in the Waneta generating facility.

In the Application, BC Hydro states that "Teck [Resources Ltd.] 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, line 22)."

Schedule 15 in Appendix A to the Application presents the revenues received from Teck Resources Ltd. from F2017 to F2021 plan:

**Miscellaneous Revenue**
**($ million)**

| | | | F2017 | | | F2018 | | | F2019 | | | F2020 | F2021 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Reference | RRA | Actual | Diff | RRA | Actual | Diff | RRA | Forecast | Diff | Plan | Plan |
| Line | | Column | 1 | 2 | 3 = 2 - 1 | 4 | 5 | 6 = 5 - 4 | 7 | 8 | 9 = 8 - 7 | 10 | 11 |
| | Waneta 2/3 | | | | | | | | | | | | |
| 20 | Lease revenue from Teck | | | | 0.0 | | | 0.0 | | | 0.0 | 75.2 | 76.7 |
| 21 | Teck portion of operating costs | | | | 0.0 | | | 0.0 | 0.0 | 3.8 | 3.8 | 5.7 | 5.9 |
| 22 | Teck portion of water rentals | | | | 0.0 | | | 0.0 | 0.0 | 2.4 | 2.4 | 3.5 | 3.7 |
| 23 | Teck portion of property taxes | | | | 0.0 | | | 0.0 | 0.0 | 0.1 | 0.1 | 0.6 | 0.6 |
| 24 | Subtotal | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 6.4 | 6.4 | 84.9 | 86.9 |

2.235.1 Please confirm, or explain otherwise, that these maintenance costs are offset by revenues received from Teck Resources Ltd.

**RESPONSE:**

**Confirmed.**

**235.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-1, Section 4.7.4, pp. 4-43–4-44; Appendix A, Schedule 15;**
**Exhibit B-6, BCOAPO IR 55.1**
**Waneta maintenance costs**

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In the Application, BC Hydro states that "Teck [Resources Ltd.] 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, line 22)."

Schedule 15 in Appendix A to the Application presents the revenues received from Teck Resources Ltd. from F2017 to F2021 plan:

**Miscellaneous Revenue**
**($ million)**

| | | F2017 | | | F2018 | | | F2019 | | | F2020 | F2021 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Reference | RRA | Actual | Diff | RRA | Actual | Diff | RRA | Forecast | Diff | Plan | Plan |
| Line | Column | 1 | 2 | 3 = 2 - 1 | 4 | 5 | 6 = 5 - 4 | 7 | 8 | 9 = 8 - 7 | 10 | 11 |
| | Waneta 2/3 | | | | | | | | | | | |
| 20 | Lease revenue from Teck | | | 0.0 | | | 0.0 | | | 0.0 | 75.2 | 76.7 |
| 21 | Teck portion of operating costs | | | 0.0 | | | 0.0 | 0.0 | 3.8 | 3.8 | 5.7 | 5.9 |
| 22 | Teck portion of water rentals | | | 0.0 | | | 0.0 | 0.0 | 2.4 | 2.4 | 3.5 | 3.7 |
| 23 | Teck portion of property taxes | | | 0.0 | | | 0.0 | 0.0 | 0.1 | 0.1 | 0.6 | 0.6 |
| 24 | Subtotal | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 6.4 | 6.4 | 84.9 | 86.9 |

2.235.1 Please confirm, or explain otherwise, that these maintenance costs are offset by revenues received from Teck Resources Ltd.

2.235.1.1 If confirmed, please also confirm, or explain otherwise, that the offsets for these costs are included in Appendix A, Schedule 15, line 22.

**RESPONSE:**

**Not confirmed. The maintenance cost increase described in BC Hydro's response to BCOAPO IR 1.55.1 is offset in Miscellaneous Revenues Appendix A, Schedule 15, line 21, not line 22.**

**236.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-6-1, BCOAPO Confidential IR 6.1, Attachment 2;**
***Financial Information Act* Return for the Year Ended March 31, 2010 to March 31, 2018**
**Employee renumeration & expenses**

On BC Hydro's website under Openness & Accountability[1], BC Hydro provides the *Financial Information Act* Returns for March 31, 2002 to March 31, 2018. Included in the *Financial Information Act* Returns is the Schedule of Remuneration and Expenses for Employees.

2.236.1 Please describe the types of employee expenses that are included in the Schedule of Remuneration and Expenses for Employees. As part of the response, please discuss whether these costs include reimbursements of employees' work-related out-of-pocket costs.

**RESPONSE:**

**Expenses are reported per the Schedule 1, subsection 6 (1) of the Financial Information Regulation which defines expenses as follows:**

**(a) includes travel expenses, memberships, tuition, relocation, vehicle leases, extraordinary hiring expenses, registration fees and similar amounts paid directly to an employee, or to a third party on behalf of the employee, and which has not been included in "remuneration",**

**(b) is not limited to expenses that are generally perceived as perquisites, or bestowing personal benefit, and may include expenditures required for employees to perform their job functions, and**

**(c) excludes benefits of a general nature applicable to all employees pursuant to an agreement such as medical, dental, counselling, insurance and similar plans.**

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[1] https://www.bchydro.com/toolbar/about/accountability_reports/openness_accountability.html.

**236.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-6-1, BCOAPO Confidential IR 6.1, Attachment 2; *Financial Information Act* Return for the Year Ended March 31, 2010 to March 31, 2018**
**Employee renumeration & expenses**

On BC Hydro's website under Openness & Accountability[1], BC Hydro provides the *Financial Information Act* Returns for March 31, 2002 to March 31, 2018. Included in the *Financial Information Act* Returns is the Schedule of Remuneration and Expenses for Employees.

2.236.2 Please discuss whether these expenses form part of an employees' salary.

**RESPONSE:**

**These expenses do not form part of an employees' salary.**

[1] https://www.bchydro.com/toolbar/about/accountability_reports/openness_accountability.html.

**236.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-6-1, BCOAPO Confidential IR 6.1, Attachment 2; *Financial Information Act* Return for the Year Ended March 31, 2010 to March 31, 2018**
**Employee renumeration & expenses**

On BC Hydro's website under Openness & Accountability[1], BC Hydro provides the *Financial Information Act* Returns for March 31, 2002 to March 31, 2018. Included in the *Financial Information Act* Returns is the Schedule of Remuneration and Expenses for Employees.

2.236.3 Please discuss whether these expenses are included in the 2017 Morneau Shepell benchmarking study and the "BCH total rewards" column of the table provided as Attachment 2 to the confidential response to BCOAPO IR 6.1. If not included, please explain why.

**RESPONSE:**

**These expenses are not included in the 2017 Morneau Shepell benchmarking study or the "BCH total rewards" column of the table provided as Attachment 2 to BC Hydro's confidential response to BCOAPO IR 1.6.1.**

**These expenses are not included because they are not considered part of the employees' salary or total rewards.**

[1] https://www.bchydro.com/toolbar/about/accountability_reports/openness_accountability.html.

**236.0 C. CHAPTER 5 – OPERATING COSTS**

**Reference: OPERATING COSTS**
**Exhibit B-6-1, BCOAPO Confidential IR 6.1, Attachment 2; *Financial Information Act* Return for the Year Ended March 31, 2010 to March 31, 2018**
**Employee renumeration & expenses**

On BC Hydro's website under Openness & Accountability[1], BC Hydro provides the *Financial Information Act* Returns for March 31, 2002 to March 31, 2018. Included in the *Financial Information Act* Returns is the Schedule of Remuneration and Expenses for Employees.

2.236.3 Please discuss whether these expenses are included in the 2017 Morneau Shepell benchmarking study and the "BCH total rewards" column of the table provided as Attachment 2 to the confidential response to BCOAPO IR 6.1. If not included, please explain why.

2.236.3.1 If yes, please identify any other columns in the table provided as Attachment 2 to the confidential response to BCOAPO IR 6.1 where these expenses would be included.

**RESPONSE:**

**Please refer to BC Hydro's response to BCUC IR 2.236.3 where BC Hydro indicates that these expenses are not included in the table provided as Attachment 2 to BC Hydro's confidential response to BCOAPO IR 1.6.1.**

[1] https://www.bchydro.com/toolbar/about/accountability_reports/openness_accountability.html.

**237.0 D. CHAPTER 5C – OPERATING COSTS – OPERATIONS BUSINESS GROUP**

**Reference: OPERATING COSTS – OPERATIONS BUSINESS GROUP**
**Exhibit B-1, Table 5C-4, p. 5C-12; pp. 5C-10, 5C-13;**
**Exhibit B-5, BCUC IR 60.1, 63.15, 66.1, 79.2, 126.1;**
**NERC FAC-003-4 Transmission Vegetation Management, Table 2, pp. 17-18**
**Vegetation management**

BC Hydro provided the actual/forecast and planned vegetation maintenance program costs for F2015 to F2021 in response to BCUC IR 63.15, as presented below:

| Vegetation Program | F2015 Actual | F2016 Actual | F2017 Actual | F2018 Actual | F2019 Forecast | F2020 Plan | F2021 Plan |
|---|---|---|---|---|---|---|---|
| Transmission | 19.5 | 16.8 | 17.5 | 18.0 | 17.7 | 17.7 | 17.8 |
| Distribution | 23.9 | 24.1 | 23.8 | 23.4 | 24.2 | 24.4 | 24.4 |

2.237.1 Please provide the budgeted costs related to Transmission and Distribution Vegetation Maintenance for each fiscal year from F2015 to F2019 and explain any variances greater than 10 percent between actual and budgeted amounts.

**RESPONSE:**

**The table below provides the costs related to transmission and distribution vegetation maintenance for each fiscal year from fiscal 2015 to fiscal 2019. The fiscal 2019 numbers have been updated with the actual amounts from that fiscal year. As shown in the table, there were no variances greater than 10 per cent between the RRA plan and actual amounts from fiscal 2015 to fiscal 2019.**

| Vegetation Program | ($ million) | Fiscal 2015 | Fiscal 2016 | Fiscal 2017 | Fiscal 2018 | Fiscal 2019 |
|---|---|---|---|---|---|---|
| Transmission | Actual | 19.5 | 16.8 | 17.5 | 18.0 | 18.2 |
| | RRA Plan | 18.0 | 18.0 | 18.7 | 18.7 | 18.0 |
| | Variance % | -8.3% | 6.7% | 6.4% | 3.7% | -1.1% |
| Distribution | Actual | 23.9 | 24.1 | 23.8 | 23.4 | 24.7 |
| | RRA Plan | 23.2 | 23.2 | 24.7 | 24.7 | 24.5 |
| | Variance % | -3.0% | -3.9% | 3.6% | 5.3% | -0.8% |

**237.0 D. CHAPTER 5C – OPERATING COSTS – OPERATIONS BUSINESS GROUP**

**Reference: OPERATING COSTS – OPERATIONS BUSINESS GROUP**
**Exhibit B-1, Table 5C-4, p. 5C-12; pp. 5C-10, 5C-13;**
**Exhibit B-5, BCUC IR 60.1, 63.15, 66.1, 79.2, 126.1;**
**NERC FAC-003-4 Transmission Vegetation Management, Table 2, pp. 17-18**
**Vegetation management**

Page 5C-10 of the Application describes the work performed by the Vegetation Management Department, some of which includes: transmission; substation and distribution vegetation management maintenance programs; right of way access maintenance programs and clearing; and storm response in aid to the removal of vegetation to reduce overall system restoration time.

Page 5C-13 of the Application states:

> The majority of this department's budget is related to labour. This represents 66 FTEs including one Department Manager, 11 Regional & Program Managers, seven Vegetation Specialists and Foresters, 33 Vegetation Coordinators and five Administrators. Nine FTEs that represent overtime which is driven by peak demand.

BC Hydro's response to BCUC IR 79.2 stated the following:

- Wind storm outages are often caused by trees and branches falling onto powerlines. BC Hydro's Vegetation Management department inspects the transmission and distribution line corridors in the preventative maintenance planning process and identifies hazardous trees for removal. These inspections also identify trees with overhanging branches that could contact the powerlines during snow/ice events.
- To meet the *BC Wildfire Act* and BC Wildfire Regulation, BC Hydro's vegetation management contractors mow the transmission corridors mechanically, with a variety of wheeled and tracked equipment, during preventative maintenance to keep wood debris levels low and reduce the potential for forest fires.
- On the overhead transmission system, BC Hydro inspects the entire length of every circuit for vegetation growth once per calendar year. In some cases, circuits in higher vegetation growth areas may receive two or more vegetation inspections per year.
- On the overhead distribution system, the vegetation maintenance inspection cycle varies across the province from three to five years depending on growth rates and vegetation species.

BC Hydro's response to BCUC IR 66.1 provided a breakdown of operating costs for each KBU's departments for the periods F2017, F2018, F2020 and F2021. A summary of the details of the Vegetation Management Department, as provided in this response, as well as the F2019 forecast data as provided in Table 5C-4 on page 5C-12 of the Application, was compiled by BCUC staff and reflected below:

| Vegetation Management ($ million) | RRA F2017 | RRA F2018 | Forecast F2019 | RRA F2020 | RRA F2021 |
|---|---|---|---|---|---|
| Labour | 3.1 | 3.2 | 3.0 | 3.1 | 3.1 |
| Services - ABSU | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Services - Other | 0.4 | 0.4 | 0.3 | 0.3 | 0.3 |
| Materials | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 |
| Building and Equipment | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 |
| Capitalized Overhead | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| External Recoveries | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| **Total** | **3.7** | **3.8** | **3.5** | **3.5** | **3.6** |
| FTEs | 71 | 71 | 66 | 65 | 65 |

2.237.2 Please discuss the relationship between the Vegetation Management Department within the Program and Contract Management KBU of the Operations Business Group and the line Asset Planning KBU of the Integrated Planning Business Group, given that the Vegetation Management Department also inspects the transmission and distribution line corridors.

**RESPONSE:**

**The Line Asset Planning KBU of the Integrated Planning Business Group is responsible for establishing the BC Hydro policy, standards, work plans and budgets for the vegetation programs.**

**The Program and Contract Management KBU of the Operations Business Group is responsible for delivering the work program, providing oversight of the vegetation contractors and completing inspections.**

**237.0 D. CHAPTER 5C – OPERATING COSTS – OPERATIONS BUSINESS GROUP**

**Reference: OPERATING COSTS – OPERATIONS BUSINESS GROUP**
**Exhibit B-1, Table 5C-4, p. 5C-12; pp. 5C-10, 5C-13;**
**Exhibit B-5, BCUC IR 60.1, 63.15, 66.1, 79.2, 126.1;**
**NERC FAC-003-4 Transmission Vegetation Management, Table 2, pp. 17-18**
**Vegetation management**

Page 5C-10 of the Application describes the work performed by the Vegetation Management Department, some of which includes: transmission; substation and distribution vegetation management maintenance programs; right of way access maintenance programs and clearing; and storm response in aid to the removal of vegetation to reduce overall system restoration time.

Page 5C-13 of the Application states:

> The majority of this department’s budget is related to labour. This represents 66 FTEs including one Department Manager, 11 Regional & Program Managers, seven Vegetation Specialists and Foresters, 33 Vegetation Coordinators and five Administrators. Nine FTEs that represent overtime which is driven by peak demand.

BC Hydro’s response to BCUC IR 79.2 stated the following:

- Wind storm outages are often caused by trees and branches falling onto powerlines. BC Hydro’s Vegetation Management department inspects the transmission and distribution line corridors in the preventative maintenance planning process and identifies hazardous trees for removal. These inspections also identify trees with overhanging branches that could contact the powerlines during snow/ice events.
- To meet the *BC Wildfire Act* and BC Wildfire Regulation, BC Hydro’s vegetation management contractors mow the transmission corridors mechanically, with a variety of wheeled and tracked equipment, during preventative maintenance to keep wood debris levels lwo and reduce the potential for forest fires.
- On the overhead transmission system, BC Hydro inspects the entire length of every circuit for vegetation growth once per calendar year. In some cases, circuits in higher vegetation growth areas may receive two or more vegetation inspections per year.
- On the overhead distribution system, the vegetation maintenance inspection cycle varies across the province from three to five years depending on growth rates and vegetation species.

BC Hydro's response to BCUC IR 66.1 provided a breakdown of operating costs for each KBU's departments for the periods F2017, F2018, F2020 and F2021. A summary of the details of the Vegetation Management Department, as provided in this response, as well as the F2019 forecast data as provided in Table 5C-4 on page 5C-12 of the Application, was compiled by BCUC staff and reflected below:

| Vegetation Management ($ million) | RRA F2017 | RRA F2018 | Forecast F2019 | RRA F2020 | RRA F2021 |
|---|---|---|---|---|---|
| Labour | 3.1 | 3.2 | 3.0 | 3.1 | 3.1 |
| Services - ABSU | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Services - Other | 0.4 | 0.4 | 0.3 | 0.3 | 0.3 |
| Materials | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 |
| Building and Equipment | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 |
| Capitalized Overhead | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| External Recoveries | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| **Total** | **3.7** | **3.8** | **3.5** | **3.5** | **3.6** |
| FTEs | 71 | 71 | 66 | 65 | 65 |

2.237.3 Please identify how much overtime, both in dollars and FTE equivalence, was charged by the line Asset Planning team to transmission and distribution vegetation management in each of F2017 to F2019.

**RESPONSE:**

**No overtime is charged by the Line Asset Planning KBU to the Vegetation Management Department. Please refer to BC Hydro's response to BCUC IR 2.237.2 where we explain the Line Asset Planning KBU's responsibilities with regards to vegetation programs.**

**237.0 D. CHAPTER 5C – OPERATING COSTS – OPERATIONS BUSINESS GROUP**

**Reference: OPERATING COSTS – OPERATIONS BUSINESS GROUP**
**Exhibit B-1, Table 5C-4, p. 5C-12; pp. 5C-10, 5C-13;**
**Exhibit B-5, BCUC IR 60.1, 63.15, 66.1, 79.2, 126.1;**
**NERC FAC-003-4 Transmission Vegetation Management, Table 2, pp. 17-18**
**Vegetation management**

In response to BCUC IR 60.1, BC Hydro stated:

> BC Hydro has a variety of transmission voltage classes ranging from 69 kV to 500 kV, with different corridor maintenance widths depending on the voltage class (e.g.,10m width for a single 69 kV circuit compared to 62.5m width for a typical 500 kV single circuit). Therefore, the corridor area maintained may be different compared to some utilities of similar transmission length with a transmission system dominated by one or two voltage classes.
>
> […]
>
> Corridor with and vegetation clearance distances maintained on distribution systems are more comparable across utilities… BC Hydro's distribution system is exposed to winter storms, especially along the South Coast, the risk from these storms is not similar to the risk that some utilities in the peer group experience due to vegetation damage from repeated exposure to hurricanes and tornados.

Table 2 of the NERC Reliablity Standard FAC-003-4 on Transmission Vegetation Management states the minimum vegetation clearance distance (MCVD) along a transmission path for a given voltage, based on elevation.

2.237.4 Please provide the standard corridor maintenance width for distribution lines or the MCVD that BC Hydro applies to distribution lines when managing vegetation growth. As part of the response, please discuss how the standard corridor maintenance width or MCVD for distribution lines are determined and include the relevant standard upon which the standard corridor maintenance width or MCVD for distribution lines is based, if applicable.

**RESPONSE:**

**The standard corridor clearance widths for vegetation on the distribution system are based on species type. For coniferous vegetation, the corridor is cleared to 3 meters on either side of the outside conductor at the time the work is performed. For deciduous vegetation, the corridor is cleared to 5 meters on either side of the outside conductor at the time the work is performed. These clearances may vary based on the vegetation type, growth rates, and regional variances. These standard widths are outlined in BC Hydro maintenance standard STD TD VS-03-50 Distribution Clearance Requirements for Vegetation R3 2015-11-27, which is provided as Attachment 1 to this response.**

**Minimum Vegetation Clearance Distances (MVCD) is a concept defined in NERC standard FAC-003-4 and only applies to transmission vegetation management. However, as noted in BC Hydro maintenance standard STD VS-03.50, clearances to distribution primary conductors shall be achieved to prevent flashover. These clearance distances are outlined in CSA Standard C22.3 No. 1-10 Overhead Systems (page 86, Table 35, Flashover distance for ac conductors for tree pruning). For example, the flashover-to-ground distance for 25 kV is 216 mm. At no time shall vegetation be allowed to come in sustained direct contact with the primary conductors.**

| BC hydro | Vegetation Standard |
|---|---|

| | | |
|---|---|---|
| Title: Distribution - Clearance Requirements for Vegetation | Group: **Clearance Requirements** | |
| | Number: **VS-03.50** | Revision: **3** |

**1.0 PURPOSE**

This standard outlines the clearance requirements for distribution vegetation maintenance.

**2.0 APPLICABILITY**

This standard applies to the Distribution Vegetation Maintenance program for circuits energized at less than 69 kV phase to phase.

**3.0 BACKGROUND**

Vegetation clearance is required for the safe and reliable operation of the electrical system. This includes both public and worker safety. Access to the facilities must also be accommodated to allow for safe and efficient maintenance and repairs. This standard also takes into account clearances required to be achieved between vegetation and underbuilt infrastructure such as TELUS communications cables. Clearances for vegetation to energized conductors are determined based on *CSA Standard C22.3 No. 1-10 Overhead Systems*.

**4.0 REQUIREMENTS**

Vegetation coordinators will identify work areas or sites within the vegetation management area (VMA) that require maintenance work in order to maintain clearance from vegetation to the distribution conductors through the duration of a given cycle. Clearances shall be achieved to prevent flashover through to the end of the maintenance cycle. Distances are outlined in *CSA Standard C22.3 No. 1-10 Overhead Systems (pg. 86, Table 35, Flashover distance for ac conductors for tree pruning).* For example, flashover-to-ground distance for 25 kV is 216 mm.

At no time shall vegetation be allowed to come in sustained direct contact with the primary conductors.**4.1 Clearance Requirements**

Clearances are prescribed in three ways; a General Clearance Specification, a Regional Clearance Specification and a Prescriptive Variance Clearance. A General Clearance Specification or a Prescriptive Variance must be used in absence of a Regional Clearance Specification.

| Prepared By: D. Isberg | Recommended By: D. Isberg | | Approved By: T.C.Wells | Issue Date: November 27, 2015 | Page 1 of 4 |
|---|---|---|---|---|---|
| Revised By: D. Isberg | Revision Date: 2015 | Revision Notes: • As per section 7.0 of this document | | | Next Review Date: 2020 |

**General Clearance Specification Table**

| **Conifers** | **All Conductors** |
|---|---|
| Overhead clearance | 5.0 m |
| Side clearance | 3.0 m field side and road side |
| Under clearance | To the ground |
| **Deciduous** | **All Conductors** |
| Overhead clearance | 5.0 m |
| Side clearance | 5.0 m field side and road side |
| Under clearance | To the ground |

**Regional Clearance Specification Table (Example)**

| **Conifers** | **Primary conductors** | **Secondary & Neutrals** | **TELUS/ Guy Wires** |
|---|---|---|---|
| Overhead clearance | 5.0 m | 5.0 m | |
| Side clearance | 3.0 m | 3.0 m | 0.5 m |
| Under clearance | 3.0 m | 2.0 m | 0.5 m |
| **Deciduous** | **Primary conductors** | **Secondary & Neutrals** | **TELUS/ Guy Wires** |
| Overhead clearance | 5.0 m | 5.0 m | |
| Side clearance | 5.0 | 5.0 m | 5.0 m |
| Under clearance | To the ground | To the ground | To the ground |
| **Brushing Clearances - Horizontal** | **Road side –** All target vegetation <15cm DBH to road edge | **Field side –** All target vegetation <15cm DBH to side clearances as per table above. | |

**Note:** the distances in the Regional Clearance Tables may vary from Region to Region

**Prescriptive Variance Clearances**

When the clearances in the tables above do not adequately address the requirements for the work task then a written prescription will be used. These prescriptions are listed in Appendix A *Site Specific Work Listing* (work package Appendix)

### 4.2 Measuring Clearances

**Overhead Clearance:**

The required overhead clearance above the conductors is measured from the primary conductors to the overhead vegetation. Vegetation shall be pruned or removed to prevent overhanging limbs from entering into flashover distances due to limb movement during storms or snow loading.

**Side Clearance:**

The required side clearance distance is measured from centerline when there is a single conductor and from the outside phases on three phase lines. Side clearance should allow for no vegetation encroachment within the flashover distance resulting from conductor sway and vegetation movement.

**Under Clearance:**
Under clearance is measured from directly under the conductors. Allowances must be made so no vegetation within the powerline corridor encroaches within the flashover distance over the maintenance cycle.

## 5.0 PERFORMANCE MEASURES

Measures to demonstrate compliance will generally include the following:

- Vegetation does not encroach within flashover distances over the duration of the prescribed maintenance cycle.

## 6.0 RESOURCES

- *CSA Standard C22.3 No. 1-10 Overhead Systems*
- *Appendix A Site Specific Work Listing* (work package Appendix)
- *Appendix I Regional Clearance Specification (DRAFT)* (work package Appendix)

## 7.0 REVISION NOTES

| Revision | Date | Revision Description |
|---|---|---|
| R2 | September 2008 | ▪ ES-64-VM-03.23 Minimum Clearing Distances |

| | | |
|---|---|---|
| R3 | November, 2015 | ▪ The standard format was changed<br>▪ Standard number changed<br>▪ Major re-write to focus on Clearance requirements only |

**237.0 D. CHAPTER 5C – OPERATING COSTS – OPERATIONS BUSINESS GROUP**

**Reference: OPERATING COSTS – OPERATIONS BUSINESS GROUP**
**Exhibit B-1, Table 5C-4, p. 5C-12; pp. 5C-10, 5C-13;**
**Exhibit B-5, BCUC IR 60.1, 63.15, 66.1, 79.2, 126.1;**
**NERC FAC-003-4 Transmission Vegetation Management, Table 2, pp. 17-18**
**Vegetation management**

In response to BCUC IR 60.1, BC Hydro stated:

> BC Hydro has a variety of transmission voltage classes ranging from 69 kV to 500 kV, with different corridor maintenance widths depending on the voltage class (e.g.,10m width for a single 69 kV circuit compared to 62.5m width for a typical 500 kV single circuit). Therefore, the corridor area maintained may be different compared to some utilities of similar transmission length with a transmission system dominated by one or two voltage classes.
>
> […]
>
> Corridor with and vegetation clearance distances maintained on distribution systems are more comparable across utilities… BC Hydro's distribution system is exposed to winter storms, especially along the South Coast, the risk from these storms is not similar to the risk that some utilities in the peer group experience due to vegetation damage from repeated exposure to hurricanes and tornados.

Table 2 of the NERC Reliablity Standard FAC-003-4 on Transmission Vegetation Management states the minimum vegetation clearance distance (MCVD) along a transmission path for a given voltage, based on elevation.

2.237.5 Please explain the process used to confirm that all transmission and distribution circuits are inspected for vegetation growth within the allotted inspection cycle.

**RESPONSE:**

**For the transmission system, a patrol schedule for all transmission circuits is created each fiscal year and reviewed so that there is a minimum of one complete inspection of each transmission circuit per calendar year with no more than 18 months between inspections. This schedule conforms with the requirements of FAC-003-4 R6.**

**Given the high growth rates and challenging terrain in much of British Columbia, BC Hydro has chosen to perform two vegetation patrols per calendar year on most circuits, usually as a combination of aerial and ground patrols. As patrols are completed, the actual patrol date is updated in the schedule and patrol notes are filed on a server. The completed schedule, including actual patrol dates, is filed annually with the Western Electricity Coordinating Council (WECC) as part of BC Hydro's self-certification audit. During WECC site audits every three years, WECC audits a random set of patrol notes to test for compliance. During each audit, BC Hydro has been found to be in compliance with FAC-003-4 R6.**

**For the distribution system, circuits are maintained on a cyclical basis (four year average) and inspected ahead of issuing work to contractors to identify specific vegetation maintenance work. Inspection results and identified work are entered into the corporate Geographic Information System. The Integrated Planning Business Group reviews this information on an ongoing basis to monitor program effectiveness.**

**237.0 D. CHAPTER 5C – OPERATING COSTS – OPERATIONS BUSINESS GROUP**

**Reference: OPERATING COSTS – OPERATIONS BUSINESS GROUP**
**Exhibit B-1, Table 5C-4, p. 5C-12; pp. 5C-10, 5C-13;**
**Exhibit B-5, BCUC IR 60.1, 63.15, 66.1, 79.2, 126.1;**
**NERC FAC-003-4 Transmission Vegetation Management, Table 2, pp. 17-18**
**Vegetation management**

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> BC Hydro has a variety of transmission voltage classes ranging from 69 kV to 500 kV, with different corridor maintenance widths depending on the voltage class (e.g.,10m width for a single 69 kV circuit compared to 62.5m width for a typical 500 kV single circuit). Therefore, the corridor area maintained may be different compared to some utilities of similar transmission length with a transmission system dominated by one or two voltage classes.
>
> […]
>
> Corridor with and vegetation clearance distances maintained on distribution systems are more comparable across utilities… BC Hydro's distribution system is exposed to winter storms, especially along the South Coast, the risk from these storms is not similar to the risk that some utilities in the peer group experience due to vegetation damage from repeated exposure to hurricanes and tornados.

Table 2 of the NERC Reliablity Standard FAC-003-4 on Transmission Vegetation Management states the minimum vegetation clearance distance (MCVD) along a transmission path for a given voltage, based on elevation.

2.237.6 Please provide the number of occurrences, if any, in each year from F2015 to F2019 where BC Hydro did not meet the standard corridor maintenance width or MVCD for transmission and distribution lines. As part of the response, please segregate the occurrences between transmission lines and distribution lines.

**RESPONSE:**

**BC Hydro is not aware of any occurrences between fiscal 2015 and fiscal 2019 where the corridor maintenance widths or MVCD requirements for either transmission or distribution lines were not met.**

**237.0 D. CHAPTER 5C – OPERATING COSTS – OPERATIONS BUSINESS GROUP**

**Reference: OPERATING COSTS – OPERATIONS BUSINESS GROUP**
**Exhibit B-1, Table 5C-4, p. 5C-12; pp. 5C-10, 5C-13;**
**Exhibit B-5, BCUC IR 60.1, 63.15, 66.1, 79.2, 126.1;**
**NERC FAC-003-4 Transmission Vegetation Management, Table 2, pp. 17-18**
**Vegetation management**

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> BC Hydro has a variety of transmission voltage classes ranging from 69 kV to 500 kV, with different corridor maintenance widths depending on the voltage class (e.g.,10m width for a single 69 kV circuit compared to 62.5m width for a typical 500 kV single circuit). Therefore, the corridor area maintained may be different compared to some utilities of similar transmission length with a transmission system dominated by one or two voltage classes.
>
> […]
>
> Corridor with and vegetation clearance distances maintained on distribution systems are more comparable across utilities… BC Hydro's distribution system is exposed to winter storms, especially along the South Coast, the risk from these storms is not similar to the risk that some utilities in the peer group experience due to vegetation damage from repeated exposure to hurricanes and tornados.

Table 2 of the NERC Reliablity Standard FAC-003-4 on Transmission Vegetation Management states the minimum vegetation clearance distance (MCVD) along a transmission path for a given voltage, based on elevation.

2.237.7 Please provide the number of occurrences, if any, in each year from F2015 to F2019 where BC Hydro did not meet the *BC Wildfire Act* and BC Wildfire Regulation with respect to vegetation management in the transmission corridors and distribution corridors. In the response, please segregate the occurrences between transmission and distribution corridors.

**RESPONSE:**

**To the best of our knowledge, from fiscal 2015 to fiscal 2019, there were no occurrences where BC Hydro was found in violation of the *BC Wildfire Act* and BC Wildfire Regulation with respect to vegetation management activities to clear and maintain vegetation in our transmission or distribution corridors.**

**237.0 D. CHAPTER 5C – OPERATING COSTS – OPERATIONS BUSINESS GROUP**

**Reference: OPERATING COSTS – OPERATIONS BUSINESS GROUP**
**Exhibit B-1, Table 5C-4, p. 5C-12; pp. 5C-10, 5C-13;**
**Exhibit B-5, BCUC IR 60.1, 63.15, 66.1, 79.2, 126.1;**
**NERC FAC-003-4 Transmission Vegetation Management, Table 2, pp. 17-18**
**Vegetation management**

In response to BCUC IR 60.1, BC Hydro stated:

> BC Hydro has a variety of transmission voltage classes ranging from 69 kV to 500 kV, with different corridor maintenance widths depending on the voltage class (e.g.,10m width for a single 69 kV circuit compared to 62.5m width for a typical 500 kV single circuit). Therefore, the corridor area maintained may be different compared to some utilities of similar transmission length with a transmission system dominated by one or two voltage classes.
>
> […]
>
> Corridor with and vegetation clearance distances maintained on distribution systems are more comparable across utilities… BC Hydro's distribution system is exposed to winter storms, especially along the South Coast, the risk from these storms is not similar to the risk that some utilities in the peer group experience due to vegetation damage from repeated exposure to hurricanes and tornados.

Table 2 of the NERC Reliablity Standard FAC-003-4 on Transmission Vegetation Management states the minimum vegetation clearance distance (MCVD) along a transmission path for a given voltage, based on elevation.

2.237.8 Please discuss whether there have been any power or safety issue with vegetation and transmission/distribution lines since F2015. If so, please provide the number of events and briefly describe the event.

**RESPONSE:**

**Please refer to BC Hydro's response to BCUC IR 2.237.6 where we state that BC Hydro is not aware of any occurrences between fiscal 2015 to fiscal 2019 where the corridor maintenance widths or MVCD requirements for either transmission or distribution lines were not met. Outages from vegetation on the**

**BC Hydro system are typically related to fallen trees or branches, particularly during storms. Please also refer to BC Hydro's response to BCUC IR 2.237.9 which provides the number of outages caused by vegetation.**

**237.0 D. CHAPTER 5C – OPERATING COSTS – OPERATIONS BUSINESS GROUP**

**Reference: OPERATING COSTS – OPERATIONS BUSINESS GROUP**
**Exhibit B-1, Table 5C-4, p. 5C-12; pp. 5C-10, 5C-13;**
**Exhibit B-5, BCUC IR 60.1, 63.15, 66.1, 79.2, 126.1;**
**NERC FAC-003-4 Transmission Vegetation Management, Table 2, pp. 17-18**
**Vegetation management**

In response to BCUC IR 60.1, BC Hydro stated:

> BC Hydro has a variety of transmission voltage classes ranging from 69 kV to 500 kV, with different corridor maintenance widths depending on the voltage class (e.g.,10m width for a single 69 kV circuit compared to 62.5m width for a typical 500 kV single circuit). Therefore, the corridor area maintained may be different compared to some utilities of similar transmission length with a transmission system dominated by one or two voltage classes.
>
> […]
>
> Corridor with and vegetation clearance distances maintained on distribution systems are more comparable across utilities… BC Hydro's distribution system is exposed to winter storms, especially along the South Coast, the risk from these storms is not similar to the risk that some utilities in the peer group experience due to vegetation damage from repeated exposure to hurricanes and tornados.

Table 2 of the NERC Reliablity Standard FAC-003-4 on Transmission Vegetation Management states the minimum vegetation clearance distance (MCVD) along a transmission path for a given voltage, based on elevation.

2.237.9 Please provide the number of outages caused by vegetation, for example trees and branches falling onto powerlines during wind storms from F2015 to F2019.

**RESPONSE:**

**The table below summarizes forced outages on the distribution system from fallen trees or branches from fiscal 2015 to fiscal 2019. BC Hydro maintains over 48,500 km of overhead distribution primary lines with vegetation clearances to the lines typically only 10 metres wide. As a result, the number of outages caused by vegetation on the distribution system is relatively high. Fallen trees and branches**

**are addressed by identification and removal of hazard trees adjacent to the lines. Even healthy trees can be damaged and cause outages during storms.**

| Fiscal Year | Forced Outage (Number) |
| --- | --- |
| 2015 | 1,689 |
| 2016 | 1,896 |
| 2017 | 2,259 |
| 2018 | 2,763 |
| 2019 | 2,920 |

**The table below summarizes forced outages on the transmission system from fallen trees or branches from fiscal 2015 to fiscal 2019. BC Hydro has over 18,500 km of transmission lines and most vegetation outages occur from falling trees on the lower voltage 69 kV to 138 kV circuits, which have narrower rights of way. To address the risk from falling trees, BC Hydro identifies and removes hazard trees adjacent to transmission lines.**

| Fiscal Year | Forced Outage (Number) |
| --- | --- |
| 2015 | 32 |
| 2016 | 80 |
| 2017 | 42 |
| 2018 | 56 |
| 2019 | 38 |

**Notable storms that occurred during the fiscal 2015 to fiscal 2019 period include:**

- **The wind storm on August 29, 2015 in the Lower Mainland;**
- **The ice storm in December 2017 in the Fraser Valley; and**
- **The wind storm in December 2018 on Vancouver Island and the Gulf Islands.**

**237.0 D. CHAPTER 5C – OPERATING COSTS – OPERATIONS BUSINESS GROUP**

**Reference: OPERATING COSTS – OPERATIONS BUSINESS GROUP**
**Exhibit B-1, Table 5C-4, p. 5C-12; pp. 5C-10, 5C-13;**
**Exhibit B-5, BCUC IR 60.1, 63.15, 66.1, 79.2, 126.1;**
**NERC FAC-003-4 Transmission Vegetation Management, Table 2, pp. 17-18**
**Vegetation management**

BC Hydro's response to BCUC IR 126.1 included the below table which identified the number of individual district storm events that BC Hydro has responded to in each of the past five years:

| Fiscal Year | F2014 | F2015 | F2016 | F2017 | F2018 |
| --- | --- | --- | --- | --- | --- |
| Number of district storm events | 52 | 62 | 88 | 125 | 148 |

2.237.10 Given the increase in the number of individual storm events, please discuss the last time the standard corridor maintenance width or MCVD for transmission and distribution lines had been reviewed and whether the standard corridor maintenance width or MCVD has increased as a proactive measure to prevent trees from falling onto power lines.

**RESPONSE:**

**The standard corridor maintenance widths for transmission and distribution lines are based on engineering requirements. Where applicable, BC Hydro acquires statutory rights of way to meet those requirements. There has been neither a review nor an immediate plan to increase the right of way widths to deal with individual storm events. BC Hydro conducts hazard tree analyses of vulnerable trees and removes those deemed to be a risk to the Power System. This is consistent with utility industry practice.**

**During high wind and precipitation storm events healthy trees can fail and cause outages. Saturated soils lose their holding strength and winds can then topple trees over. Clearances would have to be increased a minimum of one tree length of the tallest species on either side of the corridor to prevent trees from falling onto power lines. However, even an increase of that magnitude would not avoid all branch related outages such as those experienced in ice or snow storms. In addition, some trees (e.g., Douglas-fir) are known to have branches that can sail considerable distances during storms. To routinely clear corridors of tall trees to this extent would be cost prohibitive and likely not acceptable to the public from**

**an environmental perspective. BC Hydro and other utilities are in discussion on potential climate change impacts to the electrical grid to explore whether changes to current maintenance practices may be appropriate to mitigate those risks.**

**237.0 D. CHAPTER 5C – OPERATING COSTS – OPERATIONS BUSINESS GROUP**

**Reference: OPERATING COSTS – OPERATIONS BUSINESS GROUP**
**Exhibit B-1, Table 5C-4, p. 5C-12; pp. 5C-10, 5C-13;**
**Exhibit B-5, BCUC IR 60.1, 63.15, 66.1, 79.2, 126.1;**
**NERC FAC-003-4 Transmission Vegetation Management, Table 2, pp. 17-18**
**Vegetation management**

BC Hydro's response to BCUC IR 126.1 included the below table which identified the number of individual district storm events that BC Hydro has responded to in each of the past five years:

| Fiscal Year | F2014 | F2015 | F2016 | F2017 | F2018 |
|---|---|---|---|---|---|
| Number of district storm events | 52 | 62 | 88 | 125 | 148 |

2.237.11 Given the increase in the number of individual storm events, please discuss whether BC Hydro plans to extend the standard corridor maintenance width or MCVD for transmission and distribution lines in the Test Period to prevent trees from falling onto power lines. If not, please explain.

**RESPONSE:**

**Please refer to BC Hydro's response to BCUC IR 2.237.9 which summarizes the volume of outages from fallen trees and branches on the transmission and distribution system and to BC Hydro's response to BCUC IR 2.237.10 which explains why BC Hydro has not increased the corridor maintenance widths at this time.**

**237.0 D. CHAPTER 5C – OPERATING COSTS – OPERATIONS BUSINESS GROUP**

**Reference: OPERATING COSTS – OPERATIONS BUSINESS GROUP**
**Exhibit B-1, Table 5C-4, p. 5C-12; pp. 5C-10, 5C-13;**
**Exhibit B-5, BCUC IR 60.1, 63.15, 66.1, 79.2, 126.1;**
**NERC FAC-003-4 Transmission Vegetation Management, Table 2, pp. 17-18**
**Vegetation management**

BC Hydro's response to BCUC IR 126.1 included the below table which identified the number of individual district storm events that BC Hydro has responded to in each of the past five years:

| Fiscal Year | F2014 | F2015 | F2016 | F2017 | F2018 |
|---|---|---|---|---|---|
| Number of district storm events | 52 | 62 | 88 | 125 | 148 |

2.237.12 Given the increase in the number of individual storm events, please discuss whether BC Hydro plans to extend the requirements of the *BC Wildfire Act* and the BC Wildfire Regulation for vegetation management in transmission and distribution corridors in the Test Period. If not, please explain.

**RESPONSE:**

**BC Hydro vegetation maintenance standards conform to existing requirements under the *BC Wildfire Act* and the BC Wildfire Regulation. BC Hydro has no plans to change our standards to exceed the requirements of the legislation. Please refer to BC Hydro's response to BCUC IR 2.237.10 which explains why BC Hydro has not increased the corridor maintenance widths at this time.**

**237.0 D. CHAPTER 5C – OPERATING COSTS – OPERATIONS BUSINESS GROUP**

**Reference: OPERATING COSTS – OPERATIONS BUSINESS GROUP**
**Exhibit B-1, Table 5C-4, p. 5C-12; pp. 5C-10, 5C-13;**
**Exhibit B-5, BCUC IR 60.1, 63.15, 66.1, 79.2, 126.1;**
**NERC FAC-003-4 Transmission Vegetation Management, Table 2, pp. 17-18**
**Vegetation management**

BC Hydro's response to BCUC IR 126.1 included the below table which identified the number of individual district storm events that BC Hydro has responded to in each of the past five years:

| Fiscal Year | F2014 | F2015 | F2016 | F2017 | F2018 |
| --- | --- | --- | --- | --- | --- |
| Number of district storm events | 52 | 62 | 88 | 125 | 148 |

2.237.13 Please discuss whether there is a correlation between the number of individual storm events and the amount spent on vegetation management. Please explain why or why not.

**RESPONSE:**

**There is no correlation between the number of individual storm events and BC Hydro's vegetation management expenditures. The number of storms expected in any given year is hard to predict. Storm frequency has increased in the past five years but this is cyclical. BC Hydro provides stable funding to the vegetation maintenance program based on historical climatic conditions to ensure public safety, worker safety and system reliability. Please refer to BC Hydro's response to BCUC IR 2.237.10 which discusses the impacts of storms on vegetation caused outages. Additional expenditure toward vegetation maintenance to avoid damage from storms is being evaluated but is not planned at this time.**

**237.0 D. CHAPTER 5C – OPERATING COSTS – OPERATIONS BUSINESS GROUP**

**Reference: OPERATING COSTS – OPERATIONS BUSINESS GROUP**
**Exhibit B-1, Table 5C-4, p. 5C-12; pp. 5C-10, 5C-13;**
**Exhibit B-5, BCUC IR 60.1, 63.15, 66.1, 79.2, 126.1;**
**NERC FAC-003-4 Transmission Vegetation Management, Table 2, pp. 17-18**
**Vegetation management**

BC Hydro's response to BCUC IR 126.1 included the below table which identified the number of individual district storm events that BC Hydro has responded to in each of the past five years:

| Fiscal Year | F2014 | F2015 | F2016 | F2017 | F2018 |
|---|---|---|---|---|---|
| Number of district storm events | 52 | 62 | 88 | 125 | 148 |

2.237.13 Please discuss whether there is a correlation between the number of individual storm events and the amount spent on vegetation management. Please explain why or why not.

2.237.13.1 If there is a correlation, please explain why actual vegetation management costs have remained relatively flat from F2017 to F2021.

**RESPONSE:**

**Please refer to BC Hydro's response to BCUC IR 2.237.13 which outlines why there is no direct correlation between the number of individual storm events in any given year and the amount spent on vegetation management.**

**238.0 D. CHAPTER 5C – OPERATING COSTS – OPERATIONS BUSINESS GROUP**

**Reference: OPERATING COSTS – OPERATIONS BUSINESS GROUP**
**Exhibit B-1, Table 5C-4, pp. 5C-12 – 5C-13; Exhibit B-5, BCUC IR 66.1**
**Program and Contract Management Department**

Table 5C-4 on page 5C-12 of the Application shows the following for the F2019 forecast operating costs and FTEs for the Program and Contract Management Department in the Program and Contract Management KBU:

- Labour: $0.6 million
- Services – Other: $0.2 million
- Total FTEs: 4

Pages 5C-12 and 5C-13 state that the Director, Program and Contract Management Department contains four FTEs, as well as a budget of $0.2M in non-labour costs that represents funding for travel and annual dues.

BC Hydro’s response to BCUC IR 66.1 provided the following forecast operating costs for each of F2020 plan and F2021 plan for the Program and Contract Management Department in the Program and Contract Management KBU:

- Labour: $0.6 million
- Services – Other: $1.0 million
- Total FTEs: 4

2.238.1 Please explain why the F2020 and F2021 plan amounts for “Services – Other” has increased by $0.8M compared to the F2019 forecast for the Director, Program and Contract Management Department.

**RESPONSE:**

**The increase of $0.8 million in Services – Other in the Director, Program and Contract Management Department is primarily due to the re-organization in September 2018 (discussed in section 5C.4.3 of Chapter 5C of the Application) that transferred four FTEs from the Stations Field Operations KBU to the Program and Contract Management KBU. The costs associated with this transfer are net neutral to BC Hydro overall.**

**A portion of the operating budget associated with the four FTEs was budgeted in the Transmission Capital and Maintenance Department where the FTEs reside, and a portion was temporarily budgeted as Services – Other in the Director, Program and Contract Management Department while the charge out model for those FTEs was finalized.**

**239.0 D. CHAPTER 5C – OPERATING COSTS – OPERATIONS BUSINESS GROUP**

**Reference: OPERATING COSTS – OPERATIONS BUSINESS GROUP**
**Exhibit B-1, Table 5C-6, p. 5C-19;**
**Exhibit B-5, BCUC IR 66.1**
**Trouble line Field Ops and Ops Support Department**

Table 5C-6 of the Application shows F2019 forecast labour operating costs of $24.5 million and FTEs of 123 for the Trouble line Field Ops and Ops Support Department in the line Field Operations KBU.

BC Hydro’s response to BCUC IR 66.1 showed the following forecast labour operating costs and FTEs for F2020 plan and F2021 plan for the Trouble line Field Ops and Ops Support Department in the line Field Operations KBU:

- F2020:
  - Labour: $28.3 million
  - FTEs: 130

- F2021:
  - Labour: $28.6 million
  - FTEs: 130

2.239.1 Please explain how an increase in seven FTEs in the Trouble line Field Ops and Ops Support Department results in a $3.8 million increase in labour costs from F2019 to F2020.

**RESPONSE:**

**The $3.8 million increase in labour costs in the Trouble Line Field Operations and Operations Support Department from fiscal 2019 to fiscal 2020 is primarily due to:**

- **An increase to the five-year average of Storm Restoration costs of $11.1 million compared to the Previous Application. Of the $11.1 million increase, $2.7 million is attributable to operating labour costs and budgeted in the Trouble Line Field Operations and Operations Support Department;**

- **An increase of $1.0 million for Standard Labour Rate increases; and**

- **An increase of $0.1 million for seven additional FTEs, which are planned to charge out 85 per cent of their time to maintenance and capital work programs.**

**240.0 D. CHAPTER 5C – OPERATING COSTS – OPERATIONS BUSINESS GROUP**

**Reference: OPERATING COSTS – OPERATIONS BUSINESS GROUP**
**Exhibit B-1, Tables 5C-8, pp. 5C-25; Exhibit B-5, BCUC IR 66.1**
**Stations Operations Department**

Table 5C-8 in the Application shows $26.6 million for the forecast operating labour costs and 807 FTEs for F2019 for the Stations Operations Department in the Stations Field Operations KBU.

BC Hydro's response to BCUC IR 66.1 showed $33.0 million for the forecast operating labour costs and 774 FTEs for each of F2020 plan and F2021 plan for the Stations Operations Department in the Stations Field Operations KBU.

2.240.1 Please explain why labour costs are increasing by $6.4M from the F2019 forecast to the F2020 RRA plan and F2021 plan for the Stations Field Operations Department given that FTEs are decreasing from 807 to 774.

**RESPONSE:**

**In fiscal 2019, some FTEs in the Stations Operations Department would charge their operating labour costs to the Stations Asset Planning KBU which held the operating labour budget for these FTEs. In September 2018, as part of the re-organization to align with the Plan-Build-Operate-Support model, this budget was transferred over to the Stations Operations Department. This is shown in line 1 in the table below.**

**This increase in operating labour costs associated with this transfer was partially offset by the budget transfer of 33 FTEs and their associated operating labour costs budget from the Stations Operations Department to the Stations Asset Planning, Engineering and Program and Contract Management KBUs. This is shown in line 2 in the table below.**

**These budget and FTE transfers are cost and headcount neutral to BC Hydro overall and are included in the Impact of organizational changes since Fiscal 2017 to Fiscal 2019 Revenue Requirements Application line included in Table 5-12 on page 5-43 of Chapter 5 of the Application.**

**Below is a continuity table which reconciles the dollar and FTE change from fiscal 2019 forecast to the fiscal 2020 RRA plan.**

| $ in millions | Dollars | FTEs |
|---|---|---|
| F2019 Forecast – Stations Operations Labour Costs | 26.6 | 807 |
| (1) Transfer from Stations Asset Planning KBU to Stations Operations Department – Operating Labour only | 9.2 | 0 |
| (2) Transfers to Stations Asset Planning, Engineering, and Program and Contract Management KBUs – Operating Labour and FTEs | (4.0) | (33) |
| (3) Standard Labour Rate Increase | 1.2 | |
| F2020 RRA Plan – Stations Operations Labour Costs | 33.0 | 774 |

**241.0 D. CHAPTER 5C – OPERATING COSTS – OPERATIONS BUSINESS GROUP**

**Reference: OPERATING COSTS – OPERATIONS BUSINESS GROUP**
**Exhibit B-5, BCUC IR 85.1; BC Hydro Application for Reliability Coordinator Registration with the Mandatory Reliability Standards Program proceeding, Exhibit B-1, p. 1-2; Exhibit B-6, BCUC IR 8.3**
**Inter-Utility Operations Department**

BC Hydro's response to BCUC IR 85.1 provided the below table that identifies operating costs for the Inter-Utility Department:

| Inter-Utility Operating Costs – RRA Plan ($/million) | Fiscal 2015 | Fiscal 2016 | Fiscal 2017 | Fiscal 2018 | Fiscal 2019 | Fiscal 2020 | Fiscal 2021 |
|---|---|---|---|---|---|---|---|
| WECC Membership Fees | 4.4 | 4.4 | 3.3 | 3.4 | 3.6 | 4.1 | 4.1 |
| PEAK Membership Fees | - | - | 3.7 | 3.7 | 3.7 | 2.0 | 2.0 |
| Northwest Power Pool | 0.1 | 0.1 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 |
| WECC Congestion Management/Flow Mitigation | - | - | 0.4 | 0.4 | 0.4 | 0.2 | 0.2 |
| Distribution Management System | 0.6 | 0.6 | - | - | - | - | - |
| BC Hydro Internal Staff Cost | 1.0 | 1.0 | - | - | - | - | - |
| Contractor Costs | 0.5 | 0.5 | - | - | - | - | - |
| Total RRA Plan | 6.6 | 6.6 | 7.6 | 7.7 | 7.9 | 6.5 | 6.5 |

On page 1-2 of BC Hydro's Application for Reliability Coordinator Registration with the Mandatory Reliability Standards (MRS) Program states: "Recently PEAK has announced it will be winding down operations and will no longer provide RC [Reliability Coordinator] services effective December 31, 2019.

2.241.1 Please explain why estimated annual PEAK membership fees of $2M are included in the F2020 and F2021 RRA plan given that PEAK will no longer provide RC services effective December 31, 2019.

**RESPONSE:**

**When the budget was prepared in the summer of 2018, the $2.0 million budget shown as PEAK Membership Fees in BC Hydro's response to BCUC IR 1.85.1 was for additional implementation and sustainment costs, as well as host application fees. At the time of the Application, the BCUC had not yet approved BC Hydro's registration as the Reliability Coordinator. Furthermore, the total implementation and sustainment costs as well as the host application fees associated with the Reliability Coordinator function were uncertain.**

**For fiscal 2020, the budgeted amount of $2.0 million is required as BC Hydro will continue to receive full Reliability Coordinator services from PEAK until September 2, 2019, and will need access to PEAK-hosted applications until such time that a new host provider is established (CAISO plans to be the new host provider on or before December 31, 2019). Based on current information, the forecast spend for fiscal 2020 is $2.6 million ($2.5 million for PEAK membership fees and $0.1 million for access to PEAK-hosted applications from September through December 2019).**

**For fiscal 2021, BC Hydro now estimates that the Provincial Reliability Coordination Operations department will require only $0.4 million of the PEAK Membership Fee budget in fiscal 2021, and not the full $2.0 million. BC Hydro notes that this is the current estimate of budget required and until BC Hydro has performed the Reliability Coordinator function for some time, there is a possibility that some additional budget could be required.**

**If the actual costs spent against the PEAK Membership Fee budget in fiscal 2021 are in line with this updated estimate, the remaining funds would be available to respond to unplanned work demands and unanticipated cost pressures. As described in BC Hydro's responses to BCUC IRs 1.64.1 and 2.214.1, BC Hydro continues to face cost pressures due to an increased volume and complexity of work. Further, as discussed in BC Hydro's response to BCUC IR 2.231.1, as there is no unallocated funds budget available in the current test period, all funding of unplanned work demands and unanticipated cost pressures will need to come through target adjustments that equal zero on a net basis. This is the course of action management undertakes so that new arising cost pressures are addressed within the total operating cost budget of the company.**

**BC Hydro notes that, for example, a cost pressure that has arisen since the filing of the Application relates to the Commission's 2019 Indigenous Utilities Regulation Inquiry. The Inquiry was established in March 2019 and on June 19, 2019 the BCUC provided an estimate of $0.9 million to BC Hydro as to its allocation of the expected costs of the Inquiry.**

**241.0 D. CHAPTER 5C – OPERATING COSTS – OPERATIONS BUSINESS GROUP**

**Reference: OPERATING COSTS – OPERATIONS BUSINESS GROUP**
**Exhibit B-5, BCUC IR 85.1; BC Hydro Application for Reliability Coordinator Registration with the Mandatory Reliability Standards Program proceeding, Exhibit B-1, p. 1-2; Exhibit B-6, BCUC IR 8.3**
**Inter-Utility Operations Department**

In response to BCUC IR 8.3 in the BC Hydro Application for Reliability Coordinator Registration with the Mandatory Reliability Standards Program proceeding, BC Hydro stated:

…BC Hydro is not seeking cost recovery from B.C. registered entities as part of this process. In the future it may be appropriate to review cost sharing for a part of or the whole MRS Program amongst B.C. registered entities.

BC Hydro submits that there may be various cost recovery mechanisms that could be employed. One possible mechanism for cost recovery could be on a net energy for load basis, similar to how WECC fees are currently recovered from member organizations.

2.241.2 Please confirm, or explain otherwise, that cost recovery from BC registered entities with respect to BC Hydro providing RC services has not been included as an offset to the Test Period revenue requirement.

**RESPONSE:**

**Confirmed. At this time, BC Hydro has not sought cost recovery from B.C. registered entities with respect to BC Hydro providing Reliability Coordinator services and accordingly, has not included any cost recovery as an offset to the Test Period revenue requirement.**

**242.0 E. CHAPTER 5D – OPERATING COSTS – SAFETY**

**Reference: OPERATING COSTS – SAFETY**
**Exhibit B-1, p. 5D-3; Appendix A, Schedule 5.4; Figures 5D-1, 5D-2**
**Exhibit B-5, BCUC IR 87.1, 87.3.1, 88.1; Exhibit B-6, CEC IR 47.1, BCOAPO IR 3.2.1**
**Injuries and injury frequency**

BC Hydro's response to BCUC IR 87.1 stated the following:

- At the time of the Application, finalized Lost Time Injury Frequency (LTIF) and All Injury Frequency (AIF) rates for fiscal 2019 were not available. BC Hydro can now confirm that AIF for fiscal 2019 was 2.04 (target of 1.71) and LTIF for fiscal 2019 was 0.87 (target of 0.80).
- BC Hydro's Service Plan includes a LTIF target of 0.80 for fiscal 2020, 0.80 for fiscal 2021 and 0.75 for fiscal 2022. BC Hydro has not yet set LTIF targets for subsequent years.
- BC Hydro's internal target for AIF for fiscal 2020 is set to 1.70. BC Hydro has not yet set AIF targets for subsequent years.
- The majority of BC Hydro's workplace injuries are related to body mechanics.
- Initiatives to improve both the LTIF and AIF rates include developing a program by which employees can have improved access to injury recovery services as well as better accommodation for modified duties, as well as an expansion of BC Hydro's Ergonomics program.

2.242.1 Please identify the costs associated with the initiatives mentioned above. As part of the response, please identify when these initiatives started.

**RESPONSE:**

**BC Hydro's initiatives to improve Lost Time Injury Frequency and All Injury Frequency rates include:**

- **Ergonomics: The initiative to expand and implement the ergonomics program is expected to cost $1.6 million. This includes pilots undertaken in fiscal 2016 through fiscal 2018, as well as broader implementation that began in fiscal 2019 and is expected to be completed and transitioned to sustainment by fiscal 2023; and**

- **Recover and Return to work: BC Hydro has always provided recovery and return to work support for BC Hydro employees for both occupational and**

**non-occupational related injuries and illnesses. This support is delivered through the Health and Recovery Services team within the Human Resources KBU. Approximately 30 per cent of one FTE is devoted specifically to recovery and return to work support for work related injuries at an annual cost of approximately $35,000.**

**242.0 E. CHAPTER 5D – OPERATING COSTS – SAFETY**

**Reference: OPERATING COSTS – SAFETY**
**Exhibit B-1, p. 5D-3; Appendix A, Schedule 5.4; Figures 5D-1, 5D-2**
**Exhibit B-5, BCUC IR 87.1, 87.3.1, 88.1; Exhibit B-6, CEC IR 47.1, BCOAPO IR 3.2.1**
**Injuries and injury frequency**

BC Hydro's response to BCUC IR 87.1 stated the following:

- At the time of the Application, finalized Lost Time Injury Frequency (LTIF) and All Injury Frequency (AIF) rates for fiscal 2019 were not available. BC Hydro can now confirm that AIF for fiscal 2019 was 2.04 (target of 1.71) and LTIF for fiscal 2019 was 0.87 (target of 0.80).
- BC Hydro's Service Plan includes a LTIF target of 0.80 for fiscal 2020, 0.80 for fiscal 2021 and 0.75 for fiscal 2022. BC Hydro has not yet set LTIF targets for subsequent years.
- BC Hydro's internal target for AIF for fiscal 2020 is set to 1.70. BC Hydro has not yet set AIF targets for subsequent years.
- The majority of BC Hydro's workplace injuries are related to body mechanics.
- Initiatives to improve both the LTIF and AIF rates include developing a program by which employees can have improved access to injury recovery services as well as better accommodation for modified duties, as well as an expansion of BC Hydro's Ergonomics program.

2.242.1.1 Please identify any initiatives related to improving LTIF and AIF rates that have been discontinued since the last revenue requirement. Please also provide the associated cost of these initiatives. As part of the response, please explain why these initiatives were discontinued.

**RESPONSE:**

**BC Hydro has not discontinued any specific initiatives since the last revenue requirement (i.e., no initiatives were stopped before their planned conclusion). Two initiatives have been completed (i.e., the up-front costs/effort associated with the initiatives are complete and the program is now embedded into our safety programs).**

**The two completed programs are cut-resistant gloves ($0.8 million) and Flame Resistant clothing ($3.2 million).**

**242.0 E. CHAPTER 5D – OPERATING COSTS – SAFETY**

**Reference: OPERATING COSTS – SAFETY**
**Exhibit B-1, p. 5D-3; Appendix A, Schedule 5.4; Figures 5D-1, 5D-2**
**Exhibit B-5, BCUC IR 87.1, 87.3.1, 88.1; Exhibit B-6, CEC IR 47.1, BCOAPO IR 3.2.1**
**Injuries and injury frequency**

BC Hydro's response to BCUC IR 87.1 stated the following:

- At the time of the Application, finalized Lost Time Injury Frequency (LTIF) and All Injury Frequency (AIF) rates for fiscal 2019 were not available. BC Hydro can now confirm that AIF for fiscal 2019 was 2.04 (target of 1.71) and LTIF for fiscal 2019 was 0.87 (target of 0.80).
- BC Hydro's Service Plan includes a LTIF target of 0.80 for fiscal 2020, 0.80 for fiscal 2021 and 0.75 for fiscal 2022. BC Hydro has not yet set LTIF targets for subsequent years.
- BC Hydro's internal target for AIF for fiscal 2020 is set to 1.70. BC Hydro has not yet set AIF targets for subsequent years.
- The majority of BC Hydro's workplace injuries are related to body mechanics.
- Initiatives to improve both the LTIF and AIF rates include developing a program by which employees can have improved access to injury recovery services as well as better accommodation for modified duties, as well as an expansion of BC Hydro's Ergonomics program.

2.242.1.2 Please identify the department where the costs of the initiatives noted in the preamble are budgeted in the F2020 and F2021 revenue requirement.

**RESPONSE:**

**The initiative costs for Ergonomics are budgeted in the Learning and Development and Safety System and Assurance KBUs. These costs fund:**

- **Initial training to provide workers with foundational knowledge and skills to recognize the basic ergonomics hazards and build their overall core body strength and flexibility so they can move safely in all types of work and daily activities; and**
- **Follow-up to support workers and team leaders in practicing and applying their skills to maintain body and movement awareness and to identify ergonomics risks and implement controls.**

**Any on-going sustainment costs (risk assessments, additional follow-up support) would be funded by the employees' respective Departments.**

**Recovery and Return to work support is funded from the Total Rewards and Systems Department of the Human Resources KBU.**

**242.0 E. CHAPTER 5D – OPERATING COSTS – SAFETY**

**Reference: OPERATING COSTS – SAFETY**
**Exhibit B-1, p. 5D-3; Appendix A, Schedule 5.4; Figures 5D-1, 5D-2**
**Exhibit B-5, BCUC IR 87.1, 87.3.1, 88.1; Exhibit B-6, CEC IR 47.1, BCOAPO IR 3.2.1**
**Injuries and injury frequency**

In response to BCOAPO IR 3.2.1, BC Hydro stated two performance measures were revised in the 2019/2020 to 2021/2022 Service Plan, one of which includes:

1) Lost Time Injury Frequency

2018/2019 to 2020/2021 Service Plan 2020/2021 target: 0.75

2019/2020 to 2021/2022 Service Plan 2020/2021 target: 0.80

Based on the number of lost time injuries we had seen year-to-date in February 2019, BC Hydro did not expect to meet our lost time frequency target in fiscal 2019. Therefore, the 2020/2021 Lost Time Injury Frequency target was adjusted from 0.75 to 0.80, based on our 2018/2019 forecasted result.

2.242.2 Please discuss why BC Hydro has lowered the LTIF target when it has a number of initiatives in place to improve the LTIF.

**RESPONSE:**

**The Lost Time Injury Frequency (LTIF) target was adjusted from 0.75 to 0.80 for fiscal 2020 and fiscal 2021. The adjusted target still represents an improvement over past results and better reflects the pace of the performance improvement that we expect the initiatives to deliver.**

**BC Hydro has achieved consistent and measureable reductions in LTIF from 1.04 in fiscal 2017, to 0.88 in fiscal 2018 and to 0.87 in fiscal 2019.**

**242.0 E. CHAPTER 5D – OPERATING COSTS – SAFETY**

**Reference: OPERATING COSTS – SAFETY**
**Exhibit B-1, p. 5D-3; Appendix A, Schedule 5.4; Figures 5D-1, 5D-2**
**Exhibit B-5, BCUC IR 87.1, 87.3.1, 88.1; Exhibit B-6, CEC IR 47.1, BCOAPO IR 3.2.1**
**Injuries and injury frequency**

In response to BCOAPO IR 3.2.1, BC Hydro stated two performance measures were revised in the 2019/2020 to 2021/2022 Service Plan, one of which includes:

1) Lost Time Injury Frequency

2018/2019 to 2020/2021 Service Plan 2020/2021 target: 0.75

2019/2020 to 2021/2022 Service Plan 2020/2021 target: 0.80

Based on the number of lost time injuries we had seen year-to-date in February 2019, BC Hydro did not expect to meet our lost time frequency target in fiscal 2019. Therefore, the 2020/2021 Lost Time Injury Frequency target was adjusted from 0.75 to 0.80, based on our 2018/2019 forecasted result.

2.242.3 Please discuss whether lowering the LTIF will have an impact on BC Hydro's safety culture. Please explain why or why not.

**RESPONSE:**

**BC Hydro does not expect that adjusting the Lost Time Injury Frequency (LTIF) target from 0.75 to 0.80 for fiscal 2020 and fiscal 2021 will have an impact on BC Hydro's safety culture. BC Hydro has achieved consistent and measureable reductions in LTIF from fiscal 2017 to fiscal 2019 and the adjusted targets remain a stretch target compared to past results.**

**Changing the LTIF target based on actual performance in the previous year reinforces the measured and consistent approach that BC Hydro has towards injury reduction and will reinforce the current safety culture where there is a year to year expectation of continual improvement.**

**242.0 E. CHAPTER 5D – OPERATING COSTS – SAFETY**

**Reference: OPERATING COSTS – SAFETY**
**Exhibit B-1, p. 5D-3; Appendix A, Schedule 5.4; Figures 5D-1, 5D-2**
**Exhibit B-5, BCUC IR 87.1, 87.3.1, 88.1; Exhibit B-6, CEC IR 47.1, BCOAPO IR 3.2.1**
**Injuries and injury frequency**

In response to BCOAPO IR 3.2.1, BC Hydro stated two performance measures were revised in the 2019/2020 to 2021/2022 Service Plan, one of which includes:

1) Lost Time Injury Frequency

2018/2019 to 2020/2021 Service Plan 2020/2021 target: 0.75

2019/2020 to 2021/2022 Service Plan 2020/2021 target: 0.80

Based on the number of lost time injuries we had seen year-to-date in February 2019, BC Hydro did not expect to meet our lost time frequency target in fiscal 2019. Therefore, the 2020/2021 Lost Time Injury Frequency target was adjusted from 0.75 to 0.80, based on our 2018/2019 forecasted result.

2.242.4 Please provide a high-level discussion of the impact of a 0.05 reduction in the LTIF on the most recent completed annual incentive (holdback) payout. Please quantify the impact, if possible.

**RESPONSE:**

**The Lost Time Injury Frequency (LTIF) target was adjusted from 0.75 to 0.80 for fiscal 2020 and fiscal 2021. It was not adjusted for fiscal 2019, which was the most recent completed annual incentive (holdback) payout.**

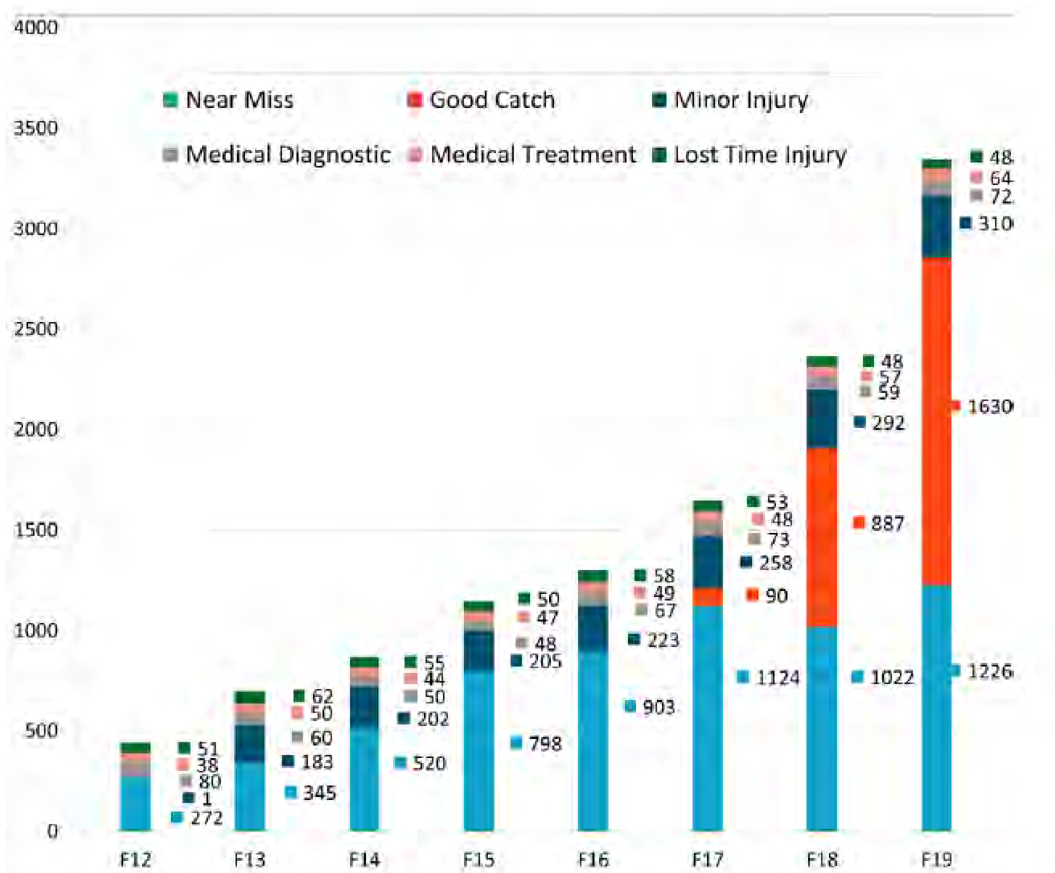
**Please refer to BC Hydro's response to BCUC IR 1.42.10.1 where we explain how salary holdback awards are calculated and provide the fiscal 2019 Service Plan Scorecard and Results for all Service Plan Measures, including LTIF.**

**242.0 E. CHAPTER 5D – OPERATING COSTS – SAFETY**

**Reference: OPERATING COSTS – SAFETY**
**Exhibit B-1, p. 5D-3; Appendix A, Schedule 5.4; Figures 5D-1, 5D-2**
**Exhibit B-5, BCUC IR 87.1, 87.3.1, 88.1; Exhibit B-6, CEC IR 47.1, BCOAPO IR 3.2.1**
**Injuries and injury frequency**

BC Hydro's response to CEC IR 47.1 stated that body mechanic injuries accounted for 72 percent of the Lost Time incidents in F2019.

BC Hydro's response to BCUC IR 87.3.1 included the chart below, which expanded Figure 5D-4 of the Application to both incorporate final numbers for 2019 and include the number of injuries per year.




Schedule 5.4 of Appendix A to the Application categorizes operating costs in the Safety Business Group, as shown below:

**Operating Costs - Safety**
**($ million)**

| | | | F2018 | | F2019 | | | F2020 | F2021 |
|---|---|---|---|---|---|---|---|---|---|
| | | Reference | Actual | Diff | RRA | Forecast | Diff | Plan | Plan |
| Line | Column | | 5 | 6 = 5 - 4 | 7 | 8 | 9 = 8 - 7 | 10 | 11 |
| | **Operating Costs by Resource** | | | | | | | | |
| 13 | Labour | | 35.0 | (0.7) | 36.1 | 36.0 | (0.0) | 37.9 | 38.6 |
| 14 | Services - ABSU | | 0.4 | 0.2 | 0.2 | 0.0 | (0.2) | 0.0 | 0.0 |
| 15 | Services - Other | | 15.9 | (1.9) | 17.8 | 17.6 | (0.2) | 17.8 | 17.8 |
| 16 | Materials | | 1.2 | 0.6 | 0.7 | 0.8 | 0.1 | 0.8 | 0.8 |
| 17 | Buildings & Equipment | | 0.7 | 0.5 | 0.2 | 0.4 | 0.1 | 0.3 | 0.3 |
| 18 | Capitalized Overhead | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 19 | External Recoveries | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 20 | Total | | 53.3 | (1.3) | 54.9 | 54.8 | (0.2) | 56.8 | 57.5 |

2.242.5 Over the period from F2018 to F2021, please explain why operating costs for the Safety Business Group have remained somewhat flat relative to the growth in the number of injuries (Medical Treatment, Medical Diagnostic, Minor Injury, Lost Time Injury) in F2018 and F2019.

**RESPONSE:**

**Combined medical treatment and diagnostic injuries were relatively flat from fiscal 2017 to fiscal 2019 (121, 116, and 136 respectfully). Lost time injuries declined over the same period (53, 48, and 48 respectively).**

**The operating costs for the Safety Business Group have remained flat because the Business Group has successfully delivered support to the organization to prevent serious and disabling injuries and has achieved a consistent, measurable reduction in lost time injuries and Lost Time Injury Frequency, year over year.**

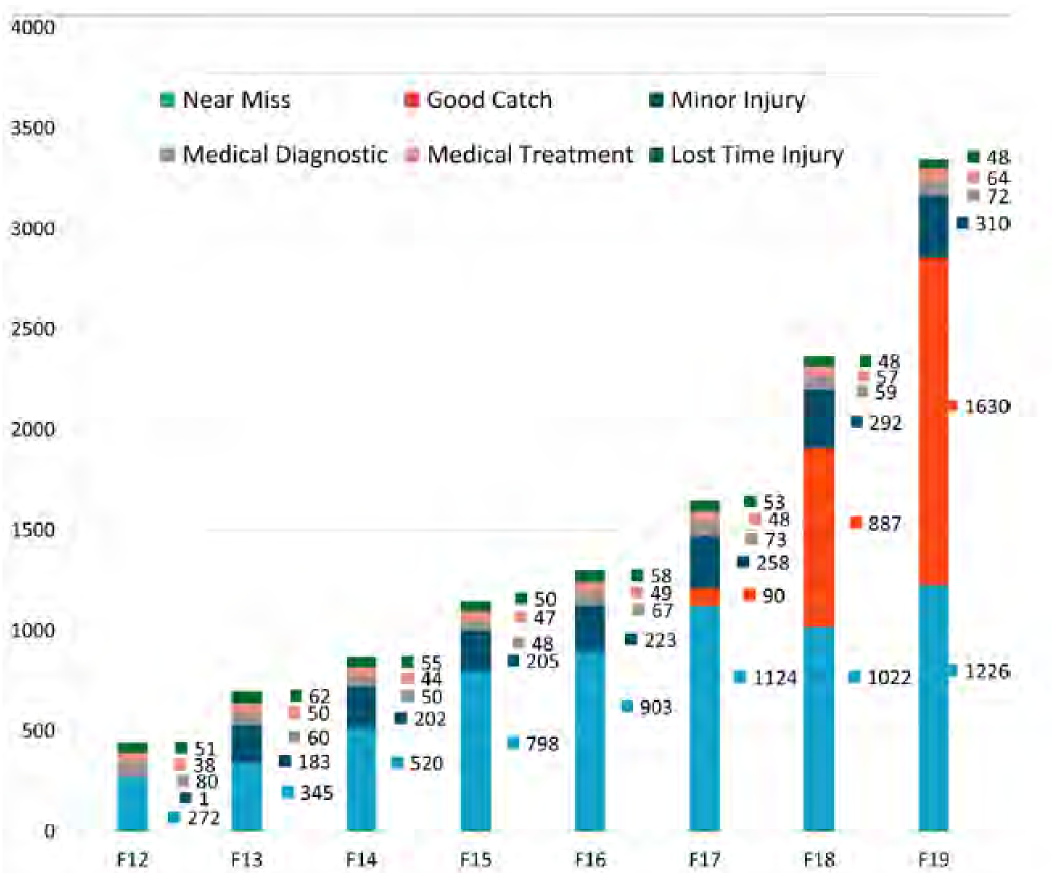
**Additionally, some initiatives, such as the expansion of the ergonomics program are not funded by the Safety Business Group. Rather, they are funded from the operating budgets of the KBUs that receive those benefits.**

**242.0 E. CHAPTER 5D – OPERATING COSTS – SAFETY**

**Reference: OPERATING COSTS – SAFETY**
**Exhibit B-1, p. 5D-3; Appendix A, Schedule 5.4; Figures 5D-1, 5D-2**
**Exhibit B-5, BCUC IR 87.1, 87.3.1, 88.1; Exhibit B-6, CEC IR 47.1, BCOAPO IR 3.2.1**
**Injuries and injury frequency**

BC Hydro's response to CEC IR 47.1 stated that body mechanic injuries accounted for 72 percent of the Lost Time incidents in F2019.

BC Hydro's response to BCUC IR 87.3.1 included the chart below, which expanded Figure 5D-4 of the Application to both incorporate final numbers for 2019 and include the number of injuries per year.




Schedule 5.4 of Appendix A to the Application categorizes operating costs in the Safety Business Group, as shown below:

**Operating Costs - Safety**
**($ million)**

| Line | | Reference | F2018 Actual | F2018 Diff | F2019 RRA | F2019 Forecast | F2019 Diff | F2020 Plan | F2021 Plan |
|---|---|---|---|---|---|---|---|---|---|
| | Column | | 5 | 6 = 5 - 4 | 7 | 8 | 9 = 8 - 7 | 10 | 11 |
| | **Operating Costs by Resource** | | | | | | | | |
| 13 | Labour | | 35.0 | (0.7) | 36.1 | 36.0 | (0.0) | 37.9 | 38.6 |
| 14 | Services - ABSU | | 0.4 | 0.2 | 0.2 | 0.0 | (0.2) | 0.0 | 0.0 |
| 15 | Services - Other | | 15.9 | (1.9) | 17.8 | 17.6 | (0.2) | 17.8 | 17.8 |
| 16 | Materials | | 1.2 | 0.6 | 0.7 | 0.8 | 0.1 | 0.8 | 0.8 |
| 17 | Buildings & Equipment | | 0.7 | 0.5 | 0.2 | 0.4 | 0.1 | 0.3 | 0.3 |
| 18 | Capitalized Overhead | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 19 | External Recoveries | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 20 | Total | | 53.3 | (1.3) | 54.9 | 54.8 | (0.2) | 56.8 | 57.5 |

2.242.6 Please explain whether an increase in Near Miss and Good Catch reporting is expected to reduce the number of injuries related to body mechanics. If so, please explain how.

**RESPONSE:**

**The increase in reporting of Near Miss and Good Catch related to body mechanics will help BC Hydro determine adequate annual safety activities and plans which in turn will reduce body mechanics injuries.**

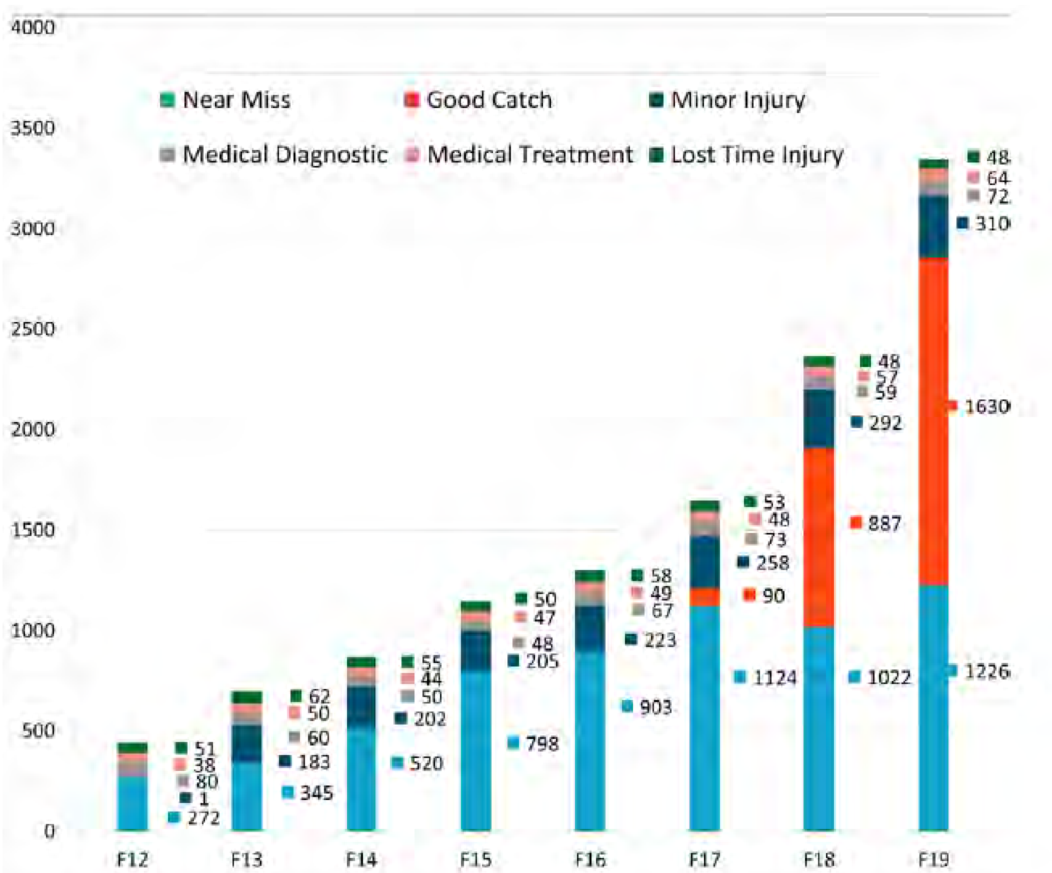
**The increase in reporting of near misses and good catches is the expected result of BC Hydro's efforts to educate employees about body mechanics and the associated hazards and best practices.**

**242.0 E. CHAPTER 5D – OPERATING COSTS – SAFETY**

**Reference: OPERATING COSTS – SAFETY**
**Exhibit B-1, p. 5D-3; Appendix A, Schedule 5.4; Figures 5D-1, 5D-2**
**Exhibit B-5, BCUC IR 87.1, 87.3.1, 88.1; Exhibit B-6, CEC IR 47.1, BCOAPO IR 3.2.1**
**Injuries and injury frequency**

BC Hydro's response to CEC IR 47.1 stated that body mechanic injuries accounted for 72 percent of the Lost Time incidents in F2019.

BC Hydro's response to BCUC IR 87.3.1 included the chart below, which expanded Figure 5D-4 of the Application to both incorporate final numbers for 2019 and include the number of injuries per year.




Schedule 5.4 of Appendix A to the Application categorizes operating costs in the Safety Business Group, as shown below:

| Operating Costs - Safety ($ million) | | | F2018 | | F2019 | | | F2020 | F2021 |
|---|---|---|---|---|---|---|---|---|---|
| | | Reference | Actual | Diff | RRA | Forecast | Diff | Plan | Plan |
| Line | | Column | 5 | 6 = 5 - 4 | 7 | 8 | 9 = 8 - 7 | 10 | 11 |
| | **Operating Costs by Resource** | | | | | | | | |
| 13 | Labour | | 35.0 | (0.7) | 36.1 | 36.0 | (0.0) | 37.9 | 38.6 |
| 14 | Services - ABSU | | 0.4 | 0.2 | 0.2 | 0.0 | (0.2) | 0.0 | 0.0 |
| 15 | Services - Other | | 15.9 | (1.9) | 17.8 | 17.6 | (0.2) | 17.8 | 17.8 |
| 16 | Materials | | 1.2 | 0.6 | 0.7 | 0.8 | 0.1 | 0.8 | 0.8 |
| 17 | Buildings & Equipment | | 0.7 | 0.5 | 0.2 | 0.4 | 0.1 | 0.3 | 0.3 |
| 18 | Capitalized Overhead | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 19 | External Recoveries | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 20 | Total | | 53.3 | (1.3) | 54.9 | 54.8 | (0.2) | 56.8 | 57.5 |

2.242.7 Please complete the table below to identify the percentage of body mechanic injuries under each classification as defined in the chart provided in response to BCUC IR 87.3.1 and reproduced in the preamble.

| Injury due to: | Minor Injury | Medical Treatment | Medical Diagnostic | Lost Time Injury | Total |
|---|---|---|---|---|---|
| Body Mechanics | | | | | |
| Other | | | | | |
| **Total** | | | | | |

**RESPONSE:**

**The table below identifies the percentage of body mechanic injuries to other injuries from fiscal 2012 to fiscal 2019 in each classification as shown in the chart provided in BC Hydro's response to BCUC IR 1.87.3.1.**

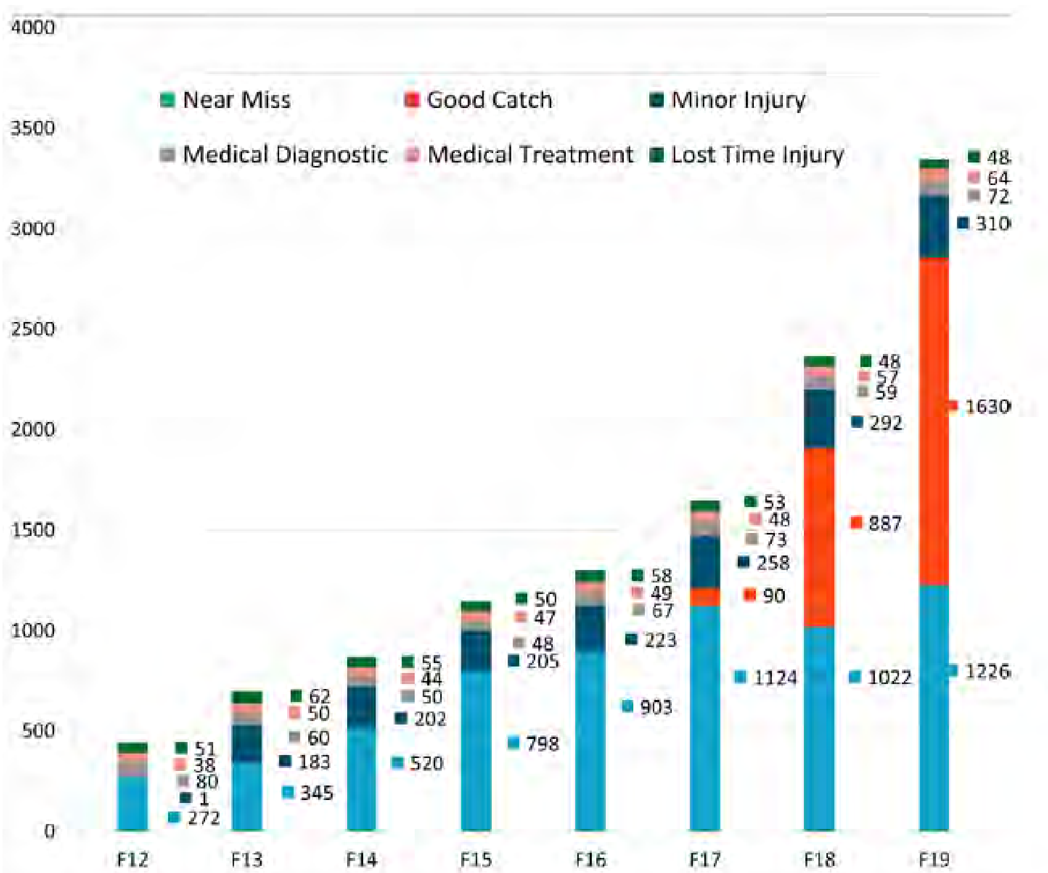
| Injury due to: | Minor Injury (%) | Medical Treatment (%) | Medical Diagnostic (%) | Lost Time Injury (%) | Total (%) |
|---|---|---|---|---|---|
| **Body Mechanics** | **64** | **65** | **50** | **74** | **63** |
| **Other** | **36** | **35** | **50** | **26** | **37** |
| **Total** | **100** | **100** | **100** | **100** | **100** |

**242.0 E. CHAPTER 5D – OPERATING COSTS – SAFETY**

**Reference: OPERATING COSTS – SAFETY**
**Exhibit B-1, p. 5D-3; Appendix A, Schedule 5.4; Figures 5D-1, 5D-2**
**Exhibit B-5, BCUC IR 87.1, 87.3.1, 88.1; Exhibit B-6, CEC IR 47.1, BCOAPO IR 3.2.1**
**Injuries and injury frequency**

BC Hydro's response to CEC IR 47.1 stated that body mechanic injuries accounted for 72 percent of the Lost Time incidents in F2019.

BC Hydro's response to BCUC IR 87.3.1 included the chart below, which expanded Figure 5D-4 of the Application to both incorporate final numbers for 2019 and include the number of injuries per year.




Schedule 5.4 of Appendix A to the Application categorizes operating costs in the Safety Business Group, as shown below:

**Operating Costs - Safety**
**($ million)**

| Line | | Reference | F2018 Actual | F2018 Diff | F2019 RRA | F2019 Forecast | F2019 Diff | F2020 Plan | F2021 Plan |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| | Column | | 5 | 6 = 5 - 4 | 7 | 8 | 9 = 8 - 7 | 10 | 11 |
| | **Operating Costs by Resource** | | | | | | | | |
| 13 | Labour | | 35.0 | (0.7) | 36.1 | 36.0 | (0.0) | 37.9 | 38.6 |
| 14 | Services - ABSU | | 0.4 | 0.2 | 0.2 | 0.0 | (0.2) | 0.0 | 0.0 |
| 15 | Services - Other | | 15.9 | (1.9) | 17.8 | 17.6 | (0.2) | 17.8 | 17.8 |
| 16 | Materials | | 1.2 | 0.6 | 0.7 | 0.8 | 0.1 | 0.8 | 0.8 |
| 17 | Buildings & Equipment | | 0.7 | 0.5 | 0.2 | 0.4 | 0.1 | 0.3 | 0.3 |
| 18 | Capitalized Overhead | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 19 | External Recoveries | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 20 | Total | | 53.3 | (1.3) | 54.9 | 54.8 | (0.2) | 56.8 | 57.5 |

2.242.7.1 Other than body mechanic injuries, please discuss the types of injuries associated with each of the four incident classifications above (i.e. the types of injuries categorized as “other” in the preceding IR).

**RESPONSE:**

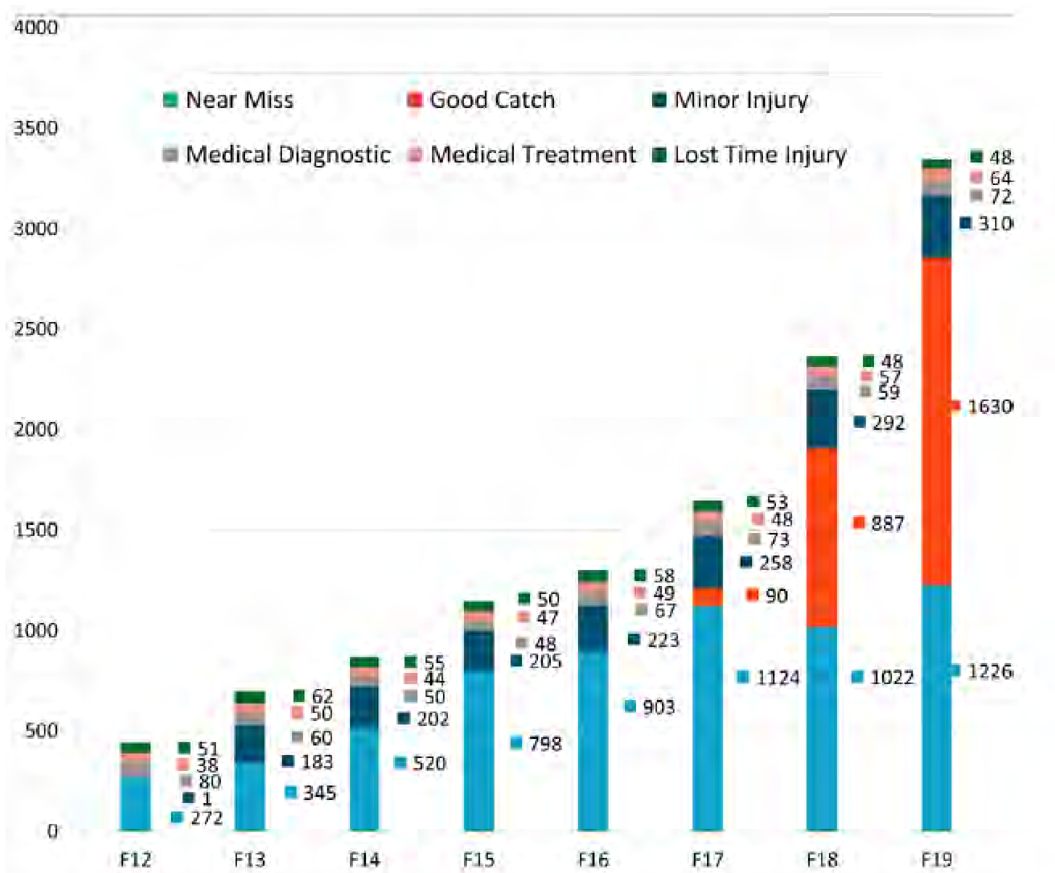
**The four injury classifications above are Minor Injury, Medical Diagnostic, Medical Treatment and Lost Time Injury. These classifications describe the severity of the injury. Each injury is further assigned one of 13 categories. Body Mechanics is one of the 13 categories. The other categories are: biological, chemical, electrical, gravity, mechanical, noise, pressure, radiant, tensile strain, thermal, transportation and general.**

**242.0 E. CHAPTER 5D – OPERATING COSTS – SAFETY**

**Reference: OPERATING COSTS – SAFETY**
**Exhibit B-1, p. 5D-3; Appendix A, Schedule 5.4; Figures 5D-1, 5D-2**
**Exhibit B-5, BCUC IR 87.1, 87.3.1, 88.1; Exhibit B-6, CEC IR 47.1, BCOAPO IR 3.2.1**
**Injuries and injury frequency**

BC Hydro's response to CEC IR 47.1 stated that body mechanic injuries accounted for 72 percent of the Lost Time incidents in F2019.

BC Hydro's response to BCUC IR 87.3.1 included the chart below, which expanded Figure 5D-4 of the Application to both incorporate final numbers for 2019 and include the number of injuries per year.




Schedule 5.4 of Appendix A to the Application categorizes operating costs in the Safety Business Group, as shown below:

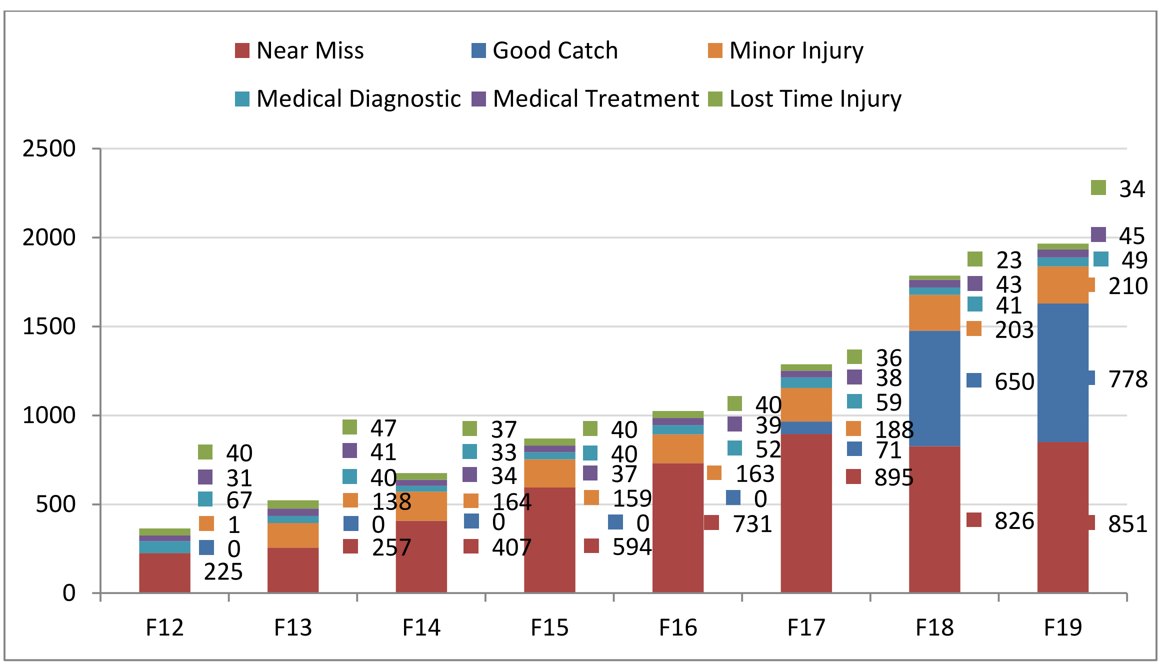
| Operating Costs - Safety ($ million) | | | F2018 | | F2019 | | | F2020 | F2021 |
|---|---|---|---|---|---|---|---|---|---|
| | | Reference | Actual | Diff | RRA | Forecast | Diff | Plan | Plan |
| Line | | Column | 5 | 6 = 5 - 4 | 7 | 8 | 9 = 8 - 7 | 10 | 11 |
| | **Operating Costs by Resource** | | | | | | | | |
| 13 | Labour | | 35.0 | (0.7) | 36.1 | 36.0 | (0.0) | 37.9 | 38.6 |
| 14 | Services - ABSU | | 0.4 | 0.2 | 0.2 | 0.0 | (0.2) | 0.0 | 0.0 |
| 15 | Services - Other | | 15.9 | (1.9) | 17.8 | 17.6 | (0.2) | 17.8 | 17.8 |
| 16 | Materials | | 1.2 | 0.6 | 0.7 | 0.8 | 0.1 | 0.8 | 0.8 |
| 17 | Buildings & Equipment | | 0.7 | 0.5 | 0.2 | 0.4 | 0.1 | 0.3 | 0.3 |
| 18 | Capitalized Overhead | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 19 | External Recoveries | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 20 | Total | | 53.3 | (1.3) | 54.9 | 54.8 | (0.2) | 56.8 | 57.5 |

2.242.8 Please re-graph the chart provided in response to BCUC IR 87.3.1 to reflect only those incidents that occurred in the field.

**RESPONSE:**

**BC Hydro's Incident Management System does not explicitly tag incidents as field or non-field.**

**The chart below provides only those incidents logged by the Operations Business Group which includes the majority of BC Hydro's field employees. The Operations Business Group also has office staff and managers and professionals.**

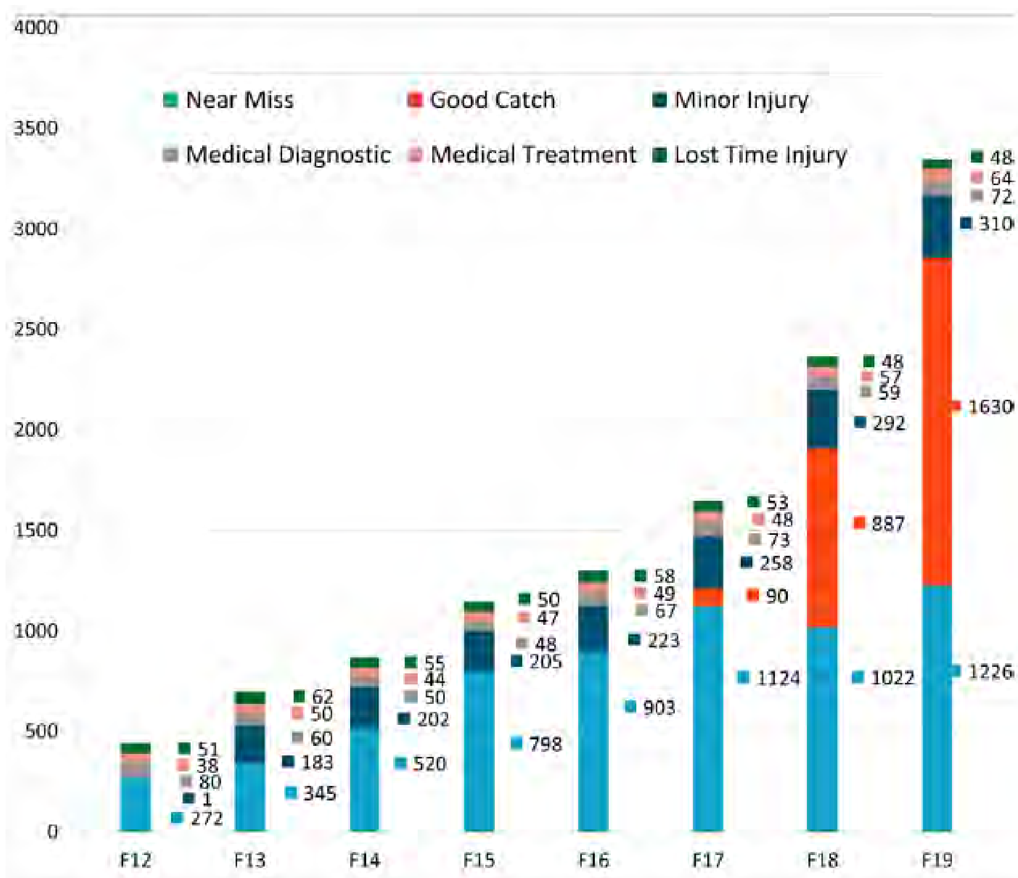


**242.0 E. CHAPTER 5D – OPERATING COSTS – SAFETY**

**Reference: OPERATING COSTS – SAFETY**
**Exhibit B-1, p. 5D-3; Appendix A, Schedule 5.4; Figures 5D-1, 5D-2**
**Exhibit B-5, BCUC IR 87.1, 87.3.1, 88.1; Exhibit B-6, CEC IR 47.1, BCOAPO IR 3.2.1**
**Injuries and injury frequency**

BC Hydro's response to CEC IR 47.1 stated that body mechanic injuries accounted for 72 percent of the Lost Time incidents in F2019.

BC Hydro's response to BCUC IR 87.3.1 included the chart below, which expanded Figure 5D-4 of the Application to both incorporate final numbers for 2019 and include the number of injuries per year.




Schedule 5.4 of Appendix A to the Application categorizes operating costs in the Safety Business Group, as shown below:

**Operating Costs - Safety**
**($ million)**

| Line | | Reference | F2018 Actual | Diff | F2019 RRA | F2019 Forecast | Diff | F2020 Plan | F2021 Plan |
|---|---|---|---|---|---|---|---|---|---|
| | Column | | 5 | 6 = 5 - 4 | 7 | 8 | 9 = 8 - 7 | 10 | 11 |
| | **Operating Costs by Resource** | | | | | | | | |
| 13 | Labour | | 35.0 | (0.7) | 36.1 | 36.0 | (0.0) | 37.9 | 38.6 |
| 14 | Services - ABSU | | 0.4 | 0.2 | 0.2 | 0.0 | (0.2) | 0.0 | 0.0 |
| 15 | Services - Other | | 15.9 | (1.9) | 17.8 | 17.6 | (0.2) | 17.8 | 17.8 |
| 16 | Materials | | 1.2 | 0.6 | 0.7 | 0.8 | 0.1 | 0.8 | 0.8 |
| 17 | Buildings & Equipment | | 0.7 | 0.5 | 0.2 | 0.4 | 0.1 | 0.3 | 0.3 |
| 18 | Capitalized Overhead | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 19 | External Recoveries | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 20 | Total | | 53.3 | (1.3) | 54.9 | 54.8 | (0.2) | 56.8 | 57.5 |

2.242.9 For each metric stated in the chart provided in response to BCUC IR 87.3.1 and reproduced in the preamble, please identify how many of these occurrences happened when an employee was working overtime, if possible.

**RESPONSE:**

**BC Hydro's Incident Management System does not track the number of incidents that occurred when an employee was working overtime.**

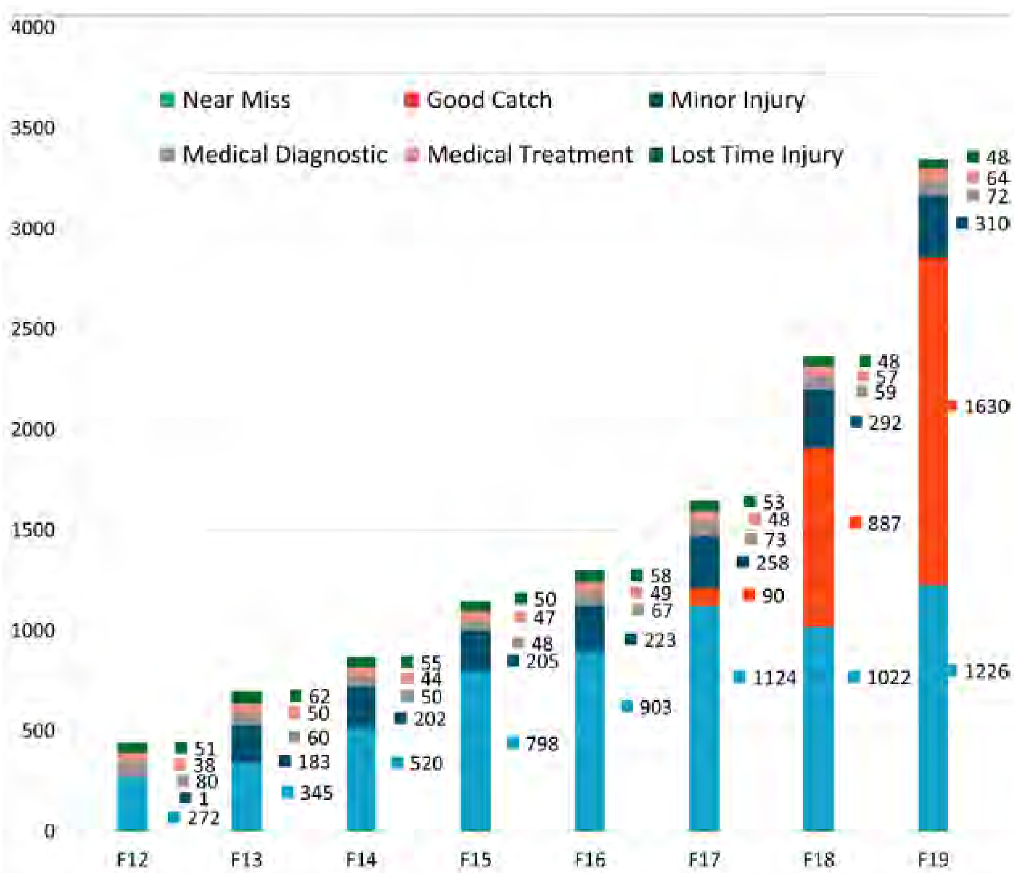
| British Columbia Utilities Commission<br>Information Request No. **2.242.9.1** Dated: **July 26, 2019**<br>British Columbia Hydro & Power Authority<br>Response issued **September 3, 2019** | Page 1<br>of 2 |
|---|---|
| British Columbia Hydro & Power Authority<br>**Fiscal 2020 to Fiscal 2021 Revenue Requirements Application** | **Exhibit:**<br>**B-12** |

**242.0 E. CHAPTER 5D – OPERATING COSTS – SAFETY**

**Reference: OPERATING COSTS – SAFETY**
**Exhibit B-1, p. 5D-3; Appendix A, Schedule 5.4; Figures 5D-1, 5D-2**
**Exhibit B-5, BCUC IR 87.1, 87.3.1, 88.1; Exhibit B-6, CEC IR 47.1, BCOAPO IR 3.2.1**
**Injuries and injury frequency**

BC Hydro's response to CEC IR 47.1 stated that body mechanic injuries accounted for 72 percent of the Lost Time incidents in F2019.

BC Hydro's response to BCUC IR 87.3.1 included the chart below, which expanded Figure 5D-4 of the Application to both incorporate final numbers for 2019 and include the number of injuries per year.




Schedule 5.4 of Appendix A to the Application categorizes operating costs in the Safety Business Group, as shown below:

**Operating Costs - Safety**
**($ million)**

| Line | | Reference | F2018 Actual | F2018 Diff | F2019 RRA | F2019 Forecast | F2019 Diff | F2020 Plan | F2021 Plan |
|---|---|---|---|---|---|---|---|---|---|
| | Column | | 5 | 6 = 5 - 4 | 7 | 8 | 9 = 8 - 7 | 10 | 11 |
| | **Operating Costs by Resource** | | | | | | | | |
| 13 | Labour | | 35.0 | (0.7) | 36.1 | 36.0 | (0.0) | 37.9 | 38.6 |
| 14 | Services - ABSU | | 0.4 | 0.2 | 0.2 | 0.0 | (0.2) | 0.0 | 0.0 |
| 15 | Services - Other | | 15.9 | (1.9) | 17.8 | 17.6 | (0.2) | 17.8 | 17.8 |
| 16 | Materials | | 1.2 | 0.6 | 0.7 | 0.8 | 0.1 | 0.8 | 0.8 |
| 17 | Buildings & Equipment | | 0.7 | 0.5 | 0.2 | 0.4 | 0.1 | 0.3 | 0.3 |
| 18 | Capitalized Overhead | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 19 | External Recoveries | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 20 | Total | | 53.3 | (1.3) | 54.9 | 54.8 | (0.2) | 56.8 | 57.5 |

2.242.9 For each metric stated in the chart provided in response to BCUC IR 87.3.1 and reproduced in the preamble, please identify how many of these occurrences happened when an employee was working overtime, if possible.

2.242.9.1 Based on the response to the preceding IR, please discuss whether there is an increased risk of injuries when an employee is working overtime.

**RESPONSE:**

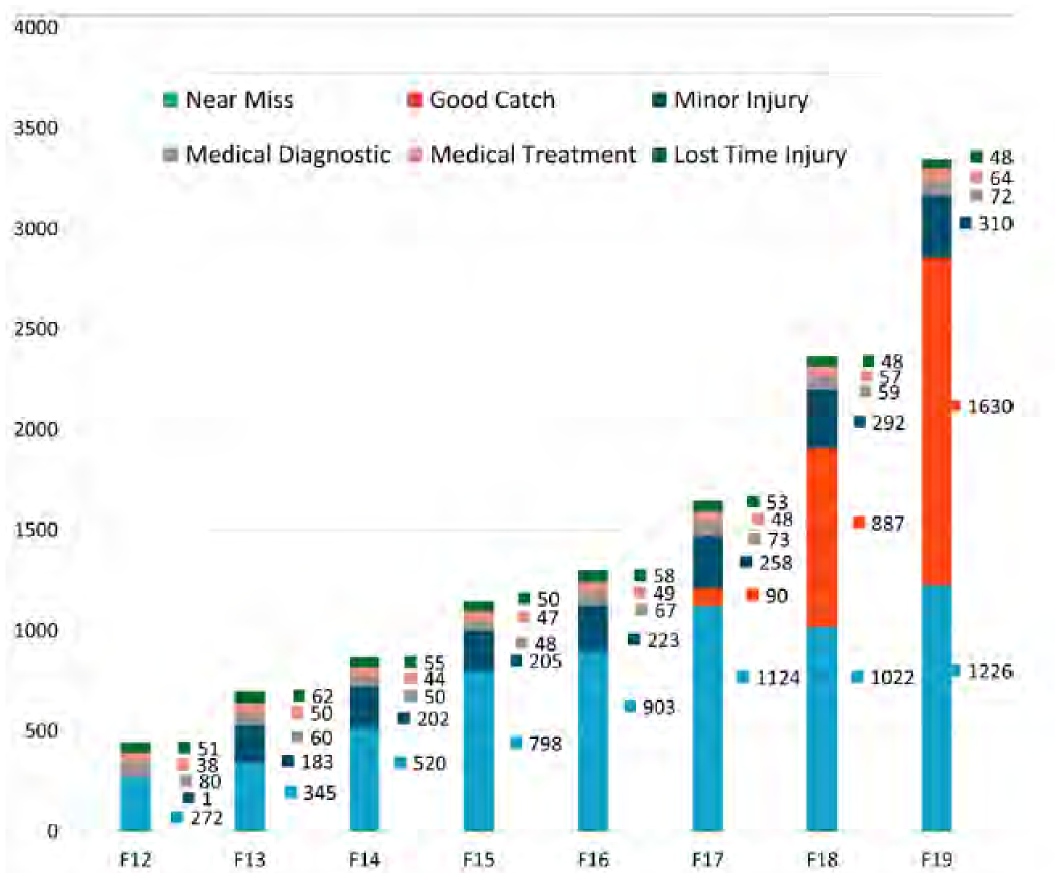
**As discussed in BC Hydro's response to BCUC IR 2.242.9, BC Hydro's Incident Management System does not track the number of incidents that occurred when an employee was working overtime. Accordingly, BC Hydro is not able to conclude whether there is any correlation between overtime and incidents.**

**242.0 E. CHAPTER 5D – OPERATING COSTS – SAFETY**

**Reference: OPERATING COSTS – SAFETY**
**Exhibit B-1, p. 5D-3; Appendix A, Schedule 5.4; Figures 5D-1, 5D-2**
**Exhibit B-5, BCUC IR 87.1, 87.3.1, 88.1; Exhibit B-6, CEC IR 47.1, BCOAPO IR 3.2.1**
**Injuries and injury frequency**

BC Hydro's response to CEC IR 47.1 stated that body mechanic injuries accounted for 72 percent of the Lost Time incidents in F2019.

BC Hydro's response to BCUC IR 87.3.1 included the chart below, which expanded Figure 5D-4 of the Application to both incorporate final numbers for 2019 and include the number of injuries per year.




Schedule 5.4 of Appendix A to the Application categorizes operating costs in the Safety Business Group, as shown below:

**Operating Costs - Safety**
**($ million)**

| Line | | Column | Reference | F2018 Actual | F2018 Diff | F2019 RRA | F2019 Forecast | F2019 Diff | F2020 Plan | F2021 Plan |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | | 5 | 6 = 5 - 4 | 7 | 8 | 9 = 8 - 7 | 10 | 11 |
| | **Operating Costs by Resource** | | | | | | | | | |
| 13 | Labour | | | 35.0 | (0.7) | 36.1 | 36.0 | (0.0) | 37.9 | 38.6 |
| 14 | Services - ABSU | | | 0.4 | 0.2 | 0.2 | 0.0 | (0.2) | 0.0 | 0.0 |
| 15 | Services - Other | | | 15.9 | (1.9) | 17.8 | 17.6 | (0.2) | 17.8 | 17.8 |
| 16 | Materials | | | 1.2 | 0.6 | 0.7 | 0.8 | 0.1 | 0.8 | 0.8 |
| 17 | Buildings & Equipment | | | 0.7 | 0.5 | 0.2 | 0.4 | 0.1 | 0.3 | 0.3 |
| 18 | Capitalized Overhead | | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 19 | External Recoveries | | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 20 | Total | | | 53.3 | (1.3) | 54.9 | 54.8 | (0.2) | 56.8 | 57.5 |

2.242.10 Please define the following categories of injuries: Minor Injury, Medical Treatment and Medical Diagnostic.

**RESPONSE:**

**As per the Canadian Electrical Association (CEA) “CEA A-2-2012: Standard for Recording and Measuring Occupational Injury/Illness Experience and Transportation Incidents”, BC Hydro uses the following definitions (abridged below, unless otherwise indicated.**

**Minor Injury (CEA defined “First Aid Injury”): An Occupational Injury/Illness that requires first aid treatment only and does not result in loss of time from work.**

**Medical Treatment (CEA defined “Medical Treatment”): A classification of Occupational Injury/Illness for Medical Treatment beyond First Aid Injury where there has been no Lost Days.**

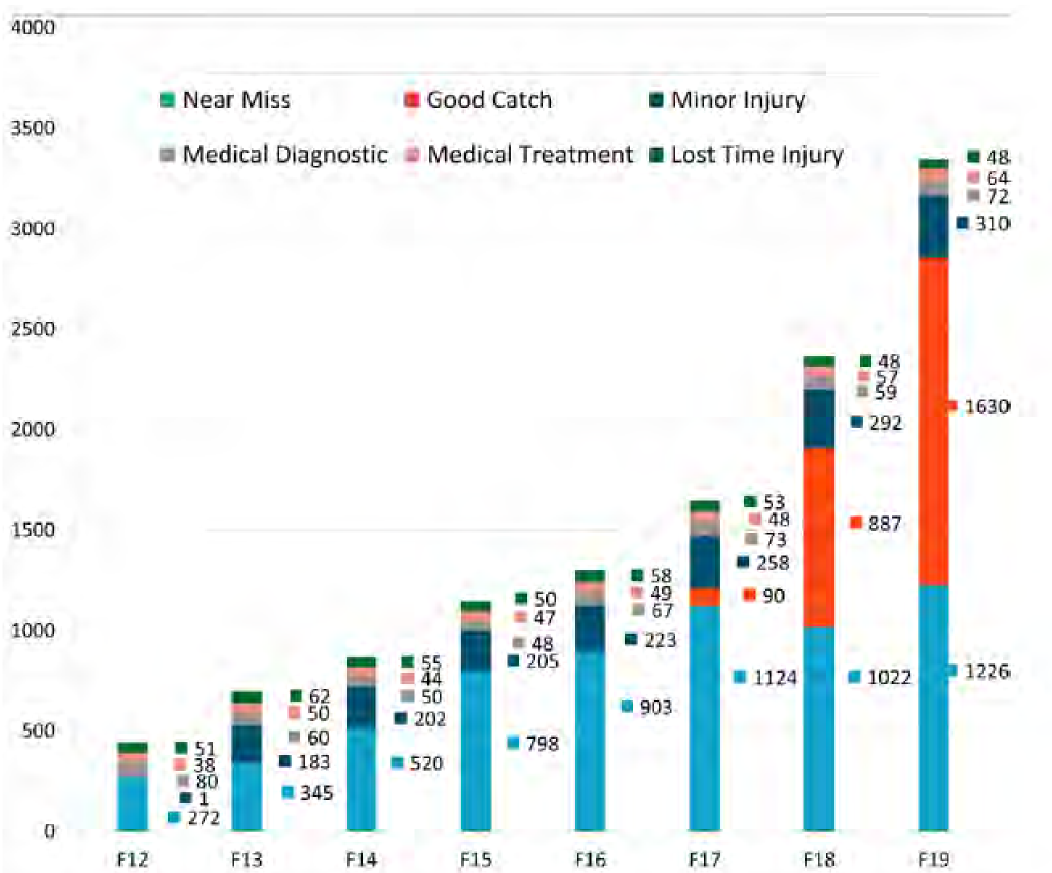
**Medical Diagnostic (No CEA defined metric): A classification of Occupational Injury/Illness where a visit to a medical practitioner happened, there has been no lost days and the treatment performed by a practitioner is limited to diagnostic work.**

**242.0 E. CHAPTER 5D – OPERATING COSTS – SAFETY**

**Reference: OPERATING COSTS – SAFETY**
**Exhibit B-1, p. 5D-3; Appendix A, Schedule 5.4; Figures 5D-1, 5D-2**
**Exhibit B-5, BCUC IR 87.1, 87.3.1, 88.1; Exhibit B-6, CEC IR 47.1, BCOAPO IR 3.2.1**
**Injuries and injury frequency**

BC Hydro's response to CEC IR 47.1 stated that body mechanic injuries accounted for 72 percent of the Lost Time incidents in F2019.

BC Hydro's response to BCUC IR 87.3.1 included the chart below, which expanded Figure 5D-4 of the Application to both incorporate final numbers for 2019 and include the number of injuries per year.



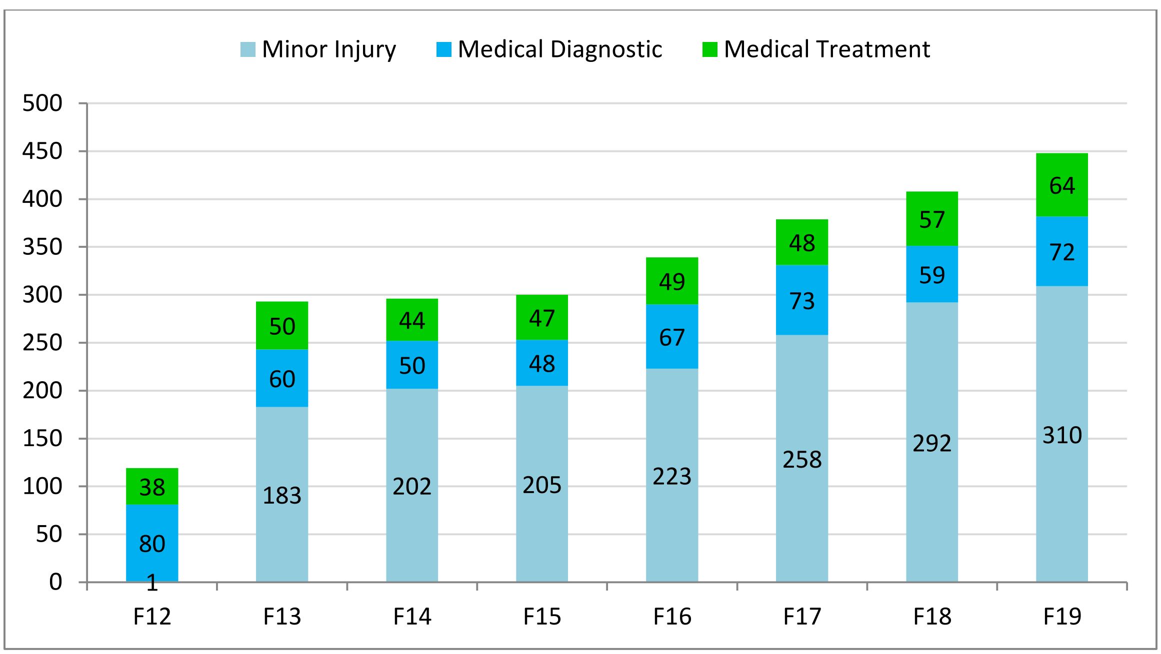

Schedule 5.4 of Appendix A to the Application categorizes operating costs in the Safety Business Group, as shown below:

| **Operating Costs - Safety** ($ million) | | | F2018 | | F2019 | | | F2020 | F2021 |
|---|---|---|---|---|---|---|---|---|---|
| | | Reference | Actual | Diff | RRA | Forecast | Diff | Plan | Plan |
| Line | Column | | 5 | 6 = 5 - 4 | 7 | 8 | 9 = 8 - 7 | 10 | 11 |
| | **Operating Costs by Resource** | | | | | | | | |
| 13 | Labour | | 35.0 | (0.7) | 36.1 | 36.0 | (0.0) | 37.9 | 38.6 |
| 14 | Services - ABSU | | 0.4 | 0.2 | 0.2 | 0.0 | (0.2) | 0.0 | 0.0 |
| 15 | Services - Other | | 15.9 | (1.9) | 17.8 | 17.6 | (0.2) | 17.8 | 17.8 |
| 16 | Materials | | 1.2 | 0.6 | 0.7 | 0.8 | 0.1 | 0.8 | 0.8 |
| 17 | Buildings & Equipment | | 0.7 | 0.5 | 0.2 | 0.4 | 0.1 | 0.3 | 0.3 |
| 18 | Capitalized Overhead | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 19 | External Recoveries | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 20 | Total | | 53.3 | (1.3) | 54.9 | 54.8 | (0.2) | 56.8 | 57.5 |

2.242.10.1 Please re-graph the chart provided in response to BCUC IR 87.3.1 to reflect only: Medical Treatment Minor Injury, Medical Diagnostic.

**RESPONSE:**

**The chart below re-graphs the chart provided in BC Hydro's response to BCUC IR 1.87.3.1 to reflect only Medical Treatment, Minor Injury and Medical Diagnostic.**



**242.0 E. CHAPTER 5D – OPERATING COSTS – SAFETY**

**Reference: OPERATING COSTS – SAFETY**
**Exhibit B-1, p. 5D-3; Appendix A, Schedule 5.4; Figures 5D-1, 5D-2**
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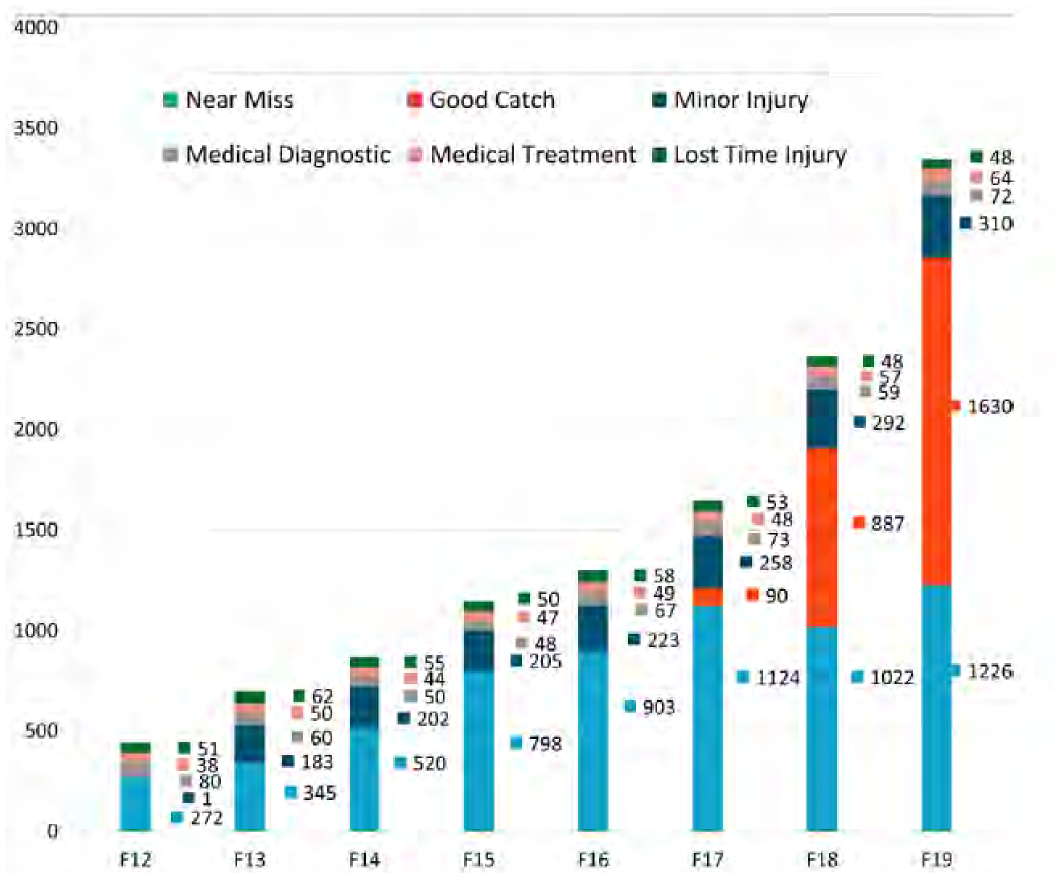
**Injuries and injury frequency**

BC Hydro's response to CEC IR 47.1 stated that body mechanic injuries accounted for 72 percent of the Lost Time incidents in F2019.

BC Hydro's response to BCUC IR 87.3.1 included the chart below, which expanded Figure 5D-4 of the Application to both incorporate final numbers for 2019 and include the number of injuries per year.




Schedule 5.4 of Appendix A to the Application categorizes operating costs in the Safety Business Group, as shown below:

**Operating Costs - Safety**
**($ million)**

| Line | | Column | Reference | F2018 Actual | Diff | F2019 RRA | F2019 Forecast | Diff | F2020 Plan | F2021 Plan |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | | 5 | 6 = 5 - 4 | 7 | 8 | 9 = 8 - 7 | 10 | 11 |
| | **Operating Costs by Resource** | | | | | | | | | |
| 13 | Labour | | | 35.0 | (0.7) | 36.1 | 36.0 | (0.0) | 37.9 | 38.6 |
| 14 | Services - ABSU | | | 0.4 | 0.2 | 0.2 | 0.0 | (0.2) | 0.0 | 0.0 |
| 15 | Services - Other | | | 15.9 | (1.9) | 17.8 | 17.6 | (0.2) | 17.8 | 17.8 |
| 16 | Materials | | | 1.2 | 0.6 | 0.7 | 0.8 | 0.1 | 0.8 | 0.8 |
| 17 | Buildings & Equipment | | | 0.7 | 0.5 | 0.2 | 0.4 | 0.1 | 0.3 | 0.3 |
| 18 | Capitalized Overhead | | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 19 | External Recoveries | | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 20 | Total | | | 53.3 | (1.3) | 54.9 | 54.8 | (0.2) | 56.8 | 57.5 |

2.242.10.2 Please discuss any trends related to the frequency and volume of Minor Injury and Medical Diagnostic metrics.

**RESPONSE:**

**BC Hydro has focused on reducing serious permanent disabling or fatal injuries through our safety initiatives, which include encouraging employees to report all incidents, not matter how minor in nature. BC Hydro believes that the increases in reporting reflect an increase in awareness and trust. In addition, as the volume of work at BC Hydro continues to increase, the hours our employees are exposed to hazards also increases.**

**The trends we have identified are:**

- **The rate at which the total number of injuries are increasing is much slower than the rate of increase in exposure hours; and**
- **The increase in the total number of injuries is mainly attributed to Minor Injuries and Medical Diagnostic (in a much smaller proportion).**

**In BC Hydro's view, the increase in Minor Injuries and Medical Diagnostic injuries reflects our efforts to address the highest risks and hazards that our employees are exposed to, which has reduced the severity of the incidents that occur.**

**242.0 E. CHAPTER 5D – OPERATING COSTS – SAFETY**

**Reference: OPERATING COSTS – SAFETY**
**Exhibit B-1, p. 5D-3; Appendix A, Schedule 5.4; Figures 5D-1, 5D-2**
**Exhibit B-5, BCUC IR 87.1, 87.3.1, 88.1; Exhibit B-6, CEC IR 47.1, BCOAPO IR 3.2.1**
**Injuries and injury frequency**

BC Hydro's response to CEC IR 47.1 stated that body mechanic injuries accounted for 72 percent of the Lost Time incidents in F2019.

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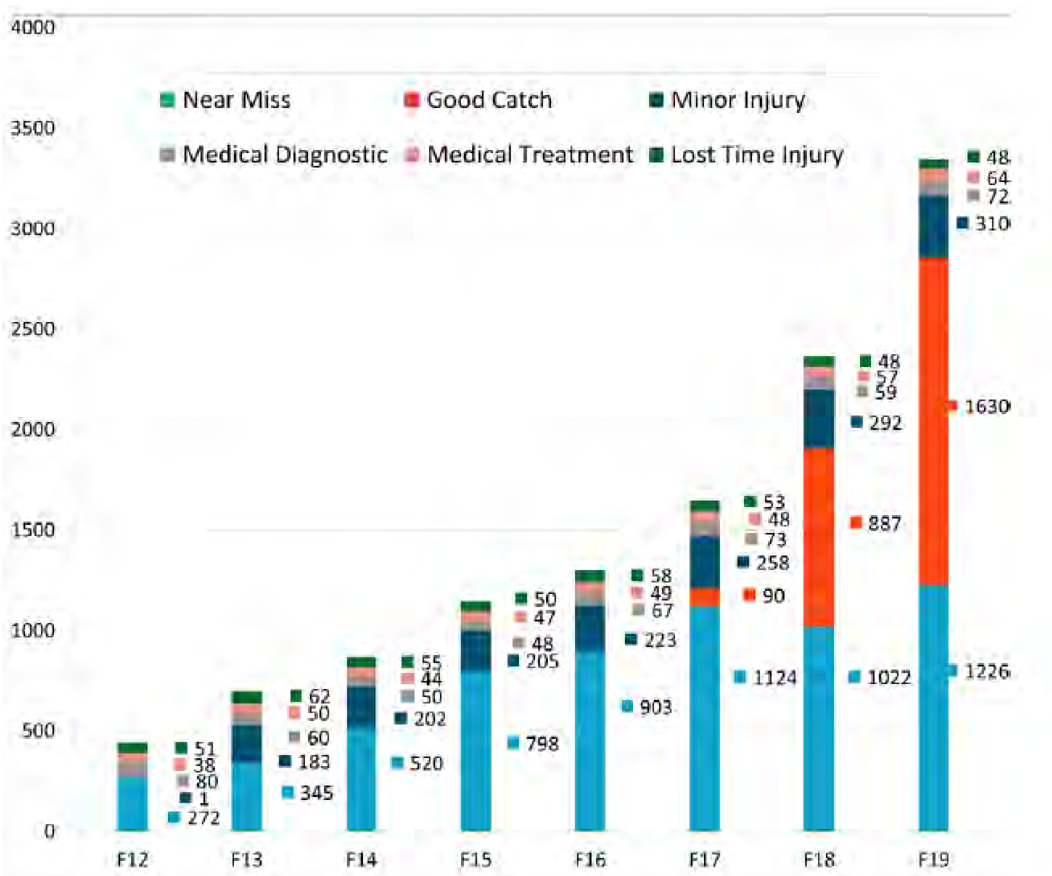


Schedule 5.4 of Appendix A to the Application categorizes operating costs in the Safety Business Group, as shown below:

**Operating Costs - Safety**
**($ million)**

| Line | | Reference | F2018 Actual | F2018 Diff | F2019 RRA | F2019 Forecast | F2019 Diff | F2020 Plan | F2021 Plan |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| | Column | | 5 | 6 = 5 - 4 | 7 | 8 | 9 = 8 - 7 | 10 | 11 |
| | **Operating Costs by Resource** | | | | | | | | |
| 13 | Labour | | 35.0 | (0.7) | 36.1 | 36.0 | (0.0) | 37.9 | 38.6 |
| 14 | Services - ABSU | | 0.4 | 0.2 | 0.2 | 0.0 | (0.2) | 0.0 | 0.0 |
| 15 | Services - Other | | 15.9 | (1.9) | 17.8 | 17.6 | (0.2) | 17.8 | 17.8 |
| 16 | Materials | | 1.2 | 0.6 | 0.7 | 0.8 | 0.1 | 0.8 | 0.8 |
| 17 | Buildings & Equipment | | 0.7 | 0.5 | 0.2 | 0.4 | 0.1 | 0.3 | 0.3 |
| 18 | Capitalized Overhead | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 19 | External Recoveries | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 20 | Total | | 53.3 | (1.3) | 54.9 | 54.8 | (0.2) | 56.8 | 57.5 |

2.242.11 Please identify the total number of labour hours lost each year from F2012 to F2019 associated with each of the following metrics: Lost Time Injury, Medical Treatment, Minor Injury and Medical Diagnostic.

**RESPONSE:**

**BC Hydro is not able to categorize the information as requested by the question. Medical Treatment, Diagnostic and Minor injuries do not necessarily involve time lost and when there time is lost, it is recorded in different ways depending on rules based on collective agreements or other Human Resources policies.**

**The table below provides time lost due to Lost Time Injuries from fiscal 2013 to fiscal 2019. Time lost due to Lost Time Injuries has declined from 33,279 hours in fiscal 2013 to 21,685.5 hours in fiscal 2019. Information is not available for fiscal 2012 because BC Hydro transitioned our time recording systems in that year.**

| Fiscal Year | From | To | Number of Hours |
| --- | --- | --- | --- |
| F2013 | 2012-04-01 | 2013-03-31 | 33,279.0 |
| F2014 | 2013-04-01 | 2014-03-31 | 32,702.0 |
| F2015 | 2014-04-01 | 2015-03-31 | 24,280.5 |
| F2016 | 2015-04-01 | 2016-03-31 | 21,063.5 |
| F2017 | 2016-04-01 | 2017-03-31 | 22,883.5 |
| F2018 | 2017-04-01 | 2018-03-31 | 22,702.5 |
| F2019 | 2018-04-01 | 2019-03-31 | 21,658.5 |

**242.0 E. CHAPTER 5D – OPERATING COSTS – SAFETY**

**Reference: OPERATING COSTS – SAFETY**
**Exhibit B-1, p. 5D-3; Appendix A, Schedule 5.4; Figures 5D-1, 5D-2**
**Exhibit B-5, BCUC IR 87.1, 87.3.1, 88.1; Exhibit B-6, CEC IR 47.1, BCOAPO IR 3.2.1**
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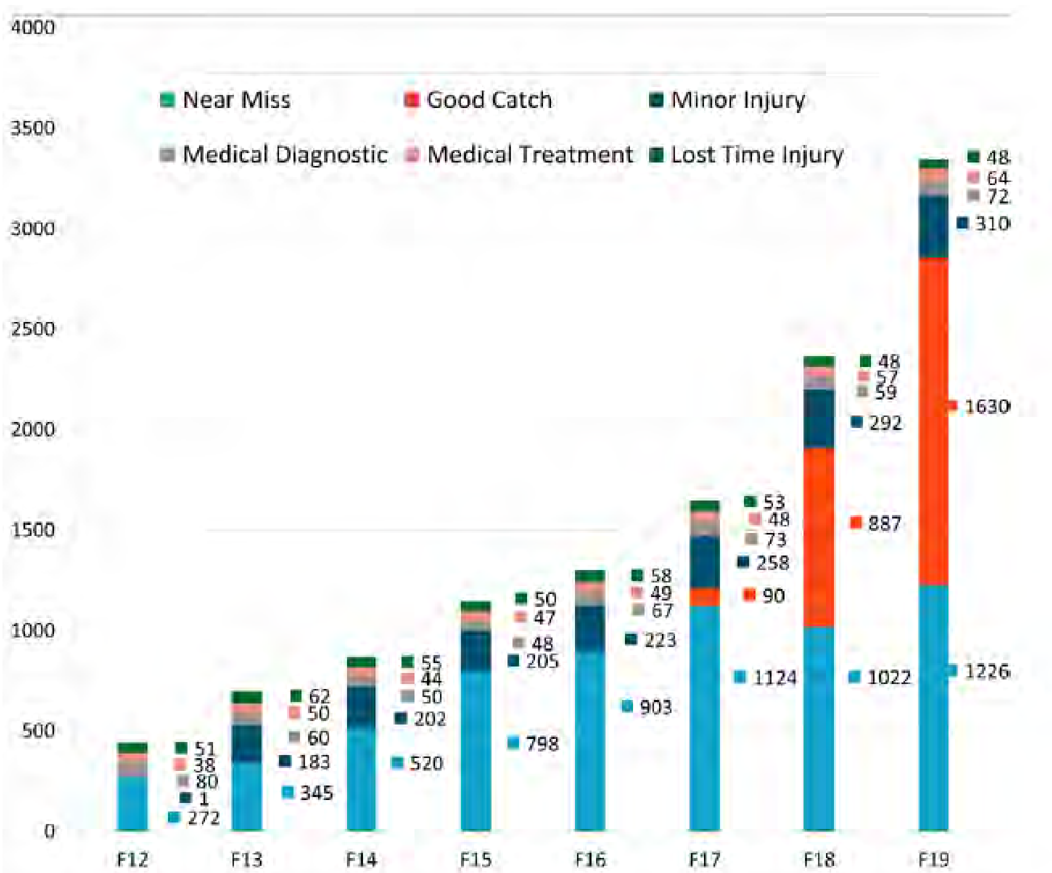
BC Hydro's response to CEC IR 47.1 stated that body mechanic injuries accounted for 72 percent of the Lost Time incidents in F2019.

BC Hydro's response to BCUC IR 87.3.1 included the chart below, which expanded Figure 5D-4 of the Application to both incorporate final numbers for 2019 and include the number of injuries per year.




Schedule 5.4 of Appendix A to the Application categorizes operating costs in the Safety Business Group, as shown below:

**Operating Costs - Safety**
**($ million)**

| | | | F2018 | | F2019 | | | F2020 | F2021 |
|---|---|---|---|---|---|---|---|---|---|
| | | Reference | Actual | Diff | RRA | Forecast | Diff | Plan | Plan |
| Line | Column | | 5 | 6 = 5 - 4 | 7 | 8 | 9 = 8 - 7 | 10 | 11 |
| | **Operating Costs by Resource** | | | | | | | | |
| 13 | Labour | | 35.0 | (0.7) | 36.1 | 36.0 | (0.0) | 37.9 | 38.6 |
| 14 | Services - ABSU | | 0.4 | 0.2 | 0.2 | 0.0 | (0.2) | 0.0 | 0.0 |
| 15 | Services - Other | | 15.9 | (1.9) | 17.8 | 17.6 | (0.2) | 17.8 | 17.8 |
| 16 | Materials | | 1.2 | 0.6 | 0.7 | 0.8 | 0.1 | 0.8 | 0.8 |
| 17 | Buildings & Equipment | | 0.7 | 0.5 | 0.2 | 0.4 | 0.1 | 0.3 | 0.3 |
| 18 | Capitalized Overhead | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 19 | External Recoveries | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 20 | Total | | 53.3 | (1.3) | 54.9 | 54.8 | (0.2) | 56.8 | 57.5 |

2.242.12 Please explain why Minor Injuries and Medical Diagnostic are not included in the calculation of the All Injury Frequency rate.

**RESPONSE:**

**As per the Canadian Electrical Association (CEA) "CEA A-2-2012: Standard for Recording and Measuring Occupational Injury/Illness Experience and Transportation Incidents", BC Hydro uses the following definition for All Injury Frequency Rate: the total number of Fatalities and Lost-Time Injuries, plus the total number of Medical Treatment Injuries which occurred in the calendar year. The following formula shall be used:**

**All Injury Frequency Rate = (No. of Fatalities + No. of Lost-Time Injuries + No. of Medical Treatment Injuries) x 200,000 divided by Exposure Hours**

**242.0 E. CHAPTER 5D – OPERATING COSTS – SAFETY**

**Reference: OPERATING COSTS – SAFETY**
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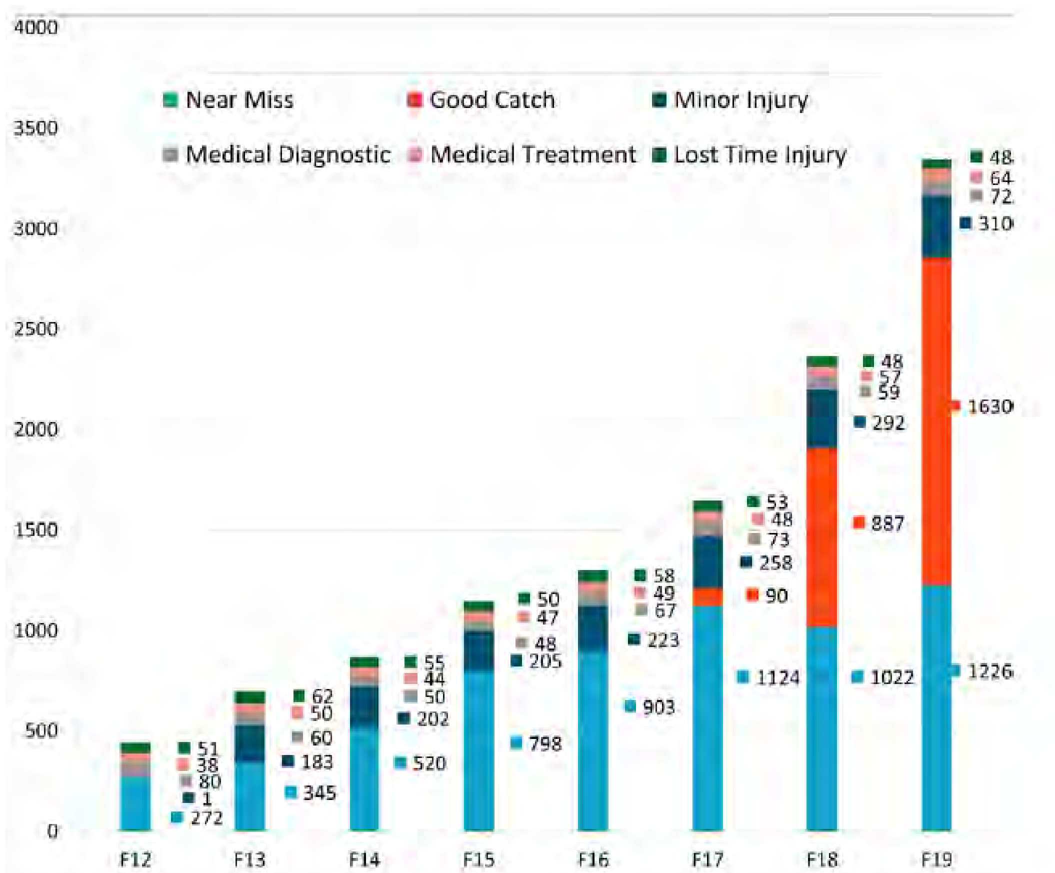



Schedule 5.4 of Appendix A to the Application categorizes operating costs in the Safety Business Group, as shown below:

| Operating Costs - Safety ($ million) | | | F2018 | | F2019 | | | F2020 | F2021 |
|---|---|---|---|---|---|---|---|---|---|
| | | Reference | Actual | Diff | RRA | Forecast | Diff | Plan | Plan |
| Line | Column | | 5 | 6 = 5 - 4 | 7 | 8 | 9 = 8 - 7 | 10 | 11 |
| | Operating Costs by Resource | | | | | | | | |
| 13 | Labour | | 35.0 | (0.7) | 36.1 | 36.0 | (0.0) | 37.9 | 38.6 |
| 14 | Services - ABSU | | 0.4 | 0.2 | 0.2 | 0.0 | (0.2) | 0.0 | 0.0 |
| 15 | Services - Other | | 15.9 | (1.9) | 17.8 | 17.6 | (0.2) | 17.8 | 17.8 |
| 16 | Materials | | 1.2 | 0.6 | 0.7 | 0.8 | 0.1 | 0.8 | 0.8 |
| 17 | Buildings & Equipment | | 0.7 | 0.5 | 0.2 | 0.4 | 0.1 | 0.3 | 0.3 |
| 18 | Capitalized Overhead | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 19 | External Recoveries | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 20 | Total | | 53.3 | (1.3) | 54.9 | 54.8 | (0.2) | 56.8 | 57.5 |

2.242.12.1 Please discuss whether BC Hydro has specific programs in place to reduce Minor Injury and Medical Diagnostic events. If so, please identify.

**RESPONSE:**

**BC Hydro's safety programs aim to improve safety overall, including the reduction of all injury types. For example, Motor Vehicle Safety would address both lost time injuries as well as minor injuries, as the conditions of the actual accident would determine the severity of the incident.**

**Some examples of BC Hydro's safety programs are:**

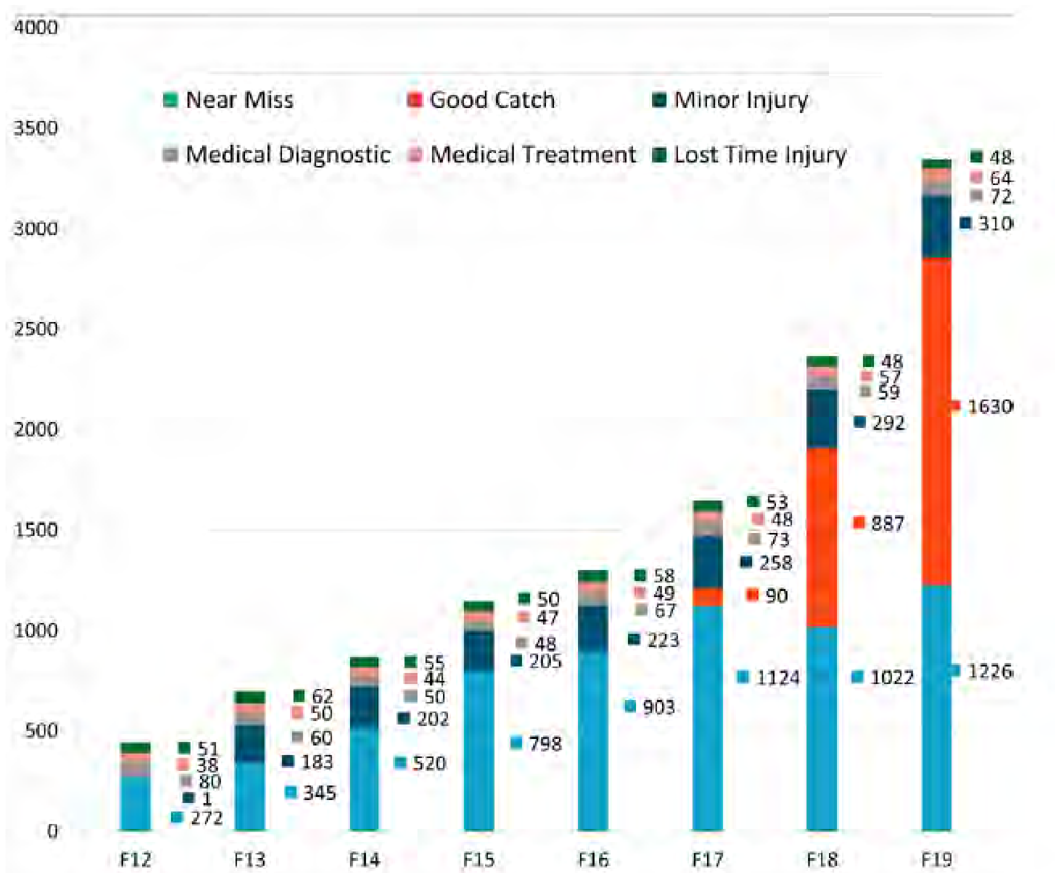
- **Avalanche Safety Program;**
- **Workplace Hazardous Materials Information System (WHMIS) Program;**
- **Exposure Control Plans for airborne contaminants (e.g., lead, silica, ammonia, SF6);**
- **PCB Exposure Control Plan;**
- **Asbestos Control Plan;**
- **Heat and Cold Stress Exposure Control Plan;**
- **Hearing Conservation Program;**
- **Ergonomics;**
- **Confined Space Program;**
- **Motor Vehicle Safety;**
- **Transportation of Dangerous Goods;**
- **Drinking Water; and**
- **Wildfire.**

**242.0 E. CHAPTER 5D – OPERATING COSTS – SAFETY**

**Reference: OPERATING COSTS – SAFETY**
**Exhibit B-1, p. 5D-3; Appendix A, Schedule 5.4; Figures 5D-1, 5D-2**
**Exhibit B-5, BCUC IR 87.1, 87.3.1, 88.1; Exhibit B-6, CEC IR 47.1, BCOAPO IR 3.2.1**
**Injuries and injury frequency**

BC Hydro's response to CEC IR 47.1 stated that body mechanic injuries accounted for 72 percent of the Lost Time incidents in F2019.

BC Hydro's response to BCUC IR 87.3.1 included the chart below, which expanded Figure 5D-4 of the Application to both incorporate final numbers for 2019 and include the number of injuries per year.




Schedule 5.4 of Appendix A to the Application categorizes operating costs in the Safety Business Group, as shown below:

**Operating Costs - Safety**
**($ million)**

| Line | | Reference | F2018 Actual | F2018 Diff | F2019 RRA | F2019 Forecast | F2019 Diff | F2020 Plan | F2021 Plan |
|---|---|---|---|---|---|---|---|---|---|
| | Column | | 5 | 6 = 5 - 4 | 7 | 8 | 9 = 8 - 7 | 10 | 11 |
| | **Operating Costs by Resource** | | | | | | | | |
| 13 | Labour | | 35.0 | (0.7) | 36.1 | 36.0 | (0.0) | 37.9 | 38.6 |
| 14 | Services - ABSU | | 0.4 | 0.2 | 0.2 | 0.0 | (0.2) | 0.0 | 0.0 |
| 15 | Services - Other | | 15.9 | (1.9) | 17.8 | 17.6 | (0.2) | 17.8 | 17.8 |
| 16 | Materials | | 1.2 | 0.6 | 0.7 | 0.8 | 0.1 | 0.8 | 0.8 |
| 17 | Buildings & Equipment | | 0.7 | 0.5 | 0.2 | 0.4 | 0.1 | 0.3 | 0.3 |
| 18 | Capitalized Overhead | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 19 | External Recoveries | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 20 | Total | | 53.3 | (1.3) | 54.9 | 54.8 | (0.2) | 56.8 | 57.5 |

2.242.13 Please discuss the process used in setting the LTIF and AIF targets in BC Hydro's Service Plan for years F2020, F2021 and F2022 and why these targets are set at levels above the AIF and LTIF of Canadian Electricity Association (CEA) (Like Utilities).

**RESPONSE:**

**On an annual basis, we set targets for Service Plan metrics, including Lost Time Injury Frequency (LTIF) as well as non-Service Plan safety metrics, including All Injury Frequency (AIF).**

**The process to determine targets is based on a review of past year's results, overall safety performance and a comparison of that performance to CEA Like Utilities.**

**Targets may be adjusted from year to year to reflect past performance while continuing to encourage improved performance.**

**Please refer to BC Hydro's response to BCUC IR 2.242.19 where we explain why our LTIF and AIF levels are set higher than the CEA Like Utilities.**

| British Columbia Utilities Commission<br>Information Request No. **2.242.14** Dated: **July 26, 2019**<br>British Columbia Hydro & Power Authority<br>Response issued **September 3, 2019** | Page 1<br>of 2 |
|---|---|
| British Columbia Hydro & Power Authority<br>**Fiscal 2020 to Fiscal 2021 Revenue Requirements Application** | **Exhibit:**<br>**B-12** |

**242.0 E. CHAPTER 5D – OPERATING COSTS – SAFETY**

**Reference: OPERATING COSTS – SAFETY**
**Exhibit B-1, p. 5D-3; Appendix A, Schedule 5.4; Figures 5D-1, 5D-2**
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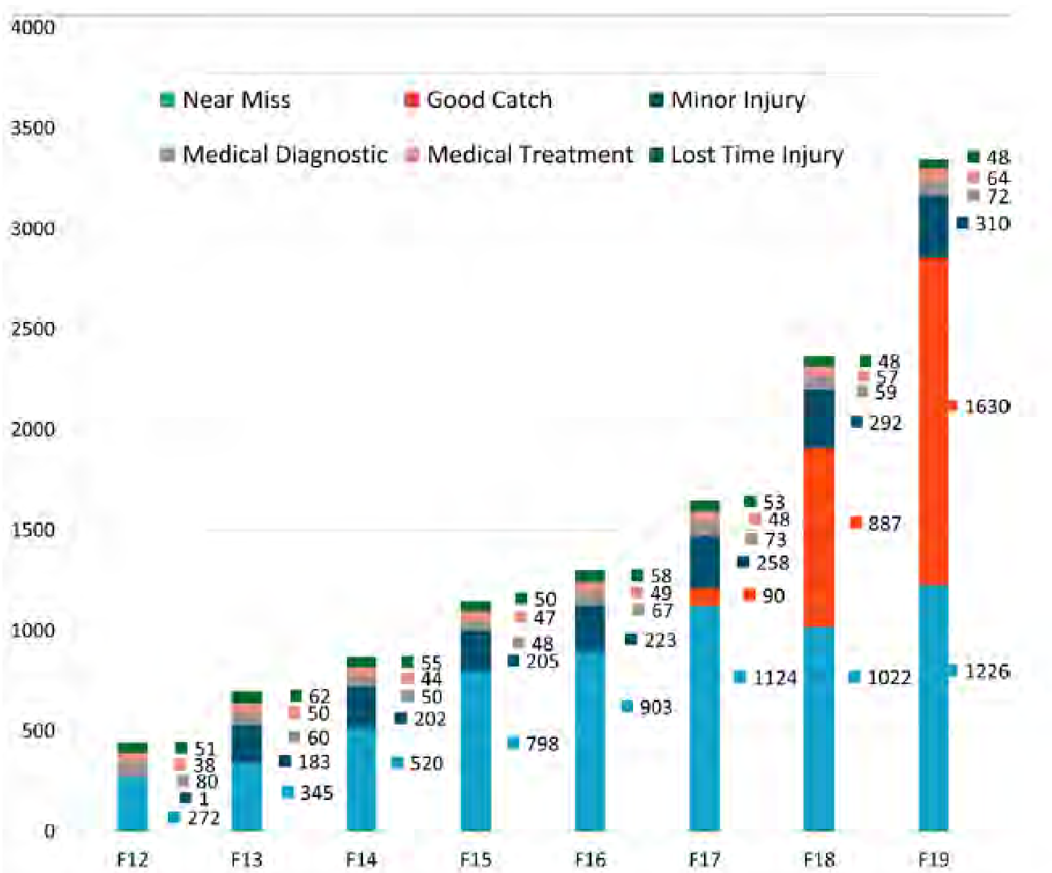


Schedule 5.4 of Appendix A to the Application categorizes operating costs in the Safety Business Group, as shown below:

| Operating Costs - Safety ($ million) | | | F2018 | | F2019 | | | F2020 | F2021 |
|---|---|---|---|---|---|---|---|---|---|
| | | Reference | Actual | Diff | RRA | Forecast | Diff | Plan | Plan |
| Line | Column | | 5 | 6 = 5 - 4 | 7 | 8 | 9 = 8 - 7 | 10 | 11 |
| | **Operating Costs by Resource** | | | | | | | | |
| 13 | Labour | | 35.0 | (0.7) | 36.1 | 36.0 | (0.0) | 37.9 | 38.6 |
| 14 | Services - ABSU | | 0.4 | 0.2 | 0.2 | 0.0 | (0.2) | 0.0 | 0.0 |
| 15 | Services - Other | | 15.9 | (1.9) | 17.8 | 17.6 | (0.2) | 17.8 | 17.8 |
| 16 | Materials | | 1.2 | 0.6 | 0.7 | 0.8 | 0.1 | 0.8 | 0.8 |
| 17 | Buildings & Equipment | | 0.7 | 0.5 | 0.2 | 0.4 | 0.1 | 0.3 | 0.3 |
| 18 | Capitalized Overhead | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 19 | External Recoveries | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 20 | Total | | 53.3 | (1.3) | 54.9 | 54.8 | (0.2) | 56.8 | 57.5 |

2.242.14 Please discuss why the Target LTIF is kept constant over the Test Period and then changes for F2022.

**RESPONSE:**

**BC Hydro has initiatives in place to reduce Lost Time Injury Frequency (LTIF) and has achieved consistent and measureable reductions from fiscal 2017 to fiscal 2019. The targets for fiscal 2020 (0.80), fiscal 2021 (0.80) and fiscal 2022 (0.75) reflect continuous improvement while recognizing that there is a lag between the implementation of these initiatives and the achievement of further improvements.**

**The implementation of the Safety & Health Management System, together with the following initiatives, will support BC Hydro in achieving future targets:**

- **Increased safe work observations by managers;**
- **Increased and more consistent use of the Return to Work/Stay at Work program;**
- **Increased Incident Management System review calls with members of the Executive Team;**
- **Expansion of the ergonomics program; and**
- **Regional safety discussion calls with crews.**

**242.0 E. CHAPTER 5D – OPERATING COSTS – SAFETY**

**Reference: OPERATING COSTS – SAFETY**
**Exhibit B-1, p. 5D-3; Appendix A, Schedule 5.4; Figures 5D-1, 5D-2**
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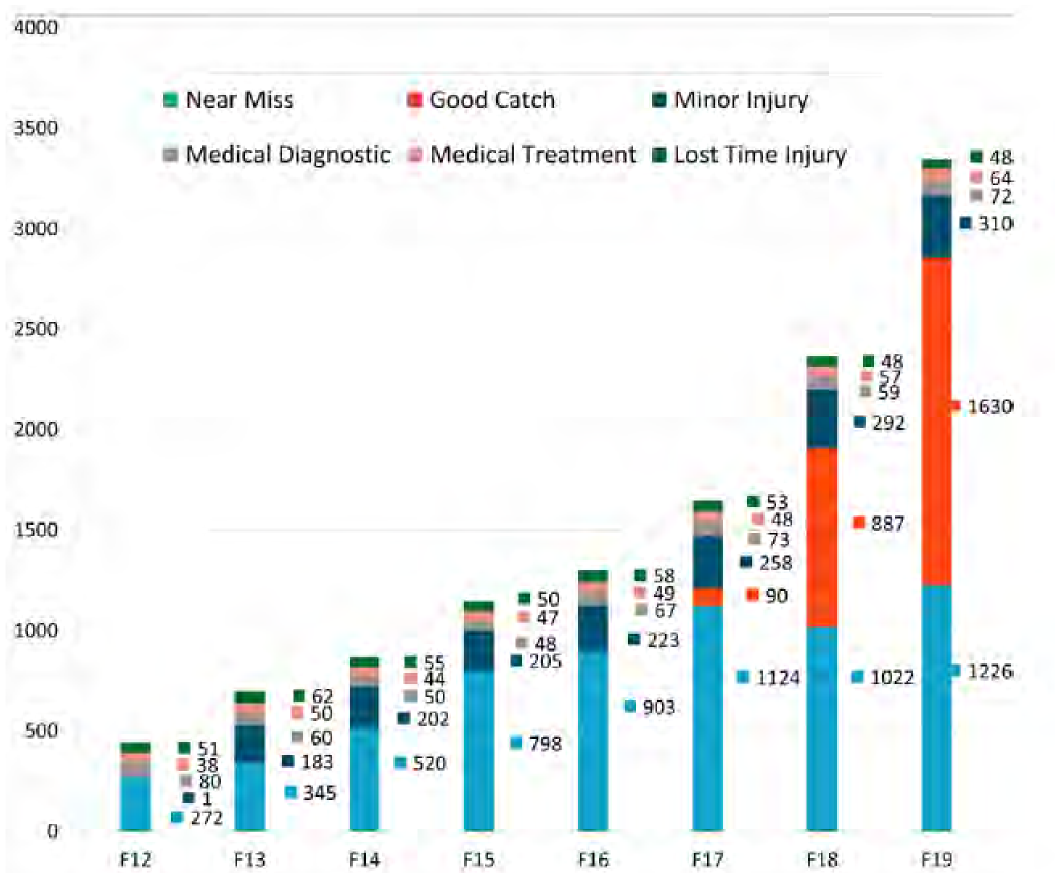


Schedule 5.4 of Appendix A to the Application categorizes operating costs in the Safety Business Group, as shown below:

**Operating Costs - Safety**
**($ million)**

| Line | | Reference | F2018 Actual | F2018 Diff | F2019 RRA | F2019 Forecast | F2019 Diff | F2020 Plan | F2021 Plan |
|---|---|---|---|---|---|---|---|---|---|
| | Column | | 5 | 6 = 5 - 4 | 7 | 8 | 9 = 8 - 7 | 10 | 11 |
| | **Operating Costs by Resource** | | | | | | | | |
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| 16 | Materials | | 1.2 | 0.6 | 0.7 | 0.8 | 0.1 | 0.8 | 0.8 |
| 17 | Buildings & Equipment | | 0.7 | 0.5 | 0.2 | 0.4 | 0.1 | 0.3 | 0.3 |
| 18 | Capitalized Overhead | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 19 | External Recoveries | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 20 | Total | | 53.3 | (1.3) | 54.9 | 54.8 | (0.2) | 56.8 | 57.5 |

2.242.15 Please explain why an AIF target has not been defined for the F2021 test year.

**RESPONSE:**

**In fiscal 2016, to reflect our focus on our Safety goals of zero fatalities, permanently disabling injuries and fewer lost time injuries, the Service Plan metric was changed from All Injury Frequency (AIF), which includes Medical Treatment, to Lost Time Injury Frequency (LTIF). In addition to the LTIF Service Plan Metric, we continue to measure AIF as an internal target which is set at 1.70 for fiscal 2020. An AIF target for fiscal 2021 will be set early in calendar year 2020.**

**242.0 E. CHAPTER 5D – OPERATING COSTS – SAFETY**

**Reference: OPERATING COSTS – SAFETY**
**Exhibit B-1, p. 5D-3; Appendix A, Schedule 5.4; Figures 5D-1, 5D-2**
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**Injuries and injury frequency**

Figures 5D-1 and 5D-2 on page 5D-3 of the Application reflect BC Hydro's Lost Time Injury Frequency and All Injury Frequency relative to CEA (Like Utilities).

**Figure 5D-1 Lost Time Injury Frequency – Employees**[234]

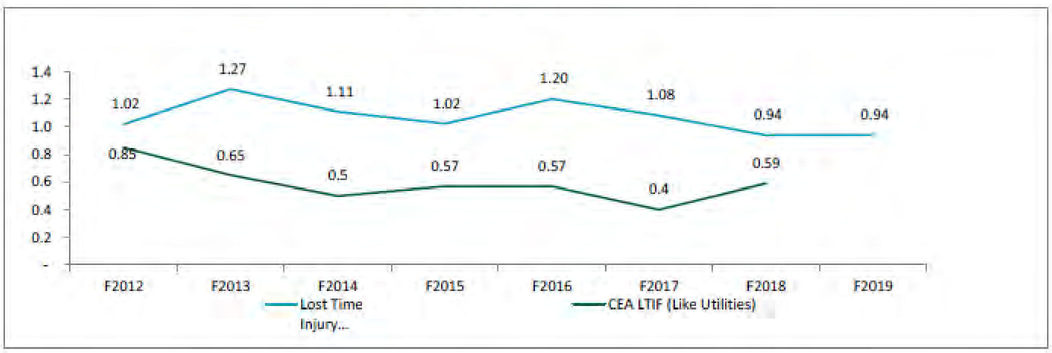
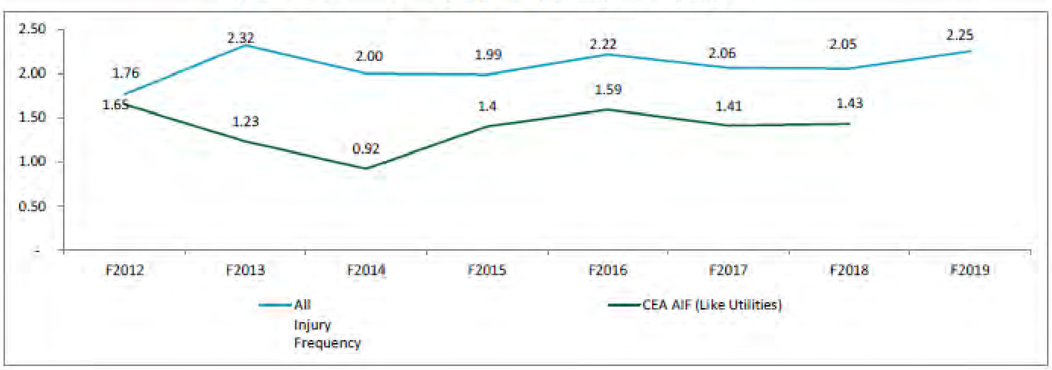



**Figure 5D-2 All Injury Frequency – Employees**[235]




2.242.16 Please identify the "Like Utilities" that represent the CEA LTIF and AIF.

**RESPONSE:**

**Like utilities used to represent the Canadian Electricity Association (CEA) Lost Time Injury Frequency (LTIF) and All Injury Frequency (AIF) are:**

- **Hydro One;**
- **SasKPower;**
- **Nova Scotia Power;**
- **Manitoba Hydro; and**
- **Ontario Power Generation.**

**The following criteria are used to determine the "Like Utilities":**

- **Size of company (over 1500 employees);**
- **Utilities that have a Transmission or Generation line of business (distribution-only utilities are excluded); and**
- **Availability of data that utilities voluntarily submit to the CEA.**

**242.0 E. CHAPTER 5D – OPERATING COSTS – SAFETY**

**Reference: OPERATING COSTS – SAFETY**
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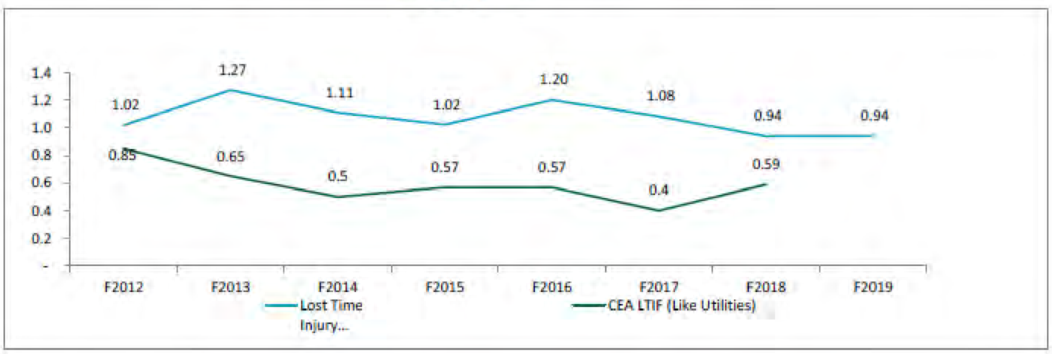
**Figure 5D-1 Lost Time Injury Frequency – Employees[234]**

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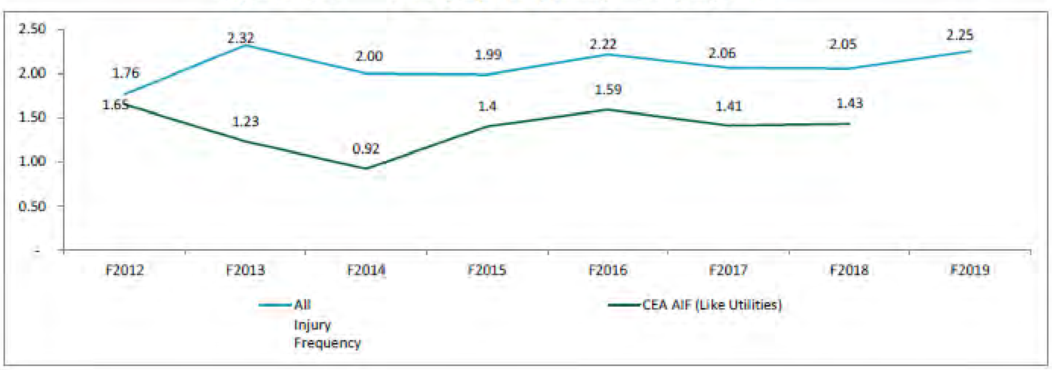


2.242.17 Please explain why BC Hydro has not been able to meet its target AIF and LTIF for F2019.

**RESPONSE:**

**BC Hydro did not meet its targets for Lost Time Injury Frequency (LTIF) and All Injury Frequency (AIF) in fiscal 2019, primarily because of the number of body mechanics injuries sustained, which resulted in Lost Time and Medical Treatment.**

**Programs and initiatives targeted at reducing injuries involve a change in behaviour and it typically takes time to see reportable results.**

**BC Hydro has initiatives underway to reduce injuries resulting in Lost Time and Medical Treatment, such as arc flash and Limits of Approach. Some of these initiatives, such as Limits of Approach, are taking longer than planned to complete. BC Hydro expects that its safety performance will improve as these initiatives are completed and the desired behaviour changes achieved. This expectation is reflected in the targets for fiscal 2020 and fiscal 2021.**

**242.0 E. CHAPTER 5D – OPERATING COSTS – SAFETY**

**Reference: OPERATING COSTS – SAFETY**
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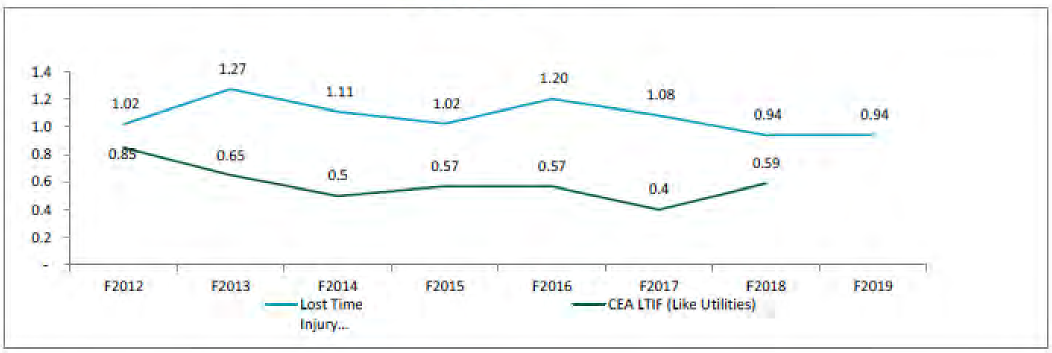


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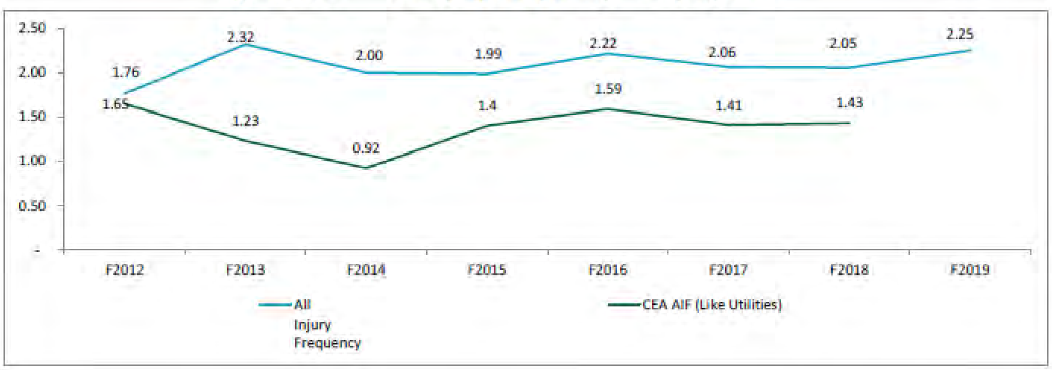


2.242.18 Please identify the years from F2012 to F2019 that BC Hydro has been able to meet its target AIF and LTIF that was set in its Service Plan. As part of the response, please provide the actual and target AIF and LTIF for each year.

**RESPONSE:**

**The table below provides the Service Plan target and actual results for All Injury Frequency (AIF) and Lost Time Injury Frequency (LTIF) from fiscal 2012 to fiscal 2019. AIF was the Service Plan metric from fiscal 2012 to fiscal 2015 and LTIF was the Service Plan metric from fiscal 2016 onwards.**

| | AIF | | LTIF | |
|---|---|---|---|---|
| | **Target** | **Actual** | **Target** | **Actual** |
| **F2012** | **1.5** | **1.7** | | |
| **F2013** | **1.4** | **2.1** | | |
| **F2014** | **1.7** | **2** | | |
| **F2015** | **1.6** | **1.9** | | |
| **F2016** | | | **1.0** | **1.1** |
| **F2017** | | | **1.00** | **1.04** |
| **F2018** | | | **0.90** | **0.88** |
| **F2019** | | | **0.85** | **0.87** |

**242.0 E. CHAPTER 5D – OPERATING COSTS – SAFETY**

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Figures 5D-1 and 5D-2 on page 5D-3 of the Application reflect BC Hydro's Lost Time Injury Frequency and All Injury Frequency relative to CEA (Like Utilities).

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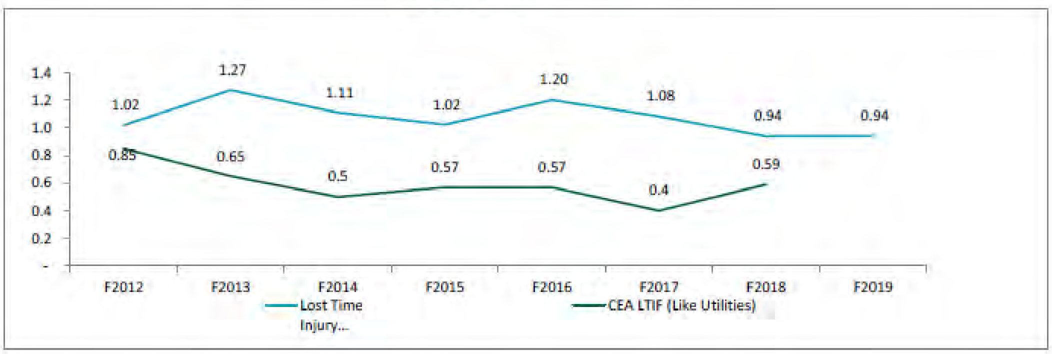


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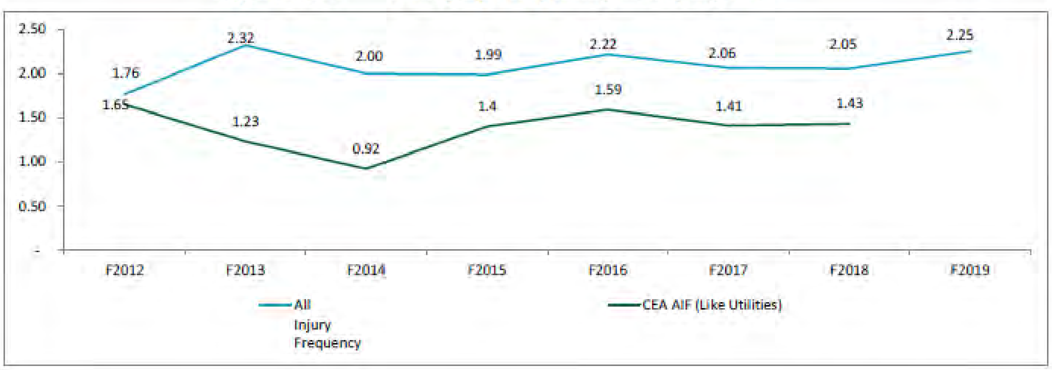


2.242.19 Please explain why BC Hydro's AIF and LTIF from F2012 to F2018 are higher than the CEA for "like utilities."

**RESPONSE:**

**Like utilities from Canadian Electricity Association (CEA) are mainly grouped based on size; however, the nature of the work and their associated safety record may vary.**

**For example, Ontario Power Generation (OPG) includes nuclear generation which has significantly better safety performance due to high redundancy and low risk tolerance. For example, in 2018, Ontario Power Generation's All Injury Frequency (AIF) was 0.53 including nuclear generation and 1.69 without nuclear generation. This shift demonstrates how nuclear power generation safety metrics can drive overall CEA averages down.**

**A utility that is more comparable to BC Hydro is Manitoba Hydro. In 2018, their AIF was 4.46 and their Lost Time Injury Frequency (LTIF) was 1.69.**

**BC Hydro collaborates with CEA member utilities to learn from each other and to identify practices that have supported positive safety outcomes in other utilities.**

**For example, to identify opportunities to address our high incident rate from body mechanics, we met with Ontario Power Generation, and incorporated their learnings into our Ergonomics program. We have also collaborated with Ontario Power Generation and Nova Scotia Power on the potential use of a slip simulator to reduce slips, trips and falls, which account for 42 per cent of all body mechanics injuries.**

**242.0 E. CHAPTER 5D – OPERATING COSTS – SAFETY**

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**Exhibit B-5, BCUC IR 87.1, 87.3.1, 88.1; Exhibit B-6, CEC IR 47.1, BCOAPO IR 3.2.1**
**Injuries and injury frequency**

BC Hydro's response to BCUC IR 88.1 stated: "Other lagging indicators used by BC Hydro include: lost time injuries, medical attentions, and minor injuries."

2.242.20 Please provide a table of the following annual metrics of "CEA Like Utilities" over the period F2012 to F2019 – Lost Time Injuries, Medical Treatment, Medical Diagnostics, Minor Injuries, if available.

**RESPONSE:**

**Detailed information regarding the number of incidents by category is not available from the Canadian Electricity Association data.**

**Typical safety benchmarking practice is to normalize the data, converting the actual incidents into incidents per 100 workers. Through this approach, utilities of different sizes can be compared to each other.**

**243.0 E. CHAPTER 5D – OPERATING COSTS – SAFETY**

**Reference: OPERATING COSTS – SAFETY**
**Exhibit B-5, BCUC IR 87.2.1, 88.3**
**Serious incidents and contractor safety**

BC Hydro's response to BCUC IR 88.3 stated:

> …For example, contractor safety has been a topic of discussion among Canadian Electricity Association members and the different members have adopted their versions of contractor safety programs to address this.
>
> Another initiative that has come out as a result of benchmarking with Canadian Electricity Association is the renewed focus on serious incidents, not only focusing on avoiding fatalities and permanently disabling injuries, but looking at a more proactive approach, learning from those incidents that could have resulted in a serious injury, what is called potential serious incidents. [emphasis added]

2.243.1 Please define what BC Hydro would classify as a serious incident. As part of the response, please identify any differences between BC Hydro's definition and the CEA's definition.

**RESPONSE:**

**The Canadian Electricity Association's (CEA) definition of Serious Injury or Fatality and Serious Injury or Fatality Potential Incidents (SIF and SIFP), are defined in the CEA A-4 Standard.**

**Section 3.1 of that standard defines Serious Injury or Fatality Incident (SIF) by three categories:**

- **Life Threatening;**
- **Life Altering; or**
- **Fatal.**

**Section 3.2 defines Serious Injury or Fatality Potential (SIFP) as follows:**

**These are incidents where the hazard exposure had a realistic potential to result in a serious injury or fatality (SIF). The appropriate controls required to prevent injury were not in place at the time of incident, increasing the risk exposure.**

**BC Hydro defines Serious Incidents based on the CEA's definition, but expands to four different levels:**

- **Permanently disabling injury (Service Plan Metric): Injuries sustained while working in one of the four high risk hazards: electrical contact, fall from heights, mechanical or transportation and injuries that have been granted permanent disability claim by WorkSafeBC;**
- **Serious Injury: Injury sustained performing any type of work categorized as serious by WorkSafeBC (Defined in *Workers Compensation Act*, Part 3, Division 10, section G-D10-172-1). An injury that can reasonably be expected at the time of the incident to endanger life or cause permanent injury;**
- **Injury with the potential for Serious Injury: An incident that resulted in a non-serious injury but had a realistic potential to result in a serious injury or fatality; and**
- **Near Miss with the potential for Serious Injury: An incident where the appropriate controls required to prevent the injury were not in place at the time of the incident and the exposure had a realistic potential to result in a serious injury or fatality.**

**243.0 E. CHAPTER 5D – OPERATING COSTS – SAFETY**

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2.243.1.1 Please discuss how serious incidents are measured in the BC Hydro Service Plan, and if not, why not.

**RESPONSE:**

**Please refer to BC Hydro's response to BCUC IR 2.243.1 for a detailed definition of Serious Incidents.**

**BC Hydro reports on Serious Permanently disabling injuries in the Service Plan. This decision was made to focus on key sources of fatalities in previous years, based on the recommendations of the safety taskforce.**

**243.0 E. CHAPTER 5D – OPERATING COSTS – SAFETY**

**Reference: OPERATING COSTS – SAFETY**
**Exhibit B-5, BCUC IR 87.2.1, 88.3**
**Serious incidents and contractor safety**

BC Hydro's response to BCUC IR 87.2.1 stated:

> All BC Hydro employee good catches, near misses and injuries that are recorded in the Incident Management System (IMS) are triaged by BC Hydro Safety Incident Investigators.
>
> BC Hydro Safety Incident Investigators do not triage or investigate public or contractor incidents. However, a process is in place to review these incidents. BC Hydro's Public Safety Team reviews all public safety incidents and takes appropriate actions. Contractor incidents are investigated by the contractors themselves, with support from BC Hydro and WorksafeBC as required.
>
> At fiscal 2019 year end, IMS logged 10,002 incidents. Out of these incidents, 3350 were employee incidents which were triaged by BC Hydro Safety Incident Investigators. The other 6652 incidents were managed through other processes per above.

2.243.2 Please discuss whether BC Hydro considers a contractor's safety history when hiring contractors. Please explain why or why not.

**RESPONSE:**

**Yes. BC Hydro employs a formalized procurement process for qualifying all contractors which includes an evaluation of safety history and safety preparedness. For further information on qualification and evaluation requirements through BC Hydro's Contractor Safety Program, please refer to BC Hydro's response to BCUC IR 2.243.6.**

**243.0 E. CHAPTER 5D – OPERATING COSTS – SAFETY**

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**Serious incidents and contractor safety**

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>
> At fiscal 2019 year end, IMS logged 10,002 incidents. Out of these incidents, 3350 were employee incidents which were triaged by BC Hydro Safety Incident Investigators. The other 6652 incidents were managed through other processes per above.

2.243.3 Please discuss what safety metrics BC Hydro uses to measure contractor performance with respect to safety once hired.

**RESPONSE:**

**BC Hydro uses the following two metrics to measure contractor performance with respect to safety once hired:**

- **Safety Incidents: injuries, near misses and good catches reported by contractors through BC Hydro's Incident Management System; and**
- **Safety Verifications, to validate that the safety systems and process identified in the safety plan comply with regulations and BC Hydro requirements.**

**This information is collected, tracked, analyzed and shared with the contractor to support continuous improvement.**

**243.0 E. CHAPTER 5D – OPERATING COSTS – SAFETY**

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>
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2.243.4 Please complete the below table to identify the total annual number of incidents logged in IMS since F2017, along with a breakdown of those incidents related to BC Hydro employees, contractors, public and other. Please identify what makes up "other," if applicable.

| | # of Employee Incidents | # of Contractor Incidents | # of Public Incidents | # of Other | # of Total Incidents |
| --- | --- | --- | --- | --- | --- |
| F2017 | | | | | |
| F2018 | | | | | |
| F2019 | 3,350 | 6,652 | | | 10,002 |

**RESPONSE:**

**The requested table is provided below. BC Hydro's Incident Management System categorizes incidents based on three groups of people: employees, contractors and public so the "other" category is not applicable.**

| | Number of Employee Incidents | Number of Contractor Incidents | Number of Public Incidents | Number of Other | Number of Total Incidents |
|---|---|---|---|---|---|
| F2017 | 1,638 | 1,909 | 479 | N/A | 4,026 |
| F2018 | 2,358 | 4,653 | 552 | N/A | 7,563 |
| F2019 | 3,350 | 6,125 | 527 | N/A | 10,002 |

**243.0 E. CHAPTER 5D – OPERATING COSTS – SAFETY**

**Reference: OPERATING COSTS – SAFETY**
**Exhibit B-5, BCUC IR 87.2.1, 88.3**
**Serious incidents and contractor safety**

BC Hydro's response to BCUC IR 87.2.1 stated:

> All BC Hydro employee good catches, near misses and injuries that are recorded in the Incident Management System (IMS) are triaged by BC Hydro Safety Incident Investigators.
>
> BC Hydro Safety Incident Investigators do not triage or investigate public or contractor incidents. However, a process is in place to review these incidents. BC Hydro's Public Safety Team reviews all public safety incidents and takes appropriate actions. Contractor incidents are investigated by the contractors themselves, with support from BC Hydro and WorksafeBC as required.
>
> At fiscal 2019 year end, IMS logged 10,002 incidents. Out of these incidents, 3350 were employee incidents which were triaged by BC Hydro Safety Incident Investigators. The other 6652 incidents were managed through other processes per above.

2.243.5 Please provide a high-level discussion of the extent the frequency of reported incidents affects the time required to complete a project or task. Please estimate the impact in terms of additional hours required, if possible.

**RESPONSE:**

**Safety incidents may or may not affect the completion of work.**

**At this time, we do not track this information and accordingly, do not have the ability to estimate the impact of incidents on the time required to complete a project or task.**

**243.0 E. CHAPTER 5D – OPERATING COSTS – SAFETY**

**Reference: OPERATING COSTS – SAFETY**
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>
> At fiscal 2019 year end, IMS logged 10,002 incidents. Out of these incidents, 3350 were employee incidents which were triaged by BC Hydro Safety Incident Investigators. The other 6652 incidents were managed through other processes per above.

2.243.6 Please discuss the initiatives that BC Hydro has in place to reduce contractor and public safety incidents.

**RESPONSE:**

**BC Hydro started a Contractor Safety Program in 2017 to reduce contractor safety incidents through requirements during the procurement process and ongoing evaluation.**

**During the qualification process, we ask for:**

- **Contractor safety performance information for the previous three years;**
- **Worksafe BC premiums;**
- **Responses to safety evaluation criteria; and**
- **For contractors working on moderate to high hazard work, a Certificate of Recognition.**

**Once hired, contractors are continuously evaluated through metrics related to their safety incidents and safety verifications performed by BC Hydro, as discussed further in BC Hydro's response to BCUC IR 2.243.3.**

**BC Hydro's public safety program continues to focus on the following initiatives to reduce public safety incidents:**

- **Installing and maintaining controls such as signs, fences, booms and sirens and implementing Public Safety Management Plans in accordance with the Canadian Dam Association Guidelines;**
- **Maintaining Public Use Management Areas to provide the public with safe places to recreate away from our hydroelectric generating facilities;**
- **Implementing a series of maintenance and inspection programs so that our assets are safe and fit for purpose;**
- **Providing members of the public workforce that are at higher risk of contact with our electrical system (e.g., trades workers and first responders such as fire fighters, police and paramedics) with electrical hazard awareness training through eLearning and face to face training; and**
- **Communicating water and electrical safety information to the public through our annual electrical safety in schools day and through paid, owned and earned media campaigns.**

**243.0 E. CHAPTER 5D – OPERATING COSTS – SAFETY**

**Reference: OPERATING COSTS – SAFETY**
**Exhibit B-5, BCUC IR 87.2.1, 88.3**
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>
> At fiscal 2019 year end, IMS logged 10,002 incidents. Out of these incidents, 3350 were employee incidents which were triaged by BC Hydro Safety Incident Investigators. The other 6652 incidents were managed through other processes per above.

2.243.7 Please discuss whether BC Hydro has any new initiatives planned for the Test Period to reduce contractor and public safety incidents.

**RESPONSE:**

**During the Test Period, BC Hydro will continue to focus on the initiatives to reduce contractor and public safety incidents outlined in BC Hydro's response to BCUC IR 2.243.6.**

**One new initiative planned for fiscal 2021 is the deployment of Life Guards and a designated swimming area at Lake Buntzen.**

**243.0 E. CHAPTER 5D – OPERATING COSTS – SAFETY**

**Reference: OPERATING COSTS – SAFETY**
**Exhibit B-5, BCUC IR 87.2.1, 88.3**
**Serious incidents and contractor safety**

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>
> At fiscal 2019 year end, IMS logged 10,002 incidents. Out of these incidents, 3350 were employee incidents which were triaged by BC Hydro Safety Incident Investigators. The other 6652 incidents were managed through other processes per above.

2.243.8 Please discuss whether BC Hydro's Service Plan has targets for reducing the number of contractor and/or public safety incidents. If yes, please identify them. If no, please explain why not.

**RESPONSE:**

**BC Hydro does not have Service Plan targets related to contractor and/or public safety.**

**The majority of Public Safety Incidents are related to Motor Vehicle Accidents involving our assets. BC Hydro has limited influence in these types of incidents, and accordingly, we have not included a metric in the Service Plan related to Public Safety.**

**As discussed in BC Hydro's response to BCUC IR 2.243.6, BC Hydro's Contractor Safety Program has qualification and evaluation requirements, including internal metrics to measure contractor safety performance, as outlined in BC Hydro's response to BCUC IR 2.243.3.**

**In addition, we are encouraging increased reporting of near misses, good catches and other incidents experienced by our contractors as we believe these are under reported and provide helpful learning opportunities.**

**As stated in BC Hydro's response to BCUC IR 2.243.1.1, BC Hydro reports on "Permanently disabling injuries" in the Service Plan. This decision was made to focus on key causes of fatalities in previous years, based on the recommendations of the safety taskforce.**

**244.0 F. CHAPTER 6 – CAPITAL EXPENDITURES**

**Reference: CAPITAL EXPENDITURES – INVESTMENT IN SUSTAINMENT**
**Exhibit B-5, BCUC 125.2.1; Exhibit B-1, p. 6-24**
**System performance**

In response to BCUC IR 125.2.1, BC Hydro stated:

> The Lower Mainland region had better reliability performance (or lower reliability indices) than the BC Hydro average in both SAIFI [System Average Interruption Frequency Index] and SAIDI [System Average Interruption Duration Index] in four of the past five fiscal years…
>
> Over the five-year period from fiscal 2014 to fiscal 2018, the remaining regions generally experienced worse reliability performance than the BC Hydro system average, with higher all-events SAIFI on outage frequency and all-events SAIDI on outage duration.

On page 6-24 of the Application, BC Hydro states: "…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."

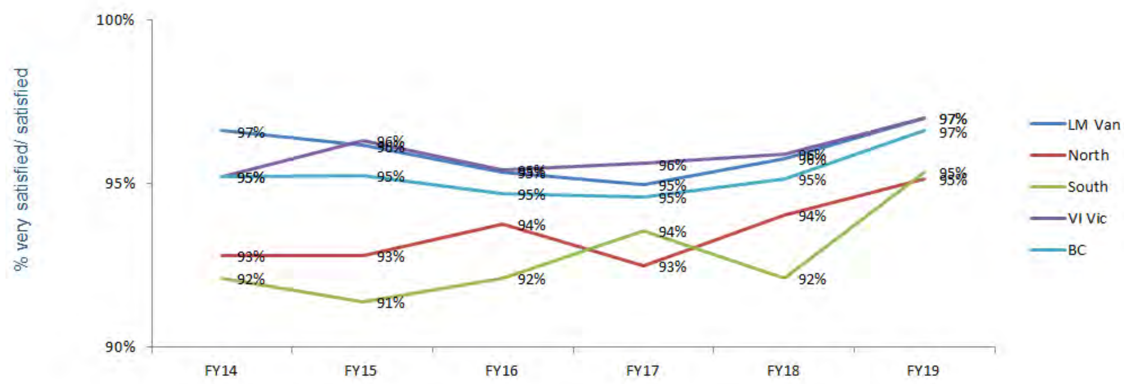
2.244.1 If possible, please provide the reliability scores in BC Hydro's Customer Satisfaction Index by geographic region (Lower Mainland, Vancouver Island, Southern Interior, North).

**RESPONSE:**

**The graph below provides a geographic breakdown of the responses to the Providing Reliable Electricity scores in BC Hydro's Customer Satisfaction Index, for residential and small and medium business customers.[1]**

**1 Key Accounts are excluded because many have accounts in multiple locations. As a result, Key Account survey results may not be attributed to the reliability of a specific region.**

Customer Satisfaction Index: Providing Reliable Electricity




**As depicted in the graph there is little variation in satisfaction amongst the geographic regions. Regional satisfaction with reliability has ranged from 91 per cent to 97 per cent for the past five years.**

**Customer satisfaction with reliability is slightly lower in the North Interior and South Interior than in the Lower Mainland and Vancouver Island; however, the regional differences in customer satisfaction with reliability are small. In addition, there are no specific regions in which customers indicated they were dissatisfied with BC Hydro's level of reliability.**

**244.0 F. CHAPTER 6 – CAPITAL EXPENDITURES**

**Reference: CAPITAL EXPENDITURES – INVESTMENT IN SUSTAINMENT**
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2.244.1 If possible, please provide the reliability scores in BC Hydro's Customer Satisfaction Index by geographic region (Lower Mainland, Vancouver Island, Southern Interior, North).

2.244.1.1 How does each region compare with the BC Hydro average?

**RESPONSE:**

**Please refer to BC Hydro's response to BCUC IR 2.244.1 where we show that there is little variation in satisfaction amongst the geographic regions.**

**244.0 F. CHAPTER 6 – CAPITAL EXPENDITURES**

**Reference: CAPITAL EXPENDITURES – INVESTMENT IN SUSTAINMENT**
**Exhibit B-5, BCUC 125.2.1; Exhibit B-1, p. 6-24**
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>
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On page 6-24 of the Application, BC Hydro states: "…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."

2.244.1 If possible, please provide the reliability scores in BC Hydro's Customer Satisfaction Index by geographic region (Lower Mainland, Vancouver Island, Southern Interior, North).

2.244.1.2 Please provide BC Hydro's assessment of the current level of customer satisfaction in each region. Are there any regions where the level of customer satisfaction needs improvement?

**RESPONSE:**

**Please refer to BC Hydro's response to BCUC IR 2.244.1 where we indicate that customer satisfaction with reliability scores do not identify any specific regions where customers are dissatisfied with BC Hydro's reliability.**

**244.0 F. CHAPTER 6 – CAPITAL EXPENDITURES**

**Reference: CAPITAL EXPENDITURES – INVESTMENT IN SUSTAINMENT**
**Exhibit B-5, BCUC 125.2.1; Exhibit B-1, p. 6-24**
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On page 6-24 of the Application, BC Hydro states: "…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."

2.244.1 If possible, please provide the reliability scores in BC Hydro's Customer Satisfaction Index by geographic region (Lower Mainland, Vancouver Island, Southern Interior, North).

2.244.1.3 Please provide reasons that customers in certain regions may experience a lower level of satisfaction compared to customers in other parts of the province.

**RESPONSE:**

**Please refer to BC Hydro's response to BCUC IR 2.244.1 where we identify there is little difference between the regions in customers' satisfaction with reliability.**

**Please also refer to BC Hydro's response to BCUC IR 2.244.2 where we indicate that capital investments for reliability improvements are identified and prioritized at an individual distribution circuit level based on outage data. Asset investment decisions are not directly increased or moderated based on customer satisfaction with reliability.**

**244.0 F. CHAPTER 6 – CAPITAL EXPENDITURES**

**Reference: CAPITAL EXPENDITURES – INVESTMENT IN SUSTAINMENT**
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>
> Over the five-year period from fiscal 2014 to fiscal 2018, the remaining regions generally experienced worse reliability performance than the BC Hydro system average, with higher all-events SAIFI on outage frequency and all-events SAIDI on outage duration.

On page 6-24 of the Application, BC Hydro states: "…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."

2.244.2 Please provide BC Hydro's historical and planned levels of investment in sustainment capital by geographic area. Are there any regions where BC Hydro plans to increase the level of investment in sustainment capital in order to address a lower level of customer satisfaction? Are there any regions where BC Hydro plans to moderate the level of investment in sustainment capital given a higher level of customer satisfaction? Please discuss.

**RESPONSE:**

**Our response to this question focuses on Distribution sustaining capital expenditures because the distribution system is the most significant contributor to customer satisfaction and reliability.**

**The table below shows BC Hydro's historical and planned levels of Distribution sustaining capital investment in different geographic areas and in system-wide programs which address common equipment or system issues that span the entire province.**

**Distribution Sustaining Capital Expenditures**
**($ million)**
**(Totals may not add due to rounding)**

| | Fiscal 2014 Actuals | Fiscal 2015 Actuals | Fiscal 2016 Actuals | Fiscal 2017 Actuals | Fiscal 2018 Actuals | Fiscal 2019 Actuals | Fiscal 2020 Plan | Fiscal 2021 Plan |
|---|---|---|---|---|---|---|---|---|
| Lower Mainland | 24.5 | 14.5 | 12.8 | 13.3 | 25.5 | 21.3 | 32.2 | 24.8 |
| Northern Interior | 7.4 | 2.3 | 5.6 | 9.6 | 16.6 | 4.6 | 2.2 | 1.4 |
| Southern Interior | 5.0 | 3.5 | 8.9 | 9.0 | 11.7 | 2.8 | 4.4 | 2.0 |
| Vancouver Island | 9.3 | 1.3 | 7.7 | 6.2 | 3.6 | 1.6 | 1.6 | 1.6 |
| Non-Integrated Areas | 0.6 | 0.7 | 0.1 | 0.1 | 0.3 | 5.4 | - | - |
| System Wide | 125.6 | 116.4 | 157.5 | 186.4 | 177.5 | 171.0 | 147.1 | 147.0 |
| Total | 172.4 | 138.5 | 192.5 | 224.6 | 235.1 | 206.7 | 187.5 | 176.8 |

**BC Hydro does not increase or moderate its capital investments in a particular region due to customer satisfaction with reliability. However, as explained in BC Hydro's response to BCUC IR 1.125.1, BC Hydro considered its customer satisfaction as well as high level of performance in moderating the level of investment in sustainment. As also explained in that response, BC Hydro believes that it has appropriately balanced affordability, system performance and risk.**

**Distribution sustaining capital investments that target reliability improvements are identified and prioritized at an individual distribution circuit level based on outage data, including all events and major events. This process is undertaken so that the worst performing circuits, in terms of reliability, are considered first. This approach may indirectly result in some regions having higher reliability-related capital investment in particular years. The variation in reliability-related capital investment is not due to BC Hydro's decision to increase or moderate spending based on a regional performance. Distribution sustaining capital investments that address end-of-life issues are driven by public and worker safety as well as equipment reliability.**

**In addition, more densely populated urban areas with higher loads (such as the Lower Mainland) require more infrastructure which then requires higher levels of sustaining capital investment.**

**Please refer to BC Hydro's response to BCUC IR 1.125.2 which provides information on reliability by geographic region and to BC Hydro's response to BCUC IR 1.125.2.3 where we discuss the reasons why reliability differs between regions.**

**245.0 F. CHAPTER 6 – CAPITAL EXPENDITURES**

**Reference: CAPITAL EXPENDITURES – INVESTMENT IN SUSTAINMENT**
**Exhibit B-5, BCUC IR 126.1**
**Standards for system performance**

In response to BCUC IR 126.1, BC Hydro stated:

> For the purposes of normalizing reliability performance measures, BC Hydro excludes major event impacts on our system. BC Hydro's definition of a major event is an uncontrollable event (e.g., windstorm, earthquake, forest fire, flood, lightning, etc.) that causes an outage resulting in more than 70,000 customer-hours lost or if customer-hours lost is greater than or equal to one per cent of annual customer-hours lost for the distribution system, whichever is less. This definition excludes controllable causes such as equipment failure or human error at the distribution, substation, or transmission level.

2.245.1 Please discuss the rationale for the selection of the threshold major event of 70,000 customer-hours lost or one percent of annual customer-hours lost for the system.

**RESPONSE:**

**In the fiscal 2004 and fiscal 2005 Annual Service Performance Reports, a major disaster was defined as an event when more than 10 per cent of the total customers supplied from the substation are out of service for more than 24 hours. This was the same definition for a "major event" used by the Institute of Electrical and Electronics Engineers (IEEE) at the time. In fiscal 2006, the BC Hydro definition was updated to the current BC Hydro definition for major event.**

**The major event threshold uses customer-hours lost because it captures both the number of customers interrupted as well as the outage duration. The 70,000 customer-hours lost threshold was selected based on the size of the major disaster events that had occurred in prior years and corresponds to 1 per cent of the previous four-year average of the annual customer-hours lost. For consistency in reliability performance reporting, the 70,000 customer-hours lost threshold for reporting major events remains the same today.**

**245.0 F. CHAPTER 6 – CAPITAL EXPENDITURES**

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2.245.1 Please discuss the rationale for the selection of the threshold major event of 70,000 customer-hours lost or one percent of annual customer-hours lost for the system.

2.245.1.1 Please discuss whether the threshold changes depending on the number of major events related to all events?

**RESPONSE:**

**Please refer to BC Hydro's response to BCUC IR 2.245.1 which states that for consistency in reliability performance reporting, the threshold and index does not change year to year.**

**245.0 F. CHAPTER 6 – CAPITAL EXPENDITURES**

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2.245.2 Please provide the number of major events on BC Hydro's system in each of the past five years. How many of these are considered weather events?

**RESPONSE:**

**The table below provides the number of major events on BC Hydro's system over the past five years.**

| **Fiscal Year** | **F2015** | **F2016** | **F2017** | **F2018** | **F2019** |
|---|---|---|---|---|---|
| **Number of major events** | **13** | **12** | **15** | **18** | **8** |

**All major events over this time period have been weather related. Please refer to BC Hydro's response to BCUC IR 1.126.3 which provides further information on historical storm events.**

**245.0 F. CHAPTER 6 – CAPITAL EXPENDITURES**

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2.245.3 Please provide BC Hydro's forecast for the number of major events in each of the next five years. How many of these are considered weather events?

**RESPONSE:**

**BC Hydro does not forecast future major events, as they are not predictable and are largely uncontrollable. However, BC Hydro does analyze historical major events to prepare for and improve BC Hydro's response to future events.**

**All major events in the previous five years have been weather related and BC Hydro expects that similar events will continue to occur. Please refer to BC Hydro's response to BCUC IR 2.245.2 which shows the variability in the number of major events over the past five years.**

**246.0 F. CHAPTER 6 – CAPITAL EXPENDITURES**

**Reference: CAPITAL EXPENDITURES – CAPITAL INVESTMENT PLANNING PROCESS**
**Exhibit B-5, BCUC IR 131.1**
**Extreme weather risk mitigation**

In response to BCUC IR 131.1, BC Hydro stated that it:

> … is undertaking climate studies to assess the impacts of extreme weather events on future load, hydroelectric generation and system resiliency…
>
> In addition, BC Hydro is performing a detailed risk assessment of the vulnerability of its power system to storm events and severe weather as part of our climate change adaption efforts. This analysis will quantify the risks to power system infrastructure due to impacts from a changing climate and incorporates climate projections created by the Pacific Climate Impacts Consortium (PCIC) with the Transmission and Distribution systems geospatial records. PCIC climate projections include a variety of future emissions scenarios and their associated projected temperature and precipitation changes.

2.246.1 Please provide the PCIC climate projections used to assess the impacts of weather events on future load, hydroelectric generation and system resiliency.

**RESPONSE:**

**PCIC projections used for hydroelectric generation are detailed in BC Hydro's response to CEC IR 1.14.1. The projections include long-term temperature and precipitation projections, which were used to assess changes in snowpack and water flows.**

**PCIC climate projections for temperature and precipitation used by BC Hydro to assess the impacts of weather events are publically available here:**

**https://data.pacificclimate.org/portal/downscaled_gcms/map/**

**https://www.pacificclimate.org/analysis-tools/pcic-climate-explorer**

**246.0 F. CHAPTER 6 – CAPITAL EXPENDITURES**

**Reference: CAPITAL EXPENDITURES – CAPITAL INVESTMENT PLANNING PROCESS**
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2.246.2 Please discuss how the PCIC climate projections are incorporated into BC Hydro’s risk assessment method. Are multiple PCIC climate projections used to quantify the risk?

**RESPONSE:**

**The Transmission and Distribution detailed risk assessment referred to in the preamble to this question has been initiated. BC Hydro will use PCIC climate projections (considering the risk event, timescale under consideration and relevant geographical area) to inform the likelihood of a climate or weather-related risk event. The specific PCIC climate projection(s) BC Hydro will use will be determined as part of the detailed risk assessment. Once the likelihood is established, BC Hydro will assess the consequence(s) of the event in order to quantify the risk to the power system.**

**246.0 F. CHAPTER 6 – CAPITAL EXPENDITURES**

**Reference: CAPITAL EXPENDITURES – CAPITAL INVESTMENT PLANNING PROCESS**
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2.246.3 Please discuss the reliability of the PCIC climate models used to assess the impacts of future weather events on BC Hydro's power system.

**RESPONSE:**

**BC Hydro uses PCIC to provide much of its climate change data inputs for system fragility modelling. PCIC is a world renowned institute with leading scientists whose methods are peer-reviewed and used by Environment Canada, as well as utilities, industry, and governmental institutions and municipalities across Canada.**

**The raw data for PCIC's models are generated by a worldwide network of climate scientists and are reviewed by the United Nations' Intergovernmental Panel on Climate Change. These raw data include a range of assumptions, such as future emissions and changes to land use. In addition, computational modelling is limited by the capacity of current computing technology. However, the projections and statistically-downscaled models generated by PCIC represent industry leading best practices.**

**For more information, please refer to PCIC's publications library at https://www.pacificclimate.org/resources/publications.**

**247.0 F. CHAPTER 6 – CAPITAL EXPENDITURES**

**Reference: CAPITAL EXPENDITURES**
**Exhibit B-1, Section 2.5.8, pp. 2-22, 2-23; BC Hydro F2017-F2019 RRA, Decision and Order G-47-18 dated March 1, 2018 (F2017-F2019 RRA Decision), Directive 3; Transmission Upgrade Exemption Regulation, BC Reg. 160/2018, Sections 2(1)(b), 2(1)(e); Exhibit B-5, BCUC IR 1.1, 1.1.6, 1.1.3**
**Northwest Substation upgrade**

In its response to BCUC IR 1.1, BC Hydro stated:

In July 2016, LNG Canada paused their interconnection project and did not restart the interconnection process again until late 2017. When the project was restarted, LNG Canada split their interconnection load and request into two phases, with separate and distinct approvals for each phase, and requested that BC Hydro only advance Phase 1…. LNG Canada has not made a decision on whether to proceed with its Phase 2 project but has requested that BC Hydro undertake interconnection studies to inform their final investment decision on this project. The additional scope that was in the original Northwest Substation Upgrade Project and was not required for Phase 1, may be required for Phase 2.

In its response to BCUC IR 1.1.6, BC Hydro stated: “The driver for the Northwest Substation Upgrade Project at the time of the Previous Application was the interconnection request by LNG Canada.”

2.247.1 Please explain why an amendment to Directive 3 of the F2017-F2019 RRA Decision to file a Certificate of Public Convenience and Necessity (CPCN) for the Northwest Substation Upgrade Project is necessary when the project has been cancelled.

**RESPONSE:**

**An amendment to Directive 3 to remove the Northwest Substation Upgrade Project (NSUP) would make it clear for BC Hydro and other stakeholders that no CPCN would be required or expected by the BCUC for the NSUP. This clarity would be advisable since BC Hydro has initiated the MIN to LNG Canada interconnection project in place of the NSUP in response to LNG Canada’s updated request. Please refer to BC Hydro’s response to BCUC IR 2.247.2 where we provide a comparison between the scope of the NSUP and Phases 1 and 2 of the MIN to LNG Canada interconnection project, with references to the Transmission Upgrade Exemption Regulation.**

**Please also refer to BC Hydro’s response to BCUC IR 1.1.1 where we provide a discussion of the NSUP and the MIN to LNG Canada interconnection project.**

**247.0 F. CHAPTER 6 – CAPITAL EXPENDITURES**

**Reference: CAPITAL EXPENDITURES**
**Exhibit B-1, Section 2.5.8, pp. 2-22, 2-23; BC Hydro F2017-F2019 RRA, Decision and Order G-47-18 dated March 1, 2018 (F2017-F2019 RRA Decision), Directive 3; Transmission Upgrade Exemption Regulation, BC Reg. 160/2018, Sections 2(1)(b), 2(1)(e); Exhibit B-5, BCUC IR 1.1, 1.1.6, 1.1.3**
**Northwest Substation upgrade**

In its response to BCUC IR 1.1, BC Hydro stated:

> In July 2016, LNG Canada paused their interconnection project and did not restart the interconnection process again until late 2017. When the project was restarted, LNG Canada split their interconnection load and request into two phases, with separate and distinct approvals for each phase, and requested that BC Hydro only advance Phase 1…. LNG Canada has not made a decision on whether to proceed with its Phase 2 project but has requested that BC Hydro undertake interconnection studies to inform their final investment decision on this project. The additional scope that was in the original Northwest Substation Upgrade Project and was not required for Phase 1, may be required for Phase 2.

In its response to BCUC IR 1.1.6, BC Hydro stated: "The driver for the Northwest Substation Upgrade Project at the time of the Previous Application was the interconnection request by LNG Canada."

2.247.2 Please explain the scope of work for Phase 2 of the Minette Station (MIN) to LNG Canada Interconnection Project. Please highlight any overlapping scope with the cancelled Northwest Substation Upgrade Project.

**RESPONSE:**

**The MIN to LNG Canada Interconnection Project is required to serve LNG Canada's Phase 1 project.**

**In October 2018, LNG Canada requested that BC Hydro proceed with interconnection studies for LNG Canada's Phase 2 project, to provide their proposed Kitimat facility with an incremental increase in load for LNG Canada Phase 2, and reduced maintenance outages.**

**BC Hydro has initiated two projects to support this request:**

- **A project to increase the supply capacity (the Minette Substation Upgrade project); and**
- **A project to mitigate outages (the Northwest Substations Outage Mitigation (NSOM) project).**

**The decisions on whether to implement these two projects will only be made once LNG Canada has made their Final Investment Decision for Phase 2 of their development.**

**The following table summarizes the overlapping scope between the cancelled Northwest Substation Upgrade Project and the current scope of the projects that would be required to support LNG Canada Phase 2. For completeness, the scope of work that is currently in the Implementation stage for LNG Canada Phase 1 is also shown in the middle column.**

| Northwest Substation Upgrade Project | LNG Canada Phase 1: MIN to LNG Canada Interconnection project | LNG Canada Phase 2: Minette Substation Upgrade project; Northwest Substations Outage Mitigation project[1] |
|---|---|---|
| Expansion of the Minette substation to accommodate the addition of three 287 kV shunt capacitor banks, a new 287 kV line position, and associated protection and control equipment | Expansion of the Minette substation to accommodate the addition of one 287 kV shunt capacitor bank, a new 287 kV line position, and associated protection and control equipment | The addition of two 287 kV shunt capacitor banks, and associated protection and control equipment (Minette Substation Upgrade project) |
| | A double circuit 287 kV transmission line from the Minette substation to the LNG Canada facility | |
| Planned transmission line entrance outage mitigation upgrades at Minette substation | | Planned transmission line entrance outage mitigation upgrades at Minette substation (NSOM project) |
| Planned transmission line entrance outage mitigation upgrades at Skeena substation | | Planned transmission line entrance outage mitigation upgrades at Skeena substation (NSOM project) |

1 Based on the leading alternative at this time.

| Northwest Substation Upgrade Project | LNG Canada Phase 1: MIN to LNG Canada Interconnection project | LNG Canada Phase 2: Minette Substation Upgrade project; Northwest Substations Outage Mitigation project[1] |
| --- | --- | --- |
| **Planned transmission line entrance equipment outage mitigation upgrades at Telkwa substation** | | **Planned transmission line entrance equipment outage mitigation upgrades at Telkwa substation (NSOM project)** |
| **Planned transmission line entrance outage mitigation upgrades at Glenannan substation** | | **Planned transmission line entrance outage mitigation upgrades at Glenannan substation (NSOM project)** |
| **Planned transmission line entrance outage mitigation upgrades at Williston substation** | | **Planned transmission line entrance outage mitigation upgrades at Williston substation (NSOM project)** |

**The MIN to LNG Canada Interconnection project, the Northwest Substations Outage Mitigation project and the Minette Substation Upgrade project are exempt from Part 3 of the *Utilities Commission Act* pursuant to the Transmission Upgrade Exemption Regulation.**

**Section 2(1)(e) of the Transmission Upgrade Exemption Regulation exempts, from Part 3 of the *Utilities Commission Act*, the addition of shunt capacitors at the Minette substation, including associated protection and control equipment, which is part of the MIN to LNG Canada Interconnection project and the Minette Substation Upgrade project, as indicated in the table above.**

**Section 2(2) of the Transmission Upgrade Exemption Regulation exempts from Part 3 of the *Utilities Commission Act*:**

> **"the construction or operation of a plant or system, or an upgrade or extension of either, to provide service for the following: (a) an LNG facility in the vicinity of the District of Kitimat; (b) a facility necessary for the construction of an LNG facility in the vicinity of the District of Kitimat."**

**The three projects described in the table above are necessary to provide service for Phases 1 and 2 of LNG Canada's LNG facility in the District of Kitimat.**

**Further to the requirement in section 2(3), at this time, BC Hydro reasonably expects that the three projects will be in service before October 1, 2025. However, BC Hydro has not yet decided to construct the NSOM project or the Minette Substation Upgrade project as they are contingent on LNG Canada proceeding with Phase 2 of its own project.**

**247.0 F. CHAPTER 6 – CAPITAL EXPENDITURES**

**Reference: CAPITAL EXPENDITURES**

**Exhibit B-1, Section 2.5.8, pp. 2-22, 2-23; BC Hydro F2017-F2019 RRA, Decision and Order G-47-18 dated March 1, 2018 (F2017-F2019 RRA Decision), Directive 3; Transmission Upgrade Exemption Regulation, BC Reg. 160/2018, Sections 2(1)(b), 2(1)(e); Exhibit B-5, BCUC IR 1.1, 1.1.6, 1.1.3**

**Northwest Substation upgrade**

In its response to BCUC IR 1.1, BC Hydro stated:

> In July 2016, LNG Canada paused their interconnection project and did not restart the interconnection process again until late 2017. When the project was restarted, LNG Canada split their interconnection load and request into two phases, with separate and distinct approvals for each phase, and requested that BC Hydro only advance Phase 1…. LNG Canada has not made a decision on whether to proceed with its Phase 2 project but has requested that BC Hydro undertake interconnection studies to inform their final investment decision on this project. The additional scope that was in the original Northwest Substation Upgrade Project and was not required for Phase 1, may be required for Phase 2.

In its response to BCUC IR 1.1.6, BC Hydro stated: "The driver for the Northwest Substation Upgrade Project at the time of the Previous Application was the interconnection request by LNG Canada."

2.247.3 Please provide BC Hydro's expected cost for Phase 2 of the project, including BC Hydro's costs to-date to perform the interconnection studies.

**RESPONSE:**

**This response includes confidential customer information which has been redacted in the public version of the response. The un-redacted version of the response is being made available to the BCUC only, in order to protect the customer's commercial interests.**

**As discussed in BC Hydro's response to BCUC IR 2.247.2, completion of two projects would be required to provide service to LNG Canada's Phase 2 project:**

- **The Minette Substation Upgrade Project, which is estimated between [redacted]; and**

- **The Northwest Substation Outage Mitigation project, which is estimated between [redacted].**

**The interconnection study costs incurred as of June 30, 2019 are [redacted].**

**247.0 F. CHAPTER 6 – CAPITAL EXPENDITURES**

**Reference: CAPITAL EXPENDITURES**
**Exhibit B-1, Section 2.5.8, pp. 2-22, 2-23; BC Hydro F2017-F2019 RRA, Decision and Order G-47-18 dated March 1, 2018 (F2017-F2019 RRA Decision), Directive 3; Transmission Upgrade Exemption Regulation, BC Reg. 160/2018, Sections 2(1)(b), 2(1)(e); Exhibit B-5, BCUC IR 1.1, 1.1.6, 1.1.3**
**Northwest Substation upgrade**

In its response to BCUC IR 1.1, BC Hydro stated:

> In July 2016, LNG Canada paused their interconnection project and did not restart the interconnection process again until late 2017. When the project was restarted, LNG Canada split their interconnection load and request into two phases, with separate and distinct approvals for each phase, and requested that BC Hydro only advance Phase 1…. LNG Canada has not made a decision on whether to proceed with its Phase 2 project but has requested that BC Hydro undertake interconnection studies to inform their final investment decision on this project. The additional scope that was in the original Northwest Substation Upgrade Project and was not required for Phase 1, may be required for Phase 2.

In its response to BCUC IR 1.1.6, BC Hydro stated: "The driver for the Northwest Substation Upgrade Project at the time of the Previous Application was the interconnection request by LNG Canada."

2.247.3.1 Please discuss the preliminary results of the interconnection studies and explain whether and how (and how much of) BC Hydro's expected cost for Phase 2 will be recovered from LNG Canada and from BC Hydro ratepayers.

**RESPONSE:**

**The interconnection studies concluded that two 287 kV shunt capacitors and associated protection and control equipment are required to be added at the Minette substation in order to supply LNG Canada's Phase 2. In addition, to meet LNG Canada's reliability requirements, upgrades to mitigate planned outages resulting from transmission line entrance equipment maintenance at the Williston, Glenannan, Telkwa, Skeena and Minette substation are also required.**

**Please refer to BC Hydro's response to BCUC IR 2.247.2 for a description of the preliminary scope of work for LNG Canada's Phase 2 project. The entire scope of**

**work is considered "System Reinforcements" under Tariff Supplement No. 6. In accordance with Tariff Supplement No. 6, LNG Canada will provide security for the costs of the work, which will be paid for by BC Hydro and then recovered from expected LNG Canada revenues within two years of LNG Canada plant operation.**

**247.0 F. CHAPTER 6 – CAPITAL EXPENDITURES**
**Reference: CAPITAL EXPENDITURES**
**Exhibit B-1, Section 2.5.8, pp. 2-22, 2-23; BC Hydro F2017-F2019 RRA, Decision and Order G-47-18 dated March 1, 2018 (F2017-F2019 RRA Decision), Directive 3; Transmission Upgrade Exemption Regulation, BC Reg. 160/2018, Sections 2(1)(b), 2(1)(e); Exhibit B-5, BCUC IR 1.1, 1.1.6, 1.1.3**
**Northwest Substation upgrade**

In its response to BCUC IR 1.1, BC Hydro stated:

> In July 2016, LNG Canada paused their interconnection project and did not restart the interconnection process again until late 2017. When the project was restarted, LNG Canada split their interconnection load and request into two phases, with separate and distinct approvals for each phase, and requested that BC Hydro only advance Phase 1…. LNG Canada has not made a decision on whether to proceed with its Phase 2 project but has requested that BC Hydro undertake interconnection studies to inform their final investment decision on this project. The additional scope that was in the original Northwest Substation Upgrade Project and was not required for Phase 1, may be required for Phase 2.

In its response to BCUC IR 1.1.6, BC Hydro stated: “The driver for the Northwest Substation Upgrade Project at the time of the Previous Application was the interconnection request by LNG Canada.”

2.247.4 Please discuss when a decision to proceed with Phase 2 of the MIN to LNG Canada Interconnection Project is expected from LNG Canada.

**RESPONSE:**

**This response includes confidential customer information which has been redacted in the public version of the response. The un-redacted version of the response is being made available to the BCUC only, in order to protect the customer’s commercial interests.**

**LNG Canada has informed BC Hydro that they expect to make a final investment decision on their Phase 2 project in [redacted]. BC Hydro will not proceed with the Minette Substation Upgrades project or the Northwest Substations Outage Mitigation Project until LNG Canada makes a formal request for service for their Phase 2 project and provides appropriate security.**

**247.0 F. CHAPTER 6 – CAPITAL EXPENDITURES**
**Reference: CAPITAL EXPENDITURES**
**Exhibit B-1, Section 2.5.8, pp. 2-22, 2-23; BC Hydro F2017-F2019 RRA, Decision and Order G-47-18 dated March 1, 2018 (F2017-F2019 RRA Decision), Directive 3; Transmission Upgrade Exemption Regulation, BC Reg. 160/2018, Sections 2(1)(b), 2(1)(e); Exhibit B-5, BCUC IR 1.1, 1.1.6, 1.1.3**
**Northwest Substation upgrade**

In its response to BCUC IR 1.1, BC Hydro stated:

> In July 2016, LNG Canada paused their interconnection project and did not restart the interconnection process again until late 2017. When the project was restarted, LNG Canada split their interconnection load and request into two phases, with separate and distinct approvals for each phase, and requested that BC Hydro only advance Phase 1…. LNG Canada has not made a decision on whether to proceed with its Phase 2 project but has requested that BC Hydro undertake interconnection studies to inform their final investment decision on this project. The additional scope that was in the original Northwest Substation Upgrade Project and was not required for Phase 1, may be required for Phase 2.

In its response to BCUC IR 1.1.6, BC Hydro stated: “The driver for the Northwest Substation Upgrade Project at the time of the Previous Application was the interconnection request by LNG Canada.”

2.247.5 Please explain whether the scope of work in the Northwest Substation Upgrade Project that is not part of the Phase 1 of the MIN to LNG Canada Interconnection Project is still planned to be completed by a separate project at a later date.

i) If yes, please indicate when that project is expected and the anticipated cost of the project.
ii) If no, please explain why this work is no longer required.

**RESPONSE:**

**This response includes confidential customer information which has been redacted in the public version of the response. The un-redacted version of the response is being made available to the BCUC only, in order to protect the customer’s commercial interests.**

**The scope of work that is not part of the Minette to LNG Canada Interconnection project is part of the scope of work required to supply LNG Canada's Phase 2 project, should LNG Canada decide to proceed with Phase 2. Please refer to BC Hydro's response to BCUC IR 2.247.2 which describes:**

- **The scope of work of the cancelled Northwest Substation Upgrade Project;**
- **The scope of work associated with LNG Canada Phase 1 (MIN to LNG Canada Interconnection project); and**
- **The expected scope of work associated with LNG Canada Phase 2 (Minette Substation Upgrade project and Northwest Substations Outage Mitigation project).**

**BC Hydro expects the MIN to LNG Canada Interconnection project will be in service in [redacted]; the Minette Substation Upgrades project will be in service in [redacted]; and the Northwest Substations Outage Mitigation project will be in service [redacted].**

**Please refer to BC Hydro's response to BCUC IR 2.247.3 for the expected costs of the projects associated with serving LNG Canada's Phase 2 project.**

**247.0 F. CHAPTER 6 – CAPITAL EXPENDITURES**

**Reference: CAPITAL EXPENDITURES**
**Exhibit B-1, Section 2.5.8, pp. 2-22, 2-23; BC Hydro F2017-F2019 RRA, Decision and Order G-47-18 dated March 1, 2018 (F2017-F2019 RRA Decision), Directive 3; Transmission Upgrade Exemption Regulation, BC Reg. 160/2018, Sections 2(1)(b), 2(1)(e); Exhibit B-5, BCUC IR 1.1, 1.1.6, 1.1.3**
**Northwest Substation upgrade**

The Transmission Upgrade Extension Regulation is detailed in Section 2.5.8 of the Application, where BC Hydro states:

> This direction, as amended by B.C. reg. 160/2018, exempts BC Hydro from Part 3 of the *Utilities Commission Act* with regards to:
>
> i. 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;

In its response to BCUC IR 1.1.3, BC Hydro stated:

> The addition of a series capacitor station and related facilities and equipment is the vicinity of the District of Vanderhoof, the Village of Burns Lake or the Village of Telkwa was not included in the Northwest Substation Project’s scope of work and is also not included in the MIN to LNG Canada Interconnection project’s scope of work.

2.247.6 Please confirm, or otherwise explain, whether BC Hydro has a project currently in any stage of development that includes the scope of a series capacitor station in the District of Vanderhoof, the Village of Burns Lake, or the Village of Telkwa.

**RESPONSE:**

**Confirmed. BC Hydro has a project called the Prince George to Terrace Capacitors (PGTC) project which proposes to construct series capacitor stations in the vicinity of the District of Vanderhoof, the Village of Burns Lake and the Village of Telkwa. BC Hydro has selected sites for the first two series capacitor stations near the District of Vanderhoof and the Village of Burns Lakes. Site investigation is currently underway for the third series capacitor station which will be located between the Village of Telkwa and the City of Terrace. The scope of the project also includes the addition of a third 500/287 kV transformer at Skeena Substation and associated protection and control equipment. For further information on the PGTC project, please refer to BC Hydro’s response to BCUC IR 2.247.6.1.**

**247.0 F. CHAPTER 6 – CAPITAL EXPENDITURES**

**Reference: CAPITAL EXPENDITURES**
**Exhibit B-1, Section 2.5.8, pp. 2-22, 2-23; BC Hydro F2017-F2019 RRA, Decision and Order G-47-18 dated March 1, 2018 (F2017-F2019 RRA Decision), Directive 3; Transmission Upgrade Exemption Regulation, BC Reg. 160/2018, Sections 2(1)(b), 2(1)(e); Exhibit B-5, BCUC IR 1.1, 1.1.6, 1.1.3**
**Northwest Substation upgrade**

The Transmission Upgrade Extension Regulation is detailed in Section 2.5.8 of the Application, where BC Hydro states:

> This direction, as amended by B.C. reg. 160/2018, exempts BC Hydro from Part 3 of the *Utilities Commission Act* with regards to:
>
> i. 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;

In its response to BCUC IR 1.1.3, BC Hydro stated:

> The addition of a series capacitor station and related facilities and equipment is the vicinity of the District of Vanderhoof, the Village of Burns Lake or the Village of Telkwa was not included in the Northwest Substation Project's scope of work and is also not included in the MIN to LNG Canada Interconnection project's scope of work.

2.247.6 Please confirm, or otherwise explain, whether BC Hydro has a project currently in any stage of development that includes the scope of a series capacitor station in the District of Vanderhoof, the Village of Burns Lake, or the Village of Telkwa.

2.247.6.1 If confirmed, please provide project details similar to information submitted in Appendix J of the Application.

**RESPONSE:**

**The table below provides the project details as of August 30, 2019.**

| **Investment Planning ID: 901574** | **Project Name:**<br>**Prince George to Terrace Capacitors (PGTC)** | |
|---|---|---|
| **Forecast Capital Cost:**<br>TBD | **Forecast In-Service Date:**<br>TBD | **Start Date of Construction:**[1]<br>TBD |
| **Development Phase:**<br>Identification | **Filing Reference:**<br>BC Hydro's F2014 Annual Report to the BCUC:<br>• Attachment to Section 8 – Part 2<br>• Appendix J, page 68 | |

**Description:**
The purpose of the project is to increase the transfer capacity of the 500 kV transmission system in the North Coast area to accommodate LNG load interconnections.

**Key Drivers:**

- Reliability

**Issues Being Addressed:**

BC Hydro's northwest service area is supplied by a single radial, 500 kV transmission line that runs from the Williston Substation near Prince George to the Skeena Substation near Terrace. Significant growth along the North Coast of B.C. is anticipated with the majority of the growth being driven by the LNG industry. With the CleanBC plan, the Government of B.C. is strongly encouraging electrification of future LNG exporting terminals. Customers have submitted requests or inquiries to BC Hydro that they are considering electrification of their loads.

The current transfer capacity of the 500 kV transmission system in the North Coast area is approximately 800 MW. By 2027, the transfer demand is expected to exceed the current transfer capacity by approximately 500 MW, according to the current load forecast and load interconnection queue.

[1] **Start Date of Construction is the Implementation Approval Date.**

**Discussion of Alternatives:**

Five alternatives were assessed during the Needs Stage:

i. **Install three new capacitor stations** along 5L61, 5L62, and 5L63 and a third 500/287 kV transformer at Skeena Substation;

ii. **Construct a second 450 km long 500 kV transmission line** parallel to the existing line plus a third transformer at Skeena Substation;

iii. **Install local generation** with dependable capacity;

iv. **Do nothing:** Continue to operate the existing system and do not increase the transmission capacity; and

v. **Defer:** Continue to operate the existing system and defer the transmission capacity increase.

Alternative i, Install three new capacitor stations, is the only viable alternative for the project.

**Project Impacts & Benefits:**

- Building capacitor stations will help maintain the voltage levels of the transmission lines, maximizing the amount of electricity the existing line can transfer.

| **Project Implementation Phase Risk:** | **Risk Treatment:** |
|---|---|
| Risks are identified starting in the Identification Phase and finalized in the Implementation Phase. | To be determined when the project reaches Implementation. |

**Additional Information:**

The original PGTC project was initiated in 2012 to supply potential LNG loads on the North Coast. Subsequently, a number of major customers cancelled their projects and load requests. As a result, the existing transfer capacity of the 500 kV transmission system became sufficient to meet the capacity required by the remaining customers and the PGTC project was no longer required. In 2016, the original PGTC project was cancelled. The PGTC project was reinitiated in 2019 to accommodate a new load interconnection request.

The project remains exempt from Part 3 of the *Utilities Commission Act* under the Transmission Upgrade Exemption Regulation.

**248.0 F. CHAPTER 6 – CAPITAL EXPENDITURES**

**Reference: CAPITAL EXPENDITURES**
**Exhibit B-5, BCUC IR 122.1.1, 122.2.1, 122.4.1; BCUC An Inquiry into the Regulation of Electric Vehicle Charging Service, Exhibit C-1-2, pp. 6–7**
**Electric vehicle charging stations**

In its response to BCUC IR 122.1.1, BC Hydro stated: “Prior to fiscal 2018, capital costs incurred by BC Hydro for the deployment of the 30 EV [electric vehicle] fast charging station pilot were classified under Technology capital.”

In its response to BCUC IR 122.2.1 pertaining to the forecast capital additions related to EV charging infrastructure, BC Hydro stated:

> In fiscal 2019, there were $0.5 million in capital additions for electric vehicle charging stations, all of which were leased to other parties.
>
> The remaining stations are operated by BC Hydro and will be put into service during the test period. Capital additions are forecast to be $3.4 million for fiscal 2020 and $2.4 million for fiscal 2021.

2.248.1 Please provide a list of all charging stations built by BC Hydro in BC to date. Please indicate:

i. whether the station is a Direct Current Fast Charging (DCFC) station;
ii. the location (include whether it is in multi-unit buildings private lots or highway corridors);
iii. the number of nozzles;
iv. the in-service date;
v. the total construction cost;
vi. the land purchase or right-of-way costs;
vii. the operator of each station; and
viii. the current charging rate or fee, if any.

**RESPONSE:**

**Please refer to Attachment 1 to this response for the requested information for public EV fast charging stations deployed by BC Hydro.**

Table 248.1 as of August 31, 2019: [Note 1]

| Station Name | Address | Location Type (Highway, Municipal/gov't lot, Private lot) | Net # 50kW DCFC's Phase 1 (chargers) | # Level 2's | Total # Dispensers | Deployment Phase(s) | Public Opening In-Service Date | Total Construction Cost (Phase 1 or 2) [Note 2] | BC Hydro Portion | 3rd Party Portion | Land Cost | Operator (Utility cost provider) | BC Hydro EV Network Segment [Note 3] | Current Charging Rate / Fee | Other Notes |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Abbotsford - EcoDairy | 1356 Sumas Way Abbotsford, BC | Private Lot | 1 | - | 1 | Phase 1 | 5-Mar-2015 | 109,087 | 9,472 | 99,615 | N/A | Bakerview Ecodiary Ltd | BC2 (Zeco Systems/Greenlots) | $0.35/kWh | |
| Boston Bar - Canyon Lanes | 47585 Trans Canada Hwy., Boston Bar, BC | Highway | 1 | - | 1 | Phase 1 | 1-Jan-2016 | 109,087 | 9,472 | 99,615 | N/A | Fraser Valley Regional District | BC2 (Zeco Systems/Greenlots) | $0.35/kWh | |
| Chase | 400 Shuswap Ave, Chase BC | Municipal/gov't lot | 1 | - | 1 | Phase 1 | 10-Jun-2016 | 109,087 | 9,472 | 99,615 | N/A | BC Hydro | BC2 (Zeco Systems/Greenlots) | 0 | |
| Chilliwack | 45950 Cheam Ave, Chilliwack, BC | Municipal/gov't lot | 1 | - | 1 | Phase 1 | 1-Jul-2016 | 109,087 | 9,472 | 99,615 | N/A | Fraser Valley Regional District | BC2 (Zeco Systems/Greenlots) | $0.35/kWh | |
| Colwood - Park and Ride | 1830 Old Island Hwy, Colwood, BC | Municipal/gov't lot | 1 | - | 1 | Phase 1 | 16-Dec-2015 | 109,087 | 9,472 | 99,615 | N/A | BC Hydro | BC2 (Zeco Systems/Greenlots) | 0 | Station to be twinned in phase 3 |
| Squamish | 37950 2nd Ave. Squamish BC | Municipal/gov't lot | 1 | - | 1 | Phase 1 | 1-Nov-2016 | 109,087 | 9,472 | 99,615 | N/A | District of Squamish | BC2 (Zeco Systems/Greenlots) | 0 | |
| Duncan - Island Savings Centre | 2680 James St, Duncan, BC | Municipal/gov't lot | 1 | - | 1 | Phase 1 | 19-Oct-2013 | 109,087 | 9,472 | 99,615 | N/A | Cowichan Valley Regional Dist | BC2 (Zeco Systems/Greenlots) | $0.35/kWh | |
| Hope | 839 4 Ave, Hope, BC | Municipal/gov't lot | 1 | - | 1 | Phase 1 | 30-Oct-2015 | 189,475 | 27,335 | 162,140 | N/A | District of Hope | BC2 (Zeco Systems/Greenlots) | 0 | Includes station upgrade costs |
| Kamloops - Hillside Stadium | 910 McGill Rd Kamloops, BC | Municipal/gov't lot | 1 | - | 1 | Phase 1 | 27-Jan-2014 | 189,475 | 27,335 | 162,140 | N/A | City of Kamloops | BC2 (Zeco Systems/Greenlots) | 0 | Includes station upgrade costs |
| Keremeos | 702 4 St, Keremeos, BC | Municipal/gov't lot | 1 | - | 1 | Phase 1 | 9-Nov-2015 | 109,087 | 9,472 | 99,615 | N/A | Town of Keremeos | BC2 (Zeco Systems/Greenlots) | $0.35/kWh | |
| Langley Events Centre | 7888 200 Street Langley, BC | Private Lot | 1 | - | 1 | Phase 1 | 2-Apr-2015 | 109,087 | 9,472 | 99,615 | N/A | Township of Langley | BC2 (Zeco Systems/Greenlots) | $0.35/kWh | |
| Malakwa Supermarket | 4270 Oxbow Frontage Rd, Malakwa, BC | Private Lot | 1 | - | 1 | Phase 1 | 31-Oct-2016 | 109,087 | 9,472 | 99,615 | N/A | Columbia Shuswap Regional District | BC2 (Zeco Systems/Greenlots) | $0.35/kWh | |
| Manning Park | 7500 BC-3, Manning Park, BC | Municipal/gov't lot | 1 | - | 1 | Phase 1 | 31-Jul-2016 | 109,087 | 9,472 | 99,615 | N/A | Regional District Okanagan Similkameen | BC2 (Zeco Systems/Greenlots) | 0 | |
| Merritt Visitor Information Centre | 2202 Voght St Merritt, BC | Municipal/gov't lot | 1 | - | 1 | Phase 1 | 1-May-2015 | 189,475 | 27,335 | 162,140 | N/A | City of Merritt | BC2 (Zeco Systems/Greenlots) | $0.35/kWh | Includes station upgrade costs |
| Nanaimo - Conference Centre | 125 Front St., Nanaimo, BC | Municipal/gov't lot | 1 | - | 1 | Phase 1 | 23-Aug-2013 | 109,087 | 9,472 | 99,615 | N/A | City of Nanaimo | BC2 (Zeco Systems/Greenlots) | 0 | |
| North Vancouver - 1st & Lonsdale | 140 1st St E North Vancouver, BC | Private Lot | 1 | - | 1 | Phase 1 | 23-Sep-2014 | 189,475 | 27,335 | 162,140 | N/A | BC Hydro | BC2 (Zeco Systems/Greenlots) | 0 | Includes station upgrade costs |
| Penticton | 234 Main St Penticton, BC | Municipal/gov't lot | 1 | - | 1 | Phase 1 | 7-Jul-2015 | 109,087 | 9,472 | 99,615 | N/A | BC Hydro | BC2 (Zeco Systems/Greenlots) | 0 | |
| Surrey - Powertech Labs | 12388 88 Ave. Surrey, BC | Municipal/gov't lot | 1 | - | 1 | Phase 1 | 13-Jul-2013 | 109,087 | 9,472 | 99,615 | N/A | Powertech Labs Inc. | BC1 (AddEnergie Technologies) | 0 | Powertech Labs is a subsidiary of BC Hydro. |
| Princeton | 114 Tapton Ave, Princeton, BC | Municipal/gov't lot | 1 | - | 1 | Phase 1 | 30-Jun-2016 | 109,087 | 9,472 | 99,615 | N/A | Town of Princeton | BC2 (Zeco Systems/Greenlots) | $0.35/kWh | |
| Revelstoke | 301 Victoria Rd, Revelstoke, BC | Private Lot | 1 | - | 1 | Phase 1 | 15-Mar-2015 | 109,087 | 9,472 | 99,615 | N/A | Revelstoke Chamber of Commerce | BC2 (Zeco Systems/Greenlots) | $0.35/kWh | |
| Saanich - Uptown Shopping Centre | 3440 Saanich Road Victoria, BC | Private Lot | 1 | - | 1 | Phase 1 | 9-Jan-2015 | 109,087 | 9,472 | 99,615 | N/A | Ravine Equities Inc. | BC2 (Zeco Systems/Greenlots) | 0 | Station to be moved / twinned in phase 3 |
| Salmon Arm | 381 Ross St Salmon Arm, BC | Private Lot | 1 | - | 1 | Phase 1 | 18-Nov-2015 | 109,087 | 9,472 | 99,615 | N/A | City of Salmon Arm | BC2 (Zeco Systems/Greenlots) | $0.35/kWh | |
| Sechelt - Trail Bay Mall | 5755 Cowrie Street, Sechelt, BC | Private Lot | 1 | - | 1 | Phase 1 | 15-Dec-2014 | 189,475 | 27,335 | 162,140 | N/A | District of Sechelt | BC2 (Zeco Systems/Greenlots) | 0 | Includes station upgrade costs |
| Spences Bridge | 3633 Station St, Spences Bridge, BC | Highway | 1 | 1 | 2 | Phase 1 | 9-Feb-2016 | 109,087 | 9,472 | 99,615 | N/A | Thompson Nicola Regional District | BC2 (Zeco Systems/Greenlots) | 0 | |
| Surrey Central - City Hall | 13450 104 Avenue, Surrey, BC | Municipal/gov't lot | 1 | - | 1 | Phase 1 | 25-Oct-2016 | 189,475 | 27,335 | 162,140 | N/A | City of Surrey | BC2 (Zeco Systems/Greenlots) | 0 | Includes station upgrade costs |
| Surrey Museum (decommissioned) | 17710 56A Avenue, Surrey, BC | Municipal/gov't lot | 0* | - | 1 | Phase 1 | 27-Aug-2013 | 109,087 | 9,472 | 99,615 | N/A | N/A | N/A | 0 | *Demcommissioned. Replaced by Surrey Cloverdale station |
| Vernon | 3004 32nd Ave, Vernon BC | Municipal/gov't lot | 1 | - | 1 | Phase 1 | 1-Sep-2016 | 109,087 | 9,472 | 99,615 | N/A | City of Vernon | BC2 (Zeco Systems/Greenlots) | 0 | |
| West Kelowna | 3678 Brown Rd, West Kelowna BC | Municipal/gov't lot | 1 | - | 1 | Phase 1 | 1-Jun-2016 | 109,087 | 9,472 | 99,615 | N/A | City of West Kelowna | BC2 (Zeco Systems/Greenlots) | $0.35/kWh | |
| Whistler | 4010 Whistler Way, Whistler, BC | Private Lot | 1 | - | 1 | Phase 1 | 12-Jan-2016 | 109,087 | 9,472 | 99,615 | N/A | Resort Municipality of Whistler | BC2 (Zeco Systems/Greenlots) | 0 | |
| Vancouver - Empire Field (decommissioned) | 3311 E Hastings Street, Vancouver, BC | Municipal/gov't lot | 0* | - | 1 | Phase 1 | 11-Jan-2016 | 109,087 | 9,472 | 99,615 | N/A | N/A | N/A | 0 | *Decommissioned and transferred to City of Vancouver |
| **Sub-Total Phase 1** | | | **28** | | | | | **3,754,938** | **391,338** | **3,363,600** | | | | | |
| Other Phase 1 Capital Costs | N/A | N/A | N/A | | N/A | Phase 1 | N/A | 2,427,398 | 210,781 | 2,216,617 | N/A | N/A | N/A | N/A | The other costs include "smart charging" demonstration projects that include the design, build and demonstration of various EV load management pathways, ranging from direct utility controlled loads using SMI pathways to demand response aggregator pathways that rely on third parties to respond and bid into market-based, utility capacity programs. |
| **Total Phase 1** | | | | | | | | **6,182,336** | **602,119** | **5,580,217** | | | | | |

| Station Name | Address | Location Type (Highway, Municipal/gov't lot, Private lot) | # 50kW DCFC's Phase 2 (chargers) | # Level 2's | Total # Dispensers | Deployment Phase(s) | Public Opening In-Service Date | Total Construction Cost (Phase 1 or 2) [Note 2] | BC Hydro Portion | 3rd Party Portion | Land Cost | Operator (Utility cost provider) | BC Hydro EV Network Segment [Note 3] | Current Charging Rate / Fee | Other Notes |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Vancouver - Homer St | 561 Homer Street, Vancouver, BC | Municipal/gov't lot | 2 | | 2 | Phase 2 | 25-May-2018 | 364,540 | 180,768 | 183,772 | N/A | BC Hydro | BC2 (Zeco Systems/Greenlots) | 0 | |
| Britton Creek Rest Area | Exit 228 at Coquihalla Lakes Rd, BC | Highway | 2 | 1 | 3 | Phase 2 | 13-Jun-2018 | 364,540 | 180,768 | 183,772 | N/A | BC Hydro | BC2 (Zeco Systems/Greenlots) | 0 | |
| Campbell River - Community Centre | 401 11 Ave, Campbell River | Municipal/gov't lot | 1 | | 1 | Phase 2 | 1-May-2018 | 182,270 | 90,384 | 91,886 | N/A | BC Hydro | BC2 (Zeco Systems/Greenlots) | 0 | |
| Coquitlam - Superstore East | 3000 Lougheed Hwy, Coquitlam, BC | Private Lot | 1 | | 1 | Phase 2 | 11-May-2018 | 182,270 | 90,384 | 91,886 | N/A | BC Hydro | BC2 (Zeco Systems/Greenlots) | 0 | Station to be twinned in phase 3 |
| Coquitlam - Superstore West | 1301 Lougheed Hwy, Coquitlam, BC | Private Lot | 1 | | 1 | Phase 2 | 20-Apr-2018 | 182,270 | 90,384 | 91,886 | N/A | BC Hydro | BC2 (Zeco Systems/Greenlots) | 0 | |
| Courtenay - Superstore | 757 Ryan Road, Courtenay, BC | Private Lot | 1 | | 1 | Phase 2 | 1-May-2018 | 182,270 | 90,384 | 91,886 | N/A | BC Hydro | BC2 (Zeco Systems/Greenlots) | 0 | |
| Vancouver - Grandview Hwy Superstore | 3185 Grandview Highway, Vancouver, BC | Private Lot | 1 | | 1 | Phase 2 | 18-Apr-2018 | 182,270 | 90,384 | 91,886 | N/A | BC Hydro | BC1 (AddEnergie Technologies) | 0 | |
| West Vancouver - Horseshoe Bay | 6400 Bruce Street, District of West Vancouver, BC | Private Lot | 1 | | 1 | Phase 2 | 25-May-2018 | 182,270 | 90,384 | 91,886 | N/A | BC Hydro | BC2 (Zeco Systems/Greenlots) | 0 | |
| Vancouver - Kerrisdale | 5356 West Boulevard, Vancouver, BC | Municipal/gov't lot | 1 | | 1 | Phase 2 | 11-Aug-2018 | 182,270 | 90,384 | 91,886 | N/A | BC Hydro | BC1 (AddEnergie Technologies) | 0 | |
| Mission Superstore | 32136 Lougheed Highway, Mission, BC | Private Lot | 1 | | 1 | Phase 2 | 29-May-2018 | 182,270 | 90,384 | 91,886 | N/A | BC Hydro | BC2 (Zeco Systems/Greenlots) | 0 | |
| Nanaimo - Superstore | 6435 Metral Drive, Nanaimo, BC | Private Lot | 1 | | 1 | Phase 2 | 17-Apr-2018 | 182,270 | 90,384 | 91,886 | N/A | BC Hydro | BC2 (Zeco Systems/Greenlots) | 0 | |
| Surrey - South Superstore | 2332 160 St., Surrey, BC | Private Lot | 1 | | 1 | Phase 2 | 18-Apr-2018 | 182,270 | 90,384 | 91,886 | N/A | BC Hydro | BC2 (Zeco Systems/Greenlots) | 0 | Station to be twinned in phase 3 |
| Surrey - Cloverdale | 5771 176A St, Surrey BC | Municipal/gov't lot | 1 | | 1 | Phase 2 | 31-Jan-2019 | 80,388 | 17,863 | 62,525 | N/A | BC Hydro | BC2 (Zeco Systems/Greenlots) | 0 | Phase 1 station upgraded and relocated from Surrey Museum during phase 2 |
| Port Alberni - No Frills | 3455 Johnston Road, Port Alberni, BC | Private Lot | 1 | | 1 | Phase 2 | 16-Apr-2018 | 182,270 | 90,384 | 91,886 | N/A | BC Hydro | BC2 (Zeco Systems/Greenlots) | 0 | |
| Qualicum - Quality Foods | 133 West Fern, Qualicum, BC | Private Lot | 1 | | 1 | Phase 2 | 19-Apr-2018 | 182,270 | 90,384 | 91,886 | N/A | BC Hydro | BC2 (Zeco Systems/Greenlots) | 0 | |
| Richmond - Superstore | 4651 No. 3 Road, Richmond, BC | Private Lot | 1 | | 1 | Phase 2 | 18-Apr-2018 | 182,270 | 90,384 | 91,886 | N/A | BC Hydro | BC2 (Zeco Systems/Greenlots) | 0 | Station to be twinned in phase 3 |
| Vancouver - SE Marine Drive Superstore | 350 South East Marine Drive, Vancouver, BC | Private Lot | 1 | | 1 | Phase 2 | 31-Dec-2018 | 182,270 | 90,384 | 91,886 | N/A | BC Hydro | BC1 (AddEnergie Technologies) | 0 | Station to be twinned in phase 3 |
| Sidney | 2330 Bevan Avenue, Sidney, BC | Municipal/gov't lot | 1 | | 1 | Phase 2 | 25-May-2018 | 182,270 | 90,384 | 91,886 | N/A | BC Hydro | BC2 (Zeco Systems/Greenlots) | 0 | |
| Surrey Tynehead Gas Station | 16815 - 96th Ave, Surrey, BC | Private Lot | 1 | | 1 | Phase 2 | 17-Jul-2018 | 182,270 | 90,384 | 91,886 | N/A | BC Hydro | BC2 (Zeco Systems/Greenlots) | 0 | |
| Ucluelet - Pacific Rim Visitor's Centre | 2791 Pacific Rim Hwy, Ucluelet, BC | Highway | 1 | 1 | 2 | Phase 2 | 9-Apr-2018 | 182,270 | 90,384 | 91,886 | N/A | BC Hydro | Both BC1 & BC2 | 0 | |
| UBC - Wesbrook Place | 6163 University Blvd, Vancouver, BC | Municipal/gov't lot | 1 | | 1 | Phase 2 | 23-Apr-2018 | 182,270 | 90,384 | 91,886 | N/A | BC Hydro | BC2 (Zeco Systems/Greenlots) | 0 | |
| **Total Phase 2** | | | **23** | | | | | **4,090,328** | **2,006,311** | **2,084,017** | | | | | |

| Station Name | Address | Location Type (Highway, Municipal/gov't lot, Private lot) | # 50kW DCFC's Phase 2-K (chargers) | # Level 2's | Total # Dispensers | Deployment Phase(s) | Public Opening In-Service Date | Total Construction Cost (Phase 1 or 2) [Note 2] | BC Hydro Portion | 3rd Party Portion | Land Cost | Operator (Utility cost provider) | BC Hydro EV Network Segment [Note 3] | Current Charging Rate / Fee | Other Notes |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Canal Flats - Columbia Discovery Centre | 4925 Burns Ave, Canal Flats, BC | Municipal/gov't lot | 1 | | 1 | Phase 2-K | 11-Dec-2017 | unknown | 61,565 | unknown | N/A | BC Hydro | BC1 (AddEnergie Technologies) | 0 | |
| Cranbrook | 38 Cranbrook St N, Cranbrook, BC | Municipal/gov't lot | 1 | | 1 | Phase 2-K | 6-Apr-2017 | unknown | 61,565 | unknown | N/A | BC Hydro | BC1 (AddEnergie Technologies) | 0 | |
| Golden | 820 9 Ave South, Golden, BC V0A 1H0 | Municipal/gov't lot | 1 | | 1 | Phase 2-K | 30-Jun-2018 | unknown | 61,565 | unknown | N/A | BC Hydro | BC1 (AddEnergie Technologies) | 0 | |
| Jaffray Pump & Pantry | 7311 Bertrand Rd., Jaffray, BC | Private Lot | 1 | | 1 | Phase 2-K | 25-Jan-2018 | unknown | 61,565 | unknown | N/A | BC Hydro | BC1 (AddEnergie Technologies) | 0 | |
| Radium Community Centre | 4863 Stanley St, Radium Hot Springs, BC | Municipal/gov't lot | 1 | | 1 | Phase 2-K | 11-Dec-2017 | unknown | 61,565 | unknown | N/A | BC Hydro | BC1 (AddEnergie Technologies) | 0 | |
| Rogers Pass Discovery Centre | 9520 Trans Canada Hwy, Rogers Pass, BC | Private Lot | 1 | 1 | 2 | Phase 2-K | 18-Dec-2018 | unknown | 61,565 | unknown | $250/yr lease to Parks Canada | BC Hydro | BC1 (AddEnergie Technologies) | 0 | |
| Sparwood | 100 Centennial St, Sparwood, BC | Municipal/gov't lot | 1 | | 1 | Phase 2-K | 5-Jun-2018 | unknown | 61,565 | unknown | N/A | BC Hydro | BC1 (AddEnergie Technologies) | 0 | |
| Field - Yoho National Park | Field, BC - Yoho National Park Visitors Centre | Municipal/gov't lot | 1 | 1 | 2 | Phase 2-K | 15-Jan-2019 | unknown | 61,565 | unknown | $250/yr lease to Parks Canada | BC Hydro | BC1 (AddEnergie Technologies) | 0 | |
| **Total Phase 2 - Kootenays** | | | **8** | | | | | **-** | **492,517** | **-** | | | | | |

| Station Name | Address (Provided below if completed or open to public) | Location Type (Highway, Municipal/gov't lot, Private lot) | # 50kW DCFC's Phase 3 (chargers) | # Exisiting Chargers | New Total # Dispensers | Deployment Phase(s) | Actual / Estimated Opening Date | Projected Total Construction Cost | Projected BC Hydro Portion | Projected 3rd Party Portion | Land Cost | Operator (Utility cost provider) | BC Hydro EV Network Segment [Note 3] | Charging Rate / Fee | Other Notes |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 70 Mile House | 1597 BC-97, 70 Mile House, BC | Municipal/gov't lot | 1 | | 1 | Phase 3 | 19-Jul-2019 | TBD | TBD | TBD | N/A | BC Hydro | BC1 (AddEnergie Technologies) | 0 | |
| Agassiz | | Private Lot | 1 | | 1 | Phase 3 | *Est. Mar 2020* | TBD | TBD | TBD | N/A | BC Hydro | BC1 (AddEnergie Technologies) | 0 | |
| Blue River | | Municipal/gov't lot | 1 | | 1 | Phase 3 | *Est. Oct 2019* | TBD | TBD | TBD | N/A | BC Hydro | BC1 (AddEnergie Technologies) | 0 | |
| Cache Creek | 1270 Stage Rd, Cache Creek, BC | Municipal/gov't lot | 1 | | 1 | Phase 3 | 19-Jul-2019 | TBD | TBD | TBD | N/A | BC Hydro | BC1 (AddEnergie Technologies) | 0 | |
| Clinton | 1423 Cariboo Hwy, Clinton, BC | Municipal/gov't lot | 1 | | 1 | Phase 3 | 19-Jul-2019 | TBD | TBD | TBD | N/A | BC Hydro | BC1 (AddEnergie Technologies) | 0 | |
| Colwood (Expansion) | 1830 Old Island Hwy, Colwood, BC | Municipal/gov't lot | 1 | 1 | 2 | Phase 3 | *Est. Nov 2019* | TBD | TBD | TBD | N/A | BC Hydro | BC1 (AddEnergie Technologies) | 0 | |
| Coquitlam - Superstore East (Expansion) | 3000 Lougheed Hwy, Coquitlam, BC | Private Lot | 1 | 1 | 2 | Phase 3 | 21-Aug-2019 | TBD | TBD | TBD | N/A | BC Hydro | BC1 (AddEnergie Technologies) | 0 | |
| Hixon | | Municipal/gov't lot | 1 | | 1 | Phase 3 | *Est. Dec 2019* | TBD | TBD | TBD | N/A | BC Hydro | BC1 (AddEnergie Technologies) | 0 | |
| Madeira Park | | Municipal/gov't lot | 1 | | 1 | Phase 3 | *Est. Dec 2019* | TBD | TBD | TBD | N/A | BC Hydro | BC1 (AddEnergie Technologies) | 0 | |
| McBride | | Municipal/gov't lot | 1 | | 1 | Phase 3 | *Est. Oct 2019* | TBD | TBD | TBD | N/A | BC Hydro | BC1 (AddEnergie Technologies) | 0 | |
| North Vancouver (Expansion) | 140 1st St E North Vancouver, BC | Municipal/gov't lot | 1 | 1 | 2 | Phase 3 | *Est. Dec 2019* | TBD | TBD | TBD | N/A | BC Hydro | BC1 (AddEnergie Technologies) | 0 | |
| Port Hardy | | Municipal/gov't lot | 1 | | 1 | Phase 3 | *Est. Oct 2019* | TBD | TBD | TBD | N/A | BC Hydro | BC1 (AddEnergie Technologies) | 0 | |
| Port McNeill | | Municipal/gov't lot | 1 | | 1 | Phase 3 | *Est. Oct 2019* | TBD | TBD | TBD | N/A | BC Hydro | BC1 (AddEnergie Technologies) | 0 | |
| Powell River | | Municipal/gov't lot | 1 | | 1 | Phase 3 | *Est. Nov 2019* | TBD | TBD | TBD | N/A | BC Hydro | BC1 (AddEnergie Technologies) | 0 | |
| Prince George | | Municipal/gov't lot | 1 | | 1 | Phase 3 | 15-Jan-2019 | TBD | TBD | TBD | N/A | BC Hydro | BC1 (AddEnergie Technologies) | 0 | |
| Quesnel | | Municipal/gov't lot | 1 | | 1 | Phase 3 | 15-Jan-2019 | TBD | TBD | TBD | N/A | BC Hydro | BC1 (AddEnergie Technologies) | 0 | |
| Richmond - Superstore (Expansion) | 4651 No. 3 Road, Richmond, BC | Private Lot | 1 | 1 | 2 | Phase 3 | *Est. Oct 2019* | TBD | TBD | TBD | N/A | BC Hydro | BC1 (AddEnergie Technologies) | 0 | |
| Saanich (Expansion) | | Municipal/gov't lot | 1 | 1 | 2 | Phase 3 | *Est. Sept 2019* | TBD | TBD | TBD | N/A | BC Hydro | BC1 (AddEnergie Technologies) | 0 | |
| South Delta/Tsawwassen | | Municipal/gov't lot | 1 | | 1 | Phase 3 | *Est. Dec 2019* | TBD | TBD | TBD | N/A | BC Hydro | BC1 (AddEnergie Technologies) | 0 | |
| Surrey - South Superstore (Expansion) | 2332 160 St., Surrey, BC | Private Lot | 1 | 1 | 2 | Phase 3 | *Est. Oct 2019* | TBD | TBD | TBD | N/A | BC Hydro | BC1 (AddEnergie Technologies) | 0 | |
| Valemount | | Municipal/gov't lot | 1 | | 1 | Phase 3 | *Est. Oct 2019* | TBD | TBD | TBD | N/A | BC Hydro | BC1 (AddEnergie Technologies) | 0 | |
| Vancouver - SE Marine Superstore (Expansion) | 350 South East Marine Drive, Vancouver, BC | Private Lot | 1 | 1 | 2 | Phase 3 | 9-Jul-2019 | TBD | TBD | TBD | N/A | BC Hydro | BC1 (AddEnergie Technologies) | 0 | |
| Williams Lake | | Municipal/gov't lot | 1 | | 1 | Phase 3 | *Est. Oct 2019* | TBD | TBD | TBD | N/A | BC Hydro | BC1 (AddEnergie Technologies) | 0 | |
| **Total Phase 3** | | | **23** | | | | | **4,400,000** | **2,675,000** | **1,725,000** | | | | | |

*Notes:*

*1. Table includes BC Hydro costs and recoveries up to March 31, 2019 for Phase 1 and Phase 2. Phase 3 costs are estimates.*

*2. Total costs for each phase are divided by the number of stations to arrive at an average cost per station. Major third party funding and project cost accounting are mainly based on deployment phases rather than individual stations.*

*3. BC Hydro has two back-end EV IT network segments due to certain chargers only working with certain IT platforms. For both network segments, BC Hydro takes all EV daytime support calls, monitors Plugshare comments and manages all station issue triage and repair. The network vendors manage the back-end IT platform and provide over-night call centre support for EV drivers outside BC Hydro call centre hours.*

**248.0 F. CHAPTER 6 – CAPITAL EXPENDITURES**

**Reference: CAPITAL EXPENDITURES**
**Exhibit B-5, BCUC IR 122.1.1, 122.2.1, 122.4.1; BCUC An Inquiry into the Regulation of Electric Vehicle Charging Service, Exhibit C-1-2, pp. 6–7**
**Electric vehicle charging stations**

In its response to BCUC IR 122.1.1, BC Hydro stated: "Prior to fiscal 2018, capital costs incurred by BC Hydro for the deployment of the 30 EV [electric vehicle] fast charging station pilot were classified under Technology capital."

In its response to BCUC IR 122.2.1 pertaining to the forecast capital additions related to EV charging infrastructure, BC Hydro stated:

> In fiscal 2019, there were $0.5 million in capital additions for electric vehicle charging stations, all of which were leased to other parties.
>
> The remaining stations are operated by BC Hydro and will be put into service during the test period. Capital additions are forecast to be $3.4 million for fiscal 2020 and $2.4 million for fiscal 2021.

2.248.1 Please provide a list of all charging stations built by BC Hydro in BC to date. Please indicate:

2.248.1.1 Please breakdown the construction costs by the portion contributed by third parties, if any, and the portion invested by BC Hydro.

**RESPONSE:**

**Please refer to Attachment 1 to BC Hydro's response to BCUC IR 2.248.1 for the average cost of each station deployed by BC Hydro.**

**The following table provides a summary of expenditures by completed deployment phases:**

| ($ thousand) | Total Construction Cost | BC Hydro Portion | Third-Party Portion |
|---|---|---|---|
| Phase 1 | 3,755(1) | 391 | 3,364 |
| Phase 2 | 4,090 | 2,006 | 2,084 |
| Phase 2 - Kootenays | –(2) | 493 | –(2) |

1. **The Phase 1 total construction costs include the costs for the deployment of the 30 fast charging stations, but exclude capital costs for smart charging demonstration projects.**
2. **Third-party funding for the eight fast charging stations located in the Kootenays was arranged for by the Community Energy Association (CEA). Although project management for the construction of these eight stations was provided by Powertech Labs, BC Hydro is unable to disclose total construction costs incurred by third-parties.**

**248.0 F. CHAPTER 6 – CAPITAL EXPENDITURES**

**Reference: CAPITAL EXPENDITURES**
**Exhibit B-5, BCUC IR 122.1.1, 122.2.1, 122.4.1; BCUC An Inquiry into the Regulation of Electric Vehicle Charging Service, Exhibit C-1-2, pp. 6–7**
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>
> The remaining stations are operated by BC Hydro and will be put into service during the test period. Capital additions are forecast to be $3.4 million for fiscal 2020 and $2.4 million for fiscal 2021.

2.248.1 Please provide a list of all charging stations built by BC Hydro in BC to date. Please indicate:

2.248.1.2 Please explain how the locations of EV charging stations are determined and who determines the locations.

**RESPONSE:**

**The locations of Phase 1 stations were chosen in discussion with the Government of B.C. based on achieving some initial coverage of key corridors from the Lower Mainland to the South Interior and Vancouver Island.**

**For Phase 2 and 3 stations, locations were chosen in consultation with the Government of B.C. based on principles that were encapsulated in their June 12, 2018 study: British Columbia Direct Current Fast Charging Network Study: Core Network for Geographic Connectivity. The document is provided as Attachment 1 to this response.**

**The principles set out in the study are as follows:**

1. **Connecting travel corridors across the province where commuter traffic, cross jurisdictional travel or tourism is supported;**

**2. Ensuring that infrastructure deployment allows for safe and convenient travel in the province while planned at a frequency that allows travel under challenging conditions, such as inclement winter weather, including ensuring that site safety and user experience are safeguarded;**

**3. Supporting regions with dense EV adoption; and**

**4. Maximizing population areas served.**

**Once a general location is selected in accordance with the process set out above, a specific site within a community or along a driving corridor is determined by BC Hydro and is based on an evaluation of various site characteristics including the following:**

- **Complexity of interconnection to our electric system;**
- **Potential site hosts and complexity of land lease agreements;**
- **Distance from commuting corridors;**
- **Proximity to nearby amenities (e.g., restaurants, restrooms, grocers, coffee shops);**
- **Adequate lighting and other factors related to safety; and**
- **Sufficient space for future expansion.**

**For existing station sites, BC Hydro monitors the usage levels at each station to determine if expansion is warranted as a result of station congestion and queuing.**

BRITISH COLUMBIA

# British Columbia Direct Current Fast Charging (DCFC) Network Study: Core Network for Geographic Connectivity

An analysis of DCFC stations required for an initial core network to ensure geographic coverage for electric vehicle drivers across all of B.C.

June 12, 2018

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# British Columbia Direct Current Fast Charging Network Study

## Introduction

Transportation emissions currently account for 39% of greenhouse gas (GHG) emissions in British Columbia (B.C.). The adoption of zero emission vehicles, including plug-in electric vehicles (EV), is ideally suited to reduce transportation GHG emissions in B.C. as well as air pollutants and noise.

B.C. is a leader in Canada in the electrification of transportation including plug-in electric vehicle adoption and the deployment of Direct Current Fast Charging (DCFC) and Level 2 charging infrastructure. DCFC stations allow EV drivers to rapidly recharge their vehicles and will give them the ability and confidence to safely travel between communities. Plug-in EVs using DCFCs typically achieve an 80 per cent charge in only 30 to 60 minutes, compared to the 4 to 8 hours required to charge a vehicle with a Level 2 charging station (240 V).

The Ministry of Energy, Mines and Petroleum Resources and the Ministry of Transportation and Infrastructure have completed a planning exercise to determine the approximate number of DCFCs needed for an initial core network to connect B.C. transportation routes and support plug-in EV adoption and long-distance travel across the entire province. This planning was informed by modelling completed by a contracted consultant using the Electric Vehicle Infrastructure Planning Assistant tool. While the number and densification of DCFC sites will need to grow with higher EV adoption, the initial base number of geographically dispersed DCFC sites expected to provide a core network to support long-distance travel in BC is approximately 200.

This document is intended as a guide for the next phase of geographic expansion of DCFC infrastructure across the province, whether sites are developed by utilities, the private sector, municipalities, or other entities. The province characterizes a DCFC network as a publicly accessible network open to all vehicle makes and appropriate direct current charging standards.

## Purpose

This document is intended to outline the approximate number and location of a core number of DCFC sites required to facilitate safe, convenient EV travel across British Columbia, and general principles for developing these sites. Locations are based on modelled results, are approximate, and are only used to provide a sense of an initial level of connectivity required across the province. Funders, governments, utilities, agencies, businesses and organizations planning to support or install DCFCs are encouraged to review the principles, map and list of suggested locations when considering supporting or installing DCFC infrastructure, to support a vision of a fully connected province for EVs. As the zero-emission vehicle market in B.C. evolves, this analysis will be updated to address evolving technologies and increasing numbers of EVs.

## Charging Types

There are three main levels of charging for EVs, which have different voltages and approximate charging time associated.

Level 1, 120 Volt

- 8 kms of range added per hour on average
- It generally takes 8 to 16 hours to fully charge a vehicle
- Uses a SAE J1772 connector

Level 2, 240 Volt

- 30 kms of range added per hour on average
- It generally takes four to eight hours to fully charge a vehicle
- Uses a SAE J1772 connector

DC fast charging station, typically 480 Volt

- 250 kms of range added per hour on average
- Charging time from a depleted to 80% full battery is approximately 30-60 minutes depending on vehicle battery size
- Uses CHAdeMO, Combined Charging System (CCS), and Supercharger (Tesla) connectors

## Current Status of Fast Charging in B.C.

B.C. has one of the largest DCFC networks in Canada. To date, the Clean Energy Vehicle (CEV) Program under the Ministry of Energy and Mines has supported two phases of DCFC station deployment in British Columbia, with future additional phases under development. DCFC site deployment has largely occurred in partnership with utilities, local, regional and federal governments, industry and electrical utilities.

The first phase of DCFC deployment occurred from 2012-2016, through a partnership between BC Hydro, the Province of British Columbia, Natural Resources Canada, local governments, and academic institutions. Phase 1 of the DCFC Network deployment installed 30 DCFCs along major highway corridors throughout B.C. This network is predominantly based in the Lower Mainland and Southern Vancouver Island region.

In 2015, to inform the Province's second phase of DCFC implementation, a Charging Infrastructure Gap Analysis[1] was undertaken utilizing charging infrastructure funds available under the CEV Program. Included in the results of that analysis was the identification of highest priority gaps in the DCFC network. Based on those priority gaps, phase 2 resulted in the development of a further 33 sites across B.C., extending throughout the Kootenay region and up Vancouver Island, again through the efforts of numerous partners.

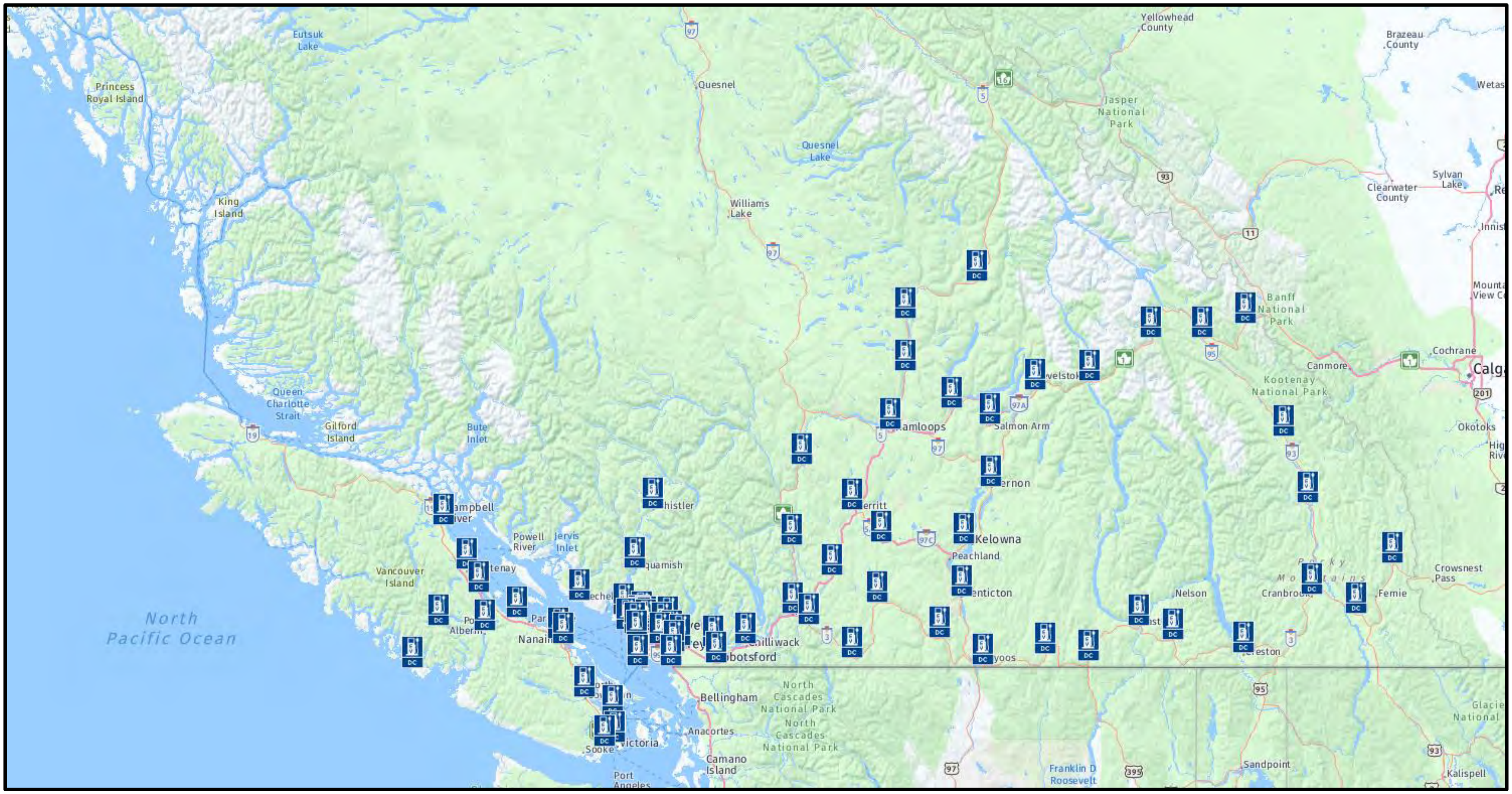
In 2017, the Ministry of Transportation and Infrastructure began planning for deployment of DCFCs in its rest areas along highway routes, including development of an EV Charging in Rest Areas Strategy. The first rest area with charging was commissioned in February 2018, and 7 additional sites are planned for installation in 2018. The Ministry plans to install DCFCs in at least five rest areas per year for the next five years.

There are currently 71 DCFC sites completed or underway. Refer to Plugshare (https://www.plugshare.com) or Chargehub (https://chargehub.com) for the latest information and locations for DCFCs in B.C.

Figure 1 shows the existing and underway DCFC sites throughout B.C.

[1] https://pluginbc.ca/wp/wp-content/uploads/2015/10/BC-DCFC-Gap-Analysis-Report-FBC_Aug-2015.pdf

**Figure 1.** Map of DCFC sites completed or underway in B.C.



## British Columbia Fast Charging Principles

The four principles below guide the planning of new DCFC infrastructure across the province. No principal is mutually exclusive and there is no requirement for all four principles to be met for an installation to occur. However, DCFC planning should aim to maximize the number of principles met.

1. Connect travel corridors across the province, where commuter traffic, cross jurisdictional travel or tourism is supported.

2. Ensure infrastructure deployment allows for safe and convenient travel in the province while planned at a frequency that allows travel under challenging conditions, such as inclement winter weather, including ensuring that site safety and user experience are safeguarded.

3. Support regions with dense EV adoption.

4. Maximize population areas served.

The location selection, site features, and service standards are all important criteria that need to be considered when planning future deployment of DCFC infrastructure. Strategic and well-planned deployment will encourage the continued adoption of EVs and allow for safe EV travel in B.C.

Site development principles that support safe and reliable EV travel throughout the province include:

- Level 2 charging available (co-located or within 100 m of DCFC)
- Dual standard connector options (CHAdeMO and CCS/SAE Combo)
- Accessible for vehicles travelling in both directions
- Accessible year round and 24 hours per day, 7 days per week
- When applicable, near amenities
- Minimum 50 kW power output, or 25 kW where 3 phase power is not available
- Well-lit and safe
- Technology future-proofing, including for future higher-power stations, greater numbers of stations, common standards, payment processes, etc.
- Where possible, for both reliability and anticipated future demand, at least two DCFCs per site

# Modelling Methodology

To determine where additional DCFC sites are notionally required in the province to facilitate safe, convenient EV travel along B.C.'s primary and secondary highways, modelling was completed by a consultant under contract with the Ministry of Energy, Mines and Petroleum Resources, using the EV Infrastructure Planning Assistant Tool. The modelling takes into account many aspects that could impact EV range, including:

- Efficiency of the vehicle
- Weight of the vehicle and contents (passengers)
- The terrain the vehicle is travelling on (particularly elevation gain and loss)
- Speed limits of the roads
- Outside air temperature

The modelling parameters used for this analysis are:

- 30 kWh vehicle
- 3 year old vehicle
- 2 individuals in vehicle
- Temperature of -10°C for Vancouver Island and Lower Mainland and -20°C for the rest of B.C.
- Vehicle fully charged at each charging stop

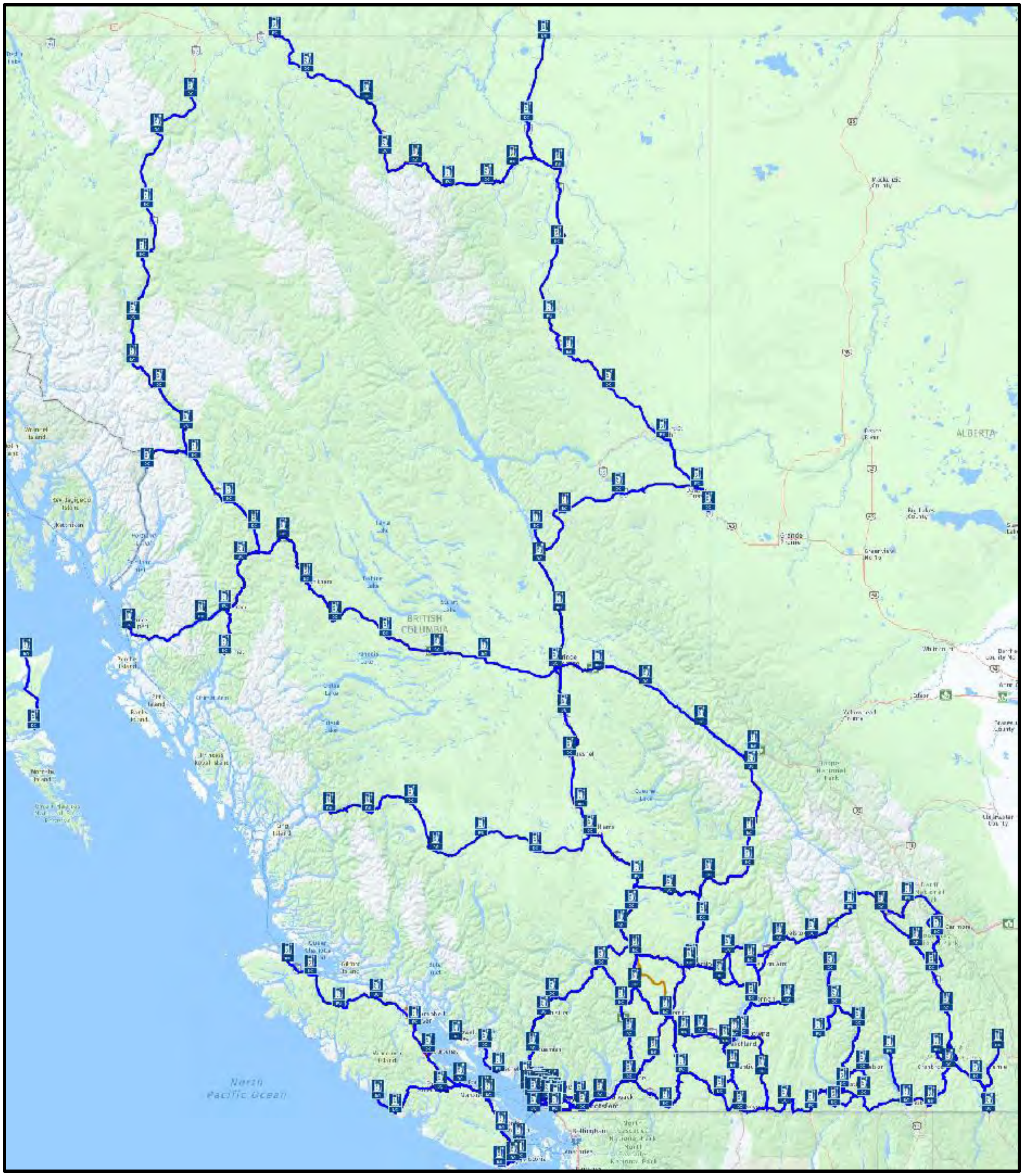
## Modelling Results

Based on this modelling, it is estimated that a total of approximately 200 DCFC sites are required to provide a base-level core network connecting all of B.C.'s primary and secondary highway routes. This constitutes approximately 130 additional locations beyond those already completed or underway to fill out a core network for geographic connectivity. Additional stations will be needed throughout the province for densification in urban and suburban centres, and redundancy along primary and secondary highway routes, in particular to support higher uptake of EVs.

See Figure 2 for a map of approximate locations for a base-level core network to support geographic connectivity. See Appendix A, Table 1 for a list of these locations. **Please note that these locations are provided for illustrative purposes, based on the mapping tool only, and are provided to give a general sense of the number and high-level distribution of DCFC sites across B.C. needed to provide a base level of geographic connectivity for EV drivers. These should not be viewed as specific sites.**

Additional sites beyond those identified in this study, including along B.C. major roads, within urban areas, and where additional density along highway corridors is an identified need, are also required to support greater EV uptake. The exact number of these additional sites and charging stations is beyond the scope of this study, which focuses on a core network to support geographic coverage for EV drivers across B.C.

**Figure 2.** Map of analysis results for core B.C. DCFC network



## Next Steps

This study will be used to inform DCFC funding and planning processes in B.C. As the zero-emission vehicle market in B.C. evolves, this analysis will be updated to address evolving technologies and increasing numbers of EVs.

## Appendix A

**Table 1.** List of additional DCFC locations for initial geographic connectivity (approximate locations only)

| | Highway Route | Approximate Location (for illustrative purposes only) |
|---|---|---|
| 1 | 1 | Lytton |
| 2 | 1 | Cache Creek |
| 3 | 1 | North Kamloops |
| 4 | 2 | Dawson Creek |
| 5 | 2 | Swan Lake |
| 6 | 3 | Osoyoos |
| 7 | 3 | Yahk |
| 8 | 3A | Crawford Bay |
| 9 | 3A | Nelson |
| 10 | 3B | Rossland |
| 11 | 4 | Tofino |
| 12 | 5 | Blue River |
| 13 | 5 | Valemount |
| 14 | 6 | Cherryville |
| 15 | 6 | Fauquier |
| 16 | 6 | Nakusp |
| 17 | 6 | New Denver |
| 18 | 12 | Lillooet |
| 19 | 14 | Sooke |
| 20 | 16 | Mount Robson |
| 21 | 16 | McBride |
| 22 | 16 | Dome/Slim Creek |
| 23 | 16 | Bowron River |
| 24 | 16 | Prince George |
| 25 | 16 | Vanderhoof |
| 26 | 16 | Fraser Lake |
| 27 | 16 | Burns Lake |
| 28 | 16 | Houston |
| 29 | 16 | Smithers |
| 30 | 16 | New Hazelton |
| 31 | 16 | Cedarvale |
| 32 | 16 | Terrace |
| 33 | 16 | Exstew |
| 34 | 16 | Prince Rupert |
| 35 | 16 | Massett |

| | | |
|---|---|---|
| 36 | 16 | Skidegate |
| 37 | 17 | Tsawwassen |
| 38 | 19 | Sayward |
| 39 | 19 | Woss |
| 40 | 19 | Port McNeil |
| 41 | 19 | Port Hardy |
| 42 | 20 | Hanceville |
| 43 | 20 | Chilanko Forks |
| 44 | 20 | Kleena Kleene |
| 45 | 20 | Anahim Lake |
| 46 | 20 | Atnarko River |
| 47 | 20 | Bella Coola |
| 48 | 23 | Galena Bay |
| 49 | 24 | Bridge Lake |
| 50 | 33 | Beaverdell |
| 51 | 37 | Kitimat |
| 52 | 37 | Kitwancool Lake |
| 53 | 37 | Nisga'a Hwy |
| 54 | 37 | Nass |
| 55 | 37 | Bell 1 |
| 56 | 37 | Mehan Lake |
| 57 | 37 | Bob Quinn Lake |
| 58 | 37 | Eastman Creek |
| 59 | 37 | Morchuea Lake |
| 60 | 37 | Dease Lake DCFC |
| 61 | 37 | Cottonwood South |
| 62 | 37 | Beaverdam |
| 63 | 37A | Stewart |
| 64 | 39 | Mackenzie |
| 65 | 77 | Fort Nelson River |
| 66 | 77 | Soma Rd |
| 67 | 93 | Hwy 93 Border Crossing |
| 68 | 93 | Vermilion Crossing |
| 69 | 95 | Spillimacheen |
| 70 | 95 | Kimberley |
| 71 | 97 | Monte Lake |
| 72 | 97 | Clinton |
| 73 | 97 | 70 Mile House |
| 74 | 97 | 100 Mile House |
| 75 | 97 | Williams Lake |
| 76 | 97 | McLeese Lake |
| 77 | 97 | Quesnel |

| | | |
|---|---|---|
| 78 | 97 | Hixon |
| 79 | 97 | Bear Lake |
| 80 | 97 | McLeod Lake |
| 81 | 97 | West Pine River |
| 82 | 97 | Chetwynd |
| 83 | 97 | Fort St John |
| 84 | 97 | Wonowon |
| 85 | 97 | Pink Mountain |
| 86 | 97 | Buckinghorse River |
| 87 | 97 | Prophet River |
| 88 | 97 | Fort Nelson |
| 89 | 97 | Muskwa River |
| 90 | 97 | Tetsa River |
| 91 | 97 | Summit Lake |
| 92 | 97 | Toad River |
| 93 | 97 | Muncho Lake |
| 94 | 97 | Liard Hotsprings |
| 95 | 97 | Liard River |
| 96 | 97 | Yukon Border |
| 97 | 97C | Peachland |
| 98 | 97C | Kelowna |
| 99 | 97C | Sunset Main (Douglas Lake) |
| 100 | 99 | Pemberton |
| 101 | 101 | Earls Cove |
| 102 | 101 | Powell River |

**248.0 F. CHAPTER 6 – CAPITAL EXPENDITURES**

**Reference: CAPITAL EXPENDITURES**
**Exhibit B-5, BCUC IR 122.1.1, 122.2.1, 122.4.1; BCUC An Inquiry into the Regulation of Electric Vehicle Charging Service, Exhibit C-1-2, pp. 6–7**
**Electric vehicle charging stations**

In the BCUC An Inquiry into the Regulation of Electric Vehicle Charging Service, BC Hydro states:

> The first phase of the DCFC infrastructure build out in B.C. (Phase 1 deployment) began in 2012. With funding from both the Federal and Provincial Governments, BC Hydro initiated the 'Electric Vehicle Smart Infrastructure Project,' which included the deployment of 30 DCFC stations on a pilot basis. BC Hydro owns each of these 30 stations and leases them for a nominal amount to the respective station host/operator.
>
> During 2016, BC Hydro received funding approvals from both Natural Resources Canada and the Provincial Government to support the installation of an additional 21 DCFC stations (Phase II deployment) … The second phase of DCFC deployment is scheduled to be complete by May 31, 2018.

2.248.2 Please confirm, or explain otherwise, that BC Hydro has completed its Phase 2 Deployment of EV charging stations.

**RESPONSE:**

**Confirmed.**

**248.0 F. CHAPTER 6 – CAPITAL EXPENDITURES**

**Reference: CAPITAL EXPENDITURES**
**Exhibit B-5, BCUC IR 122.1.1, 122.2.1, 122.4.1; BCUC An Inquiry into the Regulation of Electric Vehicle Charging Service, Exhibit C-1-2, pp. 6–7**
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>
> During 2016, BC Hydro received funding approvals from both Natural Resources Canada and the Provincial Government to support the installation of an additional 21 DCFC stations (Phase II deployment) … The second phase of DCFC deployment is scheduled to be complete by May 31, 2018.

2.248.3 Please generally discuss BC Hydro’s long-term rollout plan for the construction/deployment of EV charging stations and explain what phase BC Hydro is currently conducting.

**RESPONSE:**

**BC Hydro is currently in Phase 3 of EV fast charging station deployment, and subject to executing a contribution agreement with NRCan and BC Hydro’s internal approval, intends to commence deployment of Phase 4 during the test period. Please refer to BC Hydro’s response to BCUC IR 2.248.4 where BC Hydro provides further information on the Phase 3 and Phase 4 deployment.**

**BC Hydro is in the process of developing our plans for potential deployment beyond Phase 4.**

**248.0 F. CHAPTER 6 – CAPITAL EXPENDITURES**

**Reference: CAPITAL EXPENDITURES**
**Exhibit B-5, BCUC IR 122.1.1, 122.2.1, 122.4.1; BCUC An Inquiry into the Regulation of Electric Vehicle Charging Service, Exhibit C-1-2, pp. 6–7**
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>
> During 2016, BC Hydro received funding approvals from both Natural Resources Canada and the Provincial Government to support the installation of an additional 21 DCFC stations (Phase II deployment) … The second phase of DCFC deployment is scheduled to be complete by May 31, 2018.

2.248.4 Please provide a plan or overview of BC Hydro planned investment in EV charging stations in the Test Period. Please indicate the locations of planned investments, whether the station is DCFC, the construction cost and the expected in-service date of each station. Please breakdown the construction costs by the portion contributed by third parties, if any, and the portion of capital costs invested by BC Hydro.

**RESPONSE:**

**During the test period, BC Hydro will be deploying 23 EV fast charging stations under the Phase 3 deployment. Details regarding these stations are provided in the Attachment 1 to BC Hydro's response to BCUC IR 2.248.1.**

**The current total cost estimate for the 23 fast charging stations under the Phase 3 deployment is $4.40 million with $1.725 million contributed by third parties and $2.675 million invested by BC Hydro.**

**In addition to the Phase 3 fast charging station deployment, BC Hydro is in the planning phase for the Phase 4 deployment. BC Hydro's application to NRCan was**

**successful; however, whether Phase 4 deployment will proceed is still subject to the execution of a contribution agreement with NRCan and BC Hydro's internal approval. The capital expenditures for Phase 4 are not included in the planned capital expenditures during the test period submitted as part of the Application.**

**BC Hydro will manage any additional capital expenditures related to EV fast charging beyond those in the Application within the Distribution Sustain – System Expansion and Improvement capital budget.**

**248.0 F. CHAPTER 6 – CAPITAL EXPENDITURES**

**Reference: CAPITAL EXPENDITURES**
**Exhibit B-5, BCUC IR 122.1.1, 122.2.1, 122.4.1; BCUC An Inquiry into the Regulation of Electric Vehicle Charging Service, Exhibit C-1-2, pp. 6–7**
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> During 2016, BC Hydro received funding approvals from both Natural Resources Canada and the Provincial Government to support the installation of an additional 21 DCFC stations (Phase II deployment) … The second phase of DCFC deployment is scheduled to be complete by May 31, 2018.

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2.248.4.1 Please indicate who determines the locations of the EV charging stations planned for the Test Period and how those locations are determined.

**RESPONSE:**

**Please refer to BC Hydro's response to BCUC IR 2.248.1.2 for a discussion on the process of determining locations.**

**248.0 F. CHAPTER 6 – CAPITAL EXPENDITURES**

**Reference: CAPITAL EXPENDITURES**
**Exhibit B-5, BCUC IR 122.1.1, 122.2.1, 122.4.1; BCUC An Inquiry into the Regulation of Electric Vehicle Charging Service, Exhibit C-1-2, pp. 6–7**
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> During 2016, BC Hydro received funding approvals from both Natural Resources Canada and the Provincial Government to support the installation of an additional 21 DCFC stations (Phase II deployment) … The second phase of DCFC deployment is scheduled to be complete by May 31, 2018.

2.248.4 Please provide a plan or overview of BC Hydro planned investment in EV charging stations in the Test Period. Please indicate the locations of planned investments, whether the station is DCFC, the construction cost and the expected in-service date of each station. Please breakdown the construction costs by the portion contributed by third parties, if any, and the portion of capital costs invested by BC Hydro.

2.248.4.2 Please discuss if the funding from the Federal and Provincial Governments are contingent on certain criteria being met. If so, please elaborate.

**RESPONSE:**

**Funding from the federal and provincial governments is contingent upon BC Hydro's successful response to the Request for Proposal (RFP) from the respective governmental agencies. The RFP response details the plans for deploying EV fast charging stations, including the number of EV fast charging stations to be deployed, locations, estimated project costs and the project completion dates.**

**Government funding is also contingent on the following:**

- **Execution of a funding agreement with the respective government agencies (e.g., contract with NRCan);**
- **Deployment of minimum 50 kW EV fast charging stations (with both CHAdeMO and CCS connectors);**
- **Capability of the stations to transmit and receive information in digital form;**
- **A station lease/license in place for a minimum 10 years;**
- **Attainment of specified in-service dates;**
- **Quarterly reporting during the deployment phase; and**
- **Funding from government agencies not exceeding 75 per cent of project capital costs.**

**248.0 F. CHAPTER 6 – CAPITAL EXPENDITURES**

**Reference: CAPITAL EXPENDITURES**
**Exhibit B-5, BCUC IR 122.1.1, 122.2.1, 122.4.1; BCUC An Inquiry into the Regulation of Electric Vehicle Charging Service, Exhibit C-1-2, pp. 6–7**
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> During 2016, BC Hydro received funding approvals from both Natural Resources Canada and the Provincial Government to support the installation of an additional 21 DCFC stations (Phase II deployment) … The second phase of DCFC deployment is scheduled to be complete by May 31, 2018.

2.248.4 Please provide a plan or overview of BC Hydro planned investment in EV charging stations in the Test Period. Please indicate the locations of planned investments, whether the station is DCFC, the construction cost and the expected in-service date of each station. Please breakdown the construction costs by the portion contributed by third parties, if any, and the portion of capital costs invested by BC Hydro.

2.248.4.3 Please confirm, or explain otherwise, that BC Hydro will own and operate the EV charging stations planned to be constructed during the Test Period.

**RESPONSE:**

**Confirmed. BC Hydro currently plans to own and operate the EV charging stations planned to be constructed during the test period.**

**248.0 F. CHAPTER 6 – CAPITAL EXPENDITURES**

**Reference: CAPITAL EXPENDITURES**
**Exhibit B-5, BCUC IR 122.1.1, 122.2.1, 122.4.1; BCUC An Inquiry into the Regulation of Electric Vehicle Charging Service, Exhibit C-1-2, pp. 6–7**
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>
> During 2016, BC Hydro received funding approvals from both Natural Resources Canada and the Provincial Government to support the installation of an additional 21 DCFC stations (Phase II deployment) … The second phase of DCFC deployment is scheduled to be complete by May 31, 2018.

2.248.4.3 Please confirm, or explain otherwise, that BC Hydro will own and operate the EV charging stations planned to be constructed during the Test Period.

2.248.4.3.1 If confirmed, please discuss what impact does this business model have on BC Hydro's revenue requirement compared to leasing the stations to a host/operator.

**RESPONSE:**

**The key difference between the business model where BC Hydro owns and operates the EV charging station and the business model where BC Hydro leases the stations to a third party (e.g., municipalities) is that under the leasing model, the third party pays for the station electricity consumption under the applicable general service rate. Under the BC Hydro own-operate model, BC Hydro will not collect revenue from EV charging stations until an approved EV charging rate is in place.**

**BC Hydro currently collects an average of approximately $600 per month per station for energy consumption from site hosts leasing the stations. BC Hydro will begin to collect amounts from end users charging at BC Hydro operated stations once an EV rate is approved by the BCUC.**

**248.0 F. CHAPTER 6 – CAPITAL EXPENDITURES**

**Reference: CAPITAL EXPENDITURES**
**Exhibit B-5, BCUC IR 122.1.1, 122.2.1, 122.4.1; BCUC An Inquiry into the Regulation of Electric Vehicle Charging Service, Exhibit C-1-2, pp. 6–7**
**Electric vehicle charging stations**

In its response to BCUC IR 122.4.1, BC Hydro stated:

> These planned capital expenditures include all EV fast charging station equipment…, civil and electrical work, charger installation, and paving if required. No historical land purchase or lease costs are included to date as BC Hydro has secured 10 year land leases/licenses at no cost, except for two sites where land licenses were secured at a nominal cost.

2.248.5 Please explain whether these capital expenditures include signage, right of ways and/or other facilities.

**RESPONSE:**

**Capital expenditures included in the Application for EV fast charging include costs associated with signage and lighting. BC Hydro does not incur costs for right-of-ways or other facilities.**

**248.0 F. CHAPTER 6 – CAPITAL EXPENDITURES**

**Reference: CAPITAL EXPENDITURES**
**Exhibit B-5, BCUC IR 122.1.1, 122.2.1, 122.4.1; BCUC An Inquiry into the Regulation of Electric Vehicle Charging Service, Exhibit C-1-2, pp. 6–7**
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2.248.6 Please explain whether BC Hydro intends to provide other ancillary services at remote charging sites, such as convenience stores or washroom facilities.

**RESPONSE:**

**BC Hydro does not plan to provide ancillary services at EV fast charging stations.**

**As indicated in BC Hydro's response to BCUC IR 2.248.1.2, BC Hydro's site selection criteria considers existing amenities in the surrounding area. All else being equal, sites with greater access to amenities would be favoured.**

**248.0 F. CHAPTER 6 – CAPITAL EXPENDITURES**

**Reference: CAPITAL EXPENDITURES**
**Exhibit B-5, BCUC IR 122.1.1, 122.2.1, 122.4.1; BCUC An Inquiry into the Regulation of Electric Vehicle Charging Service, Exhibit C-1-2, pp. 6–7**
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> These planned capital expenditures include all EV fast charging station equipment…, civil and electrical work, charger installation, and paving if required. No historical land purchase or lease costs are included to date as BC Hydro has secured 10 year land leases/licenses at no cost, except for two sites where land licenses were secured at a nominal cost.

2.248.6 Please explain whether BC Hydro intends to provide other ancillary services at remote charging sites, such as convenience stores or washroom facilities.

2.248.6.1 If so, please explain who will own and operate these ancillary services and whether the construction of these facilities will be paid for by BC Hydro.

**RESPONSE:**

**Please refer to BC Hydro's response to BCUC IR 2.248.6 where we state that BC Hydro does not plan to provide ancillary services at EV fast charging stations.**

**249.0 F. CHAPTER 6 – CAPITAL EXPENDITURES**

**Reference: CAPITAL EXPENDITURES**
**Exhibit B-1, Section 6.4.14.2; Exhibit B-5, BCUC IR 117.2**
**DVES: Downtown Vancouver West End Substation**

In response to BCUC IR 117.2, BC Hydro stated that it plans to file a CPCN for the West End Substation Construction Project in F2023.

In Table 6-25 of the Application, BC Hydro lists the DVES: West End Strategic Property Purchase as a Capital Addition in F2020.

2.249.1 Please discuss how the property purchase in F2020, which is three years prior to an anticipated CPCN filing in F2023, would impact any future decisions for BC Hydro's business case or alternatives for this project.

**RESPONSE:**

**Please refer to BC Hydro's response to BCUC IRs 1.117.1 and 1.117.1.1 where we describe how BC Hydro selected the site for the new substation.**

**The property purchase in fiscal 2020, prior to the CPCN filing, does not impact any future decisions with regards to BC Hydro's business case for proceeding with the project. Rather, securing property rights for the West End Substation has provided cost and schedule certainty for one of the major components of the overall project.**

**249.0 F. CHAPTER 6 – CAPITAL EXPENDITURES**

**Reference: CAPITAL EXPENDITURES**
**Exhibit B-1, Section 6.4.14.2; Exhibit B-5, BCUC IR 117.2**
**DVES: Downtown Vancouver West End Substation**

In response to BCUC IR 117.2, BC Hydro stated that it plans to file a CPCN for the West End Substation Construction Project in F2023.

In Table 6-25 of the Application, BC Hydro lists the DVES: West End Strategic Property Purchase as a Capital Addition in F2020.

2.249.2 Please explain why this property purchase is listed as a Capital Addition in F2020, when the anticipated CPCN is not expected until F2023.

**RESPONSE:**

**The subsurface land and rights-of-way are listed as a capital addition because BC Hydro has acquired an item of property, plant and equipment and intangible assets that meet the IAS 16, Property, Plant and Equipment and IAS 38, Intangible Assets recognition criteria that there are probable future economic benefits from the item.**

**While the subsurface land and rights-of-way are intended to be used in the development of a substation, the substation development project has not commenced. Therefore, the subsurface land and rights-of-way are not part of a construction project and are not classified as unfinished construction.**

**249.0 F. CHAPTER 6 – CAPITAL EXPENDITURES**

**Reference: CAPITAL EXPENDITURES**
**Exhibit B-1, Section 6.4.14.2; Exhibit B-5, BCUC IR 117.2**
**DVES: Downtown Vancouver West End Substation**

In response to BCUC IR 117.2, BC Hydro stated that it plans to file a CPCN for the West End Substation Construction Project in F2023.

In Table 6-25 of the Application, BC Hydro lists the DVES: West End Strategic Property Purchase as a Capital Addition in F2020.

2.249.2 Please explain why this property purchase is listed as a Capital Addition in F2020, when the anticipated CPCN is not expected until F2023.

2.249.2.1 Please explain whether this asset is considered “used and useful” to ratepayers in the period F2020–F2023.

**RESPONSE:**

**As discussed in BC Hydro’s response to BCUC IR 2.249.2, BC Hydro will recognize the property purchase and rights-of-way as assets held for future development in the period between fiscal 2020 to fiscal 2023 because BC Hydro has acquired an item of property, plant and equipment and intangible assets that meet the IAS 16, Property, Plant and Equipment and IAS 38, Intangible Assets recognition criteria that there are probable future economic benefits from the item.**

**While both items will be recorded as assets held for future development, these assets do not amortize as they are generally considered to have indefinite useful lives. Therefore, no amortization related to these planned assets is included in the Application.**

**249.0 F. CHAPTER 6 – CAPITAL EXPENDITURES**

**Reference: CAPITAL EXPENDITURES**
**Exhibit B-1, Section 6.4.14.2; Exhibit B-5, BCUC IR 117.2**
**DVES: Downtown Vancouver West End Substation**

In response to BCUC IR 117.2, BC Hydro stated that it plans to file a CPCN for the West End Substation Construction Project in F2023.

In Table 6-25 of the Application, BC Hydro lists the DVES: West End Strategic Property Purchase as a Capital Addition in F2020.

2.249.2 Please explain why this property purchase is listed as a Capital Addition in F2020, when the anticipated CPCN is not expected until F2023.

2.249.2.2 Please explain how the cost of this asset will be accrued.

**RESPONSE:**

**The costs of the subsurface land and rights-of-way are recorded or accrued as capital expenditures when legal titles are transferred to BC Hydro and will be recognized as assets held for future development in fiscal 2020.**

**249.0 F. CHAPTER 6 – CAPITAL EXPENDITURES**

**Reference: CAPITAL EXPENDITURES**
**Exhibit B-1, Section 6.4.14.2; Exhibit B-5, BCUC IR 117.2**
**DVES: Downtown Vancouver West End Substation**

In response to BCUC IR 117.2, BC Hydro stated that it plans to file a CPCN for the West End Substation Construction Project in F2023.

In Table 6-25 of the Application, BC Hydro lists the DVES: West End Strategic Property Purchase as a Capital Addition in F2020.

2.249.2 Please explain why this property purchase is listed as a Capital Addition in F2020, when the anticipated CPCN is not expected until F2023.

2.249.2.3 Please explain if, and how, the financing costs related to this asset will be accrued.

**RESPONSE:**

**The carrying costs of subsurface land and rights-of-way are expensed until the substation construction project commences. Once in construction, the carrying costs will be charged to the substation project (i.e., capitalized) until it is placed in-service. When the substation project is placed in-service, depreciation or amortization of the constructed assets will commence based on their expected useful lives.**

**249.0 F. CHAPTER 6 – CAPITAL EXPENDITURES**

**Reference: CAPITAL EXPENDITURES**
**Exhibit B-1, Section 6.4.14.2; Exhibit B-5, BCUC IR 117.2**
**DVES: Downtown Vancouver West End Substation**

In response to BCUC IR 117.2, BC Hydro stated that it plans to file a CPCN for the West End Substation Construction Project in F2023.

In Table 6-25 of the Application, BC Hydro lists the DVES: West End Strategic Property Purchase as a Capital Addition in F2020.

2.249.2 Please explain why this property purchase is listed as a Capital Addition in F2020, when the anticipated CPCN is not expected until F2023.

2.249.2.4 Please confirm, or explain otherwise, that the cost of this asset will be included as part of the future CPCN application. If yes, please discuss what asset value will be included in that CPCN. For example, the net land purchase costs in F2020? Or net land purchase costs in F2020 plus increase in land value from F2020 to the filing date of the CPCN? Other?

**RESPONSE:**

**Confirmed, the subsurface land and rights-of-way costs will be included in the future CPCN application for the substation project. In accordance with International Financial Reporting Standards (IFRS), the carrying value of the assets are not adjusted for changes in market value and the costs will be included at their purchased costs.**

**249.0 F. CHAPTER 6 – CAPITAL EXPENDITURES**

**Reference: CAPITAL EXPENDITURES**
**Exhibit B-1, Section 6.4.14.2; Exhibit B-5, BCUC IR 117.2**
**DVES: Downtown Vancouver West End Substation**

In response to BCUC IR 117.2, BC Hydro stated that it plans to file a CPCN for the West End Substation Construction Project in F2023.

In Table 6-25 of the Application, BC Hydro lists the DVES: West End Strategic Property Purchase as a Capital Addition in F2020.

2.249.3 Please explain where land purchases are accounted for and whether land purchases are included in BC Hydro's rate base. As part of the discussion, please also discuss how land and property purchased for future construction are accounted for.

**RESPONSE:**

**BC Hydro follows International Financial Reporting Standards (IFRS) in accounting for land purchases. The land purchase is recorded as a tangible asset, however it is not amortized for accounting purposes and therefore no amortization for land acquisitions are included in the Application.**

**Land is included in BC Hydro's rate base except for land under development which is included in unfinished construction.**

**As discussed in BC Hydro's response to BCUC IR 2.249.2, subsurface land and rights-of-way are listed as a capital addition prior to the land or property being used as part of a development project. Once the development project commences, the assets are transferred to unfinished construction until the development project is in-service.**

**249.0 F. CHAPTER 6 – CAPITAL EXPENDITURES**

**Reference: CAPITAL EXPENDITURES**
**Exhibit B-1, Section 6.4.14.2; Exhibit B-5, BCUC IR 117.2**
**DVES: Downtown Vancouver West End Substation**

In response to BCUC IR 117.2, BC Hydro stated that it plans to file a CPCN for the West End Substation Construction Project in F2023.

In Table 6-25 of the Application, BC Hydro lists the DVES: West End Strategic Property Purchase as a Capital Addition in F2020.

2.249.3.1 Please explain whether any change in land value between F2020 and the date of completion of the Downtown Vancouver West End Substation will be accounted for.

**RESPONSE:**

**As discussed in BC Hydro's response to BCUC IR 2.249.2.4, in accordance with International Financial Reporting Standards (IFRS), the carrying value of the asset is not adjusted for changes in market value.**

**249.0 F. CHAPTER 6 – CAPITAL EXPENDITURES**

**Reference: CAPITAL EXPENDITURES**
**Exhibit B-1, Section 6.4.14.2; Exhibit B-5, BCUC IR 117.2**
**DVES: Downtown Vancouver West End Substation**

In response to BCUC IR 117.2, BC Hydro stated that it plans to file a CPCN for the West End Substation Construction Project in F2023.

In Table 6-25 of the Application, BC Hydro lists the DVES: West End Strategic Property Purchase as a Capital Addition in F2020.

2.249.4 Please explain how future land sales following de-commissioning of the old downtown Vancouver Dal Grauer substation site will be accounted for after the new Downtown Vancouver West End Substation is operational.

**RESPONSE:**

**If the Dal-Grauer Substation land is sold in the future, the gain or loss would be recorded as a gain or loss from disposal of Property, Plant and Equipment under International Financial Reporting Standards (IFRS), and would be recognized in the period in which the gain or loss occurred.**

**249.0 F. CHAPTER 6 – CAPITAL EXPENDITURES**

**Reference: CAPITAL EXPENDITURES**
**Exhibit B-1, Section 6.4.14.2; Exhibit B-5, BCUC IR 117.2**
**DVES: Downtown Vancouver West End Substation**

In response to BCUC IR 117.2, BC Hydro stated that it plans to file a CPCN for the West End Substation Construction Project in F2023.

In Table 6-25 of the Application, BC Hydro lists the DVES: West End Strategic Property Purchase as a Capital Addition in F2020.

2.249.4.1 Please explain whether gains or losses on future land sales following de-commissioning of the old downtown Vancouver Dal Grauer substation site will be accounted for and how this would impact future revenue requirements.

**RESPONSE:**

**As stated in BC Hydro's response to BCUC IR 2.249.4, if the Dal Grauer Substation land is sold in the future, the gain or loss would be recorded as a gain or loss from disposal of Property, Plant and Equipment under International Financial Reporting Standards (IFRS), and would be recognized in the period in which the gain or loss occurred.**

**By Order No. G-48-14, the Real Property Sales Regulatory Account was established to defer the variances between BC Hydro's actual and forecast real property gain or loss from real estate sales. Accordingly, the gain or loss from a potential sale of the Dal Grauer Substation land would be recorded in the Real Property Sales Regulatory Account.**

**Please refer to BC Hydro's response to BCUC IR 1.151.5 where we explain that BC Hydro expects that the Real Property Sales Regulatory Account may be closed once the balance in the account reaches zero. If the land were sold after this regulatory account is closed, then the gain or loss would be to the account of the shareholder.**

**Please refer to section 7.8.7 of Chapter 7 of the Fiscal 2020 to Fiscal 2021 Revenue Requirements Application for more information on the Real Property Sales Regulatory Account.**

**250.0 F. CHAPTER 6 – CAPITAL EXPENDITURES**

**Reference: CAPITAL EXPENDITURES**
**Exhibit B-6, Ince IR 6.15, Attachment 1, pp. 11–12;**
**BC Hydro Application for a CPCN for the Dawson Creek/Chetwynd Area Transmission Project, Order G-144-12 with Reasons for Decision dated October 12, 2012, pp. 12–13**
**Peace Region Electric Supply (PRES) Project**

On October 10, 2012, the BCUC approved a CPCN for the Dawson Creek/Chetwynd Area Transmission Project (DCAT) by Order G-144-12.

2.250.1 Please explain how the need for the DCAT project differs from the need for the PRES project.

**RESPONSE:**

**Both the Peace Region Electric Supply Project (PRES) project and the Dawson Creek/Chetwynd Area Transmission Project (DCAT) help to address load growth in the Peace region.**

**The purpose of the PRES project is to reduce GHG emissions in B.C. by enabling the electrification of natural gas production, processing and compression. The purpose of the DCAT project was to increase the supply capacity for existing customers. DCAT also resulted in a reduction to GHG emissions in B.C. by electrifying additional industrial loads, rather than burning fossil fuels.**

**The DCAT Project increased the supply capacity under system normal conditions to about 400 MW and resolved existing 138 kV transmission system constraints. However, by 2021, the forecast load demand is expected to exceed the 400 MW, primarily due to natural gas production. At this point, no further load can be connected in the area without further system reinforcement by the PRES project.**

**250.0 F. CHAPTER 6 – CAPITAL EXPENDITURES**

**Reference: CAPITAL EXPENDITURES**
**Exhibit B-6, Ince IR 6.15, Attachment 1, pp. 11–12;**
**BC Hydro Application for a CPCN for the Dawson Creek/Chetwynd Area Transmission Project, Order G-144-12 with Reasons for Decision dated October 12, 2012, pp. 12–13**
**Peace Region Electric Supply (PRES) Project**

On October 10, 2012, the BCUC approved a CPCN for the Dawson Creek/Chetwynd Area Transmission Project (DCAT) by Order G-144-12.

2.250.1 Please explain how the need for the DCAT project differs from the need for the PRES project.

2.250.1.1 Please identify and discuss any significant similarities and differences in these projects which may support the PRES project to be a prescribed undertaking, as proposed by BC Hydro.

**RESPONSE:**

**The DCAT project was approved prior to OIC 101, which amended the Greenhouse Gas Reduction (Clean Energy) Regulation criteria for projects that qualify as a Prescribed Undertaking.**

**The PRES project satisfies the amended criteria for a project to be a Prescribed Undertaking as described in BC Hydro's response to BCUC IR 1.119.2.**

**250.0 F. CHAPTER 6 – CAPITAL EXPENDITURES**

**Reference: CAPITAL EXPENDITURES**
**Exhibit B-6, Ince IR 6.15, Attachment 1, pp. 11–12;**
**BC Hydro Application for a CPCN for the Dawson Creek/Chetwynd Area Transmission Project, Order G-144-12 with Reasons for Decision dated October 12, 2012, pp. 12–13**
**Peace Region Electric Supply (PRES) Project**

On October 10, 2012, the BCUC approved a CPCN for the Dawson Creek/Chetwynd Area Transmission Project (DCAT) by Order G-144-12.

2.250.2 Please explain how lessons learned from the DCAT project have been applied to the planning and/or will be applied to the execution of the PRES project.

**RESPONSE:**

**The table below shows how the key lessons learned on the DCAT project, which are applicable to the PRES project, have been applied.**

| DCAT | PRES |
|---|---|
| **First Nations: Project teams should ensure there is sufficient time to consult and plan for potential delays in the process.**<br>**When BC Hydro funds and agrees to receipt dates for reports from First Nations, where possible, project teams should actively manage these dates with First Nations to ensure adequate review time.** | **The PRES project initiated consultation in 2013 and started construction in 2018.**<br>**The PRES project has supported the identified First Nations in conducting Traditional Land Use Studies and other community impact studies. The PRES project provided receipt dates in funding agreements for these studies tied to the project schedule.**<br>**The PRES project is also funding a dedicated Liaison Officer position as a salaried employee with six First Nations to coordinate and support activities contemplated in funding agreements and to facilitate an effective working relationship. Project funding related to the Liaison Officer position has been offered for up to three years.** |

| DCAT | PRES |
|---|---|
| **Construction and Contract Management: It was recommended that the construction management planning on future large line projects assumes a seven day a week construction schedule, incorporates fatigue management principles, and reviews the construction management plan with team members from previous line projects. A conservative approach to estimating resources was also recommended.** | **The construction management plan for the PRES project was developed with input from team members from previous transmission line projects. It assumed construction would generally be active seven days per week and included fatigue management principles. The plan has been aligned with the transmission line contractor's schedule, including the number of staff on the construction management team. The plan will be updated as the work progresses, as appropriate.** |
| **Procurement: To mitigate the risk of material quality issues on future projects, it was recommended that all production at offshore manufacturing plants be inspected by a BC Hydro representative regardless of whether the supplier had previously provided materials with no quality issues.**<br>**For projects relying on a steady supply of materials to facilitate construction, it was recommended that BC Hydro include specific interim delivery milestones, with consideration of associated liquidated damages to incentivize timely delivery of materials, and to minimize the impact of material delivery on construction costs and schedule.**<br>**The transmission line construction contractor's bid schedule lacked sufficient detail to track progress and the schedule had logic flaws. This impacted BC Hydro's ability to assess the delays and impacts claimed. It was recommended that a more detailed schedule should be specified in the bid process and the submittal of a suitably detailed schedule early after contract award should be required.** | **BC Hydro has taken a risk-based approach to mitigate quality issues with equipment and materials for the PRES project from both onshore and offshore manufacturing plants. BC Hydro has conducted, or plans to conduct, inspections at vendor facilities for all material and equipment that it is procuring for the PRES project. For all higher-risk items, or if inspections have not been done recently for other non-PRES supply, BC Hydro has done new inspections. For lower risk items that are routinely and often supplied by the vendor, BC Hydro has relied on the plant audits and inspections it has already done instead of doing new inspections specifically for the PRES project.**<br>**Interim milestones have been included in some of the contracts for supply of larger equipment and materials such as transformers and steel structures. Delivery dates for all material and equipment have been set with consideration of the milestones in the transmission line construction contract and include some schedule contingency to manage the risk of delayed delivery.**<br>**BC Hydro requested transmission line proponents to submit detailed schedules as part of the proposal package. BC Hydro undertook a review of the schedule logic and productivity assumptions. A detailed schedule was attached to the signed contract.** |

| DCAT | PRES |
|---|---|
| **Estimating: Internal estimating was required to assist the engineering service providers in achieving a more realistic cost estimate.** | **BC Hydro prepared the cost estimate for the project and it was reviewed through a multi-disciplinary review process.** |

**250.0 F. CHAPTER 6 – CAPITAL EXPENDITURES**

**Reference: CAPITAL EXPENDITURES**
**Exhibit B-6, Ince IR 6.15, Attachment 1, pp. 11–12;**
**BC Hydro Application for a CPCN for the Dawson Creek/Chetwynd Area Transmission Project, Order G-144-12 with Reasons for Decision dated October 12, 2012, pp. 12–13**
**Peace Region Electric Supply (PRES) Project**

On October 10, 2012, the BCUC approved a CPCN for the Dawson Creek/Chetwynd Area Transmission Project (DCAT) by Order G-144-12.

2.250.3 Please explain any future anticipated or expected transmission upgrade or extension projects in the Peace Region.

**RESPONSE:**

**In addition to the projects included in the Fiscal 2020 to Fiscal 2024 Capital Plan, BC Hydro expects there will be two other projects related to transmission system upgrades for the Liquefied Natural Gas and Oil and Gas sectors in the Peace region:**

1. **Bear Mountain Terminal (BMT) To Dawson Creek (DAW) Transmission Voltage Conversion (IPID 901573); and**
2. **North Montney – Transmission Development (IPID 901572).**

**Please refer to BC Hydro’s response to BCUC IR 2.254.2 for additional information on these ex-plan projects.**

**BC Hydro has not identified a need for any other transmission upgrade or extension projects in the Peace Region at this time.**

**250.0 F. CHAPTER 6 – CAPITAL EXPENDITURES**

**Reference: CAPITAL EXPENDITURES**
**Exhibit B-6, Ince IR 6.15, Attachment 1, pp. 11–12;**
**BC Hydro Application for a CPCN for the Dawson Creek/Chetwynd Area Transmission Project, Order G-144-12 with Reasons for Decision dated October 12, 2012, pp. 12–13**
**Peace Region Electric Supply (PRES) Project**

On October 10, 2012, the BCUC approved a CPCN for the Dawson Creek/Chetwynd Area Transmission Project (DCAT) by Order G-144-12.

2.250.3 Please explain any future anticipated or expected transmission upgrade or extension projects in the Peace Region.

2.250.3.1 Please explain whether BC Hydro anticipates filing a CPCN or capital expenditure schedule with the BCUC for any of these future projects.

**RESPONSE:**

**Based on current plans, BC Hydro expects to file CPCNs for the Bear Mountain Terminal (BMT) To Dawson Creek (DAW) Transmission Voltage Conversion (IPID 901573) and North Montney – Transmission Development (IPID 901572) projects in the Peace Region. However, these projects may qualify as prescribed undertakings pursuant to section 18 of the *Clean Energy Act*, and as such may be exempt from Part 3 of the *Utilities Commission Act*.**

**250.0 F. CHAPTER 6 – CAPITAL EXPENDITURES**

**Reference: CAPITAL EXPENDITURES**
**Exhibit B-6, Ince IR 6.15, Attachment 1, pp. 11–12;**
**BC Hydro Application for a CPCN for the Dawson Creek/Chetwynd Area Transmission Project, Order G-144-12 with Reasons for Decision dated October 12, 2012, pp. 12–13**
**Peace Region Electric Supply (PRES) Project**

In its reasons for decision accompanying Order G-144-12, the BCUC discusses the need for BC Hydro to provide N-1 reliability in the Peace Region:

> Pursuant to section 125.2 of the UCA, BCUC has adopted the Western Electric Coordinating Council (WECC) standards for reliability, which includes the N-1 operating criterion for service on the bulk transmission system. N-1 means that the transmission system will remain operative even with the loss of one key element…. [where] the 'bulk power system' which is defined to mean …operated at 100kV or greater…excludes radial transmission facilities, regardless of voltage.

2.250.4 Please explain whether the PRES project is driven by the need to meet the N-1 reliability criteria.

**RESPONSE:**

**The Peace Region Electric Supply (PRES) project is not driven by the need to meet N-1 reliability criteria. Rather, the PRES project is driven by and for the purpose of reducing GHG emissions in B.C., by enabling the electrification of natural gas production, processing and compression (new loads).**

**250.0 F. CHAPTER 6 – CAPITAL EXPENDITURES**

**Reference: CAPITAL EXPENDITURES**
**Exhibit B-6, Ince IR 6.15, Attachment 1, pp. 11–12;**
**BC Hydro Application for a CPCN for the Dawson Creek/Chetwynd Area Transmission Project, Order G-144-12 with Reasons for Decision dated October 12, 2012, pp. 12–13**
**Peace Region Electric Supply (PRES) Project**

In its reasons for decision accompanying Order G-144-12, the BCUC discusses the need for BC Hydro to provide N-1 reliability in the Peace Region:

> Pursuant to section 125.2 of the UCA, BCUC has adopted the Western Electric Coordinating Council (WECC) standards for reliability, which includes the N-1 operating criterion for service on the bulk transmission system. N-1 means that the transmission system will remain operative even with the loss of one key element…. [where] the 'bulk power system' which is defined to mean …operated at 100kV or greater…excludes radial transmission facilities, regardless of voltage.

2.250.5 Please explain how the PRES project "primarily serves natural gas producers and processors."

**RESPONSE:**

**As explained in BC Hydro's response to BCUC IR 2.250.7, the purpose of the PRES project is to reduce GHG emissions in B.C. by enabling the electrification of natural gas production, processing and compression (new loads). It is not driven by a need to increase reliability for existing customers.**

**The PRES project will provide additional capacity to serve new customer loads in the South Peace region, which are primarily natural gas producers and processors.**

**250.0 F. CHAPTER 6 – CAPITAL EXPENDITURES**

**Reference: CAPITAL EXPENDITURES**
**Exhibit B-6, Ince IR 6.15, Attachment 1, pp. 11–12;**
**BC Hydro Application for a CPCN for the Dawson Creek/Chetwynd Area Transmission Project, Order G-144-12 with Reasons for Decision dated October 12, 2012, pp. 12–13**
**Peace Region Electric Supply (PRES) Project**

In its reasons for decision accompanying Order G-144-12, the BCUC discusses the need for BC Hydro to provide N-1 reliability in the Peace Region:

> Pursuant to section 125.2 of the UCA, BCUC has adopted the Western Electric Coordinating Council (WECC) standards for reliability, which includes the N-1 operating criterion for service on the bulk transmission system. N-1 means that the transmission system will remain operative even with the loss of one key element…. [where] the 'bulk power system' which is defined to mean …operated at 100kV or greater…excludes radial transmission facilities, regardless of voltage.

2.250.6 Please explain who determines if a given project meets the definition of a prescribed undertaking.

**RESPONSE:**

**This answer also responds to BCUC IR 2.277.2.**

**Section 18(1) of the *Clean Energy Act* (CEA) defines what constitutes a "prescribed undertaking". The Greenhouse Gas Reduction (Clean Energy) Regulation (GGRR) is the legal instrument which prescribes the classes of "prescribed undertakings".**

**A public utility will determine whether a project constitutes a "prescribed undertaking" under the GGRR and is obliged to put forward evidence to support its determination. However, the BCUC can disagree with the utility's assertion that a project meets the definition of a "prescribed undertaking" (e.g., when the utility seeks to recover costs of a prescribed undertaking in a revenue requirement proceeding).**

**250.0 F. CHAPTER 6 – CAPITAL EXPENDITURES**

**Reference: CAPITAL EXPENDITURES**
**Exhibit B-6, Ince IR 6.15, Attachment 1, pp. 11–12;**
**BC Hydro Application for a CPCN for the Dawson Creek/Chetwynd Area Transmission Project, Order G-144-12 with Reasons for Decision dated October 12, 2012, pp. 12–13**
**Peace Region Electric Supply (PRES) Project**

In its reasons for decision accompanying Order G-144-12, the BCUC discusses the need for BC Hydro to provide N-1 reliability in the Peace Region:

> Pursuant to section 125.2 of the UCA, BCUC has adopted the Western Electric Coordinating Council (WECC) standards for reliability, which includes the N-1 operating criterion for service on the bulk transmission system. N-1 means that the transmission system will remain operative even with the loss of one key element…. [where] the 'bulk power system' which is defined to mean …operated at 100kV or greater…excludes radial transmission facilities, regardless of voltage.

2.250.7 Please explain which portion(s) of the project's scope, if any, pertain to the need to increase reliability to existing customers, and which portion(s) of the project's scope pertain to the need to add new loads related to the criteria of a prescribed undertaking.

**RESPONSE:**

**The Peace Region Electric Supply (PRES) project is for the purpose of reducing GHG emissions in B.C., by enabling the electrification of natural gas production, processing and compression (new loads). It is not driven by a need to increase reliability for existing customers.**

**The PRES project includes two new 230 kV circuits and both circuits are required to achieve GHG reduction by electrifying the new loads. As an additional benefit, one of the two new 230 kV circuits that are part of the PRES project also increases reliability for existing customers.**

**Please also refer to BC Hydro's response to BCUC IR 1.119.2, where we explain that the PRES project satisfies the criteria in the Greenhouse Gas Reduction (Clean Energy) Regulation and is therefore a prescribed undertaking.**

**250.0 F. CHAPTER 6 – CAPITAL EXPENDITURES**

**Reference: CAPITAL EXPENDITURES**
**Exhibit B-6, Ince IR 6.15, Attachment 1, pp. 11–12;**
**BC Hydro Application for a CPCN for the Dawson Creek/Chetwynd Area Transmission Project, Order G-144-12 with Reasons for Decision dated October 12, 2012, pp. 12–13**
**Peace Region Electric Supply (PRES) Project**

A business case for the PRES project, published in October 2014, was provided as Attachment 1 in response to Ince IR 6.15. It stated that costs of $178,800 for "Legal and Regulatory" costs were incurred in the Identification Phase. On page 11 of Attachment 1, the scope of work for "Regulatory and Legal" is listed as:

- Reviewing Planning Report and participation in Structured Decision Making process
- Planning of regulatory application
- Legal support of First Nations consultation.

2.250.8 Please explain the scope of work described by "Planning of regulatory application."

**RESPONSE:**

**The scope of work for planning of the regulatory application in the Identification Phase business case included the following activities:**

1. **Developing a regulatory strategy for the project; and**

2. **Developing a schedule for drafting, reviewing and seeking internal approval of the CPCN application.**

**When this Identification Phase business case was prepared in October 2014, the PRES project did not meet the definition of a prescribed undertaking as described in the Greenhouse Gas Reduction (Clean Energy) Regulation approved in May 2012 (Order in Council 295). As a result, BC Hydro expected to file a CPCN application for this project.**

**In March 2017, the definition of a prescribed undertaking in the Greenhouse Gas Reduction (Clean Energy) Regulation was amended under Order in Council 101. The PRES project meets the amended definition of a prescribed undertaking and, as a result, BC Hydro will not file a CPCN application for this project as a CPCN application is no longer required. Please refer to BC Hydro's response to BCUC IR 1.119.2 for an explanation of how the PRES project meets the definition of a prescribed undertaking.**

**250.0 F. CHAPTER 6 – CAPITAL EXPENDITURES**

**Reference: CAPITAL EXPENDITURES**
**Exhibit B-6, Ince IR 6.15, Attachment 1, pp. 11–12;**
**BC Hydro Application for a CPCN for the Dawson Creek/Chetwynd Area Transmission Project, Order G-144-12 with Reasons for Decision dated October 12, 2012, pp. 12–13**
**Peace Region Electric Supply (PRES) Project**

A business case for the PRES project, published in October 2014, was provided as Attachment 1 in response to Ince IR 6.15. It stated that costs of $178,800 for "Legal and Regulatory" costs were incurred in the Identification Phase. On page 11 of Attachment 1, the scope of work for "Regulatory and Legal" is listed as:

- Reviewing Planning Report and participation in Structured Decision Making process
- Planning of regulatory application
- Legal support of First Nations consultation.

2.250.8 Please explain the scope of work described by "Planning of regulatory application."

2.250.8.1 If this scope of work included the preparation of a CPCN application, please explain why that expectation changed.

**RESPONSE:**

**Please refer to BC Hydro's response to BCUC IR 2.250.8 where we explain the scope of work and why it changed.**

**251.0 F. CHAPTER 6 – CAPITAL EXPENDITURES**

**Reference: CAPITAL EXPENDITURES**
**Exhibit B-1, Appendix I, p. 7; Exhibit B-5, BCUC IR 113;**
**BC Hydro Review of the Regulatory Oversight of Capital Expenditures and Projects proceeding, Exhibit B-7, p. 46**
**Distribution sustaining capital expenditures and additions**

In BC Hydro's Review of the Regulatory Oversight of Capital Expenditures and Projects proceeding, BC Hydro defines a "Program of Projects" as the following:

> A Program of Projects is a group of related projects with common business drivers and or technical characteristics which are managed in a coordinated way to deliver a common business requirement or achieve delivery efficiencies by sharing teams, resources, and information technology environments. The projects are managed together to reduce risk and achieve efficiencies and other delivery benefits not available if managed individually. Programs of Projects usually have long durations (multiple years), a finite end date, and are often flexible in scope with new projects added over time.

In its response to BCUC IR 113 regarding Distribution Automation projects, BC Hydro stated:

> Automation of distribution devices is a work program that facilitates a high volume of asset additions, replacements, or improvements consisting of repeatable work units located throughout the system. Each individual unit is relatively low cost and below the $5 million threshold…
>
> The execution of the work will, in most instances, be in groups of units for delivery efficiency. This work program is managed and executed as a recurring capital program and is ongoing…
>
> As the Distribution Automation work program is not executed as a program of projects, there is no reference to this program in Appendix J of the Application.

In Appendix I of the Application, BC Hydro lists the capital expenditures and additions for the Distribution Automation Work Program:

| Planning ID | Name of Project or Program of Projects | Capital Additions Plan F2020 ($ million) | Capital Additions Plan F2021 ($ million) | Capital Expenditures Plan F2020 ($ million) | Capital Expenditures Plan F2021 ($ million) |
|---|---|---|---|---|---|
| | **Distribution Automation Work Program** | **21** | **20** | **20** | **18** |

2.251.1 Given the level of capital investment and the recurring nature of this work program, please explain why the Distribution Automation Work Program is not managed as a Program of Projects.

**RESPONSE:**

**The Distribution Automation Work Program is managed as a recurring capital work program, not a Program of Projects, as it is highly standardized, high volume, low complexity, repeatable work.**

**Please refer to lines 23 to 26 in section 6.2.1 of Chapter 6 of BC Hydro's Revised Proposal in the Review of the Regulatory Oversight of Capital Expenditures and Projects proceeding. This section describes work programs and indicates that these are approved each year as an annual program:**

> **"These (work programs) are usually highly standardized high volume and low complexity asset replacements or improvements. These programs consist of repeatable work units that are grouped to deliver an aggregate benefit, and are annual recurring expenditures. These programs are usually planned and approved as a unit."**

**In addition, lines 2 to 5 in section 6.4.2 describes the rationale for proposed guidelines for recurring capital work programs:**

> **"The BC Hydro approval processes for recurring capital programs are streamlined as they comprise low-complexity work and are recurring in nature. These programs often involve work on assets that are put into service in the same year as the expenditure is made."**

**In contrast, as explained in section 6.1 of BC Hydro's Revised Proposal, Programs of Projects usually have long duration (multiple years), a finite end date, and often have flexibility in scope.**

**251.0 F. CHAPTER 6 – CAPITAL EXPENDITURES**

**Reference: CAPITAL EXPENDITURES**
**Exhibit B-1, Appendix I, p. 7; Exhibit B-5, BCUC IR 113;**
**BC Hydro Review of the Regulatory Oversight of Capital Expenditures and Projects proceeding, Exhibit B-7, p. 46**
**Distribution sustaining capital expenditures and additions**

In BC Hydro’s Review of the Regulatory Oversight of Capital Expenditures and Projects proceeding, BC Hydro defines a “Program of Projects” as the following:

> A Program of Projects is a group of related projects with common business drivers and or technical characteristics which are managed in a coordinated way to deliver a common business requirement or achieve delivery efficiencies by sharing teams, resources, and information technology environments. The projects are managed together to reduce risk and achieve efficiencies and other delivery benefits not available if managed individually. Programs of Projects usually have long durations (multiple years), a finite end date, and are often flexible in scope with new projects added over time.

In its response to BCUC IR 113 regarding Distribution Automation projects, BC Hydro stated:

> Automation of distribution devices is a work program that facilitates a high volume of asset additions, replacements, or improvements consisting of repeatable work units located throughout the system. Each individual unit is relatively low cost and below the $5 million threshold…
>
> The execution of the work will, in most instances, be in groups of units for delivery efficiency. This work program is managed and executed as a recurring capital program and is ongoing…
>
> As the Distribution Automation work program is not executed as a program of projects, there is no reference to this program in Appendix J of the Application.

In Appendix I of the Application, BC Hydro lists the capital expenditures and additions for the Distribution Automation Work Program:

| Planning ID | Name of Project or Program of Projects | Capital Additions Plan F2020 ($ million) | Capital Additions Plan F2021 ($ million) | Capital Expenditures Plan F2020 ($ million) | Capital Expenditures Plan F2021 ($ million) |
|---|---|---|---|---|---|
| | Distribution Automation Work Program | 21 | 20 | 20 | 18 |

2.251.2 Please explain the advantages and disadvantages of managing the Distribution Automation Work Program as a Program of Projects.

**RESPONSE:**

**BC Hydro does not see any advantage of managing the Distribution Automation Work Program as a Program of Projects. As discussed in BC Hydro's response to BCUC IR 2.38.1.3 in the Review of the Regulatory Oversight of Capital Expenditure and Projects, which is provided as Attachment 1 to this response, delivery of a series of investments as a Program of Projects is meant to create project delivery efficiencies. With the Distribution Automation Work Program, delivery efficiencies are already derived from combining the standardized high volume and low complexity asset replacements or improvements through managing this as a recurring capital work program.**

**The disadvantages of managing the Distribution Automation Work Program as a Program of Projects are reduced efficiency due to increased process burden, such as the need to justify and approve individual scopes of work (i.e., each unit as a "project"). In addition, the annual recurring nature of the expenditures would create the same approval requirements for each individual scope of work and additional burden each year.**

| British Columbia Utilities Commission<br>Information Request No. **2.38.1.3** Dated: **June 5, 2019**<br>British Columbia Hydro & Power Authority<br>Response issued **July 4, 2019** | Page 1<br>of 3 |
|---|---|
| British Columbia Hydro & Power Authority<br>**Review of the Regulatory Oversight of Capital Expenditures and Projects** | **Exhibit:**<br>**B-16** |

**38.0 H. PROGRAMS OF PROJECTS**

**Reference: CLARITY ON PROGRAMS**
**Exhibit B-7, pp. 46–48, 63**
**Exhibit B-4, Response to BCUC IR 10.8**
**BC Hydro Inquiry of Expenditures related to the adoption of the SAP Platform,**
**Exhibit B-3, Attachments 11, 13–15; Final Report, pp. 41–42**
**Programs of projects**

On pages 46 to 47 of the Revised Proposal, BC Hydro provides information regarding programs of projects. On pages 47 to 48, BC Hydro summarized recurring capital programs.

BC Hydro on page 48 states:

As projects within the program are initiated, they should be reviewed as individual projects in a revenue requirements application and, if the project exceeds the major project threshold, in a major project filing. BC Hydro will identify in Appendix I of revenue requirements applications projects above the materiality limit that are anticipated to be delivered as part of Programs of Projects, and where available will provide a summary of the program strategy for all identified Programs of Projects.

On page 63 of the Revised Proposal, BC Hydro states:

BC Hydro is proposing to provide additional data on capital projects and programs in revenue requirements applications. This additional data will be included in Appendix I in future revenue requirements applications. The proposed changes are as follows:

…
- Indication of which projects are part of Programs of Projects.

In the BC Hydro Inquiry of Expenditures related to the adoption of the SAP Platform (SAP Inquiry), BC Hydro sets out the following:
- “Approval must be obtained in advance of any monetary outlays” (Exhibit B-3, Attachment 11, p. 2)
- An Expenditure Approval Request (EAR) is “an approval document required for all initiatives exceeding $100,000.” (Exhibit B-3, Attachment 15, p. 1)
- A business case is required for “any project (or initiative) requiring investment, expenditure or commitment which has a significant impact on business operations, creates material risk, and/or where there are credible alternatives to a recommended course of action.” (Exhibit B-3, Attachment 14, p. 1)

- Approval levels for business cases are based on estimated project costs, as described in the EAR procedures. (Exhibit B-3, Attachment 14, Table 1)
- "Multiple projects that are intended to be run as a program, or that have a common objective with similar characteristics, shall be consolidated into one Program Initiative for approval purposes. Approval is required at the FAAP [Financial Approval Authority] level for the entire program." (Exhibit B-3, Attachment 15, p. 2)
- "Documentation-splitting is prohibited as it circumvents the intent of the [Financial Responsibility] policy." (Exhibit B-3, Attachment 13, page 1)

In the SAP Inquiry Final Report, on pages 41 and 42 the BCUC found that the SAP "the SAP Decision was a financial decision" and that "BC Hydro should have developed an EAR and an accompanying business case to properly support the SAP Decision." In response to BCUC IR 10.8, BC Hydro states:

A strategy may identify specific investments over a definite period of time that could be combined into a single project, which would be filed as a single CPCN or section 44.2 application if it exceeded the Major Project threshold.

2.38.1 Please explain whether BC Hydro includes information in Appendix I of the RRA, and files an Appendix J summary sheet, for all forecasted programs of projects that exceed or are expected to exceed the relevant materiality threshold, regardless of whether the individual projects meet the relevant materiality threshold.

2.38.1.3 Please explain why, in RRA proceeding, the separate review of individual projects within a program is the more effective and efficient approach.

**RESPONSE:**

**BC Hydro believes a review of individual projects within a program in revenue requirements proceedings is an effective and efficient approach due to the nature of Programs of Projects. The concept of a Program of Projects is to create project delivery efficiencies rather than an approval mechanism. Programs of Projects are flexible in scope, have long durations and are subject to reprioritization over time. Each project within a Program of Projects delivers individual benefits and is justified on its own merits. As this type of program consists of individual, separate projects with standalone benefits, the projects within these types of programs are best reviewed individually in revenue requirements proceedings, rather than as a Program of Projects which does not indicate a BC Hydro investment decision and may have significant uncertainty.**

**Nonetheless, as discussed in BC Hydro's response to BCUC IR 2.38.1, BC Hydro has identified and described Programs of Projects in its Fiscal 2020 to Fiscal 2021 Revenue Requirements Application (RRA). If the BCUC has concerns with a particular program, then the BCUC is able to review the projects associated with that program on a retrospective basis through a prudence review, or on a forecast basis in a revenue requirements application or, potentially, a major project application.**

**For example, Appendix I – Attachment 1 of the RRA identifies a number of shunt reactor projects that are part of a Program of Projects. The index in Appendix I shows these projects are associated with BC Hydro's Shunt Reactors Asset Management Strategy described on page 67 of Appendix K – Attachment 1. If upon review of the Shunt Reactors Asset Management Strategy, the BCUC had concerns with BC Hydro's Program of Projects, the BCUC could inquire into the projects that are a part of this program over the test period. The BCUC could either satisfy itself that the projects over the test period were reasonable or, if the BCUC determined they were not reasonable, the BCUC could exclude the associated forecast additions when setting rates for the test period.**

**The BCUC therefore has several regulatory tools at its disposal to conduct its oversight over BC Hydro capital expenditures associated with a program of projects.**

**251.0 F. CHAPTER 6 – CAPITAL EXPENDITURES**

**Reference: CAPITAL EXPENDITURES**
**Exhibit B-1, Appendix I, p. 7; Exhibit B-5, BCUC IR 113;**
**BC Hydro Review of the Regulatory Oversight of Capital Expenditures and Projects proceeding, Exhibit B-7, p. 46**
**Distribution sustaining capital expenditures and additions**

In BC Hydro's Review of the Regulatory Oversight of Capital Expenditures and Projects proceeding, BC Hydro defines a "Program of Projects" as the following:

> A Program of Projects is a group of related projects with common business drivers and or technical characteristics which are managed in a coordinated way to deliver a common business requirement or achieve delivery efficiencies by sharing teams, resources, and information technology environments. The projects are managed together to reduce risk and achieve efficiencies and other delivery benefits not available if managed individually. Programs of Projects usually have long durations (multiple years), a finite end date, and are often flexible in scope with new projects added over time.

In its response to BCUC IR 113 regarding Distribution Automation projects, BC Hydro stated:

> Automation of distribution devices is a work program that facilitates a high volume of asset additions, replacements, or improvements consisting of repeatable work units located throughout the system. Each individual unit is relatively low cost and below the $5 million threshold…
>
> The execution of the work will, in most instances, be in groups of units for delivery efficiency. This work program is managed and executed as a recurring capital program and is ongoing…
>
> As the Distribution Automation work program is not executed as a program of projects, there is no reference to this program in Appendix J of the Application.

In Appendix I of the Application, BC Hydro lists the capital expenditures and additions for the Distribution Automation Work Program:

| Planning ID | Name of Project or Program of Projects | Capital Additions Plan F2020 ($ million) | Capital Additions Plan F2021 ($ million) | Capital Expenditures Plan F2020 ($ million) | Capital Expenditures Plan F2021 ($ million) |
|---|---|---|---|---|---|
| | **Distribution Automation Work Program** | **21** | **20** | **20** | **18** |

2.251.3 Please confirm that the Distribution Automation Work Program would require a filing of a CPCN or capital expenditure schedule if it was managed as a Program of Projects.

**RESPONSE:**

**If the Distribution Automation Work Program was managed as a Program of Projects, it would not require a filing of a CPCN or capital expenditure schedule as each individual project within the program would not meet the proposed thresholds for a CPCN or section 44.2 filing.**

**As discussed in BC Hydro's response to BCUC IR 2.38.5 in the Review of the Regulatory Oversight of Capital Expenditures and Projects, which if provided as Attachment 1 to this response, it would not be feasible to undertake a separate CPCN type review for recurring capital programs because these work programs are expected to occur annually with individual work units. In addition, as also explained in the referenced response, a CPCN type review is not warranted as the work program is a collection of low risk, repeatable work units.**

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|---|---|
| British Columbia Hydro & Power Authority<br>**Review of the Regulatory Oversight of Capital Expenditures and Projects** | **Exhibit:<br>B-16** |

**38.0 H. PROGRAMS OF PROJECTS**

**Reference: CLARITY ON PROGRAMS**
**Exhibit B-7, pp. 46–48, 63**
**Exhibit B-4, Response to BCUC IR 10.8**
**BC Hydro Inquiry of Expenditures related to the adoption of the SAP Platform,**
**Exhibit B-3, Attachments 11, 13–15; Final Report, pp. 41–42**
**Programs of projects**

On pages 46 to 47 of the Revised Proposal, BC Hydro provides information regarding programs of projects. On pages 47 to 48, BC Hydro summarized recurring capital programs.

BC Hydro on page 48 states:

As projects within the program are initiated, they should be reviewed as individual projects in a revenue requirements application and, if the project exceeds the major project threshold, in a major project filing. BC Hydro will identify in Appendix I of revenue requirements applications projects above the materiality limit that are anticipated to be delivered as part of Programs of Projects, and where available will provide a summary of the program strategy for all identified Programs of Projects.

On page 63 of the Revised Proposal, BC Hydro states:

BC Hydro is proposing to provide additional data on capital projects and programs in revenue requirements applications. This additional data will be included in Appendix I in future revenue requirements applications. The proposed changes are as follows:

…

- Indication of which projects are part of Programs of Projects.

In the BC Hydro Inquiry of Expenditures related to the adoption of the SAP Platform (SAP Inquiry), BC Hydro sets out the following:

- “Approval must be obtained in advance of any monetary outlays” (Exhibit B-3, Attachment 11, p. 2)
- An Expenditure Approval Request (EAR) is “an approval document required for all initiatives exceeding $100,000.” (Exhibit B-3, Attachment 15, p. 1)
- A business case is required for “any project (or initiative) requiring investment, expenditure or commitment which has a significant impact on business operations, creates material risk, and/or where there are credible alternatives to a recommended course of action.” (Exhibit B-3, Attachment 14, p. 1)

- Approval levels for business cases are based on estimated project costs, as described in the EAR procedures. (Exhibit B-3, Attachment 14, Table 1)
- "Multiple projects that are intended to be run as a program, or that have a common objective with similar characteristics, shall be consolidated into one Program Initiative for approval purposes. Approval is required at the FAAP [Financial Approval Authority] level for the entire program." (Exhibit B-3, Attachment 15, p. 2)
- "Documentation-splitting is prohibited as it circumvents the intent of the [Financial Responsibility] policy." (Exhibit B-3, Attachment 13, page 1)

In the SAP Inquiry Final Report, on pages 41 and 42 the BCUC found that the SAP "the SAP Decision was a financial decision" and that "BC Hydro should have developed an EAR and an accompanying business case to properly support the SAP Decision." In response to BCUC IR 10.8, BC Hydro states:

A strategy may identify specific investments over a definite period of time that could be combined into a single project, which would be filed as a single CPCN or section 44.2 application if it exceeded the Major Project threshold.

2.38.5 For a major recurring capital program, such as one involving a large and ongoing capital expenditure, viable alternatives, or significant impacts on customers, First Nations or stakeholders, please discuss the feasibility of undertaking a separate, CPCN type review of the program.

**RESPONSE:**

**Recurring work programs as described in BC Hydro's Revised Proposal are standardized high volume and low complexity asset replacements. It would not be feasible to undertake a separate CPCN type review of the program because these programs are expected to recur on an ongoing basis with individual work units defined across the province on an annual basis.**

**Further, this type of review is not warranted because the work program is in fact a collection of low risk, repeatable work units. By their definition these low risk repeatable work units have only one viable alternative (typically like for like replacement) and will not present significant impacts on customers, First Nations or stakeholders. BC Hydro's program management practices ensure that we engage communities, First Nations, and other stakeholders as part of the delivery of our recurring capital programs.**

**A revenue requirements application is the most efficient way to review these types of programs.**

**252.0 F. CHAPTER 6 – CAPITAL EXPENDITURES**

**Reference: CAPITAL EXPENDITURES**
**Exhibit B-5, BCUC IR 120.1; BC Hydro Review of the Regulatory Oversight of Capital Expenditures and Projects proceeding, Exhibit B-7, p. 46**
**Mica Replace Units 1-4 Generator Transformers and Mica Modernize Controls Project**

In response to BCUC IR 120.1, it stated:

> BC Hydro does not believe that efficiencies could be found by combining these projects into a single project… That said, BC Hydro recognize the opportunity to take advantage of the same outage period and that efficiencies could be achieved by combining the procurement and contract management of the installation work. While these activities were coordinated, the independent delivery of the projects allows each project to continue with minimal potential impacts from any delivery risks faced by the other project.

In the BC Hydro Review of the Regulatory Oversight of Capital Expenditures and Projects proceeding, BC Hydro defines a “Program of Projects.”

2.252.1 Please explain whether there are any interdependencies between any current or upcoming projects at the Mica generating station.

**RESPONSE:**

**There are no interdependencies between any current or upcoming projects (i.e. those listed in Appendix I of the Application) at the Mica generating station because:**

- **There is no scope of work dependent upon the scope of work from another project; and**
- **Any of the projects could be stopped, without affecting the other projects.**

**While there are no interdependencies, projects may be coordinated to achieve delivery efficiencies.**

**252.0 F. CHAPTER 6 – CAPITAL EXPENDITURES**

**Reference: CAPITAL EXPENDITURES**
**Exhibit B-5, BCUC IR 120.1; BC Hydro Review of the Regulatory Oversight of Capital Expenditures and Projects proceeding, Exhibit B-7, p. 46**
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> BC Hydro does not believe that efficiencies could be found by combining these projects into a single project… That said, BC Hydro recognize the opportunity to take advantage of the same outage period and that efficiencies could be achieved by combining the procurement and contract management of the installation work. While these activities were coordinated, the independent delivery of the projects allows each project to continue with minimal potential impacts from any delivery risks faced by the other project.

In the BC Hydro Review of the Regulatory Oversight of Capital Expenditures and Projects proceeding, BC Hydro defines a "Program of Projects."

2.252.2 Please explain whether all projects currently underway at the Mica generating station have a common business driver and/or a common business requirement.

**RESPONSE:**

**Of the five projects listed in Appendix J at Mica, two have a Reliability driver, two have Safety and Reliability drivers, and one has a Financial driver. While there are some projects with common business drivers, they all have different scope specific technical requirements, require different design resources and equipment supplier types, have different outage requirements (e.g., length, number, or none required), have different design and construction complexity, and may take place at different locations.**

**For example:**

- **The MCA Modernize Controls project has a reliability business driver and takes place among the generating units and control room in the powerhouse. This project uses a combination of external and internal design and supply resources. For some equipment, BC Hydro carries the design ownership, for other equipment, the vendor carries the design risk. The project requires**

**specialty electrical equipment supply and installation vendors. The project requires a series of annual, seven to eight month duration generating unit outages;**

- **The MCA Recoat Intake Maintenance Gates & Draft Tube Maintenance Gates project has a reliability driver. BC Hydro carries the design ownership. This project involves mechanical equipment located on the dam deck outside the powerhouse as well as equipment in the draft tube gallery of the powerhouse. This project requires specialty coating vendors and the gate refurbishment work takes place off-site. No project specific outages are required as the testing can take place at a time when another outage is already scheduled; and**

- **The MCA Townsite Augment Accommodations Capacity project has a financial driver. This project is a design-build project where an external vendor carries the design ownership. This project takes place at the Townsite and uses commercial construction vendors that are specialists of industrial site kitchen and accommodation construction. This project has no effect on the generation or transmission system and no outages are required.**

**252.0 F. CHAPTER 6 – CAPITAL EXPENDITURES**

**Reference: CAPITAL EXPENDITURES**
**Exhibit B-5, BCUC IR 120.1; BC Hydro Review of the Regulatory Oversight of Capital Expenditures and Projects proceeding, Exhibit B-7, p. 46**
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In response to BCUC IR 120.1, it stated:

> BC Hydro does not believe that efficiencies could be found by combining these projects into a single project… That said, BC Hydro recognize the opportunity to take advantage of the same outage period and that efficiencies could be achieved by combining the procurement and contract management of the installation work. While these activities were coordinated, the independent delivery of the projects allows each project to continue with minimal potential impacts from any delivery risks faced by the other project.

In the BC Hydro Review of the Regulatory Oversight of Capital Expenditures and Projects proceeding, BC Hydro defines a “Program of Projects.”

2.252.3 Please explain whether all projects at a single site, such as Mica, would have to be managed in a coordinated way to reduce risk and achieve efficiencies.

**RESPONSE:**

**Coordinated project planning and construction activities can reduce risk and achieve efficiencies where there is a need for managing items such as: the use of site laydown space, the use of common resources and the risk related to asset interfaces. However, project differences such as scope, complexity, timing, location at the site, outage requirements and resources may mean that there are no opportunities to reduce risk or achieve efficiencies by coordinating projects.**

**An example of two projects where there are no opportunities to manage in a coordinated way is the MCA Townsite Augment Accommodations Capacity project and the MCA Recoat Intake Maintenance Gates & Draft Tube Maintenance. These projects have different technical requirements, different construction timing and durations, use very different design and supply vendors, are located in different areas at the site, and have very limited use of common project resources.**

**In contrast, the MCA 1-4 Transformer Replacement and the MCA Digital Controls projects take place in the powerhouse, have some common interfaces and share an outage which creates opportunities for efficiencies through coordinating some aspects of their delivery.**

**252.0 F. CHAPTER 6 – CAPITAL EXPENDITURES**

**Reference: CAPITAL EXPENDITURES**
**Exhibit B-5, BCUC IR 120.1; BC Hydro Review of the Regulatory Oversight of Capital Expenditures and Projects proceeding, Exhibit B-7, p. 46**
**Mica Replace Units 1-4 Generator Transformers and Mica Modernize Controls Project**

In response to BCUC IR 120.1, it stated:

> BC Hydro does not believe that efficiencies could be found by combining these projects into a single project… That said, BC Hydro recognize the opportunity to take advantage of the same outage period and that efficiencies could be achieved by combining the procurement and contract management of the installation work. While these activities were coordinated, the independent delivery of the projects allows each project to continue with minimal potential impacts from any delivery risks faced by the other project.

In the BC Hydro Review of the Regulatory Oversight of Capital Expenditures and Projects proceeding, BC Hydro defines a "Program of Projects."

2.252.4 Please explain why BC Hydro does not view all projects at a single site to be a Program of Projects or as a single overarching project.

**RESPONSE:**

**The projects taking place at a single site do not constitute a Program of Projects. A Program of Projects is intended for situations where a common business driver results in multiple similar projects in response, all of which together achieve the common objectives articulated in the business case. The projects at a single site, however, can vary greatly in their nature, ranging from heavy civil construction, such as blasting and quarrying, to upgrades of mechanical systems such as gates and hoists, to installation of sophisticated electronic control and communication systems.**

**BC Hydro does not view all individual projects at a single site to be a single overarching project. A project is time-bound, one time undertakings to buy, to replace, to maintain, or to rehabilitate a distinct asset, a set of assets, or a group of assets to achieve specified set of objectives. In contrast, the projects planned for, and delivered at, a single site can be numerous, with new projects continually being identified over time, with varying objectives.**

**BC Hydro's approach to managing projects at a single site is to coordinate the projects when it is operationally necessary or where there are opportunities for efficiencies and/or risk reduction, as described in BC Hydro's response to BCUC IR 2.252.1 and 2.253.1. BC Hydro also considers strategic or planning decisions related to the work on a single facility in its facility asset plans, examples of which are included in Attachment K of the Application. This approach enables BC Hydro to optimize capital resources across all sites and all asset types.**

**252.0 F. CHAPTER 6 – CAPITAL EXPENDITURES**

**Reference: CAPITAL EXPENDITURES**
**Exhibit B-5, BCUC IR 120.1; BC Hydro Review of the Regulatory Oversight of Capital Expenditures and Projects proceeding, Exhibit B-7, p. 46**
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In response to BCUC IR 120.1, it stated:

> BC Hydro does not believe that efficiencies could be found by combining these projects into a single project… That said, BC Hydro recognize the opportunity to take advantage of the same outage period and that efficiencies could be achieved by combining the procurement and contract management of the installation work. While these activities were coordinated, the independent delivery of the projects allows each project to continue with minimal potential impacts from any delivery risks faced by the other project.

In the BC Hydro Review of the Regulatory Oversight of Capital Expenditures and Projects proceeding, BC Hydro defines a "Program of Projects."

2.252.5 Please discuss whether there are any public interest or public perception concerns at the Mica generating station which may warrant a higher level of BCUC oversight. If not, why not?

**RESPONSE:**

**BC Hydro is not aware of any public interest or public perception concerns at the Mica generating station that would warrant a higher level of BCUC oversight.**

**BC Hydro consults with First Nations and conducts community engagement and does environmental reviews, as part of our project delivery practices. Regarding the work at the Mica generating station, nothing has been brought to our attention through our consultation, engagement, or environmental reviews that would warrant a higher level of BCUC oversight.**

**253.0 F. CHAPTER 6 – CAPITAL EXPENDITURES**

**Reference: CAPITAL EXPENDITURES**
**Exhibit B-5, BCUC IR 116.8**
**G.M. Shrum G1 to 10 Control System Upgrade Project**

In response to BCUC IR 116.8, BC Hydro provided a list of projects that have or will take place at GMS concurrently with the $75 million GMS G1 to 10 Control System Upgrade Project:

- GMS Unit 1-5 Turbine Rehabilitation Project (PID G000611),
- GMS G1-G5 Rotor Rehabilitation Project (PID G000651),
- GMS Spillway Chute Interim Upgrade Project (PID G000595),
- GMS W.A.C. Bennett Dam Riprap Project (PID G000623),
- GMS Spillway Gate Upgrade Project (PID G000656),
- GMS W.A.C. Bennett Dam - Core Upgrades Project (PID G000110),
- GMS Draft Tube Maintenance Gates Refurbishment Project (PID G000129),
- GMS Control System Upgrade Project (PID 93687),
- GMS 500kV Disconnect Switch Replacement/Refurbishment Project (PID G000135),
- GMS Upgrade HVAC System Project (PID G000114),
- GMS Replace Unit 1-5 Exciter Transformers Project (PID G000121),
- GMS Unwatering System Refurbishment Project (PID G000128),
- GMS Seal Low Level Outlets Project (PID G003555),
- GMS Auxiliary Building Service Upgrade (PID G0030088), and
- GMS Visitor Centre Water Supply Project (PID G003001).

Future projects forecast to be greater than $5 million at the GMS facility which may run concurrently with the GMS G1-10 Control Systems Upgrade Project include:

- GMS Intake Operating Gate and Intake Maintenance Gate Refurbishment (PIDG000131)
- GMS Intake Operating Gate Hydraulic Upgrade (Planning ID G003336)
- GMS Pauwels Transformer Life Extension (PID G003826)
- GMS Transformers Phase 4 Replacement (PID G000133)
- GMS U1 - U10 Water Passage Refurbishment (PID G000130)
- GMS U9 - U10 Circuit Breaker Replacement (PID G000120)
- GMS U5 Stator Replacement (PID G003837)
- GMS U6 Stator Replacement (PID G000124)
- GMS U5 - U8 Generator Air Cooler Replacement (PID G000126)
- W.A.C. Bennett Dam - Spillway Seismic Upgrade (PID G000109)

2.253.1 Please explain whether there are any interdependencies in the projects listed above.

**RESPONSE:**

**In responding to this question, BC Hydro noticed the following errors in our response to BCUC IR 1.116.8:**

1. **PID 93687 is the GMS Substation Controls Upgrade Project, not the GMS Control System Upgrade Project; and**
2. **The correct PID number for the GMS Auxiliary Building Service Upgrade Project is G003088.**

**The projects listed in BC Hydro's response to BCUC IR 1.116.8 do not have interdependencies because:**

- **There is no particular work package within a project that cannot proceed without a particular work package being competed in a separate project; and**
- **Any of the projects could be stopped, without affecting the other projects.**

**These projects range from heavy civil construction, such as blasting and quarrying, to upgrades of mechanical systems such as gates and hoists, to installation of sophisticated electronic control and communication systems.**

**Despite differences in technical characteristics and required construction approaches across most of these projects, BC Hydro coordinates the projects to take advantage of common outages, common procurement strategies, planned reservoir operations, etc.**

**253.0 F. CHAPTER 6 – CAPITAL EXPENDITURES**

**Reference: CAPITAL EXPENDITURES**
**Exhibit B-5, BCUC IR 116.8**
**G.M. Shrum G1 to 10 Control System Upgrade Project**

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- GMS Unit 1-5 Turbine Rehabilitation Project (PID G000611),
- GMS G1-G5 Rotor Rehabilitation Project (PID G000651),
- GMS Spillway Chute Interim Upgrade Project (PID G000595),
- GMS W.A.C. Bennett Dam Riprap Project (PID G000623),
- GMS Spillway Gate Upgrade Project (PID G000656),
- GMS W.A.C. Bennett Dam - Core Upgrades Project (PID G000110),
- GMS Draft Tube Maintenance Gates Refurbishment Project (PID G000129),
- GMS Control System Upgrade Project (PID 93687),
- GMS 500kV Disconnect Switch Replacement/Refurbishment Project (PID G000135),
- GMS Upgrade HVAC System Project (PID G000114),
- GMS Replace Unit 1-5 Exciter Transformers Project (PID G000121),
- GMS Unwatering System Refurbishment Project (PID G000128),
- GMS Seal Low Level Outlets Project (PID G003555),
- GMS Auxiliary Building Service Upgrade (PID G0030088), and
- GMS Visitor Centre Water Supply Project (PID G003001).

Future projects forecast to be greater than $5 million at the GMS facility which may run concurrently with the GMS G1-10 Control Systems Upgrade Project include:

- GMS Intake Operating Gate and Intake Maintenance Gate Refurbishment (PIDG000131)
- GMS Intake Operating Gate Hydraulic Upgrade (Planning ID G003336)
- GMS Pauwels Transformer Life Extension (PID G003826)
- GMS Transformers Phase 4 Replacement (PID G000133)
- GMS U1 - U10 Water Passage Refurbishment (PID G000130)
- GMS U9 - U10 Circuit Breaker Replacement (PID G000120)
- GMS U5 Stator Replacement (PID G003837)
- GMS U6 Stator Replacement (PID G000124)
- GMS U5 - U8 Generator Air Cooler Replacement (PID G000126)
- W.A.C. Bennett Dam - Spillway Seismic Upgrade (PID G000109)

2.253.2 Please estimate the sum total cost of all the projects listed above.

**RESPONSE:**

**The total capital cost of the projects listed in the preamble to the question, including the GMS Controls System Upgrade Project, is estimated to be in the order of $1 billion in nominal dollars. This includes $371 million related to completed projects, including $182 million for the GMS Unit 1-5 Turbine Rehabilitation Project and $119 million for the GMS W.A.C. Bennett Dam Riprap Project, which were both reviewed through a CPCN process.**

**Projects currently underway represent $192 million. The remainder represents Future Planned Projects, including the W.A.C. Bennett Dam – Spillway Seismic Upgrade project, which BC Hydro expects to exceed the current major project filing threshold of $100 million.**

**253.0 F. CHAPTER 6 – CAPITAL EXPENDITURES**

**Reference: CAPITAL EXPENDITURES**
**Exhibit B-5, BCUC IR 116.8**
**G.M. Shrum G1 to 10 Control System Upgrade Project**

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- GMS Seal Low Level Outlets Project (PID G003555),
- GMS Auxiliary Building Service Upgrade (PID G0030088), and
- GMS Visitor Centre Water Supply Project (PID G003001).

Future projects forecast to be greater than $5 million at the GMS facility which may run concurrently with the GMS G1-10 Control Systems Upgrade Project include:

- GMS Intake Operating Gate and Intake Maintenance Gate Refurbishment (PIDG000131)
- GMS Intake Operating Gate Hydraulic Upgrade (Planning ID G003336)
- GMS Pauwels Transformer Life Extension (PID G003826)
- GMS Transformers Phase 4 Replacement (PID G000133)
- GMS U1 - U10 Water Passage Refurbishment (PID G000130)
- GMS U9 - U10 Circuit Breaker Replacement (PID G000120)
- GMS U5 Stator Replacement (PID G003837)
- GMS U6 Stator Replacement (PID G000124)
- GMS U5 - U8 Generator Air Cooler Replacement (PID G000126)
- W.A.C. Bennett Dam - Spillway Seismic Upgrade (PID G000109)

2.253.3 Please explain whether these projects could be considered to have: a common business driver or business requirement; a long duration; a finite end date; and could be managed together to reduce business risk.

**RESPONSE:**

**As noted in BC Hydro's response to BCUC IR 2.253.1, there is a wide range of activities included in the projects listed, similar to the different work at Mica, as described in our response to BCUC IRs 2.252.2 and 2.252.3. The project drivers include one or more of the five business drivers: Safety, Environmental, Reliability, Reputational and Financial Loss. The majority of the projects listed have either a Safety or Reliability driver, which may include several variables within each driver, for example:**

- **Safety may include: different dam safety issues across disciplines including erosion protection, seismic stability, gate operability and reliability, and remediation of inherent vulnerabilities; worker and public safety, including penstock dewatering, operation of plant systems, operation of isolating devices, and reservoir management; and public access to BC Hydro facilities; or**
- **Reliability may include: generation reliability including age and condition of major components, condition of ancillary equipment, and replacement of obsolete protection and control components.**

**The summary of drivers for each project referenced in BC Hydro's response to BCUC IR 1.116.8 is as follows:**

| IPID | Project Name | Drivers |
|---|---|---|
| PID G000611 | GMS Unit 1-5 Turbine Rehabilitation Project | Reliability, Financial Loss |
| PID G000651 | GMS G1-G5 Rotor Rehabilitation Project | Reliability |
| PID G000595 | GMS Spillway Chute Interim Upgrade Project | Safety |
| PID G000623 | GMS W.A.C. Bennett Dam Riprap Project | Safety |
| PID G000656 | GMS Spillway Gate Upgrade Project | Safety, Reliability |
| PID G000110 | GMS W.A.C. Bennett Dam - Core Upgrades Project | Safety |
| PID G000129 | GMS Draft Tube Maintenance Gates Refurbishment Project | Reliability |
| PID G000127 | GMS Control System Upgrade Project | Reliability |

| IPID | Project Name | Drivers |
|---|---|---|
| PID 93687 | GMS Substation Controls Upgrade Project | Reliability |
| PIDG003554[1] | GMS WAC Bennett Dam Recommission / Seal Spillway Sluice Gates | Safety, Financial Loss, Reputational |
| PID G000135 | GMS 500kV Disconnect Switch Replacement/Refurbishment Project | Safety, Reliability |
| PID G000114 | GMS Upgrade HVAC System Project | Reliability, Safety |
| PID G000121 | GMS Replace Unit 1-5 Exciter Transformers Project | Reliability |
| PID G000128 | GMS Unwatering System Refurbishment Project | Safety |
| PID G003555 | GMS Seal Low Level Outlets Project | Safety, Financial Loss, Reputational |
| PID G003088 | GMS Auxiliary Building Service Upgrade | Reliability |
| PID G003001 | GMS Visitor Centre Water Supply Project | Reputational |
| PIDG000131 | GMS Intake Operating Gate and Intake Maintenance Gate Refurbishment | Reliability |
| PID G003336 | GMS Intake Operating Gate Hydraulic Upgrade | Reliability |
| PID G003826 | GMS Pauwels Transformer Life Extension | Reliability |
| PID G000133 | GMS Transformers Phase 4 Replacement | Reliability |
| PID G000130 | GMS U1 - U10 Water Passage Refurbishment | Financial, Safety, Reliability |
| PID G000120 | GMS U9 - U10 Circuit Breaker Replacement | Reliability |
| PID G003837 | GMS U5 Stator Replacement | Reliability |
| PID G000124 | GMS U6 Stator Replacement | Reliability |
| PID G000126 | GMS U5 - U8 Generator Air Cooler Replacement | Reliability |
| PID G000109 | W.A.C. Bennett Dam - Spillway Seismic Upgrade | Safety |

1. Not included in the preamble list above but included in Appendix J.

**With regards to project duration, there are varying durations, from one to ten years, and each project had or will have an in-service date.**

**BC Hydro is coordinating projects, in that outage schedules and resource schedules have been managed to minimize outages, to maximize the amount of work performed in each outage, and to make appropriate resources available for the projects as required. If "managed together" is intended to mean combination into a reduced number of projects, then BC Hydro does not believe that such closer integration of the projects would reduce business risk – the drivers, implementation approaches, and project requirements are too disparate. Combinations of unrelated skill requirements and activities into a project would require greater supervision and management effort, and the extended timelines would make project estimates less certain.**

**253.0 F. CHAPTER 6 – CAPITAL EXPENDITURES**

**Reference: CAPITAL EXPENDITURES**
**Exhibit B-5, BCUC IR 116.8**
**G.M. Shrum G1 to 10 Control System Upgrade Project**

In response to BCUC IR 116.8, BC Hydro provided a list of projects that have or will take place at GMS concurrently with the $75 million GMS G1 to 10 Control System Upgrade Project:

- GMS Unit 1-5 Turbine Rehabilitation Project (PID G000611),
- GMS G1-G5 Rotor Rehabilitation Project (PID G000651),
- GMS Spillway Chute Interim Upgrade Project (PID G000595),
- GMS W.A.C. Bennett Dam Riprap Project (PID G000623),
- GMS Spillway Gate Upgrade Project (PID G000656),
- GMS W.A.C. Bennett Dam - Core Upgrades Project (PID G000110),
- GMS Draft Tube Maintenance Gates Refurbishment Project (PID G000129),
- GMS Control System Upgrade Project (PID 93687),
- GMS 500kV Disconnect Switch Replacement/Refurbishment Project (PID G000135),
- GMS Upgrade HVAC System Project (PID G000114),
- GMS Replace Unit 1-5 Exciter Transformers Project (PID G000121),
- GMS Unwatering System Refurbishment Project (PID G000128),
- GMS Seal Low Level Outlets Project (PID G003555),
- GMS Auxiliary Building Service Upgrade (PID G0030088), and
- GMS Visitor Centre Water Supply Project (PID G003001).

Future projects forecast to be greater than $5 million at the GMS facility which may run concurrently with the GMS G1-10 Control Systems Upgrade Project include:

- GMS Intake Operating Gate and Intake Maintenance Gate Refurbishment (PIDG000131)
- GMS Intake Operating Gate Hydraulic Upgrade (Planning ID G003336)
- GMS Pauwels Transformer Life Extension (PID G003826)
- GMS Transformers Phase 4 Replacement (PID G000133)
- GMS U1 - U10 Water Passage Refurbishment (PID G000130)
- GMS U9 - U10 Circuit Breaker Replacement (PID G000120)
- GMS U5 Stator Replacement (PID G003837)
- GMS U6 Stator Replacement (PID G000124)
- GMS U5 - U8 Generator Air Cooler Replacement (PID G000126)
- W.A.C. Bennett Dam - Spillway Seismic Upgrade (PID G000109)

2.253.4 Please explain whether these projects constitute a program of projects. If not, please explain why.

**RESPONSE:**

**The projects taking place at GMS do not constitute a Program of Projects. A Program of Projects is intended for situations where a common business driver results in multiple similar projects in response, all of which together achieve the common objectives articulated in the business case.**

**Please refer to BC Hydro's response to BCUC IR 2.253.1 where we explain that the projects at GMS range from heavy civil construction, such as blasting and quarrying, to upgrades of mechanical systems such as gates and hoists, to installation of sophisticated electronic control and communication systems.**

**Please also refer to BC Hydro's response to BCUC IR 2.252.4 where we explain why BC Hydro does not consider a group of ongoing projects, at a single site, to constitute a Program of Projects.**

**254.0 F. CHAPTER 6 – CAPITAL EXPENDITURES**

**Reference: CAPITAL EXPENDITURES**
**Exhibit B-5, BCUC IR 110.1**
**Ex-plan projects**

In its response to BCUC IR 110.1, BC Hydro stated:

> BC Hydro considers an ex-plan project as a project that was not included in the approved Capital Plan (fiscal 2020 to fiscal 2024) or a project that was in the approved Capital Plan outside of the current test period, but that is required to address an immediate need such that the project must be advanced into the current year.
>
> When submitting a project as ex-plan, the responsible KBU must validate that the project meets the ex-plan criteria described above. In addition, the responsible KBU will determine if the ex-plan project's capital expenditures in the current fiscal year can be accommodated within its own current fiscal year capital plan. If the KBU cannot manage the additional investment within their current fiscal year capital plan, redirection from another KBU will be considered based on the latest portfolio forecasts…
>
> Three ex-plan projects related to transmission system upgrades for the Liquefied Natural Gas and Oil and Gas sectors in the North Coast and Peace regions have been initiated since the fiscal 2020 to fiscal 2024 Capital Plan was finalized. These additional investments and the related increase in unplanned future amortization will be offset by the expected increase in future revenue related to these projects. These projects and any other ex-plan projects will be incorporated into the capital plan during the annual capital planning cycle in 2019 as explained above.

2.254.1 In the above preamble, BC Hydro stated: "If the KBU cannot manage the additional investment within their current fiscal year capital plan, redirection from another KBU will be considered based on the latest portfolio forecasts." Please confirm, or explain otherwise, that "redirection" in this context means that BC Hydro will move excess funds from other KBU to meet additional capital funding needs in any particular KBU.

**RESPONSE:**

**Redirection in this context means that BC Hydro would reallocate funds from other KBUs to meet additional capital funding needs for an ex-plan project. Funds from other KBUs may be available for reallocation due to a change in the timing or**

**forecast of capital expenditures. If no funds are available for reallocation, the proposed ex-plan investment will be prioritized against the entire capital portfolio in determining whether and how to accommodate the ex-plan request. This may include making changes to the timing of other investments to fund a required ex-plan investment.**

**254.0 F. CHAPTER 6 – CAPITAL EXPENDITURES**

**Reference: CAPITAL EXPENDITURES**
**Exhibit B-5, BCUC IR 110.1**
**Ex-plan projects**

In its response to BCUC IR 110.1, BC Hydro stated:

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>
> Three ex-plan projects related to transmission system upgrades for the Liquefied Natural Gas and Oil and Gas sectors in the North Coast and Peace regions have been initiated since the fiscal 2020 to fiscal 2024 Capital Plan was finalized. These additional investments and the related increase in unplanned future amortization will be offset by the expected increase in future revenue related to these projects. These projects and any other ex-plan projects will be incorporated into the capital plan during the annual capital planning cycle in 2019 as explained above.

2.254.2 Please list the three ex-plan projects mentioned in the quote in the preamble. Include scope details and project budget amounts. Please explain why each of these projects was deemed necessary to be advanced outside of the normal capital planning process.

**RESPONSE:**

**Please refer to the table below for a list of the three ex-plan projects mentioned in the preamble.**

| **Project Name:** | **Bear Mountain Terminal (BMT) To Dawson Creek (DAW) Transmission Voltage Conversion** |
|---|---|
| **Investment Planning ID:** | **901573** |
| **Development Phase:** | **Identification** |
| **Forecasted Capital Cost:** | **TBD** |
| **Forecasted In-Service Date:** | **TBD** |
| **Description:** | **In the Bear Mountain Terminal (BMT) – Dawson Creek (DAW) Transmission voltage conversion project, two 138 kV lines (1L348 and 1L350) between BMT and DAW substations, which were constructed to 230 kV standard as part of the Dawson Creek Area Transmission (DCAT) project, will be converted to 230 kV operation.**<br>**The purpose of this project is to further increase the capacity of the electricity supply to the Dawson Creek area to enable BC Hydro to supply reliable power to industrial customers in that area and help reduce greenhouse gas emissions by enabling natural gas industrial customers to use clean electricity rather than fossil fuels to power their operations. This project will help British Columbia achieve the Province's CleanBC goals of increasing access to clean electricity for large industrial operations such as planned natural gas production in the Peace Region.** |

| **Project Name:** | **North Montney – Transmission Development** |
|---|---|
| **Investment Planning ID:** | **901572** |
| **Development Phase:** | **Identification** |
| **Forecasted Capital Cost:** | **TBD** |
| **Forecasted In-Service Date:** | **TBD** |
| **Description:** | **The purpose of this project is to provide transmission facilities in the North Montney area to supply a number of gas producers that have expressed interest in grid supply service from BC Hydro.**<br>**A number of gas producers in the North Montney area located northeast of BC Hydro's G.M. Shrum generating station have expressed interest in grid supply service from BC Hydro. However, there are currently no transmission facilities in this area, which presents a significant barrier for these gas producers to connect to BC Hydro's grid in terms of cost. Providing transmission facilities in this area would reduce the cost of interconnection and provide incentive for these upstream gas producers to electrify their operations.**<br>**A 230 kV transmission extension into the North Montney area would contribute to the Province's CleanBC goal of increasing access to clean electricity for large operations and facilitate interconnection to provide clean electricity to planned natural gas productions. As a result, this presents an opportunity to access Federal Government funding for up to 50 per cent of the expansion costs through the Investing in Canada Infrastructure Program (ICIP), which is designed to assist in the expansion of transmission systems which would result in the reduction of greenhouse gas emissions.** |
| **Project Name:** | **Prince George to Terrace Capacitors** |
| | **Please refer to BC Hydro's response to BCUC IR 2.247.6.1 for information on this project.** |

**Each of the three projects listed above was approved as an ex-plan project in order to:**

- **Encourage new load growth and revenue, and ensure that BC Hydro is able to provide transmission services in the timeline required for customer need and desire to electrify their operations;**
- **Support the CleanBC Plan to provide clean electricity to planned natural gas and LNG production; and**
- **Access federal investment to reduce costs to BC Hydro's customers.**

**As discussed in BC Hydro's response to BCUC IR 2.254.2.1, capital investment in these ex-plan projects will be minimized until load commitments from potential customers are confirmed.**

**254.0 F. CHAPTER 6 – CAPITAL EXPENDITURES**

**Reference: CAPITAL EXPENDITURES**
**Exhibit B-5, BCUC IR 110.1**
**Ex-plan projects**

In its response to BCUC IR 110.1, BC Hydro stated:

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>
> When submitting a project as ex-plan, the responsible KBU must validate that the project meets the ex-plan criteria described above. In addition, the responsible KBU will determine if the ex-plan project's capital expenditures in the current fiscal year can be accommodated within its own current fiscal year capital plan. If the KBU cannot manage the additional investment within their current fiscal year capital plan, redirection from another KBU will be considered based on the latest portfolio forecasts…
>
> Three ex-plan projects related to transmission system upgrades for the Liquefied Natural Gas and Oil and Gas sectors in the North Coast and Peace regions have been initiated since the fiscal 2020 to fiscal 2024 Capital Plan was finalized. These additional investments and the related increase in unplanned future amortization will be offset by the expected increase in future revenue related to these projects. These projects and any other ex-plan projects will be incorporated into the capital plan during the annual capital planning cycle in 2019 as explained above.

2.254.2 Please list the three ex-plan projects mentioned in the quote in the preamble. Include scope details and project budget amounts. Please explain why each of these projects was deemed necessary to be advanced outside of the normal capital planning process.

2.254.2.1 Please indicate from which department and line of business the funds for these projects were reallocated.

**RESPONSE:**

**No funds have been reallocated for the Bear Mountain Terminal (BMT) To Dawson Creek (DAW) Transmission Voltage Conversion (Planning ID 901573), North Montney Power Supply (Planning ID 901572) or Prince George to Terrace**

**Capacitors (Planning ID 901574) projects. Capital investment in these ex-plan projects will be minimized until load commitments from potential customers are confirmed. As this initial investment can be accommodated within the Lines Asset Planning KBU's current fiscal year capital plan, reallocation of funding from other KBUs was not required.**

**When potential customers confirm sufficient load commitments, the projects will proceed in accordance with BC Hydro's financial approval procedures as described in section 6.4.10 of Chapter 6 of the Application. In addition, once these customer commitments are confirmed, the required investments and associated future revenue will be included in the annual capital planning process as described in section 6.3 of Chapter 6 of the Application.**

**254.0 F. CHAPTER 6 – CAPITAL EXPENDITURES**

**Reference: CAPITAL EXPENDITURES**
**Exhibit B-5, BCUC IR 110.1**
**Ex-plan projects**

In its response to BCUC IR 110.1, BC Hydro stated:

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>
> When submitting a project as ex-plan, the responsible KBU must validate that the project meets the ex-plan criteria described above. In addition, the responsible KBU will determine if the ex-plan project's capital expenditures in the current fiscal year can be accommodated within its own current fiscal year capital plan. If the KBU cannot manage the additional investment within their current fiscal year capital plan, redirection from another KBU will be considered based on the latest portfolio forecasts…
>
> Three ex-plan projects related to transmission system upgrades for the Liquefied Natural Gas and Oil and Gas sectors in the North Coast and Peace regions have been initiated since the fiscal 2020 to fiscal 2024 Capital Plan was finalized. These additional investments and the related increase in unplanned future amortization will be offset by the expected increase in future revenue related to these projects. These projects and any other ex-plan projects will be incorporated into the capital plan during the annual capital planning cycle in 2019 as explained above.

2.254.3 Please explain who approves ex-plan project decisions and how these decisions are communicated to the BCUC.

**RESPONSE:**

**As discussed in section 6.3.5 of Chapter 6 of the Application, ex-plan expenditure requests less than $3 million are reviewed and approved at the Enterprise Capital Planning Working Group level, and requests greater than $3 million are reviewed and approved at the Capital Delivery Management Committee level. The Capital Delivery Management Committee and Enterprise Capital Planning Working Group manage continuing, planned and ex-plan investments such that the total cumulative portfolio capital expenditures and additions for the Test Period, excluding Site C, are not exceeded. If ex-plan projects will result in exceeding the**

**planned Test Period total cumulative capital expenditures and additions, additional Executive and Board approval would be required. Once an ex-plan project has been approved by either the Enterprise Capital Planning Working Group, or the Capital Delivery Management Committee, it follows the appropriate BC Hydro financial review and approval process, as described in section 6.4.10 of Chapter 6 in the Application.**

**The Enterprise Capital Planning Working Group is chaired by the Director of Lines Asset Planning, and the members are representatives with capital planning expertise from Integrated Planning, Technology, Properties, Fleet, and Finance. The Capital Delivery Management Committee is chaired by the Senior Vice President of Integrated Planning, and the members are Director or Vice President representation from Integrated Planning, Technology, Properties, Fleet, Finance, Project Delivery, Operations, and Program and Contract Management.**

**Ex-plan projects will be included in subsequent revenue requirements applications to the extent that they meet the materiality limit for inclusion in Appendix I and Appendix J.**

**In addition, please refer to BC Hydro's response to BCUC IR 2.31.1 in BC Hydro's Capital Expenditures and Project Review proceeding, which is provided as Attachment 1 to this response, where we discuss how BC Hydro will communicate extensions over the materiality limit that are identified between revenue requirements applications.**

| **British Columbia Utilities Commission**<br>Information Request No. **2.31.1** Dated: **June 5, 2019**<br>British Columbia Hydro & Power Authority<br>Response issued **July 4, 2019** | Page 1<br>of 1 |
|---|---|
| British Columbia Hydro & Power Authority<br>**Review of the Regulatory Oversight of Capital Expenditures and Projects** | **Exhibit:**<br>**B-16** |

**31.0 D. CPCN AND SECTION 44.2 APPLICATIONS**

**Reference: BC HYDRO REVISED PROPOSAL**
**Exhibit B-15, p. 56; UCA section 45(6)**
**Annual Report Statement of Planned Extensions**

The BC Hydro Revised Proposal at page 56 states:

The Annual Report has historically included the following information on capital expenditures and projects:

(a) a summary of capital expenditures by capital category;
(b) a listing of the planned expenditures in the current fiscal year for projects over the materiality limit ($2 million for Information Technology projects, $5 million for all other capital projects), and Demand Side Management;
(c) an indication of which projects are considered extensions, pursuant to section 45(6) of the UCA for all projects over the materiality limit; and
(d) a listing of projects over the major project threshold and the anticipated type of regulatory filings.

Starting in fiscal 2017, changes to the Annual Report have increased the transparency, improved efficiency, reduced redundancy, and provided more relevant information on capital expenditures and projects.

Section 45(6) of the UCA states:

A public utility must file with the commission at least once each year a statement in the form proscribed by the commission of the extensions to its system that it plans to construct.

2.31.1 For a year in which an RRA is not filed, please discuss the advantages and disadvantages of filing near the start of the fiscal year, versions of Appendices I and J providing information about planned extensions and other capital expenditures for the year to fulfil the requirements of section 45(6).

**RESPONSE:**

**As discussed in BC Hydro's response to BCUC IR 1.14.1, we do not consider it practical to provide updates to Appendices I and J from a revenue requirements application on an annual basis.**

**To fulfill the requirements of section 45(6), BC Hydro will provide a list of extensions over the materiality limit in the Annual Report to the BCUC including projects that were identified in years between revenue requirements applications.**

**254.0 F. CHAPTER 6 – CAPITAL EXPENDITURES**

**Reference: CAPITAL EXPENDITURES**
**Exhibit B-5, BCUC IR 110.1**
**Ex-plan projects**

In its response to BCUC IR 110.1, BC Hydro stated:

> BC Hydro considers an ex-plan project as a project that was not included in the approved Capital Plan (fiscal 2020 to fiscal 2024) or a project that was in the approved Capital Plan outside of the current test period, but that is required to address an immediate need such that the project must be advanced into the current year.
>
> When submitting a project as ex-plan, the responsible KBU must validate that the project meets the ex-plan criteria described above. In addition, the responsible KBU will determine if the ex-plan project's capital expenditures in the current fiscal year can be accommodated within its own current fiscal year capital plan. If the KBU cannot manage the additional investment within their current fiscal year capital plan, redirection from another KBU will be considered based on the latest portfolio forecasts…
>
> Three ex-plan projects related to transmission system upgrades for the Liquefied Natural Gas and Oil and Gas sectors in the North Coast and Peace regions have been initiated since the fiscal 2020 to fiscal 2024 Capital Plan was finalized. These additional investments and the related increase in unplanned future amortization will be offset by the expected increase in future revenue related to these projects. These projects and any other ex-plan projects will be incorporated into the capital plan during the annual capital planning cycle in 2019 as explained above.

2.254.4 Please confirm, or explain otherwise, that if any ex-plan project met the appropriate criteria, a CPCN application or capital expenditure filing would be made to the BCUC.

**RESPONSE:**

**Confirmed. A CPCN application or capital expenditure filing would be made to the BCUC for any ex-plan project that met the appropriate criteria and was not exempted.**

**255.0 F. CHAPTER 6 – CAPITAL EXPENDITURES**

**Reference: CAPITAL EXPENDITURES**
**Exhibit B-1, Section 2, pp. 2-16–2-17; Section 6; Appendix J; Appendix K**
**General capital expenditures**

In Section 2 of the Application, BC Hydro discusses the filing of CPCN applications:

> BC Hydro files applications for a CPCN or acceptance of a capital expenditure schedule for projects with an authorized cost estimate that exceeds the financial thresholds in BC Hydro's 2010 Capital Project Filing Guidelines. BC Hydro has proposed an update to these guidelines in the Review of the Regulatory Oversight of Capital Expenditures and Projects proceeding currently before the BCUC. The BCUC also has discretion to direct BC Hydro to file a CPCN for projects that are below the financial thresholds, if they are extensions to BC Hydro's system.

2.255.1 Please confirm, or explain otherwise, that BC Hydro proposes to keep the CPCN filing thresholds at the current levels during the Test Period.

**RESPONSE:**

**Not Confirmed. BC Hydro is seeking approval of its proposed 2018 Capital Filing Guidelines as an outcome of the BCUC's Review of the Regulatory Oversight of Capital Expenditures and Projects (Capital Expenditures and Projects Review) proceeding. BC Hydro anticipates that a decision in that proceeding will be issued prior to the end of calendar year 2019. If the BCUC approves the proposed 2018 Capital Filing Guidelines, including the proposed expenditure (filing) thresholds, BC Hydro will adopt the 2018 Capital Filing Guidelines.**

**The major project application expenditure filing thresholds in the 2010 Capital Project Filing Guidelines (current) and the 2018 Capital Filing Guidelines (proposed) are set out in the table below.**

| Expenditure (filing) Thresholds ($ million) | 2018 Capital Filing Guidelines Threshold Categories | 2010 Capital Project Filing Guidelines Threshold Categories |
|---|---|---|
| **100** | **Power System*** | **Generation and Transmission, including Substation Distribution Assets** |
| **50** | **Buildings** | **Buildings and Distribution** |
| **20** | **Information Technology** | **Information Technology and Telecommunication** |

*** Power system projects are those required to effectively generate, transmit, and distribute electricity to BC Hydro's residential, commercial, and industrial customers.**

**255.0 F. CHAPTER 6 – CAPITAL EXPENDITURES**

**Reference: CAPITAL EXPENDITURES**
**Exhibit B-1, Section 2, pp. 2-16–2-17; Section 6; Appendix J; Appendix K**
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2.255.2 Please confirm, or explain otherwise, that if after refinement but before construction, BC Hydro foresees that any of its capital projects' budgets will be revised to potentially exceed the CPCN threshold, BC Hydro will file CPCN applications for these refined projects with the BCUC for approval.

**RESPONSE:**

**Consistent with BC Hydro proposed 2018 Capital Filing Guidelines, BC Hydro will file a CPCN application if the authorized cost for an extension project exceeds the major project expenditure (filing) thresholds based on the Preliminary Design cost estimate. As shown in Figure 6-13 of Chapter 6 of the Application, this is the cost estimate that BC Hydro presents for BCUC regulatory approval or acceptance and for full funding implementation approval from BC Hydro's Board of Directors. The Preliminary Design cost estimate has an accuracy range of +15 per cent to -10 per cent and is developed in the Definition phase.**

**BC Hydro recognizes that under section 45(5) of the *Utilities Commission Act*, the BCUC has the discretion to direct BC Hydro to file a CPCN for an extension "not later than 30 days after construction of the extension is begun".**

**Given BC Hydro's capital project delivery governance processes, it is very unlikely that a project's authorized cost would be revised to exceed the major project expenditure (filing) threshold after it has advanced into the Implementation phase, but prior to the commencement of construction.**

**If this scenario were to occur, BC Hydro would inform the BCUC of the change in the authorized cost of the project and would provide the BCUC with its evaluation of whether a CPCN was warranted, considering factors such as:**

- **The negative impacts from a delay in addressing safety, reliability or environmental risks;**
- **An increase in a project's financial cost;**
- **A loss of financial value; and**
- **The reasons for the increase in the authorized cost.**

**This approach is consistent with the Revised Proposal in the Capital Expenditure Review Proceedings. The BCUC can exercise effective oversight over BC Hydro's capital investments through prospective and retrospective reviews in major projects, revenue requirement and Integrated Resources Plan proceedings, while recognizing the importance of allowing BC Hydro to proceed with required investments in a timely manner.**

**255.0 F. CHAPTER 6 – CAPITAL EXPENDITURES**

**Reference: CAPITAL EXPENDITURES**
**Exhibit B-1, Section 2, pp. 2-16–2-17; Section 6; Appendix J; Appendix K**
**General capital expenditures**

In Section 2 of the Application, BC Hydro discusses the filing of CPCN applications:

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2.255.3 If the BCUC were to find that BC Hydro's capital expenditure program (as filed) required reductions, which projects or programs or budgets would BC Hydro propose to cut back. Please explain why.

**RESPONSE:**

**BC Hydro believes that the capital expenditures and additions proposed in the Application are reasonable and in the interest of ratepayers, taking into account BC Hydro's goals, including affordability, safety, and reliability. As discussed in section 6.3.2.3 of Chapter 6 of the Application, we are monitoring the load forecast, asset condition and asset performance to sustain the long-term performance of key assets and maintain customer service levels. If capital expenditures were reduced, we would expect asset condition and asset health to degrade more than anticipated, with a corresponding negative impact on customer service levels.**

**As explained in sections 6.3.2.1 and 6.3.2.2 of Chapter 6 of the Application BC Hydro has already reduced the overall portfolio level of growth and sustainment expenditures relative to previously planned amounts. If the BCUC determines that further reductions are warranted, the adjustments that BC Hydro would make to its capital investments over the test period would depend on the reasons for the BCUC's decision.**

**256.0 F. CHAPTER 6 – CAPITAL EXPENDITURES**

**Reference: CAPITAL EXPENDITURES**
**Exhibit B-1, Appendix J, p. 82; Exhibit B-5, BCUC IR 121.4**
**Capacitor Bank Project alternatives**

BC Hydro states it is planning projects to add capacitor banks to its transmission grid, including the Peace to Kelly Lake Capacitors project:

> The Peace Region is a major generation source for BC Hydro, generating enough power to meet about 36 per cent of the total energy demand in the province… The existing transfer demand on the Peace to Kelly Lake transmission section is near 95 per cent of the transfer capacity of the lines. The addition of Site C and other generation in the Peace Region will cause the required power transfer to exceed the available transmission capacity… and will require significant reinforcements starting in 2024 to deliver the power from the Peace Region to the south of the province without constraints.

In response to BCUC IR 121.4, BC Hydro wrote of Project Alternatives that were dismissed:

> Alternative (iii): Build a new transmission line from Peace Canyon to Williston Substation and provide additional 15 per cent series compensation to 5L11, 5L12, and 5L13: This third alternative of building a new transmission line was eliminated due to the extensive project footprint and environmental impacts, which were expected to represent a significant schedule risk to the project.

2.256.1 Please confirm, or explain otherwise, that the purpose of installing capacitor banks is to increase the capacity to transfer power on a transmission line.

**RESPONSE:**

**BC Hydro confirms that the purpose of installing series capacitor banks is to increase the transfer capacity of the existing transmission lines.**

**56.0 F. CHAPTER 6 – CAPITAL EXPENDITURES**

**Reference: CAPITAL EXPENDITURES**
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2.256.2 Please explain what benefits would result from building additional transmission lines as opposed to adding series capacitor stations to existing lines, as proposed in the Peace to Kelly Lake Capacitor Project.

**RESPONSE:**

**In general, adding a new transmission line to an existing transmission corridor will increase the capability of the corridor. In particular, a new line would provide the following benefits:**

1. **Provide an additional path for power flow, increasing the thermal capacity of the transmission corridor;**

**2. Reduce transmission losses due to the additional power flow path, as more fully discussed in BC Hydro's response to BCUC IR 2.256.3;**

**3. Increase the reliability of the system, if the new line is over a different corridor, by reducing exposure to single points of failure; and**

**4. Allow for future increases in transfer capability by increasing the series compensation level as required.**

**While new transmission lines provide significant benefits, they require significant investment and may impose additional environmental and stakeholder impacts. Please refer to BC Hydro's response to BCUC IR 2.256.3.2 for a discussion of how these factors were considered in the Peace to Kelly Lake corridor.**

**A new transmission line from Peace Canyon to Williston was considered as an alternative to the series compensation increase to 65 per cent in the Peace to Kelly Lake Capacitor project. This alternative was ruled out due to high cost, increased footprint and environmental impacts. The new transmission line would also require 50 per cent series compensation to be installed in the middle of the line, because of the length of the line and to match the compensation level of the existing lines.**

**256.0 F. CHAPTER 6 – CAPITAL EXPENDITURES**

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2.256.3 Please explain how the ability to transfer power differs between building a parallel transmission line and adding series capacitor stations as proposed in the Peace to Kelly Lake Capacitor Project.

**RESPONSE:**

**Adding a parallel transmission line provides a new path for power to flow between stations. The parallel path reduces the impedance to the flow of electricity. A new line increases the power transfer capability of the transmission corridor by increasing thermal, voltage and transient stability limits. In addition, a new line reduces line losses by reducing the current on each line, since line losses are proportional to the line resistance and the square of the current.**

**Series capacitors are installed in series with the transmission line at series capacitor stations. Series capacitors provide negative reactance to the**

**transmission line, and adding series capacitors (or series compensation) also reduces impedance to the flow of electricity. Consequently the voltage and transient stability limits of the transmission corridor will increase, which increases the power transfer capability of the transmission corridor. However, adding series capacitors will not increase the thermal rating of the line. Also, series capacitors do not reduce line losses because they do not change the current on each line for a given amount of power transfer.**

**256.0 F. CHAPTER 6 – CAPITAL EXPENDITURES**

**Reference: CAPITAL EXPENDITURES**
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2.256.3 Please explain how the ability to transfer power differs between building a parallel transmission line and adding series capacitor stations as proposed in the Peace to Kelly Lake Capacitor Project.

2.256.3.1 Please explain under what conditions BC Hydro would consider building additional transmission lines instead of other options to increase transfer capacity.

**RESPONSE:**

**BC Hydro will consider building new transmission lines whenever an increase in transfer capability is required on a given transmission corridor. Building additional transmission lines is an effective solution to increase thermal, voltage and transient stability limits of the transmission system; however, building a new line can be expensive, and have public, First Nations, and environmental impacts.**

**The transfer capability of an existing transmission circuit can be increased by series compensation or shunt reactive equipment addition. There are technical limits to these approaches and they do not increase the thermal capacity of the line. Due to lower cost and impacts, increasing the transfer capability on the existing transmission circuit(s) tends to be the preferred solution when it meets the project objectives. In cases where thermal limits are binding or an increase in series or shunt compensation is not feasible, a new circuit (or re-configuration of an existing circuit) is required.**

**BC Hydro considers a number of factors to evaluate transmission reinforcement alternatives and determine a leading alternative. These factors include, but are not limited to, technical constraints, cost, public impact, First Nations impact, environmental impact, and existing and expected system needs.**

**Please refer to BC Hydro's response to BCUC IR 2.256.3.2 where we discuss how these factors were considered in the Peace to Kelly Lake corridor.**

**256.0 F. CHAPTER 6 – CAPITAL EXPENDITURES**

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2.256.3 Please explain how the ability to transfer power differs between building a parallel transmission line and adding series capacitor stations as proposed in the Peace to Kelly Lake Capacitor Project.

2.256.3.2 Please generally explain the benefits and costs of each option.

**RESPONSE:**

**The addition of series compensation or building a new parallel transmission line would meet BC Hydro's system needs for transfer capability on the Peace to Kelly corridor over the current planning horizon (to 2035). Adding a new transmission line would increase transfer capability beyond system need, but at a considerably higher cost. A new transmission circuit can be added to the corridor at a future date, if required, but it is more economic to defer that expenditure and adopt the lower-cost alternative of increasing series compensation in the near term.**

**Compared to increasing series compensation, a new parallel transmission line would:**

- **Increase the thermal limits on the corridor, thus increasing the total power transfer capability, as noted in BC Hydro's response to BCUC IR 2.256.3;**
- **Reduce line losses by approximately 100 GWh annually; and**
- **Provide a small reliability benefit through route diversity. A single event, such as an avalanche or wildfire, would be less likely to affect all circuits in the corridor. This benefit is limited, though, because the new line was planned to share an expanded right of way with the existing circuits over much or even all of the route.**

**Compared to adding a new parallel line, increasing the series compensation on the existing circuits would:**

- **Be significantly less expensive than a new transmission line. Based on conceptual-level estimates for only the northern portion of the corridor (from Peace Canyon to Williston Substation), the lifecycle cost of increasing series compensation was $210 million, compared to $520 million for the transmission line alternative (including avoided losses at $101/MWh from fiscal 2027). The cost differential between the two alternatives implies a cost of over $300/MWh to reduce line losses, which is well above current market value;**
- **Involve much lower worker safety hazards due to the much reduced level of forest clearing compared to a new or expanded right of way; reduction of the number of new transmission towers required in the northern segment from approximately 700 to approximately a dozen, thus reducing the hazards of helicopter work and work at height on transmission towers; and a reduced requirement for work in proximity to energized transmission lines; and**
- **Require a much smaller footprint, of approximately 16 hectares in the northern section, compared to 1,400 hectares for the new line alternative. The larger footprint of the transmission line was expected to increase the cost of mitigation and potential concerns from First Nations and other land users along the route, as well as requiring a significantly longer consultation and engagement process, which presented a high schedule risk to the project.**

**256.0 F. CHAPTER 6 – CAPITAL EXPENDITURES**

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2.256.3.2 Please generally explain the benefits and costs of each option.

2.256.3.2.1 Please explain how these decisions relate to the current and future capacity available on BC Hydro's transmission grid.

**RESPONSE:**

**The transmission reinforcements proposed in the Peace to Kelly Lake Capacitor Project will meet the transmission requirements for Site C generation and any expected additional renewable generation up to fiscal 2035. Future generation additions in the Peace Region may trigger additional transmission reinforcements to deliver the power from the Peace Region to load centers.**

**256.0 F. CHAPTER 6 – CAPITAL EXPENDITURES**

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2.256.4 Please explain how the decision to install capacitor banks or stations versus additional transmission lines impacts BC Hydro's ability to deliver power to new loads.

**RESPONSE:**

**Capacitor stations or new transmission lines would each enable BC Hydro to deliver power to serve additional load. Please refer to BC Hydro's response to BCUC IR 2.256.3.1 for a discussion of the considerations in determining the appropriate alternative.**

**256.0 F. CHAPTER 6 – CAPITAL EXPENDITURES**

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2.256.5 Please explain how BC Hydro's transmission losses will be impacted after the completion of the additional series capacitor station projects, both in the Northwest and on the North to South 500kV lines.

**RESPONSE:**

**Please refer to BC Hydro's response to BCUC IR 2.256.3 where we explain that transmission losses are not affected by increases in series compensation. As a result, transmission losses for a given power transfer level on the Peace-to-Kelly (north-south) and Williston to Kitimat (northwest) transmission corridors will not be impacted by the Peace to Kelly Lake Capacitors Project.**

**257.0 F. CHAPTER 6 – CAPITAL EXPENDITURES**

**Reference: CAPITAL EXPENDITURES**
**Exhibit B-1, Table 6-56, p. 6-152;**
**Exhibit B-5, BCUC IR 123.1, 123.2.1, 123.3, 123.5, 123.9, 123.13**
**Cybersecurity**

In its response to BCUC IR 123.1 and 123.2.1, BC Hydro stated:

> BC Hydro uses a risk-based approach to cybersecurity and information protection and is currently conducting a risk assessment of the environments identified by the Auditor General's report. Following the results of this assessment, BC Hydro will be able to better prioritize investments and efforts that will address the audit recommendations.
>
> The assessment is expected to conclude in fall 2019. An action plan and timelines will be determined based on the results of the risk assessment.
>
> […]
>
> The cost to perform the risk assessment is estimated at $0.3 million and is not included in the Application.

2.257.1 Please explain where the $0.3 million budget to perform the risk assessment is allocated and why it is not included in the Application.

**RESPONSE:**

**The estimated $0.3 million cost to perform the risk assessment is an unplanned expenditure which will be managed within the Technology Key Business Unit operating budget. This cost was not included in the Application as the need was not known as of the Application currency date.**

**257.0 F. CHAPTER 6 – CAPITAL EXPENDITURES**

**Reference: CAPITAL EXPENDITURES**
**Exhibit B-1, Table 6-56, p. 6-152;**
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2.257.2 Please explain whether there are any other assessments or studies being performed by BC Hydro in the Test Period which are not included in the budgets submitted in the Application.

**RESPONSE:**

**No other assessments are being performed directly related to ICS (Industrial Control Systems) which was the subject of the Auditor General's audit.**

**BC Hydro is currently conducting one other Cybersecurity related assessment on the feasibility of an enterprise-wide 24x7 Cybersecurity Operations Center. The cost is expected to be less than $0.1 million and will be managed within the Technology KBU operating budget.**

**257.0 F. CHAPTER 6 – CAPITAL EXPENDITURES**

**Reference: CAPITAL EXPENDITURES**
**Exhibit B-1, Table 6-56, p. 6-152;**
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2.257.2 Please explain whether there are any other assessments or studies being performed by BC Hydro in the Test Period which are not included in the budgets submitted in the Application.

2.257.2.1 If yes, please explain where the budgets are allocated for these assessments or studies.

**RESPONSE:**

**Please refer to BC Hydro’s response to BCUC IR 2.257.2 where we explain that while no other assessments are being performed directly related to ICS (Industrial Control Systems), BC Hydro is currently conducting two other assessments related to Cybersecurity, both of which include unplanned expenditures.**

**257.0 F. CHAPTER 6 – CAPITAL EXPENDITURES**

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2.257.2 Please explain whether there are any other assessments or studies being performed by BC Hydro in the Test Period which are not included in the budgets submitted in the Application.

2.257.2.2 Please explain whether BC Hydro considers that it performs a sufficient number of risk assessment or studies related to Cybersecurity, and whether it has sufficient resources to perform risk assessments or studies.

**RESPONSE:**

**Yes, BC Hydro considers that it performs a sufficient number of risk assessments related to cybersecurity and has sufficient resources to perform these assessments.**

**Currently, BC Hydro performs risk assessments for all Technology projects and initiatives. The cybersecurity threat landscape has been growing every year over the last decade, and BC Hydro expects that this trend will continue into the foreseeable future. BC Hydro regularly assesses its resource needs and we expect that more resources will be required to keep pace with the increasing scope and sophistication of cybersecurity threats in the future.**

**257.0 F. CHAPTER 6 – CAPITAL EXPENDITURES**

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2.257.3 Please discuss whether BC Hydro plans to file the cybersecurity risk assessment on industrial control systems as an evidentiary update following its completion in fall 2019.

**RESPONSE:**

**This answer also responds to BCUC IRs 2.257.3.1 and 2.257.4.**

**At this time, the specific timelines for the cybersecurity risk assessment on industrial control systems have not been finalized and accordingly, BC Hydro does not plan to file the risk assessment or an action plan and timeline based on its results, in this proceeding.**

**BC Hydro expects the content of the risk assessment, action plan and timelines to be highly confidential. Once complete, BC Hydro could file these materials with the BCUC on a confidential basis, upon request.**

**257.0 F. CHAPTER 6 – CAPITAL EXPENDITURES**

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2.257.3 Please discuss whether BC Hydro plans to file the cybersecurity risk assessment on industrial control systems as an evidentiary update following its completion in fall 2019.

2.257.3.1 If not, please discuss whether BC Hydro plans to file the report with the BCUC outside of this proceeding. If not, please explain why.

**RESPONSE:**

**Please refer to BC Hydro's response to BCUC IR 2.257.3.**

**257.0 F. CHAPTER 6 – CAPITAL EXPENDITURES**

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**Exhibit B-1, Table 6-56, p. 6-152;**
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2.257.4 Please discuss whether BC Hydro plans to file an action plan and timelines based on the results of the risk assessment mentioned above as an evidentiary update or as a filing outside of this proceeding, following its completion. If not, please explain why.

**RESPONSE:**

**Please refer to BC Hydro's response to BCUC IR 2.257.3.**

**257.0 F. CHAPTER 6 – CAPITAL EXPENDITURES**

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> The cost to perform the risk assessment is estimated at $0.3 million and is not included in the Application.

2.257.5 Please explain whether BC Hydro has chosen to take any immediate actions following the public release of the recommendations highlighted in the Auditor General's report, ahead of the formal risk assessments and plans, in order to address any of the areas of concern.

**RESPONSE:**

**BC Hydro takes a risk based approach to cybersecurity and information protection. BC Hydro is conducting a risk assessment of the environments identified by the Auditor General's report to better prioritize investments and efforts that will address the audit recommendations.**

**BC Hydro continuously improves security processes and implements new controls through active projects. For example, BC Hydro has improved security controls for transient and removable devices through the NERC CIPv6 project. These improvements have been made to all facilities, not just those subject to NERC CIP standards. We are also improving our Cybersecurity Incident Response Plan and are investigating the feasibility of a 24x7 Cybersecurity Operations Center.**

**257.0 F. CHAPTER 6 – CAPITAL EXPENDITURES**

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**Cybersecurity**

In its response to BCUC IR 123.3, BC Hydro wrote of its investments in its North American Electric Reliability Corporation (NERC) critical infrastructure protection (CIP) version 5 (v5) compliance initiative:

The purpose of the initiative is to upgrade electronic and physical security for computer/electronic equipment used to control and to monitor industrial control systems connected to the Bulk Electric System to meet compliance standards defined by the North American Electric Reliability Corporation (NERC) associated with critical infrastructure. As of March 31, 2019, $30.2 million has been spent on these initiatives, including both capital and associated operating expenditures. The NERC CIP v5 Compliance initiative consists of the following five initiatives:

1. Transmission Stations - $18.6 million;
2. Generation Stations - $2.7 million;
3. Grid Operations - $3.1 million;
4. Technology - $5.8 million;
5. Physical Key Management Work Package – addresses physical spaces containing Cyber Assets and is funded by the above initiatives;

These initiatives started in 2016 and BC Hydro achieved compliance with NERC CIP Version 5 by October 1, 2018. Further work on the Transmission Stations initiatives will continue through to 2023 to extend the use of the Station Gateway System to automate a number of manual compliance processes.

2.257.6 Please provide the project scope of each of the five projects identified in the preamble above.

**RESPONSE:**

**The scope of each of the five projects identified in the preamble to the question is described below.**

- **Transmission Stations:**
  - **Implement Critical Infrastructure Protection (CIP) v5 requirements at 44 Medium Impact transmission stations;**

- ▶ **Implement updates to a variety of protection and control devices (e.g., security patches, anti-malware, event logging, password changes) and collect baseline information based on engineering work instructions;**
- ▶ **Document compliance procedures and verify compliance evidence; and**
- ▶ **Implement a middleware system to help automate compliance tasks to reduce manual, on-site compliance activities, enabling automated data collection and configuration monitoring.**

- **Generation Stations:**
  - ▶ **Implement CIPv5 requirements at three medium impact generating stations including installation of high-availability firewalls for redundancy and to support removal of virtual networks;**
  - ▶ **Install Generation App Servers to support controlled remote access to CIP systems;**
  - ▶ **Implement CIPv5 requirements for serial-based CIP systems; and**
  - ▶ **Update CIP compliance documentation and evidence.**
- **Grid Operations:**
  - ▶ **Implement CIPv5 requirements at high impact control centres and five associated data concentration point sites, including:**
    - ▪ **Installation of GRID Console Servers to support controlled remote access to the Energy Management System;**
    - ▪ **Integration of the Tripwire system with the Mandatory Reliability Standards (MRS) Compliance System to automate collection of baseline information;**
    - ▪ **Expansion of physical security perimeter at BC Hydro's backup control centre to accommodate cabling protection requirements; and**
    - ▪ **Update CIP compliance documentation and evidence.**
- **Technology:**
  - ▶ **Implement common IT solutions to be used by the other BC Hydro business groups for CIPv5 compliance including:**
    - ▪ **An Intermediate System for secure access to CIP systems;**
    - ▪ **The MRS Compliance System which is used as a centralized CIP compliance evidence database;**

- **Enhancements to the RightCrowd SureSite request and approval system for physical/electronic access;**
- **Update IT and Physical Security-owned systems to address v5 requirements; and**
- **Update enterprise-wide policies and training materials.**

- **Physical Key Management Work Package:**
  - **Implement physical key management at two control centres, five data concentration point sites, three generation stations, 44 transmission stations, and three physical security command centres, including re-keying, lock replacement, barrel replacement and new doors to secure perimeters of CIP systems**
  - **Install an onsite key management/control with either a manual lock box or an access card-driven key cabinet;**
  - **Provide compliance evidence including annotated drawings and photos demonstrating implementation of key controls; and**
  - **Provide process documentation and operating procedures for key controls related to the requesting, issuing, tracking, and revocation of keys.**

**257.0 F. CHAPTER 6 – CAPITAL EXPENDITURES**

**Reference: CAPITAL EXPENDITURES**
**Exhibit B-1, Table 6-56, p. 6-152;**
**Exhibit B-5, BCUC IR 123.1, 123.2.1, 123.3, 123.5, 123.9, 123.13**
**Cybersecurity**

In its response to BCUC IR 123.3, BC Hydro wrote of its investments in its North American Electric Reliability Corporation (NERC) critical infrastructure protection (CIP) version 5 (v5) compliance initiative:

The purpose of the initiative is to upgrade electronic and physical security for computer/electronic equipment used to control and to monitor industrial control systems connected to the Bulk Electric System to meet compliance standards defined by the North American Electric Reliability Corporation (NERC) associated with critical infrastructure. As of March 31, 2019, $30.2 million has been spent on these initiatives, including both capital and associated operating expenditures. The NERC CIP v5 Compliance initiative consists of the following five initiatives:

1. Transmission Stations - $18.6 million;
2. Generation Stations - $2.7 million;
3. Grid Operations - $3.1 million;
4. Technology - $5.8 million;
5. Physical Key Management Work Package – addresses physical spaces containing Cyber Assets and is funded by the above initiatives;

These initiatives started in 2016 and BC Hydro achieved compliance with NERC CIP Version 5 by October 1, 2018. Further work on the Transmission Stations initiatives will continue through to 2023 to extend the use of the Station Gateway System to automate a number of manual compliance processes.

2.257.7 Please explain where these budgets were accounted for. For example, are these projects under the Technology budget?

**RESPONSE:**

**The projects are budgeted under the individual Business Groups as follows:**

- **The Transmission Stations project is budgeted at $38.2 million and funded under the Integrated Planning Business Group. Amounts are inclusive of capital and associated operating expenditures and the project reserve;**
- **The Generation Stations and Grid Operations project is budgeted at $6.7 million and funded under the Operations Business Group. Amounts are**

**inclusive of capital and associated operating expenditures and the project reserve; and**

- **The Technology project is budgeted at $5.9 million and funded under the Technology KBU. Amounts are inclusive of capital and associated operating expenditures.**

**257.0 F. CHAPTER 6 – CAPITAL EXPENDITURES**

**Reference: CAPITAL EXPENDITURES**
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**Exhibit B-5, BCUC IR 123.1, 123.2.1, 123.3, 123.5, 123.9, 123.13**
**Cybersecurity**

In its response to BCUC IR 123.3, BC Hydro wrote of its investments in its North American Electric Reliability Corporation (NERC) critical infrastructure protection (CIP) version 5 (v5) compliance initiative:

The purpose of the initiative is to upgrade electronic and physical security for computer/electronic equipment used to control and to monitor industrial control systems connected to the Bulk Electric System to meet compliance standards defined by the North American Electric Reliability Corporation (NERC) associated with critical infrastructure. As of March 31, 2019, $30.2 million has been spent on these initiatives, including both capital and associated operating expenditures. The NERC CIP v5 Compliance initiative consists of the following five initiatives:

1. Transmission Stations - $18.6 million;
2. Generation Stations - $2.7 million;
3. Grid Operations - $3.1 million;
4. Technology - $5.8 million;
5. Physical Key Management Work Package – addresses physical spaces containing Cyber Assets and is funded by the above initiatives;

These initiatives started in 2016 and BC Hydro achieved compliance with NERC CIP Version 5 by October 1, 2018. Further work on the Transmission Stations initiatives will continue through to 2023 to extend the use of the Station Gateway System to automate a number of manual compliance processes.

2.257.8 Please confirm, or explain otherwise, that these projects are required for MRS compliance.

**RESPONSE:**

**Confirmed.**

**257.0 F. CHAPTER 6 – CAPITAL EXPENDITURES**

**Reference: CAPITAL EXPENDITURES**
**Exhibit B-1, Table 6-56, p. 6-152;**
**Exhibit B-5, BCUC IR 123.1, 123.2.1, 123.3, 123.5, 123.9, 123.13**
**Cybersecurity**

In its response to BCUC IR 123.3, BC Hydro wrote of its investments in its North American Electric Reliability Corporation (NERC) critical infrastructure protection (CIP) version 5 (v5) compliance initiative:

The purpose of the initiative is to upgrade electronic and physical security for computer/electronic equipment used to control and to monitor industrial control systems connected to the Bulk Electric System to meet compliance standards defined by the North American Electric Reliability Corporation (NERC) associated with critical infrastructure. As of March 31, 2019, $30.2 million has been spent on these initiatives, including both capital and associated operating expenditures. The NERC CIP v5 Compliance initiative consists of the following five initiatives:

1. Transmission Stations - $18.6 million;
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3. Grid Operations - $3.1 million;
4. Technology - $5.8 million;
5. Physical Key Management Work Package – addresses physical spaces containing Cyber Assets and is funded by the above initiatives;

These initiatives started in 2016 and BC Hydro achieved compliance with NERC CIP Version 5 by October 1, 2018. Further work on the Transmission Stations initiatives will continue through to 2023 to extend the use of the Station Gateway System to automate a number of manual compliance processes.

2.257.8 Please confirm, or explain otherwise, that these projects are required for MRS compliance.

2.257.8.1 If not confirmed, please explain why BC Hydro has chosen to perform these projects. For example, for efficiency, or security enhancement, or another reason.

**RESPONSE:**

**Please refer to BC Hydro's response to BCUC IR 2.257.8.**

**257.0 F. CHAPTER 6 – CAPITAL EXPENDITURES**

**Reference: CAPITAL EXPENDITURES**
**Exhibit B-1, Table 6-56, p. 6-152;**
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**Cybersecurity**

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1. Transmission Stations - $18.6 million;
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5. Physical Key Management Work Package – addresses physical spaces containing Cyber Assets and is funded by the above initiatives;

These initiatives started in 2016 and BC Hydro achieved compliance with NERC CIP Version 5 by October 1, 2018. Further work on the Transmission Stations initiatives will continue through to 2023 to extend the use of the Station Gateway System to automate a number of manual compliance processes.

2.257.9 Please provide the total actual and/or forecast costs for capital and associated operating costs spent for NERC CIP v5 compliance compared to the original amount estimated at assessment of the NERC CIP v5 standard. Please explain any variances.

**RESPONSE:**

**The total actual capital expenditures and associated operating expenditures at October 1, 2018, when NERC CIPv5 compliance was achieved, was $23.8 million.**

**The July 24, 2015 MRS Assessment BCUC Report No. 8 provided an initial compliance cost estimate of $31.3 million. The intention of this cost estimate was**

**to reflect the minimum spending levels required to meet the requirements of the standard. The cost estimate, based on a bottom up estimating approach, had a range of -30/+100 per cent. Subsequent to this report, the total approved NERC CIPv5 project costs is $50.8 million, inclusive of capital and associated operating expenditures and project reserve. The difference in the cost estimates are a result of more certainty as the projects moved through BC Hydro's standard project phases (Identification, Definition and Implementation) and project scope was finalized.**

**As of June 30, 2019, total actual expenditures on NERC CIPv5 were $31.2 million, and total forecast expenditures were $42.8 million. Expenditures after the compliance date are to implement the Station Gateway System, an automation solution and to complete transition to sustainment.**

**257.0 F. CHAPTER 6 – CAPITAL EXPENDITURES**

**Reference: CAPITAL EXPENDITURES**
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The purpose of the initiative is to upgrade electronic and physical security for computer/electronic equipment used to control and to monitor industrial control systems connected to the Bulk Electric System to meet compliance standards defined by the North American Electric Reliability Corporation (NERC) associated with critical infrastructure. As of March 31, 2019, $30.2 million has been spent on these initiatives, including both capital and associated operating expenditures. The NERC CIP v5 Compliance initiative consists of the following five initiatives:

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2. Generation Stations - $2.7 million;
3. Grid Operations - $3.1 million;
4. Technology - $5.8 million;
5. Physical Key Management Work Package – addresses physical spaces containing Cyber Assets and is funded by the above initiatives;

These initiatives started in 2016 and BC Hydro achieved compliance with NERC CIP Version 5 by October 1, 2018. Further work on the Transmission Stations initiatives will continue through to 2023 to extend the use of the Station Gateway System to automate a number of manual compliance processes.

2.257.10 Please explain whether BC Hydro extends its MRS cybersecurity program implementation to assets outside the scope of mandatory MRS standards, such as to distribution assets.

**RESPONSE:**

**While BC Hydro has not extended its MRS cybersecurity program implementation to assets outside the scope of the MRS standards, we are planning to extend some requirements in response to the Auditor General's report on Industrial Control Systems. We are currently conducting a risk assessment to prioritize investments and efforts to address the audit recommendations.**

**257.0 F. CHAPTER 6 – CAPITAL EXPENDITURES**

**Reference: CAPITAL EXPENDITURES**
**Exhibit B-1, Table 6-56, p. 6-152;**
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**Cybersecurity**

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4. Technology - $5.8 million;
5. Physical Key Management Work Package – addresses physical spaces containing Cyber Assets and is funded by the above initiatives;

These initiatives started in 2016 and BC Hydro achieved compliance with NERC CIP Version 5 by October 1, 2018. Further work on the Transmission Stations initiatives will continue through to 2023 to extend the use of the Station Gateway System to automate a number of manual compliance processes.

2.257.10.1 Please explain whether BC Hydro’s cybersecurity program is consistently applied to all of BC Hydro assets, not just to assets governed under mandatory MRS regulations.

**RESPONSE:**

**BC Hydro’s cybersecurity program applies a consistent risk-based and compliance approach to cybersecurity across the enterprise.**

**This approach is well-established for some assets, including those assets that fall under the MRS requirements.**

**BC Hydro is currently conducting a cybersecurity risk assessment of its other assets to establish the same level of maturity with regards to those assets.**

**257.0 F. CHAPTER 6 – CAPITAL EXPENDITURES**

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**Cybersecurity**

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3. Grid Operations - $3.1 million;
4. Technology - $5.8 million;
5. Physical Key Management Work Package – addresses physical spaces containing Cyber Assets and is funded by the above initiatives;

These initiatives started in 2016 and BC Hydro achieved compliance with NERC CIP Version 5 by October 1, 2018. Further work on the Transmission Stations initiatives will continue through to 2023 to extend the use of the Station Gateway System to automate a number of manual compliance processes.

2.257.11 Please confirm whether learnings from the MRS program are applied to assets outside the MRS program, to enhance security or other reasons.

**RESPONSE:**

**Confirmed. Any learnings from the MRS program that are considered appropriate for assets outside the MRS program, are applied to those assets.**

**257.0 F. CHAPTER 6 – CAPITAL EXPENDITURES**

**Reference: CAPITAL EXPENDITURES**
**Exhibit B-1, Table 6-56, p. 6-152;**
**Exhibit B-5, BCUC IR 123.1, 123.2.1, 123.3, 123.5, 123.9, 123.13**
**Cybersecurity**

In its response to BCUC IR 123.13, BC Hydro stated that it estimates an additional $12 million will be required for implementation work on NERC CIP V5 through to 2023: “This work will extend the used of the Station Gateway System, which automates a number of manual compliance processes, and will help facilitate ongoing sustainment.”

2.257.12 Please explain the scope, timelines and budget for the work yet to be completed for the Transmission Stations initiatives. Please explain which KBU the budget for this project is accounted for in the Application.

**RESPONSE:**

**The NERC CIPv5 Transmission stations project scope met compliance by October 1, 2018. The remainder of the work under the project is to stabilize compliance activities and implement the Station Gateway System by fiscal 2023. The Station Gateway System is a system of record and inventory of cyber assets with the capability to automatically collect configuration data from BC Hydro's industrial control systems.**

**As of August 15, 2019, approximately $20 million has been spent on this project within the approved budget of $32 million under the Line Asset Planning KBU.**

**257.0 F. CHAPTER 6 – CAPITAL EXPENDITURES**

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**Exhibit B-1, Table 6-56, p. 6-152;**
**Exhibit B-5, BCUC IR 123.1, 123.2.1, 123.3, 123.5, 123.9, 123.13**
**Cybersecurity**

In its response to BCUC IR 123.13, BC Hydro stated that it estimates an additional $12 million will be required for implementation work on NERC CIP V5 through to 2023: “This work will extend the used of the Station Gateway System, which automates a number of manual compliance processes, and will help facilitate ongoing sustainment.”

2.257.13 Please provide details for the Station Gateway System, including the: scope; functions; benefits; and costs.

**RESPONSE:**

**The Station Gateway System (SGS) is an inventory of cyber assets with the capability to automatically collect configuration data from BC Hydro's industrial control systems (ICS).**

**The scope of the project is the deployment of central and local networking and servers at our Medium Impact stations. Key functionalities of SGS include:**

- **Inventory of ICS cyber assets through the asset life cycle (initial focus on medium impact cyber systems); and**
- **Automated and manual secure data collection from substation cyber assets.**

**The overall benefits of the SGS are to:**

- **Reduce the risk of a cybersecurity incident;**
- **Reduce the risk of compliance violations; and**
- **Improve efficiency of sustaining compliance to NERC CIP standards.**

**BC Hydro currently relies on manual processes to capture and record cyber asset information. These manual processes are inefficient and prone to human error that can lead to compliance violations. The SGS provides a foundation to inventory all substation ICS cyber assets as recommended by the 2019 Auditor General’s audit.**

**The budget for SGS is approximately $7.6 million (excluding contingency and reserve). This budget includes approximately $7.0 million for the development and rollout of the SGS and approximately $0.6 million for change management activities, training and sustainment. Due to the technical complexity of this system and potential high risk of implementation in approximately 30 sites, the project carries a contingency and reserve of $4.2 million, for a total of $11.8 million.**

**257.0 F. CHAPTER 6 – CAPITAL EXPENDITURES**

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**Cybersecurity**

In its response to BCUC IR 123.13, BC Hydro stated that it estimates an additional $12 million will be required for implementation work on NERC CIP V5 through to 2023: “This work will extend the used of the Station Gateway System, which automates a number of manual compliance processes, and will help facilitate ongoing sustainment.”

2.257.14 Please explain whether the Station Gateway System is required by NERC CIP v5 standards.

**RESPONSE:**

**While NERC Standards do not specifically require the Station Gateway System (SGS), NERC/WECC encourage utilities to automate their compliance processes to increase efficiency and reduce human error.**

**The SGS is a system of record and inventory of cyber assets with the capability to automatically collect configuration data from BC Hydro's industrial control systems. BC Hydro is pursuing this project to reduce the risk of cybersecurity incidents and compliance violations and to improve efficiency of sustainment processes in transmission stations related to maintaining the CIP standards.**

**257.0 F. CHAPTER 6 – CAPITAL EXPENDITURES**

**Reference: CAPITAL EXPENDITURES**
**Exhibit B-1, Table 6-56, p. 6-152;**
**Exhibit B-5, BCUC IR 123.1, 123.2.1, 123.3, 123.5, 123.9, 123.13**
**Cybersecurity**

In its response to BCUC IR 123.13, BC Hydro stated that it estimates an additional $12 million will be required for implementation work on NERC CIP V5 through to 2023: "This work will extend the used of the Station Gateway System, which automates a number of manual compliance processes, and will help facilitate ongoing sustainment."

2.257.14 Please explain whether the Station Gateway System is required by NERC CIP v5 standards.

2.257.14.1 If not required by NERC CIP v5 standards, please explain why BC Hydro is pursuing this project.

**RESPONSE:**

**Please refer to BC Hydro's response to BCUC IR 2.257.14.**

**257.0 F. CHAPTER 6 – CAPITAL EXPENDITURES**

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**Cybersecurity**

In its response to BCUC IR 123.9, BC Hydro explained its corporate governance, including a summary of its MRS Steering Committee and its Cybersecurity Oversight Committee. It appears that many positions listed are included on both committees.

2.257.15 Please explain any interactions or overlap between Cybersecurity and MRS governance.

**RESPONSE:**

**The interaction and overlap between the two governance structures is the cybersecurity component of the Critical Infrastructure Protection (CIP) standards.**

**Cybersecurity governance is accountable for enterprise-wide cybersecurity of Information Technology and Operations Technology systems including CIP cybersecurity.**

**MRS governance is accountable for ensuring BC Hydro meets all MRS compliance requirements including those for CIP cybersecurity as well as all other reliability standards unrelated to cybersecurity.**

**The overlap in committee membership supports coordinated governance for both Cybersecurity and MRS.**

**257.0 F. CHAPTER 6 – CAPITAL EXPENDITURES**

**Reference: CAPITAL EXPENDITURES**
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**Exhibit B-5, BCUC IR 123.1, 123.2.1, 123.3, 123.5, 123.9, 123.13**
**Cybersecurity**

In its response to BCUC IR 123.9, BC Hydro explained its corporate governance, including a summary of its MRS Steering Committee and its Cybersecurity Oversight Committee. It appears that many positions listed are included on both committees.

2.257.16 Please explain any interactions or overlap between Cybersecurity and MRS work.

**RESPONSE:**

**The interaction and overlap between cybersecurity and MRS work is the cybersecurity component of the Critical Infrastructure Protection (CIP) standards. This overlap does not result in any duplication of work.**

**Cybersecurity applies to enterprise-wide Information Technology and Operations Technology systems including CIP cybersecurity.**

**MRS work ensures BC Hydro meets all MRS compliance requirements including those for CIP cybersecurity.**

**257.0 F. CHAPTER 6 – CAPITAL EXPENDITURES**

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**Cybersecurity**

In its response to BCUC IR 123.9, BC Hydro explained its corporate governance, including a summary of its MRS Steering Committee and its Cybersecurity Oversight Committee. It appears that many positions listed are included on both committees.

2.257.17 Please explain whether there is consistency in how Cybersecurity and MRS are governed.

**RESPONSE:**

**As discussed in BC Hydro’s response to BCUC IR 2.257.16, there is an overlap between cybersecurity and MRS work and as discussed in BC Hydro’s response to BCUC IR 2.257.15, there is an overlap between cybersecurity and MRS committee membership.**

**Despite these overlaps, the full scope of each of the cybersecurity and MRS functions has different objectives, which are reflected in their respective approaches to governance.**

**Cybersecurity governance is accountable for enterprise-wide cybersecurity of all Technology systems including Critical Infrastructure Protection (CIP) cybersecurity. BC Hydro’s Chief Information Officer (CIO) is accountable for cybersecurity governance and is the designated CIP Senior Manager. As a result, the CIO sits on both the cybersecurity and MRS governance committees.**

**MRS governance is accountable for ensuring BC Hydro meets all MRS compliance requirements. BC Hydro’s Executive Vice President of People, Customer and Corporate Affairs is designated as BC Hydro’s Compliance Officer, is responsible for BC Hydro’s MRS compliance program and leads the MRS steering committee, which provides governance for the MRS program.**

**257.0 F. CHAPTER 6 – CAPITAL EXPENDITURES**

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**Cybersecurity**

In its response to BCUC IR 123.9, BC Hydro explained its corporate governance, including a summary of its MRS Steering Committee and its Cybersecurity Oversight Committee. It appears that many positions listed are included on both committees.

2.257.18 Please confirm, or explain otherwise, that the Reliability Compliance Manager is designated as the main person responsible in the event of a situation of urgency due to a cybersecurity breach.

**RESPONSE:**

**Not confirmed. The Cybersecurity Incident Response Team Leader manages the response to cybersecurity incidents. An incident with potentially severe business impacts may be further supported by others including a Technology Situation Manager, the Chief Information Officer, and an Emergency Response Duty Coordinator. The Reliability Compliance Manager has no defined role during a cybersecurity incident but would be made available for compliance consultation, if required.**

**Please also refer to BC Hydro's response to BCUC IR 2.257.27 where we describe the roles involved in incident response.**

**257.0 F. CHAPTER 6 – CAPITAL EXPENDITURES**

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**Cybersecurity**

In its response to BCUC IR 123.9, BC Hydro explained its corporate governance, including a summary of its MRS Steering Committee and its Cybersecurity Oversight Committee. It appears that many positions listed are included on both committees.

2.257.18 Please confirm, or explain otherwise, that the Reliability Compliance Manager is designated as the main person responsible in the event of a situation of urgency due to a cybersecurity breach.

2.257.18.1 Please describe what actions are taken by the main person responsible in the event of a situation of urgency due to a cybersecurity breach.

**RESPONSE:**

**In the event of a cybersecurity breach, the Cybersecurity Incident Response Team Leader (CSIRT Leader) follows BC Hydro's Cybersecurity Incident Response Plan (CSIRP). The CSIRP is based on advice described in the National Institute of Standards and Technology's Computer Security Incident Handling Guide.**

**Since each incident is unique, the actions taken for each incident may vary. Typical actions undertaken or overseen by the CSIRT Leader include:**

1. **Analyze and confirm – not all situations reported as cybersecurity incidents are valid so a key first step is to analyze the details to confirm we have or reasonably suspect we have, a cybersecurity incident;**

2. **Assemble resources and investigate – the make-up of the CSIRT is dependent on the nature of the threat, systems impacted, and business impact. Our processes allow BC Hydro to quickly scale up and engage support from other Technology teams, the Chief Information Officer, or third parties as necessary.**

   **The CSIRT investigates to determine answers to such questions as:**

   a. **How did the incident occur?**

**b. Is the incident contained and, if not, how do we contain it?**

**c. What are the impacts?**

**d. What is the attacker's motivation?**

**e. What are the tools, techniques and procedures used by the attacker?**

**f. Who is the attacker?**

**3. Inform and Escalate – the CSIRT Leader also oversees informing executive management, the Board of Directors, and stakeholders, and escalating where additional resources and support are required from other parts of the organization;**

**4. Contain – once an incident has been confirmed, the next action is to contain the incident to mitigate damage; and**

**5. Eradicate – once the incident is contained, the CSIRT will work to eradicate the incident.**

**Please also refer to BC Hydro's response to BCUC IR 2.257.27 where we describe the roles involved in incident response.**

**257.0 F. CHAPTER 6 – CAPITAL EXPENDITURES**

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**Cybersecurity**

In its response to BCUC IR 123.9, BC Hydro explained its corporate governance, including a summary of its MRS Steering Committee and its Cybersecurity Oversight Committee. It appears that many positions listed are included on both committees.

2.257.18 Please confirm, or explain otherwise, that the Reliability Compliance Manager is designated as the main person responsible in the event of a situation of urgency due to a cybersecurity breach.

2.257.18.2 Please discuss the effectiveness of this current structure.

**RESPONSE:**

**BC Hydro's effective and efficient handling of cybersecurity incidents to date demonstrates that our response structure and processes are meeting current needs.**

**BC Hydro regularly reviews and refines response structures and processes as the nature of cyber threats grows in sophistication and complexity, and as power systems become increasingly digitized. Exercises such as the bi-annual E-ISAC (NERC) GridEx mock cyber attack are designed to test and identify improvement opportunities so they can be addressed.**

**BC Hydro's 2019 Internal Cybersecurity Audit found that:**

- **Effective processes are in place to detect and respond to cybersecurity incidents in the Information Technology and NERC CIP regulated Operational Technology environments;**
- **Potential cybersecurity incidents are directed to Cybersecurity Operations for immediate triage and analysis. Handling of declared incidents is prioritized based on urgency and impact; and**
- **Large scale, joint incident response exercises occur on a regular basis with key participants across the enterprise. These exercises strengthen BC Hydro's capability to identify and respond to cyber incidents and receive appropriate support from senior management and participating business units.**

**257.0 F. CHAPTER 6 – CAPITAL EXPENDITURES**

**Reference: CAPITAL EXPENDITURES**
**Exhibit B-1, Table 6-56, p. 6-152;**
**Exhibit B-5, BCUC IR 123.1, 123.2.1, 123.3, 123.5, 123.9, 123.13**
**Cybersecurity**

In its response to BCUC IR 123.9, BC Hydro explained its corporate governance, including a summary of its MRS Steering Committee and its Cybersecurity Oversight Committee. It appears that many positions listed are included on both committees.

2.257.18 Please confirm, or explain otherwise, that the Reliability Compliance Manager is designated as the main person responsible in the event of a situation of urgency due to a cybersecurity breach.

2.257.18.3 Please explain whether the team responsible for these actions is sufficiently resourced.

**RESPONSE:**

**To date, BC Hydro has been adequately resourced from a response perspective. There is a dedicated BC Hydro cybersecurity operations function staffed with capable resources, using fit-for-purpose tools, following the National Institute of Standards and Technology and industry best practices. There is also a 24x7 senior cybersecurity analyst on call. The team is well supported with training and education and are backed by third-party incident response resources, if required.**

**BC Hydro continually assesses the resourcing requirements to ensure the appropriate complement of resources to meet increasing cybersecurity complexity and risks. This includes the increasing number and complexity of threats, the expansion of cybersecurity monitoring of BC Hydro's power system and the resulting alerts, and the further digitization of power systems. BC Hydro will be assessing its current capabilities in fiscal 2020 which may result in recommendations with regards to facilities, services, processes, tools, and people.**

**257.0 F. CHAPTER 6 – CAPITAL EXPENDITURES**

**Reference: CAPITAL EXPENDITURES**
**Exhibit B-1, Table 6-56, p. 6-152;**
**Exhibit B-5, BCUC IR 123.1, 123.2.1, 123.3, 123.5, 123.9, 123.13**
**Cybersecurity**

In Table 6-56 of its Application, BC Hydro provides a summary of Technology projects over $2 million, including the "NERC CIP v7" project, with capital expenditures of $2.3 million in F2020 and capital additions of $2.3 million in F2020.

2.257.19 Please explain the scope of work BC Hydro has done to investigate or become compliant with NERC CIP v7.

**RESPONSE:**

**BC Hydro has conducted an initial pre-project study of the NERC CIPv7 requirements. The study team worked with subject matter experts to assess the cost and requirements of adopting NERC CIPv7. The initial results were reported to BCUC through MRS Assessment Report No. 12.**

**257.0 F. CHAPTER 6 – CAPITAL EXPENDITURES**

**Reference: CAPITAL EXPENDITURES**
**Exhibit B-1, Table 6-56, p. 6-152;**
**Exhibit B-5, BCUC IR 123.1, 123.2.1, 123.3, 123.5, 123.9, 123.13**
**Cybersecurity**

In Table 6-56 of its Application, BC Hydro provides a summary of Technology projects over $2 million, including the "NERC CIP v7" project, with capital expenditures of $2.3 million in F2020 and capital additions of $2.3 million in F2020.

2.257.20 Please explain the scope and budget for the "NERC CIP v7" project.

**RESPONSE:**

**NERC CIPv7 refers to the reliability standard CIP-003-7 which covers electronic access controls and physical access controls for low impact Bulk Electric System Cyber Systems within transmission and generating stations.**

**BC Hydro has 130 low-impact facilities in scope (113 transmission stations and 17 generating stations) and two additional low-impact facilities (one transmission station and one generating station) coming into service between fiscal 2021 and fiscal 2024. At this point, the project cost is estimated to be approximately $25.0 million to $33.0 million including both capital and associated operating expenditures. This is an initial pre-project estimate with a -30 per cent/+100 per cent estimating range which will be refined as the project progresses.**

**257.0 F. CHAPTER 6 – CAPITAL EXPENDITURES**

**Reference: CAPITAL EXPENDITURES**
**Exhibit B-1, Table 6-56, p. 6-152;**
**Exhibit B-5, BCUC IR 123.1, 123.2.1, 123.3, 123.5, 123.9, 123.13**
**Cybersecurity**

In response to BCUC IR 123.5, BC Hydro stated: "BC Hydro conducted Cybersecurity Program Audits in 2016 and 2019. …BC Hydro expects to be able to provide the 2019 internal audit report after it has been approved by BC Hydro's Board of Directors in June 2019."

2.257.21 Please discuss whether BC Hydro plans to file the 2019 Internal Cybersecurity Program Audit as an evidentiary update in this proceeding or outside of this proceeding.

**RESPONSE:**

**Attachment 1 to this response provides BC Hydro's 2019 Cybersecurity Program Internal Audit Report. This attachment is being provided in confidence to the BCUC only and cannot be made available to interveners (even on undertakings), due to the significant potential security risks associated with inadvertent disclosure.**

# CONFIDENTIAL ATTACHMENT

# FILED WITH BCUC ONLY

**257.0 F. CHAPTER 6 – CAPITAL EXPENDITURES**

**Reference: CAPITAL EXPENDITURES**
**Exhibit B-1, Table 6-56, p. 6-152;**
**Exhibit B-5, BCUC IR 123.1, 123.2.1, 123.3, 123.5, 123.9, 123.13**
**Cybersecurity**

In response to BCUC IR 123.5, BC Hydro stated: "BC Hydro conducted Cybersecurity Program Audits in 2016 and 2019. …BC Hydro expects to be able to provide the 2019 internal audit report after it has been approved by BC Hydro's Board of Directors in June 2019."

2.257.21 Please discuss whether BC Hydro plans to file the 2019 Internal Cybersecurity Program Audit as an evidentiary update in this proceeding or outside of this proceeding.

2.257.21.1 Please provide BC Hydro's entity-wide risk assessment analysis for cybersecurity and how the scope of the 2019 Internal Cybersecurity Program Audit was designed to address these key risks.

**RESPONSE:**

**Cybersecurity is identified as an enterprise risk. The enterprise defines this risk as a cybersecurity incident that causes a significant disruption of our operations or loss of data. BC Hydro's enterprise risk assessment process and cybersecurity risk assessment is included in BC Hydro's response to INCE IR 2.17.0.**

**A significant disruption of our operations or loss of data can result from many different possible threats. BC Hydro's cybersecurity program uses an approach based on risk management principles including identifying the threats, assessing the risk, defining protection and mitigation controls to reduce the likelihood and impact of an incident and having an effective governance structure in place.**

**The 2019 Cybersecurity Program Audit was designed to build on the results of the 2016 Cybersecurity Audit. These results prompted an action plan to extend the cybersecurity program beyond information technology to an enterprise-wide approach that includes governance, strategy, protection controls and effective response.**

**The 2019 Cybersecurity Audit focused on:**

- **Enterprise-wide governance as an area of the 2016 action plan that was newly implemented;**

- **Enterprise-wide threat vulnerability and incident response; and**
- **Vendor risk management.**

**These areas of focus were identified with input from cybersecurity subject matter specialists in the utility industry.**

**257.0 F. CHAPTER 6 – CAPITAL EXPENDITURES**

**Reference: CAPITAL EXPENDITURES**
**Exhibit B-1, Table 6-56, p. 6-152;**
**Exhibit B-5, BCUC IR 123.1, 123.2.1, 123.3, 123.5, 123.9, 123.13**
**Cybersecurity**

In response to BCUC IR 123.5, BC Hydro stated: “BC Hydro conducted Cybersecurity Program Audits in 2016 and 2019. …BC Hydro expects to be able to provide the 2019 internal audit report after it has been approved by BC Hydro’s Board of Directors in June 2019.”

2.257.21 Please discuss whether BC Hydro plans to file the 2019 Internal Cybersecurity Program Audit as an evidentiary update in this proceeding or outside of this proceeding.

2.257.21.2 Please include a description of how this audit scope was developed and include consideration of the most current risks in cybersecurity.

**RESPONSE:**

**Please refer to BC Hydro’s response to BCUC IR 257.21.1 where we explain that BC Hydro determined the 2019 audit scope from the 2016 audit results. The scope was developed with input from external cybersecurity subject matter specialists in the utility industry who provided insight into current and emerging risks.**

**257.0 F. CHAPTER 6 – CAPITAL EXPENDITURES**

**Reference: CAPITAL EXPENDITURES**
**Exhibit B-1, Table 6-56, p. 6-152;**
**Exhibit B-5, BCUC IR 123.1, 123.2.1, 123.3, 123.5, 123.9, 123.13**
**Cybersecurity**

In response to BCUC IR 123.5, BC Hydro stated: "BC Hydro conducted Cybersecurity Program Audits in 2016 and 2019. …BC Hydro expects to be able to provide the 2019 internal audit report after it has been approved by BC Hydro's Board of Directors in June 2019."

2.257.21 Please discuss whether BC Hydro plans to file the 2019 Internal Cybersecurity Program Audit as an evidentiary update in this proceeding or outside of this proceeding.

2.257.21.3 Please contrast this scope with the scope of the audit performed in 2016.

**RESPONSE:**

**Please refer to BC Hydro's response to BCUC IR 257.21.1 where we explain that the scope of the 2019 audit was determined from the 2016 audit results which provided a baseline for measuring the overall effectiveness of the cybersecurity program.**

**The 2019 audit focused on enterprise-wide governance (a newly implemented area from the 2016 action plan) as well as the critical areas of threat vulnerability management and incident response, and a newly emerging threat in vendor management.**

**257.0 F. CHAPTER 6 – CAPITAL EXPENDITURES**

**Reference: CAPITAL EXPENDITURES**
**Exhibit B-1, Table 6-56, p. 6-152;**
**Exhibit B-5, BCUC IR 123.1, 123.2.1, 123.3, 123.5, 123.9, 123.13**
**Cybersecurity**

In response to BCUC IR 123.5, BC Hydro stated: "BC Hydro conducted Cybersecurity Program Audits in 2016 and 2019. …BC Hydro expects to be able to provide the 2019 internal audit report after it has been approved by BC Hydro's Board of Directors in June 2019."

2.257.22 Some BC utilities are members of the Emergency Cyber Threat Organization with Natural Resources Canada (NRCan). Please confirm, or explain otherwise, that BC Hydro is a member.

**RESPONSE:**

**BC Hydro is not a member of the Emergency Threat Organization with Natural Resources Canada.**

**Please refer to BC Hydro's response to BCUC IR 2.257.27 where we explain that BC Hydro receives threat notifications from federal cybersecurity agencies and subscribes to dozens of open source threat intelligence feeds.**

**257.0 F. CHAPTER 6 – CAPITAL EXPENDITURES**

**Reference: CAPITAL EXPENDITURES**
**Exhibit B-1, Table 6-56, p. 6-152;**
**Exhibit B-5, BCUC IR 123.1, 123.2.1, 123.3, 123.5, 123.9, 123.13**
**Cybersecurity**

In response to BCUC IR 123.5, BC Hydro stated: "BC Hydro conducted Cybersecurity Program Audits in 2016 and 2019. …BC Hydro expects to be able to provide the 2019 internal audit report after it has been approved by BC Hydro's Board of Directors in June 2019."

2.257.23 Please confirm, or explain otherwise, that BC Hydro is a member of the "Energy Sector Network."

**RESPONSE:**

**BC Hydro is not a member of the "Energy Sector Network".**

**Please refer to BC Hydro's response to BCUC IR 2.257.27 where we explain that BC Hydro receives threat notifications from federal cybersecurity agencies and subscribes to dozens of open source threat intelligence feeds.**

**257.0 F. CHAPTER 6 – CAPITAL EXPENDITURES**

**Reference: CAPITAL EXPENDITURES**
**Exhibit B-1, Table 6-56, p. 6-152;**
**Exhibit B-5, BCUC IR 123.1, 123.2.1, 123.3, 123.5, 123.9, 123.13**
**Cybersecurity**

In response to BCUC IR 123.5, BC Hydro stated: "BC Hydro conducted Cybersecurity Program Audits in 2016 and 2019. …BC Hydro expects to be able to provide the 2019 internal audit report after it has been approved by BC Hydro's Board of Directors in June 2019."

2.257.24 Please confirm, or explain otherwise, that BC Hydro receives threat notifications from the Energy Sector Network or the Emergency Cyber Threat Organization or NRCan.

**RESPONSE:**

**Not confirmed. Please refer to BC Hydro's response to BCUC IR 2.257.27 where we explain that BC Hydro receives threat notifications from federal cybersecurity agencies and subscribes to dozens of open source threat intelligence feeds.**

**257.0 F. CHAPTER 6 – CAPITAL EXPENDITURES**

**Reference: CAPITAL EXPENDITURES**
**Exhibit B-1, Table 6-56, p. 6-152;**
**Exhibit B-5, BCUC IR 123.1, 123.2.1, 123.3, 123.5, 123.9, 123.13**
**Cybersecurity**

In response to BCUC IR 123.5, BC Hydro stated: “BC Hydro conducted Cybersecurity Program Audits in 2016 and 2019. …BC Hydro expects to be able to provide the 2019 internal audit report after it has been approved by BC Hydro’s Board of Directors in June 2019.”

2.257.24 Please confirm, or explain otherwise, that BC Hydro receives threat notifications from the Energy Sector Network or the Emergency Cyber Threat Organization or NRCan.

2.257.24.1 If confirmed, please explain what actions BC Hydro takes when it receives a threat notification.

**RESPONSE:**

**Please refer to BC Hydro’s response to BCUC IR 2.257.27 where we explain BC Hydro’s threat notification and response process.**

**257.0 F. CHAPTER 6 – CAPITAL EXPENDITURES**

**Reference: CAPITAL EXPENDITURES**
**Exhibit B-1, Table 6-56, p. 6-152;**
**Exhibit B-5, BCUC IR 123.1, 123.2.1, 123.3, 123.5, 123.9, 123.13**
**Cybersecurity**

In response to BCUC IR 123.5, BC Hydro stated: "BC Hydro conducted Cybersecurity Program Audits in 2016 and 2019. …BC Hydro expects to be able to provide the 2019 internal audit report after it has been approved by BC Hydro's Board of Directors in June 2019."

2.257.25 Please explain whether BC Hydro is a member of any other organization that provides real time information or notifications related to cybersecurity or threats.

**RESPONSE:**

**Please refer to BC Hydro's response to BCUC IR 2.257.27 where we explain that BC Hydro receives threat notifications from federal cybersecurity agencies and subscribes to dozens of open source threat intelligence feeds.**

**257.0 F. CHAPTER 6 – CAPITAL EXPENDITURES**

**Reference: CAPITAL EXPENDITURES**
**Exhibit B-1, Table 6-56, p. 6-152;**
**Exhibit B-5, BCUC IR 123.1, 123.2.1, 123.3, 123.5, 123.9, 123.13**
**Cybersecurity**

In response to BCUC IR 123.5, BC Hydro stated: “BC Hydro conducted Cybersecurity Program Audits in 2016 and 2019. …BC Hydro expects to be able to provide the 2019 internal audit report after it has been approved by BC Hydro’s Board of Directors in June 2019.”

2.257.26 Please confirm whether BC Hydro participates in the annual E-ISAC (NERC) GridEx mock cyber-attack.

**RESPONSE:**

**Confirmed. BC Hydro participates in the bi-annual E-ISAC (NERC) GridEx mock cyber-attack exercises.**

**257.0 F. CHAPTER 6 – CAPITAL EXPENDITURES**

**Reference: CAPITAL EXPENDITURES**
**Exhibit B-1, Table 6-56, p. 6-152;**
**Exhibit B-5, BCUC IR 123.1, 123.2.1, 123.3, 123.5, 123.9, 123.13**
**Cybersecurity**

In response to BCUC IR 123.5, BC Hydro stated: “BC Hydro conducted Cybersecurity Program Audits in 2016 and 2019. …BC Hydro expects to be able to provide the 2019 internal audit report after it has been approved by BC Hydro’s Board of Directors in June 2019.”

2.257.27 Please explain the process BC Hydro follows if it receives a credible cyber threat or attack, including: timelines; key internal and external contacts; manager of the situation; and authority of all people involved to carry out assigned duties.

**RESPONSE:**

**The processes for responding to a threat versus an attack differ and are described separately below.**

**Threat Response**

**BC Hydro receives threat notifications from federal cybersecurity agencies including the:**

- **Canadian Centre for Cyber Security (CCCS);**
- **Department of Homeland Security (DHS);**
- **North American Electric Reliability Corporation (NERC); and**
- **US Computer Emergency Response Team (US-CERT).**

**BC Hydro also subscribes to dozens of open source threat intelligence feeds which are automatically processed by a Security Information and Event Management (SIEM) system for analysis and alerts.**

**One or more of the following actions may be taken depending on the nature of the threat:**

- **Receipt of the threat advisory is logged;**

- **Threats are triaged as they are received for applicability to BC Hydro's systems;**
- **A determination is made as to whether indicators of compromise (IOCs) are present in BC Hydro's systems. If IOCs are found, then a further investigation is conducted;**
- **IOCs are added to preventative and detective security controls (e.g., threat mitigation and monitoring);**
- **Threat information is disseminated to other parts of the organization, including senior management and executives;**
- **Where a threat presents a risk that can't be fully mitigated in the short term, then an entry is made to BC Hydro's cybersecurity risk register and mitigations are considered amongst the other recorded risks; or**
- **Threat intelligence data is added to block and monitor controls.**

**If a breach is confirmed, then the Incident Response process would take over.**

**Incident Response**

**Response to a cybersecurity incident follows BC Hydro's enterprise Cybersecurity Incident Response Plan (CSIRP). The initial response is led by the Cybersecurity Incident Response Team Leader (CSIRT Leader) who has authority to prescribe or authorize the protective actions be taken where there is an immediate and severe risk to the enterprise, and where not acting could result in further harm to BC Hydro's corporate systems.**

**For systems that generate, transmit and distribute power, the CSIRT Leader will advise operations management on cybersecurity aspects of an incident but, for safety and other reasons, the authority for directing a response remains with operations management.**

**A cybersecurity detection and response function is staffed during business hours, supplemented with afterhours on-call support. During business hours, alerts received from monitoring systems or incidents received through the Service Desk are typically triaged within 15 minutes.**

**If a severe business impacting incident occurs, other management and supporting resources may be added to the response team. These roles include:**

- **Major Incident Coordinator – assembles and coordinates any IT infrastructure and application support personnel that may be required to respond to an incident;**
- **Situation Manager – assumes overall management of an incident with severe business impact, freeing up the CSIRT Leader to focus on directing the technical cybersecurity aspects of the response;**
- **Duty Coordinator – co-ordinates enterprise-wide support during an incident, as required. Determines if the Emergency Centre is required in partial or full form and activates the Emergency Response Plan, if required;**
- **Chief Information Officer and the Executive Team – are kept informed during severe business impacting incidents and give direction as required and/or approve expenditures that exceed the authority of the other roles;**
- **Board of Directors – may be informed and consulted depending on the business impact;**
- **Legal Services Department – consulted on severe business impacting incidents and engaged as required. The Legal Services Department may also engage external counsel;**
- **Communications and Community Engagement KBU – engaged when BC Hydro's customers are or could be impacted;**
- **Privacy Manager – engaged when personal data has been compromised or is at risk;**
- **Third Party Incident Response Services – BC Hydro has a third-party on retainer for cybersecurity response assistance;**
- **Cybersecurity Insurer and Breach Coach – BC Hydro has a cybersecurity insurance policy and in the event of an incident is required to inform the insurer immediately. A Breach Coach is made available for consultation through the policy;**
- **E-ISAC and/or CCCS – per NERC Standard CIP-008 Requirement R1.2, BC Hydro is required to report certain incidents to the Electricity Information Sharing and Analysis Center (E-ISAC) within 60 minutes of determining that there was an incident. A reportable incident is one that "has compromised or disrupted one or more reliability tasks of a functional entity". BC Hydro may report incident details to the Canadian Centre for Cyber Security (CCCS); and**
- **Law Enforcement – depending on the scenario, BC Hydro may contact local law enforcement.**

**257.0 F. CHAPTER 6 – CAPITAL EXPENDITURES**

**Reference: CAPITAL EXPENDITURES**
**Exhibit B-1, Table 6-56, p. 6-152;**
**Exhibit B-5, BCUC IR 123.1, 123.2.1, 123.3, 123.5, 123.9, 123.13**
**Cybersecurity**

In response to BCUC IR 123.5, BC Hydro stated: "BC Hydro conducted Cybersecurity Program Audits in 2016 and 2019. …BC Hydro expects to be able to provide the 2019 internal audit report after it has been approved by BC Hydro's Board of Directors in June 2019."

2.257.27 Please explain the process BC Hydro follows if it receives a credible cyber threat or attack, including: timelines; key internal and external contacts; manager of the situation; and authority of all people involved to carry out assigned duties.

2.257.27.1 Please explain who BC Hydro notifies if it receives a threat or an attack.

**RESPONSE:**

**Please refer to BC Hydro's response to BCUC IR 2.257.27 where we explain who is notified if BC Hydro receives a threat or an attack.**

**257.0 F. CHAPTER 6 – CAPITAL EXPENDITURES**

**Reference: CAPITAL EXPENDITURES**
**Exhibit B-1, Table 6-56, p. 6-152;**
**Exhibit B-5, BCUC IR 123.1, 123.2.1, 123.3, 123.5, 123.9, 123.13**
**Cybersecurity**

In response to BCUC IR 123.5, BC Hydro stated: "BC Hydro conducted Cybersecurity Program Audits in 2016 and 2019. …BC Hydro expects to be able to provide the 2019 internal audit report after it has been approved by BC Hydro's Board of Directors in June 2019."

2.257.28 Please explain whether BC Hydro performs any internal mock cyber-attacks.

**RESPONSE:**

**As required by NERC, BC Hydro tests the Cybersecurity Incident Response Plan (CSIRP) at least once every 15 months using table top exercises, and participates in the bi-annual E-ISAC (NERC) GridEx mock cyber attack exercise.**

**In addition, BC Hydro conducts quarterly IT Service Continuity Management Plan table top exercises. The IT Service Continuity Management Plan includes response plans for the disruption of IT services from any cause, including, but not limited to cyber attacks.**

**257.0 F. CHAPTER 6 – CAPITAL EXPENDITURES**

**Reference: CAPITAL EXPENDITURES**
**Exhibit B-1, Table 6-56, p. 6-152;**
**Exhibit B-5, BCUC IR 123.1, 123.2.1, 123.3, 123.5, 123.9, 123.13**
**Cybersecurity**

In response to BCUC IR 123.5, BC Hydro stated: "BC Hydro conducted Cybersecurity Program Audits in 2016 and 2019. …BC Hydro expects to be able to provide the 2019 internal audit report after it has been approved by BC Hydro's Board of Directors in June 2019."

2.257.28 Please explain whether BC Hydro performs any internal mock cyber-attacks.

2.257.28.1 Please provide the results of any internal mock cyber-attacks.

**RESPONSE:**

**BC Hydro's most recent cybersecurity-focused table top exercise was held in November 2018.**

**The exercise scenario involved BC Hydro's Energy Management System being compromised and involved multiple teams across BC Hydro including Cybersecurity Operations and Transmission and Distribution System Operations.**

**The results from the exercise showed that BC Hydro's overall response plan works effectively. Corrective actions were identified with regards to communication protocols and clarifying roles and responsibilities.**

**258.0 F. CHAPTER 6 – CAPITAL EXPENDITURES**

**Reference: CAPITAL EXPENDITURES**
**Exhibit B-5, BCUC IR 133.1, Attachment 1, pp. 12, 17**
**Capital expenditures and additions**

On page 12 of Attachment 1 to BCUC IR 133.1, it showed a capital expenditure variance of $13.1 million above plan for F2018 for the "New Feeder to Bowen Island (LM-NSC-125)" project. BC Hydro provided the following explanation for the variance:

The Previous Application Plan was based on early cable routing reviews; the cost increase is due to the final route selection and the associated increase in design, engineering, materials, construction and project management costs.

2.258.1 Please explain how the early cable routing reviews were determined and why those routes were not suitable as the final route selection.

**RESPONSE:**

**BC Hydro clarifies that the variance of $13.1 million for fiscal 2018 was not driven by route selection. Rather, the variance was due to:**

- **Deferring the in-service date by one year; and**
- **The final cable configuration and the associated increase in design, engineering, materials, construction and project management costs.**

**Early cable routing reviews in the Identification phase were based on desktop assessments and marine surveys of the existing 240 m wide Right-of-Way (RoW) in the Queen Charlotte Channel.**

**These assessments concluded that the physical constraints (e.g., steep slopes, submarine slide, and outcropping bedrock) under water near the cable landing sites at both ends would not allow for laying cables outside of the existing RoW. Accordingly, an expansion of the RoW was determined to be impractical.**

**Two options for undertaking the project within the RoW were further developed. Of the two options, BC Hydro selected the more economical option.**

**258.0 F. CHAPTER 6 – CAPITAL EXPENDITURES**

**Reference: CAPITAL EXPENDITURES**
**Exhibit B-5, BCUC IR 133.1, Attachment 1, pp. 12, 17**
**Capital expenditures and additions**

Further on page 12 of Attachment 1 to BCUC IR 133.1, it showed the following capital expenditure variances for F2018:

- H-Frame Elimination – Chinatown (IPID 900557) - $7.8 million above plan
- Variance Sites – LED Street Light Conversion (IPID 900556) - $5.7 million below plan

2.258.2 Please explain the above variances.

**RESPONSE:**

**H-Frame Elimination – Chinatown (IPID 900557)**

**In June 2015, the fiscal 2017 to fiscal 2026 Capital Plan was developed to support the Previous Application. At that time, the project scope included only one portion of the H-Frame Elimination - Chinatown project.**

**Following the submission of the Previous Application, BC Hydro determined that delivery efficiencies could be realized by consolidating three additional projects and delivering them as a program of projects. This consolidation allowed for more effective coordination of design and construction activities across the projects.**

**Variance Sites – LED Street Light Conversion (IPID 900556)**

**The fiscal 2018 forecast amount provided in the Previous Application assumed deployment would begin in fiscal 2018.**

**Since then, BC Hydro determined that a more thorough review of the latest LED street light technologies was required before implementation. The review, which is nearing completion, considered the needs of the customers and the costs and benefits of the different technologies.**

**The current forecast in the fiscal 2021 to fiscal 2030 Capital Plan assumes a project start date of fiscal 2020.**

**258.0 F. CHAPTER 6 – CAPITAL EXPENDITURES**

**Reference: CAPITAL EXPENDITURES**
**Exhibit B-5, BCUC IR 133.1, Attachment 1, pp. 12, 17**
**Capital expenditures and additions**

On page 17 of Attachment 1 to BCUC IR 133.1, it showed the following for "Risk Adjustment" in Technology Capital Additions:

- 2017: RRA = ($17.6 million), Actual = $0
- 2018: RRA = ($9.9 million), Actual = $0
- 2019: RRA = ($12.2 million), Forecast = $0

2.258.3 Please explain what the "Risk Adjustment" is and how the RRA amounts are determined.

**RESPONSE:**

**The Risk Adjustment in the capital plan is used to offset an intentional oversubscription of the portfolio. The portfolio is intentionally oversubscribed to account for uncertainty in project scope, cost and schedule.**

**In any given period, the timing of a large number of technology investments are expected to shift due to new information, changing priorities and availability of resources. Due to this uncertainty, the portfolio is oversubscribed so that the month-to-month release and initiation of investments can draw from a larger pool of demand.**

**The size of the adjustment is based on the level of uncertainty in the portfolio. The adjustment will vary based on the mix of project types and phases of delivery. For example, the uncertainty will be greater with projects that are still in the planning stages or for large projects with a high monthly spend where a small schedule delay can have a significant impact.**

**In the fiscal years 2017, 2018 and 2019, a capital expenditure Risk Adjustment was determined as part of the Technology Capital Investment Planning process described in section 6.5.3.3 of Chapter 6 of the Application. The bottom-up capital plans in those fiscal years determined the necessary Risk Adjustment amounts for both capital expenditures and additions.**

**259.0 G. CHAPTER 8 – OTHER REVENUE REQUIREMENTS ITEMS**

**Reference: OTHER REVENUE REQUIREMENTS ITEMS**
**Exhibit B-5, BCUC IR 157.6; 157.6.1**
**Full adoption of IFRS**

In response to BCUC IR 157.6, BC Hydro stated that it had applied or intends to apply “the full retrospective adoption approach” for certain IFRS standards.

2.259.1 Please provide a high-level discussion of the differences, if any, to the Test Period and future periods’ revenue requirements of applying a full retrospective approach versus a modified retrospective approach.

**RESPONSE:**

**The total amount recovered from ratepayers over time is the same in both methods and only the timing of recovery differs.**

**BC Hydro’s adoption of the full retrospective approach has resulted in higher costs in the test period than would have been included under the modified retrospective approach. The costs are higher due to an upfront adjustment under the full retrospective approach partially offset by lower annual ongoing costs.**

**Upfront Impact**

- **Under the full retrospective approach, there is an upfront adjustment of $64.8 million recorded to the Non-Heritage Deferral Account that is proposed to be amortized over the test period. Under the modified retrospective approach, there is no upfront impact, but there are higher costs over the remaining term of the lease equivalent to the upfront adjustment under the full retrospective approach.**

**Ongoing Impact**

- **The fiscal 2020 and fiscal 2021 expenses, excluding the Non-Heritage Deferral Account amortization, are lower under the full retrospective approach.**

**The two adoption approaches primarily affect the number of leases recognized on the balance sheet, the timing of recognition of costs and the classification of the**

**costs (e.g., cost of energy and operating costs versus depreciation and finance charges). The table below provides a discussion of the differences between the two approaches in terms of the number of leases, timing of recognition and cost classification.**

| | **Full Retrospective** | **Modified Retrospective (Cumulative Catch-up)** |
|---|---|---|
| **Number of leases and definition of lease** | **Only leases that meet the lease definition under IFRS 16 are recognized on the balance sheet** | **Higher number of leases as all finance leases that existed under the previous standard (IAS 17) remain leases even if they do not meet the definition of a lease under the new standard.**<br>**Two definitions of a lease – one for leases that commenced pre-adoption and one for post adoption.** |
| **Timing of recognition of costs** | **The measurement of lease balances recorded under IFRS 16 is based on a fully retrospective restatement.**<br>**The difference between the lease asset and the lease liability is recognized in retained earnings in the absence of regulatory accounting.**<br>**For leases derecognized under IFRS 16, the difference between the lease asset and lease liability is recognized in retained earnings in the absence of regulatory accounting.**<br>**As BC Hydro had not completed its assessment of the impacts of IFRS 16, BC Hydro requested in the Application that differences attributable to Electricity Purchase Agreements be transferred to the Non-Heritage Deferral Account for recovery in future periods. The requested deferral treatment has ongoing applicability as the adoption impacts are subject to audit and variances may arise from new leases that may be identified in future periods.** | **Finance lease balances that existed under IAS 17 remain on the balance sheet and continue to be recorded as leases.**<br>**For leases recognized under IFRS 16, the lease asset and lease liability amounts are the same. There is no impact on retained earnings or regulatory assets. There are higher expenses over the remainder of the lease than under the retrospective restatement approach.** |

| | **Full Retrospective** | **Modified Retrospective (Cumulative Catch-up)** |
|---|---|---|
| **Classification of Costs** | **The operating and maintenance and taxes expenses associated with Electricity Purchase Agreement finance leases under IAS 17 are reclassified to cost of energy.** | **The operating and maintenance and taxes expenses associated with Electricity Purchase Agreement finance leases under IAS 17 are retained.** |

**The magnitude and the direction (i.e., higher or lower) will depend on the following factors:**

- **Maturity of the lease (i.e. the number of years since commencement relative to the total term of the lease); and**
- **Whether the agreement is being recognized or derecognized under the new standard.**

**259.0 G. CHAPTER 8 – OTHER REVENUE REQUIREMENTS ITEMS**

**Reference: OTHER REVENUE REQUIREMENTS ITEMS**
**Exhibit B-5, BCUC IR 157.6; 157.6.1**
**Full adoption of IFRS**

In response to BCUC IR 157.6.1, BC Hydro provides the following IFRS 1 elections adopted by BC Hydro and a description of the related adjustments:

| | | | | |
|---|---|---|---|---|
| Deemed Cost | IFRS D5-D8B | PP&E | Prior GAAP carrying value of PP&E can be used as a deemed cost for assets used in operations subject to rate regulation on transition date. Election available on an asset-by-asset basis. In the absence of taking this election, full retroactive restatement of PP&E and Intangible assets would be required. | Reclassification from PP&E accumulated depreciation to PP&E cost |

[…]

| | | | | |
|---|---|---|---|---|
| Cumulative translation differences | IFRS 1 D12-D13 | Consolidation | The cumulative translation differences for all foreign operations are deemed to be zero at the date of transition to IFRSs. In the absence of this election, the cumulative translation differences would be subject to full retrospective restatement. | Reclassification between cumulative translation adjustment and retained earnings. |
| Decommissioning liabilities included in the cost of property, plant and equipment | IFRS 1 D21 | PP&E | Instead of retrospectively accounting for changes, entities can include in the depreciated cost of the asset an amount calculated by discounting the liability estimated at the date of transition to IFRSs back to, and depreciating it from, when the liability was first incurred. | Reduction in book value of PP&E and retained earnings that is expected to be insignificant. |

2.259.2 Please discuss whether any of the above elections could impact the Test Period and future periods' revenue requirements. As part of the discussion, please also discuss whether a change in the accounting "cost" of an asset or future gains/losses on a disposition of a related entity would have any implications on the Test Period and future periods' revenue requirements.

**RESPONSE:**

**The impacts on the current and future test periods of each of the elections noted in the preamble to the question are as follows:**

| Election | Impact |
|---|---|
| **Deemed Cost** | **No impact on the Test Period or future revenue requirements. The cost and the accumulated depreciation of assets were adjusted; however, the net book value of the assets did not change and therefore there is no impact to depreciation expense.** |
| **Cumulative translation differences** | **There is no impact on the Test Period. There is also no impact on future revenue requirements, except in the case of a forecast disposal of a subsidiary with a foreign functional currency, as cumulative translation adjustments are not included in the revenue requirements.**<br>**If there was a forecast disposition of a subsidiary with a foreign functional currency, BC Hydro expects that the cumulative translation adjustment would be recognized in income.** |
| **Decommissioning liabilities included in the cost of property, plant and equipment** | **This election reduced the net book value of the decommissioning liabilities included in the costs of property, plant and equipment by $4 million with an offsetting reduction in retained earnings. The reduced net book value of the assets reduced depreciation expense in BC Hydro's fiscal 2018 and fiscal 2019 financial statements. The difference in the net book value of the affected assets between the actual amount and the amount forecast for the Application was only $0.1 million at March 31, 2019. As a result of the reduced net book value of the assets, there would be a reduction in depreciation expense in future revenue requirements of $0.1 million in total (i.e., over a number of years).**<br>**BC Hydro adopted this election due to the complexity and administrative effort that would have been required to retrospectively restate the balance of the assets.** |

**259.0 G. CHAPTER 8 – OTHER REVENUE REQUIREMENTS ITEMS**

**Reference: OTHER REVENUE REQUIREMENTS ITEMS**
**Exhibit B-5, BCUC IR 157.6; 157.6.1**
**Full adoption of IFRS**

In response to BCUC IR 157.6.1, BC Hydro provides the following IFRS 1 elections adopted by BC Hydro and a description of the related adjustments:

| | | | | |
|---|---|---|---|---|
| Deemed Cost | IFRS D5-D8B | PP&E | Prior GAAP carrying value of PP&E can be used as a deemed cost for assets used in operations subject to rate regulation on transition date. Election available on an asset-by-asset basis. In the absence of taking this election, full retroactive restatement of PP&E and Intangible assets would be required. | Reclassification from PP&E accumulated depreciation to PP&E cost |

[…]

| | | | | |
|---|---|---|---|---|
| Cumulative translation differences | IFRS 1 D12-D13 | Consolidation | The cumulative translation differences for all foreign operations are deemed to be zero at the date of transition to IFRSs. In the absence of this election, the cumulative translation differences would be subject to full retrospective restatement. | Reclassification between cumulative translation adjustment and retained earnings. |
| Decommissioning liabilities included in the cost of property, plant and equipment | IFRS 1 D21 | PP&E | Instead of retrospectively accounting for changes, entities can include in the depreciated cost of the asset an amount calculated by discounting the liability estimated at the date of transition to IFRSs back to, and depreciating it from, when the liability was first incurred. | Reduction in book value of PP&E and retained earnings that is expected to be insignificant. |

2.259.2 Please discuss whether any of the above elections could impact the Test Period and future periods' revenue requirements. As part of the discussion, please also discuss whether a change in the accounting "cost" of an asset or future gains/losses on a disposition of a related entity would have any implications on the Test Period and future periods' revenue requirements.

2.259.2.1 If yes, please discuss how the changes arising from IFRS 1 are being considered and tracked.

**RESPONSE:**

**As noted in BC Hydro's response to BCUC IR 2.259.2, only the decommissioning liabilities included in the cost of property, plant and equipment election has an impact on future revenue requirements. The impact over future revenue requirements is $0.1 million in total (i.e., over a number of years). As the future impact is $0.1 million in total, the impact is not being tracked and there was no adjustment to depreciation expense in the Evidentiary Update for this item.**

**260.0 G. CHAPTER 8 – OTHER REVENUE REQUIREMENTS ITEMS**

**Reference: OTHER REVENUE REQUIREMENTS ITEMS**
**Exhibit B-5, BCUC IR 158.1.1, 158.7.1**
**Infrastructure rights**

BC Hydro stated in response to BCUC IR 158.1.1 that:

BC Hydro has incurred costs related to customer-owned equipment upgrades (infrastructure rights) prior to fiscal 2019 but that these upgrades did not commonly occur and were not material. Any amounts incurred were recorded with the other voltage conversion capital costs.

2.260.1 Please provide the following actuals for each of F2014 to F2019:

i) The number of voltage conversion projects;
ii) The number of voltage conversion projects that had customer-owned equipment upgrades (infrastructure rights); and
iii) The capital additions related to infrastructure rights that were recorded with the other voltage conversion capital costs.

**RESPONSE:**

**The table below provides the following for each fiscal year from fiscal 2014 to fiscal 2019:**

**(i) the number of active voltage conversion projects,**

**(ii) the number of active voltage conversion projects that had incurred costs related to customer-owned equipment upgrades, and**

**(iii) the estimated capital additions related to infrastructure rights that were recorded with the other voltage conversion capital costs.**

**The total capital additions related to infrastructure rights recorded with the other voltage conversion capital costs are estimated at $4.9 million for the fiscal 2014 to fiscal 2019 period. Capital additions related to infrastructure rights were not separately tracked in BC Hydro's financial system from fiscal 2014 to fiscal 2019 as annual amounts were not material and the infrastructure rights asset class was not yet established. The dollar amounts for the fiscal years shown in the table below are based on assumptions and estimates to determine the likely amount of additions during the year.**

| Fiscal Year | Fiscal 2014 | Fiscal 2015 | Fiscal 2016 | Fiscal 2017 | Fiscal 2018 | Fiscal 2019 |
|---|---|---|---|---|---|---|
| **Number of active voltage conversion projects** | **20** | **20** | **24** | **29** | **30** | **39** |
| **Number of active voltage conversion projects that had incurred costs related to customer-owned equipment upgrades** | **9** | **12** | **17** | **19** | **20** | **20** |
| **Estimated capital additions related to infrastructure rights for active voltage conversion projects (in $ million)** | **0.13** | **0.16** | **0.42** | **0.96** | **1.02** | **2.18** |

**260.0 G. CHAPTER 8 – OTHER REVENUE REQUIREMENTS ITEMS**

**Reference: OTHER REVENUE REQUIREMENTS ITEMS**
**Exhibit B-5, BCUC IR 158.1.1, 158.7.1**
**Infrastructure rights**

BC Hydro stated in response to BCUC IR 158.7.1 that its accounting treatment for infrastructure rights is consistent with other utilities and cites Toronto Hydro and AltaGas as examples.

2.260.2 Please discuss whether there are other Canadian utilities that use a different accounting treatment for infrastructure rights. If so, please identify the utility and describe the accounting treatment.

**RESPONSE:**

**BC Hydro reviewed the financial statements of Toronto Hydro and Altagas and they, like BC Hydro, capitalize contributions to third-party infrastructure as intangible assets. Toronto Hydro reports these as “Contributions” and Altagas reports these as “Electricity Service Agreements” assets.**

**BC Hydro also reviewed the publicly available annual reports and financial statements of the following five Canadian utilities to attempt to identify their accounting treatment for infrastructure rights:**

- **Hydro Quebec;**
- **Manitoba Hydro;**
- **Hydro One;**
- **Fortis Inc.; and**
- **SaskPower.**

**With respect to the additional five utilities listed above, BC Hydro found no references to the accounting treatment for infrastructure rights in their annual reports and therefore was unable to determine if their accounting treatment for infrastructure rights is similar to BC Hydro’s.**

**260.0 G. CHAPTER 8 – OTHER REVENUE REQUIREMENTS ITEMS**

**Reference: OTHER REVENUE REQUIREMENTS ITEMS**
**Exhibit B-5, BCUC IR 158.1.1, 158.7.1**
**Infrastructure rights**

BC Hydro stated in response to BCUC IR 158.7.1 that its accounting treatment for infrastructure rights is consistent with other utilities and cites Toronto Hydro and AltaGas as examples.

2.260.3 Please discuss if the proposed accounting treatment of infrastructure rights has been reviewed by BC Hydro's external auditor. If so, please provide the external auditor's assessment of BC Hydro's eligibility to recognize the infrastructure rights as intangible assets with depreciation over a 35-year useful life.

**RESPONSE:**

**BC Hydro's proposed accounting treatment of infrastructure rights was reviewed by BC Hydro's previous external auditors and they issued an unqualified opinion on BC Hydro's fiscal 2019 financial statements. BC Hydro's current external auditor has not yet reviewed BC Hydro's accounting treatment for infrastructure rights and they will not issue an audit opinion on BC Hydro's fiscal 2020 financial statements until after March 31, 2020.**

**260.0 G. CHAPTER 8 – OTHER REVENUE REQUIREMENTS ITEMS**

**Reference: OTHER REVENUE REQUIREMENTS ITEMS**
**Exhibit B-5, BCUC IR 158.1.1, 158.7.1**
**Infrastructure rights**

BC Hydro stated in response to BCUC IR 158.7.1 that its accounting treatment for infrastructure rights is consistent with other utilities and cites Toronto Hydro and AltaGas as examples.

2.260.4 Under a scenario where BC Hydro's external auditor assesses that the infrastructure rights either cannot be capitalized or the useful life differs from 35 years, please discuss the implications to BC Hydro's ratepayers and shareholders in the Test Period and beyond.

**RESPONSE:**

**Under a scenario where BC Hydro's external auditor assesses that infrastructure rights cannot be capitalized, BC Hydro would be required to write-off the infrastructure rights assets balances and any work in progress balances. The write-off would be to the account of the shareholder as the expense is not in the scope of an existing regulatory account.**

**Under a scenario where the external auditor assesses that the useful life of the infrastructure rights should differ from 35 years, the change in life would result in amortization variances during the test period. Amortization variances attributable to infrastructure rights additions during the test period are eligible for deferral to the Amortization of Capital Additions Regulatory Account. These deferred amortization variances would be to the account of the ratepayers and would result in ratepayers paying the actual cost of the infrastructure rights.**

**If the useful life difference caused variances in amortization of infrastructure rights in-service prior to this test period, these variances would be to the account of the shareholder as they are not in-scope of the Amortization of Capital Additions Regulatory Account as they are not attributable to test period additions.**

**261.0 G. CHAPTER 8 – OTHER REVENUE REQUIREMENTS ITEMS**

**Reference: OTHER REVENUE REQUIREMENTS ITEMS**
**Exhibit B-1, Appendix A, Schedule 5; Exhibit B-5, BCUC IR 161.3, 161.7**
**Provision and other**

In response to BCUC IR 161.3, BC Hydro provided the incremental rate impact for the Test Period based on the three-year historical actuals of 0.9 percent of the Power System and Technology capital expenditures for each year.

2.261.1 Please provide a high level discussion of the rate impact beyond the Test Period of over or under forecasting project write-offs in the Test Period (i.e. would it have an upward or downward impact on rates, if any). As part of the discussion, please discuss if over or under forecasting project write-offs would impact BC Hydro’s regulatory accounts, such as the Amortization of Capital Additions Regulatory Account.

**RESPONSE:**

**Variances between actual and planned project write-offs in the Test Period will only impact BC Hydro’s net income in the fiscal year the variance is incurred and will have no rate impact beyond the current Test Period. Project write-off variances will not be recorded to any regulatory accounts, such as the Amortization of Capital Additions Regulatory Account.**

## 261.0 G. CHAPTER 8 – OTHER REVENUE REQUIREMENTS ITEMS

**Reference: OTHER REVENUE REQUIREMENTS ITEMS**
**Exhibit B-1, Appendix A, Schedule 5; Exhibit B-5,**
**BCUC IR 161.3, 161.7**
**Provision and other**

In response to BCUC IR 161.7, BC Hydro provided the following:

| $ million | F2017 RRA | F2017 Actual | F2018 RRA | F2018 Actual | F2019 RRA | F2019 Forecast | F2020 Plan | F2021 Plan |
|---|---|---|---|---|---|---|---|---|
| Dismantling costs | 30.9 | 33.7 | 35.7 | 67.5 | 30.6 | 44.5 | 67.0 | 43.0 |
| Gains/losses on mass asset retirements | 31.0 | 33.5 | 33.1 | 34.0 | 33.6 | 33.6 | 35.9 | 38.7 |
| Capital asset write-offs | 7.9 | 13.5 | 7.0 | 9.7 | 6.1 | 6.1 | 8.0 | 8.1 |
| Project write-offs | - | 14.8 | - | 27.3 | - | - | 9.9 | 9.7 |
| Non-cash provision expenses [1] | (5.3) | (31.3) | - | (3.1) | - | (2.0) | - | - |
| Other costs [2] | 1.5 | (0.7) | (14.8) | 16.9 | (18.6) | 0.1 | (12.6) | (12.5) |
| Total (Schedule 5.0 Line 110) | 66.0 | 63.6 | 61.0 | 152.3 | 51.7 | 82.3 | 108.2 | 87.0 |

Note:
1. Non-cash provision expenses pertain to the three non-cash provision regulatory accounts: the First Nations Provisions, the Environmental Provisions, and the Arrow Water Systems Provision regulatory accounts described in Chapter 7, Section 7.5.3 Non-Cash Provisions.

2. Other costs includes real property sales gains, liquidated damages received from vendor, banking fees, electricity purchase agreements termination and other provision expenses.

2.261.2 Please provide a breakdown of "Other costs" by the items listed in Note 2 of the preamble for F2017 to F2021. Please provide explanations for variances greater than 10 percent and ensure that the totals agree with the table in the preamble.

**RESPONSE:**

**The financial information provided in this response has been updated based on the information included in the BC Hydro's Evidentiary Update.**

**Table A provides the updated financial information to the table in BC Hydro's response to BCUC IR 1.161.7. Table B provides the breakdown of "Other costs" and explanations for variances greater than 10 per cent.**

**Table A**

| $ million | F2017 RRA | F2017 Actual | F2018 RRA | F2018 Actual | F2019 RRA | F2019 Actual | F2020 Update | F2021 Update |
|---|---|---|---|---|---|---|---|---|
| Dismantling costs | 30.9 | 33.7 | 35.7 | 67.5 | 30.6 | 42.0 | 67.0 | 43.0 |
| Gains/losses on mass asset retirements | 31.0 | 33.5 | 33.1 | 34.0 | 33.6 | 36.3 | 35.9 | 38.7 |
| Capital asset write-offs | 7.9 | 13.5 | 7.0 | 9.7 | 6.1 | 7.3 | 8.0 | 8.1 |
| Project write-offs | - | 14.8 | - | 27.3 | - | 17.1 | 9.9 | 9.7 |
| Non-cash provision expenses[1] | (5.3) | (31.3) | - | (3.1) | - | (4.7) | - | - |
| Other costs [2] | 1.5 | (0.7) | (14.8) | 16.9 | (18.6) | 14.0 | (13.7) | (13.5) |
| Total (Schedule 5.0 Line 110) | 66.0 | 63.6 | 61.0 | 152.3 | 51.7 | 111.9 | 107.1 | 86.0 |

Note:

1. Non-cash provision expenses pertain to the three non-cash provision regulatory accounts: the First Nations Provisions, the Environmental Provisions, and the Arrow Water Systems Provision regulatory accounts described in Chapter 7, Section 7.5.3 Non-Cash Provisions.

2. Other costs includes real property sales gains, liquidated damages received from vendor, banking fees, electricity purchase agreements termination and other provision expenses.

**Table B**

| $ million | **F2017 RRA** | **F2017 Actual** | **F2018 RRA** | **F2018 Actual** | **F2019 RRA** | **F2019 Actual** | **F2020 Update** | **F2021 Update** | **Explanation of Change** |
|---|---|---|---|---|---|---|---|---|---|
| Real property sales (gains)/losses | (3.5) | (1.0) | (20.0) | (3.2) | (24.0) | (0.6) | (19.1) | (19.1) | Mainly due to timing of surplus property sales delayed to future years. |
| Bank Fees | 5.0 | 5.1 | 5.2 | 5.3 | 5.4 | 5.5 | 5.5 | 5.6 | |
| Electricity purchase agreement terminations | - | 0.4 | - | 4.0 | - | | - | - | Penalties and other transaction costs related to electricity purchase agreement terminations. |
| Provision expense | | | | | | 2.0 | | | Provision for expected dispute resolution cost with a third party. |
| Other Provision Expenses: | | | | | | | | | |
| Legal fees and claims | - | 0.5 | - | 8.0 | - | 5.6 | - | - | Provision mainly related to legal fees for a capital project. |
| Liquidated damages payment | - | (3.8) | - | - | - | - | - | - | Liquidated damage payment received from vendor relating to the Smart Metering technology. |
| Environmental remediation | - | (1.7) | - | 2.2 | - | 0.7 | - | - | Provision for environmental remediation work which includes removal and disposal of contaminated soil, monitoring storm water and gravel work yard restoration. |
| Insurance | - | - | - | 0.3 | - | 0.3 | - | - | Amortization of the prepaid Protective Professional Indemnity insurance premiums for the Site C project. |
| Other | - | (0.1) | - | 0.2 | - | 0.3 | - | - | |
| **Total Other Costs** | **1.5** | **(0.7)** | **(14.8)** | **16.9** | **(18.6)** | **14.0** | **(13.7)** | **(13.5)** | |

**261.0 G. CHAPTER 8 – OTHER REVENUE REQUIREMENTS ITEMS**

**Reference: OTHER REVENUE REQUIREMENTS ITEMS**
**Exhibit B-1, Appendix A, Schedule 5; Exhibit B-5, BCUC IR 161.3, 161.7**
**Provision and other**

BC Hydro presents the net provisions and other costs in lines 65 to 77 in Schedule 5 of Appendix A to the Application. A BCUC prepared summary of specific data from this section of the Application is presented below:

| Line | Net Provision & Other | F2019 Forecast ($ millions) | F2020 Plan ($ millions) | F2021 Plan ($ millions) |
| --- | --- | --- | --- | --- |
| 65 | Integrated Planning | 36.5 | 40.5 | 42.9 |
| 71 | Other | 5.8 | 12.2 | 11.9 |
| 72 | Dismantling Expense-Integrated Planning | 24.0 | 33.0 | 34.8 |
| 74 | Dismantling Expense-Operations | 6.0 | 32.4 | 7.8 |

2.261.3 Please explain the variance from the F2019 forecast to F2020 and F2021 plan for each of the line items listed above.

**RESPONSE:**

**The financial information provided in this response has been updated based on the information included in the BC Hydro's Evidentiary Update.**

**Table A below provides the updated financial information to the table referenced above. Table B provides explanations for changes from fiscal 2019 actual to fiscal 2020 and fiscal 2021 plan.**

**Table A**

**Appendix A - Evidentiary Update**
$ Million

| Schedule 5.0 Line | Table B Reference | Net Provision & Other | F2019 Actual | F2020 Update | F2021 Update |
|---|---|---|---|---|---|
| 65 | Line 1+9 | Integrated Planning | 50.7 | 40.5 | 42.9 |
| 66 | Line 2+10+17 | Capital Infrastructure Project Delivery | 3.9 | 0.0 | 0.0 |
| 67 | Line 3+11 | Operations | 3.7 | 6.5 | 7.2 |
| 68 | Line 4 | Safety | 0.4 | 0.0 | 0.0 |
| 69 | Line 5+12 | Finance, Technology, Supply Chain | 3.9 | 0.0 | 0.0 |
| 70 | Line 6+13 | People, Customer, Corporate Affairs | 1.5 | 0.0 | 0.0 |
| 71 | Line 7+14+16 | Other | 11.2 | 12.2 | 11.9 |
| | Line 18 | Total | 75.2 | 59.2 | 62.1 |
| | | | | | |
| | | Dismantling Expense | | | |
| 72 | Line 19 | Integrated Planning | 24.0 | 33.0 | 34.8 |
| 73 | Line 20 | Capital Infrastructure Project Delivery | 0.7 | 1.5 | 0.3 |
| 74 | Line 21 | Operations | 6.0 | 32.4 | 7.8 |
| 75 | Line 22 | Finance, Technology, Supply Chain | 0.0 | 0.2 | 0.2 |
| | | Total Dismantling Expense Before Deferrals | 30.6 | 67.0 | 43.0 |
| 108 | Line 23 | Dismantling Expense - Deferred | 11.3 | | |
| | Line 24 | Total Gross Dismantling Expense | 42.0 | 67.0 | 43.0 |

### Table B

| $ million<br><br>Line Reference | Item | RRA Schedule 5 Line | F2019 Actual | F2020 Update | F2021 Update | Variance Explanation |
| --- | --- | --- | --- | --- | --- | --- |
| 1 | Gain/Loss on Capital Asset Disposal, Gain/Loss on Mass Asset Retirements and Project Write-Offs [1] | 65 | 50.9 | 40.5 | 42.9 | |
| 2 | | 66 | 2.0 | | | |
| 3 | | 67 | 3.4 | 6.5 | 7.2 | |
| 4 | | 68 | 0.4 | | | |
| 5 | | 69 | 2.8 | | | |
| 6 | | 70 | 1.2 | | | |
| 7 | | 71 | - | 6.8 | 6.3 | |
| 8 | | Subtotal | 60.7 | 53.8 | 56.4 | Fiscal 2020 and fiscal 2021 amounts are lower than the fiscal 2019 actuals primarily due to higher project write-off expenditures in fiscal 2019. For further details on the approach to forecasting project write-offs, please refer to section 8.11 of Chapter 8 of the Application and BC Hydro's response to BCUC IR 1.161.1. |
| 9 | Other Provision | 65 | (0.2) | | | |
| 10 | | 66 | (0.1) | | | |
| 11 | | 67 | 0.3 | | | |
| 12 | | 69 | 1.1 | | | Fiscal 2019 provision mainly relates to environmental remediation. |
| 13 | | 70 | 0.3 | | | |
| 14 | | 71 | 5.7 | | | Fiscal 2019 provision mainly relates to legal fees associated with a capital project and the prepaid Protective Professional Indemnity insurance premiums. |
| 15 | | Subtotal | 7.0 | - | - | |
| 16 | Bank Fees | 71 | 5.5 | 5.5 | 5.6 | |
| 17 | Provision Expense | 66 | 2.0 | | | Fiscal 2019 provision for expected dispute resolution cost with a third party. |
| 18 | **Total** | | **75.2** | **59.2** | **62.1** | |
| 19 | Dismantling Expense [1] | 72 | 24.0 | 33.0 | 34.8 | |
| 20 | | 73 | 0.7 | 1.5 | 0.3 | |
| 21 | | 74 | 6.0 | 32.4 | 7.8 | |
| 22 | | 75 | - | 0.2 | 0.2 | |
| 23 | | 108 | 11.3 | - | - | |
| 24 | | Total | 42.0 | 67.0 | 43.0 | Fiscal 2020 plan includes $23.7 million of dismantling work relating to the John Hart Generating Station Replacement project. |

Note:
1. Business group expenditures related to the gain/loss on capital asset disposal and mass asset retirements, and project write-offs and dismantling expense categories about have been consolidated in order to provide an overall view of these type of expenditures.

**262.0 G. CHAPTER 8 – OTHER REVENUE REQUIREMENTS ITEMS**

**Reference: OTHER REVENUE REQUIREMENTS ITEMS**
**Exhibit B-6, BCOAPO IR 72.1**
**Forecast interest rates and forecast foreign exchange rate**

In response to BCOAPO IR 72.1, BC Hydro provided the forecast interest and foreign exchange rates from the January 2019 forecast received from the Treasury Board of the Government of BC.

2.262.1 Please discuss if BC Hydro plans to update the Application with the forecast interest and foreign exchange rates from the January 2019 forecast received from the Treasury Board of the Government of BC in the September 3, 2019 Evidentiary Update as contemplated in the Regulatory Timetable. If not, please explain why not.

**RESPONSE:**

**Confirmed. All the items updated in BC Hydro's Evidentiary Update used the January 2019 forecast interest rates and foreign exchange rates received from the Treasury Board of the Government of B.C.**

**262.0 G. CHAPTER 8 – OTHER REVENUE REQUIREMENTS ITEMS**

**Reference: OTHER REVENUE REQUIREMENTS ITEMS**
**Exhibit B-6, BCOAPO IR 72.1**
**Forecast interest rates and forecast foreign exchange rate**

In response to BCOAPO IR 72.1, BC Hydro provided the forecast interest and foreign exchange rates from the January 2019 forecast received from the Treasury Board of the Government of BC.

2.262.2 Please provide the rate impact of updating the Application with the forecast interest and foreign exchange rates from the January 2019 forecast received from the Treasury Board of the Government of BC.

**RESPONSE:**

**The proposed net bill impacts filed in BC Hydro's Evidentiary Update incorporates the impact of the inclusion of the January 2019 forecast for interest and foreign exchange rates received from Treasury Board of the Government of B.C., as described in BC Hydro's response to BCUC IR 2.262.1.**

**BC Hydro is unable to readily segregate the rate impact related to the updated interest and foreign exchange rates.**

**263.0 G. CHAPTER 8 – OTHER REVENUE REQUIREMENTS ITEMS**

**Reference: OTHER REVENUE REQUIREMENTS ITEMS**
**Exhibit B-6, CEC IRs 74.2, 74.3**
**Water rights**

BC Hydro stated in response to CEC IR 74.2 that:

> The term of water licence renewals for BC Hydro is determined at the discretion of the Comptroller of Water Rights. BC Hydro anticipates that a 40-year term set out in the *Water Sustainability Act* will be the minimum term for BC Hydro's water licence renewals.

BC Hydro stated in response to CEC IR 74.3 that:

> BC Hydro is in the process of applying for renewals of water licenses for Bridge, Shuswap and Alouette; however, BC Hydro has not renewed a power water licence for approximately 40 years.

2.263.1 Please discuss when BC Hydro expects to finalize the terms of the water licences identified in the preamble.

**RESPONSE:**

**All three water license applications have been submitted to the Government of B.C. and are currently in the technical review phase. The Comptroller of Water Rights may begin their review and engagement process once the technical review phase is complete. The table below provides expected dates for completion of the technical review phase and target dates for a decision on the applications.**

**With submission of the applications, BC Hydro's licenced rights are protected until the Comptroller of Water Rights makes a decision.**

| | Date submitted | Expected Completion of Technical Review Phase | Target date for decision by Comptroller of Water Rights |
|---|---|---|---|
| Shuswap | December 15, 2017 | September 31, 2019 | December 2020 |
| Alouette | September 21, 2018 | December 31, 2019 | December 2021 |
| Bridge | November 2, 2018 | December 31, 2019 | December 2021 |

**263.0 G. CHAPTER 8 – OTHER REVENUE REQUIREMENTS ITEMS**

**Reference: OTHER REVENUE REQUIREMENTS ITEMS**
**Exhibit B-6, CEC IRs 74.2, 74.3**
**Water rights**

BC Hydro stated in response to CEC IR 74.2 that:

> The term of water licence renewals for BC Hydro is determined at the discretion of the Comptroller of Water Rights. BC Hydro anticipates that a 40-year term set out in the Water Sustainability Act will be the minimum term for BC Hydro's water licence renewals.

BC Hydro stated in response to CEC IR 74.3 that:

> BC Hydro is in the process of applying for renewals of water licenses for Bridge, Shuswap and Alouette; however, BC Hydro has not renewed a power water licence for approximately 40 years.

2.263.2 Please discuss why BC Hydro anticipates that a 40-year term will be the minimum term for BC Hydro's water licence renewals.

**RESPONSE:**

**BC Hydro expects that a 40-year term will be the minimum term for BC Hydro's power water licence renewals because BC Hydro is not aware of any case where the Comptroller of Water Rights has issued a power water license for less than 40 years.**

**263.0 G. CHAPTER 8 – OTHER REVENUE REQUIREMENTS ITEMS**

**Reference: OTHER REVENUE REQUIREMENTS ITEMS**
**Exhibit B-6, CEC IRs 74.2, 74.3**
**Water rights**

BC Hydro stated in response to CEC IR 74.2 that:

> The term of water licence renewals for BC Hydro is determined at the discretion of the Comptroller of Water Rights. BC Hydro anticipates that a 40-year term set out in the Water Sustainability Act will be the minimum term for BC Hydro's water licence renewals.

BC Hydro stated in response to CEC IR 74.3 that:

> BC Hydro is in the process of applying for renewals of water licenses for Bridge, Shuswap and Alouette; however, BC Hydro has not renewed a power water licence for approximately 40 years.

2.263.2.1 Please confirm, or explain otherwise, that all of BC Hydro's water licences that have finite terms would be renewed at the same term (i.e. 40 years).

**RESPONSE:**

**Not confirmed. The term of the licences is determined at the discretion of the Comptroller of Water Rights and it is possible that the Comptroller will approve different licence terms for each facility.**

**263.0 G. CHAPTER 8 – OTHER REVENUE REQUIREMENTS ITEMS**

**Reference: OTHER REVENUE REQUIREMENTS ITEMS**
**Exhibit B-6, CEC IRs 74.2, 74.3**
**Water rights**

BC Hydro stated in response to CEC IR 74.2 that:

> The term of water licence renewals for BC Hydro is determined at the discretion of the Comptroller of Water Rights. BC Hydro anticipates that a 40-year term set out in the Water Sustainability Act will be the minimum term for BC Hydro's water licence renewals.

BC Hydro stated in response to CEC IR 74.3 that:

> BC Hydro is in the process of applying for renewals of water licenses for Bridge, Shuswap and Alouette; however, BC Hydro has not renewed a power water licence for approximately 40 years.

2.263.3 In the event that the term of the water licence renewals differs from 40 years, please discuss if BC Hydro plans to adjust the amortization period in the next RRA to reflect the actual term of each licence. If not, please explain why not.

**RESPONSE:**

**Yes, if the term of the water licence renewals differs from 40 years, BC Hydro would adjust the amortization period to reflect the actual term of each licence.**

**263.0 G. CHAPTER 8 – OTHER REVENUE REQUIREMENTS ITEMS**

**Reference: OTHER REVENUE REQUIREMENTS ITEMS**
**Exhibit B-6, CEC IRs 74.2, 74.3**
**Water rights**

BC Hydro stated in response to CEC IR 74.2 that:

> The term of water licence renewals for BC Hydro is determined at the discretion of the Comptroller of Water Rights. BC Hydro anticipates that a 40-year term set out in the Water Sustainability Act will be the minimum term for BC Hydro's water licence renewals.

BC Hydro stated in response to CEC IR 74.3 that:

> BC Hydro is in the process of applying for renewals of water licenses for Bridge, Shuswap and Alouette; however, BC Hydro has not renewed a power water licence for approximately 40 years.

2.263.4 Please discuss the impact to the Test Period revenue requirements and rates of a one, five and ten-year difference from the anticipated 40-year term of the licences.

**RESPONSE:**

**BC Hydro is forecasting no additions of finite term water licence assets prior to fiscal 2021. Therefore, there is no amortization forecast on these assets for fiscal 2020.**

**The table below shows forecast amortization expense for fiscal 2021 and annual periods thereafter based on the forecast test period additions, the 40-year useful life and 40 years plus the difference periods identified in the question. Although there are differences in amortization expenses resulting from different useful lives, the differences do not appear in the table due to rounding of the amounts. The annual amortization is not significant due to additions of $5.3 million in fiscal 2021 and the long amortization period of 30-plus years based on the scenarios provided in the question.**

| Requested Useful life & life Adjustments | F2021 ($ million) | Post F2021 ($ million) |
|---|---|---|
| 40 | 0.1 | 0.1 |
| 1 | 0.1 | 0.1 |
| -1 | 0.1 | 0.1 |
| 5 | 0.1 | 0.1 |
| -5 | 0.1 | 0.2 |
| 10 | 0.1 | 0.1 |
| -10 | 0.1 | 0.2 |

**Any of the differences in useful lives would have less than a 0.001 per cent impact on rates in the test period.**

**263.0 G. CHAPTER 8 – OTHER REVENUE REQUIREMENTS ITEMS**

**Reference: OTHER REVENUE REQUIREMENTS ITEMS**
**Exhibit B-6, CEC IRs 74.2, 74.3**
**Water rights**

BC Hydro stated in response to CEC IR 74.2 that:

> The term of water licence renewals for BC Hydro is determined at the discretion of the Comptroller of Water Rights. BC Hydro anticipates that a 40-year term set out in the Water Sustainability Act will be the minimum term for BC Hydro's water licence renewals.

BC Hydro stated in response to CEC IR 74.3 that:

> BC Hydro is in the process of applying for renewals of water licenses for Bridge, Shuswap and Alouette; however, BC Hydro has not renewed a power water licence for approximately 40 years.

2.263.5 Please discuss if variances between forecast and actual costs to renew finite term water licences can be deferred and recovered from/repaid to ratepayers in future test period(s) via existing regulatory accounts. If so, please identify the regulatory account(s).

**RESPONSE:**

**Differences between the forecast and actual costs of finite term water licences will result in higher/lower asset additions which will result in higher/lower actual amortization expense than forecast. These amortization variances are within the scope of the Amortization of Capital Additions Regulatory Account. Therefore, the amortization variances in the test period would be deferred and refunded to or recovered from ratepayers in future periods, as applicable. As a result, ratepayers will only be charged for the actual costs of the water licences.**

**264.0 H. CHAPTER 9 – TRANSMISSION REVENUE REQUIREMENT**

**Reference: TRANSMISSION REVENUE REQUIREMENT**
**Exhibit B-5, BCUC IR 163.1, Attachment 3, Table 1, p. 2; Attachment 7, p. 1; BCUC IR 163.1.1, 163.1.2**
**Exports from BC**

BC Hydro's response to BCUC IR 163.1 stated:

> …BC Hydro also notes that in any scenario where Point B is at the U.S. border, this indicates that the Transmission Customer intends to export electrical energy from Canada for sale in the U.S. In order to do so, the Transmission customer also requires an export sales permit or licence from the National Energy Board (NEB), which has jurisdiction to regulate electricity energy exports from Canada.

Excerpts from Table 1 of Attachment 3 to BCUC IR 163.1 is provided below, and identifies the potential Path Name and Point of Receipt (POR) and Point of Delivery (POD) Combinations for exports from the BC Hydro System to the US and Alberta:

**Table 1: Valid Path Name and POR/POD Combinations on the BC Hydro System**

| Path Name | POR | POD |
|---|---|---|
| BC – US | | |
| W/BCHA/BCHA – BPAT/KI – BC.US.BORDER/ | KI | BC.US.BORDER |
| W/BCHA/BCHA – BPAT/GMS.MCA.REV – BC.US.BORDER | GMS.MCA.REV | BC.US.BORDER |
| W/BCHA/BCHA – BPAT/BCHA.INT.SYS – BC.US.BORDER/ | BCHA.INT.SYS | BC.US.BORDER |
| W/BCHA/BCHA – BPAT/BCHA.LM.SYS – BC.US.BORDER/ | BCHA.LM.SYS | BC.US.BORDER |
| W/BCHA/BCHA–BPAT/POWELL.RIVER – BC.US.BORDER | POWELL.RIVER | BC.US.BORDER |
| BC – AB | | |
| W/BCHA/BCHA – AESO/KI – AB.BC/ | KI | AB.BC |
| W/BCHA/BCHA – AESO/GMS.MCA.REV – AB.BC/ | GMS.MCA.REV | AB.BC |
| W/BCHA/BCHA – AESO/BCHA.INT.SYS – AB.BC/ | BCHA.INT.SYS | AB.BC |
| W/BCHA/BCHA – AESO/BCHA.LM.SYS – AB.BC/ | BCHA.LM.SYS | AB.BC |
| W/BCHA/BCHA – AESO/POWELL.RIVER – AB.BC/ | POWELL.RIVER | AB.BC |

Attachment 7 in response to BCUC IR 163.1 stated the following:

> - BC Hydro requires the use of eTags to schedule energy in both Pre-schedule and Real-time for all interchange energy transactions, including internal paths.
> - An important element of the eTag is its specification of which transmission reservation the energy is to be scheduled on.

BC Hydro's response to BCUC IR 163.1.2 stated: "In the above example, KI is the Kootenay Interconnection point of interconnection with FortisBC…"

2.264.1 Please clarify what each of the PORs listed in Table 1 above represents: GMS.MCA.REV, BCHA.INT.SYS, BCHA.LM.SYS and POWELL.RIVER.

**RESPONSE:**

**Point(s) of Receipt (POR) are defined in section 1.36 of the Open Access Transmission Tariff, as follows:**

> **Point(s) of interconnection on the Transmission Provider's Transmission System where capacity and energy will be made available to the Transmission Provider by the Delivering Party under Part II of the Tariff. The Point(s) of Receipt shall be specified in the Service Agreement for Long-Term Firm Point-To-Point Transmission Service.**

**The POR listed in Table 1 of Attachment 3 to BC Hydro's response to BCUC IR 1.163.1 represent the following:**

| POR | Represents |
|---|---|
| **GMS.MCA.REV** | **The point of interconnection on the transmission system where capacity and energy are made available from generating resources located around the G.M. Shrum, Mica, and Revelstoke geographic locations.** |
| **BCHA.INT.SYS** | **The point of interconnection on the transmission system where capacity and energy are made available from the BC Hydro Interior system.** |
| **BCHA.LM.SYS** | **The point of interconnection on the transmission system where capacity and energy are made available from the BC Hydro Lower Mainland system.** |
| **POWELL.RIVER** | **The point of interconnection on the transmission system where capacity and energy are made available from Powell River.** |

**264.0 H. CHAPTER 9 – TRANSMISSION REVENUE REQUIREMENT**

**Reference: TRANSMISSION REVENUE REQUIREMENT**
**Exhibit B-5, BCUC IR 163.1, Attachment 3, Table 1, p. 2; Attachment 7, p. 1; BCUC IR 163.1.1, 163.1.2**
**Exports from BC**

BC Hydro's response to BCUC IR 163.1.1 stated:

> In this scenario, Point A could be the Point of Receipt for a generator located in BC Hydro's Service area while Point B could be the Point of Delivery at a border for the Point to Point reservation.
>
> For example, the path, Point of Receipt, and Point of Delivery could be as follows:
>
> Path = W/BCHA/BCHA-BPAT/GMS.MCA.REV-BC.US.BORDER
>
> In the above example, the path is from BC Hydro's service area to the U.S. Border.
>
> This scenario represents all transmission exports from BC Hydro's service area because Network Integration Transmission Service cannot be used for third party sales.

2.264.2 Please clarify where the PORs (BCHA.INT.SYS, BCHA.LM.SYS and POWELL.RIVER) listed in Table 1 above are located, if not from BC Hydro's service area.

**RESPONSE:**

**As indicated in BC Hydro's response to BCUC IR 2.264.1, the Points of Receipt, GMS.MCA.REV, BCHA.INT.SYS, BCHA.LM.SYS and POWELL.RIVER, are all located within BC Hydro's service area. Any of these Points of Receipt could have been used as the Point of Receipt in the example provided in BC Hydro's response to BCUC IR 1.163.1.1.**

**264.0 H. CHAPTER 9 – TRANSMISSION REVENUE REQUIREMENT**

**Reference: TRANSMISSION REVENUE REQUIREMENT**
**Exhibit B-5, BCUC IR 163.1, Attachment 3, Table 1, p. 2; Attachment 7, p. 1; BCUC IR 163.1.1, 163.1.2**
**Exports from BC**

BC Hydro's response to BCUC IR 163.1.1 stated:

> In this scenario, Point A could be the Point of Receipt for a generator located in BC Hydro's Service area while Point B could be the Point of Delivery at a border for the Point to Point reservation.
>
> For example, the path, Point of Receipt, and Point of Delivery could be as follows:
>
> Path = W/BCHA/BCHA-BPAT/GMS.MCA.REV-BC.US.BORDER
>
> In the above example, the path is from BC Hydro's service area to the U.S. Border.
>
> This scenario represents all transmission exports from BC Hydro's service area because Network Integration Transmission Service cannot be used for third party sales.

2.264.3 Please confirm, or explain otherwise, that Network Integration Transmission Service is associated with each of the following PORs: BCHA.INT.SYS, BCHA.LM.SYS and POWELL.RIVER.

**RESPONSE:**

**Not confirmed.**

**Designated resources supplying network load are not associated with a Point(s)-of-Receipt (POR) and are managed by BC Hydro as the Network Customer rather than by BC Hydro as the Transmission Provider. The Network Customer has a Network Integration Transmission Service Agreement (NITSA) with the Transmission Provider per Attachment F of the Open Access Transmission Tariff (OATT). Included in the NITSA is the Network Operating Agreement per Attachment G of the OATT, which contains the technical specifications associated with the service. This allows the Network Customer to reserve and use Network Integration Transmission Service to serve network load from designated network resources.**

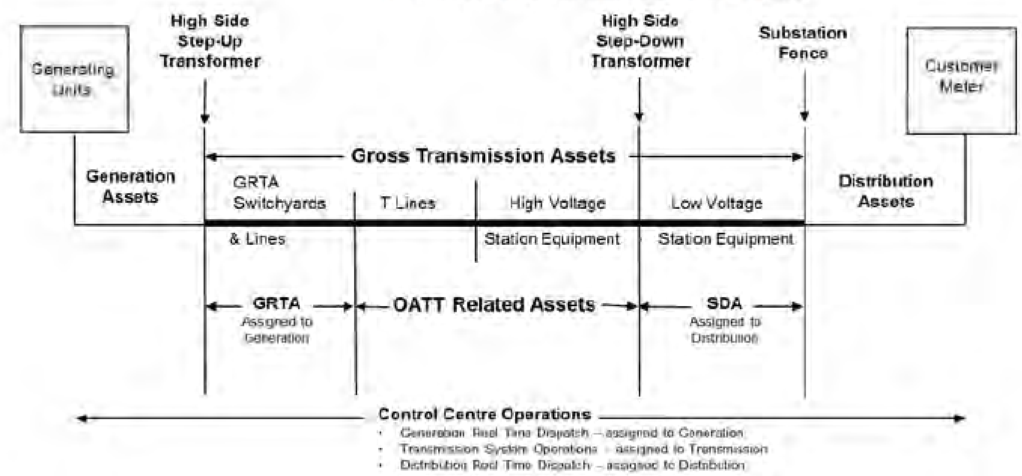
**The valid PORs used to transmit energy from a non-designated resource to serve Network Load using Network Economy Transmission Service (a form of short-term Point-To-Point Transmission Service) include AB.BC, BC.US.Border, KI, and BCHA.INTRNL. These PORs all have their Point of Delivery as BCHA.NTWK.LD (BC Hydro Network Load). Please refer to BC Hydro's response to BCUC IR 1.163.5 for an explanation of non-designated resources.**

**265.0 H. CHAPTER 9 – TRANSMISSION REVENUE REQUIREMENT**

**Reference: TRANSMISSION REVENUE REQUIREMENT**
**Exhibit B-1, Figure 9-1, p. 9-3; Exhibit B-5, BCUC IR 163.2**
**NITS current costs – transmission line and station equipment allocation**

Figure 9-1 in the Application illustrates that the Open Access Transmission Tariff (OATT) Related Assets are a combination of High Voltage Station Equipment and Transmission Lines:

**Figure 9-1 Asset Boundary for Transmission Revenue Requirement and OATT Rates**




BC Hydro's response to BCUC IR 163.2 stated: "The total current costs…of $931.9M in fiscal 2020 and $930.3 million in fiscal 2021 all relate to BC Hydro's transmission system (transmission lines and high voltage station equipment)."

2.265.1 Please complete the table below to breakdown the Total Current Costs between transmission line and high-voltage station equipment

| | F2020 | F2021 |
|---|---|---|
| Costs Allocated to Transmission Lines | | |
| Costs Allocated to High-Voltage Station Equipment | | |
| Internal Ancillary Services | | |
| Internal Scheduling and Dispatch | | |
| **Total Current Costs** | **$931.9M** | **$930.3M** |

**RESPONSE:**

**While Figure 9-1 depicts the asset boundaries for the Transmission Revenue Requirement and OATT Rates, the calculation of Transmission Revenue Requirement and OATT Rates is not based on asset boundaries.**

**The sub-functionalization of all Transmission costs to either transmission lines or high voltage station equipment is not required to determine the OATT rates and BC Hydro did not undertake to calculate these values as part of the Transmission Revenue Requirement cost of service study. Given the resource intensity of sub-functionalization of all Transmission costs to either transmission lines or high voltage station equipment, BC Hydro is unable to calculate these costs at this time.**

**The following table provides estimates of the requested amounts based on the Evidentiary Update, and shows how Total Current Costs and the Total NITS charge can be calculated from the Transmission Revenue Requirement, as well as how Internal Ancillary Services and Internal Scheduling and Dispatch charges are included in the calculation.**

**The table also provides an estimate of costs related to Transmission Lines and costs related to high-voltage lines; however, these estimates were derived using readily available rate-base analysis of Transmission assets and do not account for sub-functionalization of other costs such as operating costs.**

| | Reference | F2020 Evidentiary Update ($ million) | F2021 Evidentiary Update ($ million) |
|---|---|---|---|
| Costs Related to Transmission Lines | Estimate | 499.4 | 501.8 |
| plus Costs Related to High-Voltage Station Equipment | Estimate | 592.3 | 588.0 |
| Transmission Revenue Requirement | Sch. 3.4 L. 28 | 1,091.7 | 1,089.9 |
| less External OATT Revenue | Sch. 3.4 L. 27 | (15.9) | (15.9) |
| less Inter-Segment Revenues | Sch. 3.4 L. 26 | (60.6) | (69.0) |
| less PTP Allocation to Distribution | Sch. 3.4 L. 25 | (43.6) | (36.0) |
| Total Current Costs | Sch. 3.4 L. 24 | 971.6 | 969.0 |
| less Internal Ancillary Services | Sch. 3.4 L. 30 | - | - |
| less Internal Scheduling & Dispatch | Sch. 3.4 L. 31 | (3.8) | (4.0) |
| Total NITS Charge | Sch. 3.4 L. 32 | 967.8 | 965.0 |

**266.0 H. CHAPTER 9 – TRANSMISSION REVENUE REQUIREMENT**

**Reference: TRANSMISSION REVENUE REQUIREMENT**
**Exhibit B-1, p. 9-27; Appendix A, Schedule 3.4; Exhibit B-5, BCUC IR 163.1**
**External OATT revenue**

Page 9-27 of the Application states:

> The long-term PTP revenue is derived 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.

The table below prepared by BCUC staff summarizes the F2017 and F2018 actual, F2019 forecast and F2020 and F2021 plan short-term and long-term PTP transmission sales volumes and revenues using data provided in Schedule 3.4 of Appendix A to the Application:

| **($ million)** | **2017** | **2018** | **2019** | **2020** | **2021** |
|---|---|---|---|---|---|
| **[A]** External Revenue (Line 68) | 9.7 | 8.5 | 9.0 | 12.4 | 12.4 |
| **[B]** Total PTP Revenue (Line 69) | 90.4 | 99.4 | 96.3 | 113.3 | 114.2 |
| **% ([A]/[B])** | **10.7** | **8.6** | **9.3** | **10.9** | **10.9** |
| **GWh** | **2017** | **2018** | **2019** | **2020** | **2021** |
| **[C]** External LT PTP (Line 50) | 1,130 | 908 | 1,039 | 1,314 | 1,314 |
| **[D]** External ST PTP (Line 59) | 288 | 446 | 266 | 240 | 240 |
| **[E]** Total External PTP Volume **[C + D]** | 1,418 | 1,354 | 1,305 | 1,554 | 1,554 |
| **[F]** Total PTP Volume (Line 51 + Line 60) | 16,252 | 18,140 | 19,572 | 19,821 | 20,206 |
| **% ([E] + [F])** | **8.7** | **7.5** | **6.7** | **7.8** | **7.7** |

2.266.1 Please explain why the volume of PTP transmission used by external customers as a percentage of the total volume of PTP transmission used by all transmission customers has declined since 2017.

**RESPONSE:**

**The table below updates the table provided in the preamble to the question to reflect fiscal 2019 actuals and updates to fiscal 2020 and fiscal 2021 plan included in BC Hydro's Evidentiary Update.**

| ($ million) | F2017 Actual | F2018 Actual | F2019 Actual | F2020 Evidentiary Update | F2021 Evidentiary Update |
|---|---|---|---|---|---|
| [A] External Revenue (Line 68) | 9.7 | 8.5 | 9.2 | 12.9 | 12.8 |
| [B] Total PTP Revenue (Line 69) | 90.4 | 99.4 | 105.6 | 117.0 | 117.8 |
| % ([A]/[B]) | 10.7 | 8.6 | 8.7 | 11.0 | 10.9 |
| | | | | | |
| GWh | F2017 Actual | F2018 Actual | F2019 Actual | F2020 Evidentiary Update | F2021 Evidentiary Update |
| [C] External LT PTP (Line 50) | 1,130 | 908 | 876 | 1,314 | 1,314 |
| [D] External ST PTP (Line 59) | 288 | 446 | 657 | 240 | 240 |
| [E] Total External PTP Volume [C + D] | 1,418 | 1,354 | 1,533 | 1,554 | 1,554 |
| [F] Total PTP Volume (Line 51 + Line 60) | 16,252 | 18,140 | 17,253 | 19,821 | 20,206 |
| % ([E]/[F]) | 8.7 | 7.5 | 8.9 | 7.8 | 7.7 |

**Based on the updated fiscal 2019 actuals provided in the table above:**

- **The volume of Short-Term and Long-Term PTP transmission used by external customers as a percentage of the total volume of PTP transmission used by all transmission customers declined in fiscal 2018 but increased in fiscal 2019.**

- **Long-Term Point-To-Point contracts have not decreased; however, some of the external long-term volume was re-allocated to internal volume when the actuals were prepared due to the resale by an external customer of its long-term contracted volume to an internal customer. Such resales cannot be forecast for the current test period because we do not know if an external customer will resell its volume, or to whom.**

- **External Short-Term PTP volume has increased each year from fiscal 2017 to fiscal 2019. Short-term volume is largely based on customers' business requirements and market pricing and is difficult to forecast for any given year.**

**266.0 H. CHAPTER 9 – TRANSMISSION REVENUE REQUIREMENT**

**Reference: TRANSMISSION REVENUE REQUIREMENT**
**Exhibit B-1, p. 9-27; Appendix A, Schedule 3.4; Exhibit B-5, BCUC IR 163.1**
**External OATT revenue**

Page 9-27 of the Application states:

> The long-term PTP revenue is derived 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.

The table below prepared by BCUC staff summarizes the F2017 and F2018 actual, F2019 forecast and F2020 and F2021 plan short-term and long-term PTP transmission sales volumes and revenues using data provided in Schedule 3.4 of Appendix A to the Application:

| **($ million)** | **2017** | **2018** | **2019** | **2020** | **2021** |
|---|---|---|---|---|---|
| **[A]** External Revenue (Line 68) | 9.7 | 8.5 | 9.0 | 12.4 | 12.4 |
| **[B]** Total PTP Revenue (Line 69) | 90.4 | 99.4 | 96.3 | 113.3 | 114.2 |
| **% ([A]/[B])** | **10.7** | **8.6** | **9.3** | **10.9** | **10.9** |
| **GWh** | **2017** | **2018** | **2019** | **2020** | **2021** |
| **[C]** External LT PTP (Line 50) | 1,130 | 908 | 1,039 | 1,314 | 1,314 |
| **[D]** External ST PTP (Line 59) | 288 | 446 | 266 | 240 | 240 |
| **[E]** Total External PTP Volume **[C + D]** | 1,418 | 1,354 | 1,305 | 1,554 | 1,554 |
| **[F]** Total PTP Volume (Line 51 + Line 60) | 16,252 | 18,140 | 19,572 | 19,821 | 20,206 |
| **% ([E] + [F])** | **8.7** | **7.5** | **6.7** | **7.8** | **7.7** |

2.266.2 Excluding BC Hydro and Powerex, please identify the number of OATT customers who use BC Hydro's PTP transmission service.

**RESPONSE:**

**Excluding BC Hydro and Powerex, 22 OATT customers have executed point-to-point Umbrella Agreements to use BC Hydro's Point To-Point transmission service.**

**266.0 H. CHAPTER 9 – TRANSMISSION REVENUE REQUIREMENT**

**Reference: TRANSMISSION REVENUE REQUIREMENT**
**Exhibit B-1, p. 9-27; Appendix A, Schedule 3.4; Exhibit B-5, BCUC IR 163.1**
**External OATT revenue**

Page 9-27 of the Application states:

> The long-term PTP revenue is derived 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.

The table below prepared by BCUC staff summarizes the F2017 and F2018 actual, F2019 forecast and F2020 and F2021 plan short-term and long-term PTP transmission sales volumes and revenues using data provided in Schedule 3.4 of Appendix A to the Application:

| **($ million)** | **2017** | **2018** | **2019** | **2020** | **2021** |
|---|---|---|---|---|---|
| **[A]** External Revenue (Line 68) | 9.7 | 8.5 | 9.0 | 12.4 | 12.4 |
| **[B]** Total PTP Revenue (Line 69) | 90.4 | 99.4 | 96.3 | 113.3 | 114.2 |
| **% ([A]/[B])** | **10.7** | **8.6** | **9.3** | **10.9** | **10.9** |
| **GWh** | **2017** | **2018** | **2019** | **2020** | **2021** |
| **[C]** External LT PTP (Line 50) | 1,130 | 908 | 1,039 | 1,314 | 1,314 |
| **[D]** External ST PTP (Line 59) | 288 | 446 | 266 | 240 | 240 |
| **[E]** Total External PTP Volume **[C + D]** | 1,418 | 1,354 | 1,305 | 1,554 | 1,554 |
| **[F]** Total PTP Volume (Line 51 + Line 60) | 16,252 | 18,140 | 19,572 | 19,821 | 20,206 |
| **% ([E] + [F])** | **8.7** | **7.5** | **6.7** | **7.8** | **7.7** |

2.266.2 Excluding BC Hydro and Powerex, please identify the number of OATT customers who use BC Hydro's PTP transmission service.

2.266.2.1 Please confirm, or explain otherwise, that the customers identified in the preceding IR are the "external" customers in Schedule 3.4.

**RESPONSE:**

**Confirmed. The number of OATT customers identified in BC Hydro's response to BCUC IR 2.266.2 is the number of "external" customers.**

**266.0 H. CHAPTER 9 – TRANSMISSION REVENUE REQUIREMENT**

**Reference: TRANSMISSION REVENUE REQUIREMENT**
**Exhibit B-1, p. 9-27; Appendix A, Schedule 3.4; Exhibit B-5, BCUC IR 163.1**
**External OATT revenue**

Page 9-27 of the Application states:

> The long-term PTP revenue is derived 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.

The table below prepared by BCUC staff summarizes the F2017 and F2018 actual, F2019 forecast and F2020 and F2021 plan short-term and long-term PTP transmission sales volumes and revenues using data provided in Schedule 3.4 of Appendix A to the Application:

| ($ million) | 2017 | 2018 | 2019 | 2020 | 2021 |
|---|---|---|---|---|---|
| **[A]** External Revenue (Line 68) | 9.7 | 8.5 | 9.0 | 12.4 | 12.4 |
| **[B]** Total PTP Revenue (Line 69) | 90.4 | 99.4 | 96.3 | 113.3 | 114.2 |
| **% ([A]/[B])** | **10.7** | **8.6** | **9.3** | **10.9** | **10.9** |
| **GWh** | **2017** | **2018** | **2019** | **2020** | **2021** |
| **[C]** External LT PTP (Line 50) | 1,130 | 908 | 1,039 | 1,314 | 1,314 |
| **[D]** External ST PTP (Line 59) | 288 | 446 | 266 | 240 | 240 |
| **[E]** Total External PTP Volume **[C + D]** | 1,418 | 1,354 | 1,305 | 1,554 | 1,554 |
| **[F]** Total PTP Volume (Line 51 + Line 60) | 16,252 | 18,140 | 19,572 | 19,821 | 20,206 |
| **% ([E] + [F])** | **8.7** | **7.5** | **6.7** | **7.8** | **7.7** |

2.266.2 Excluding BC Hydro and Powerex, please identify the number of OATT customers who use BC Hydro's PTP transmission service.

2.266.2.2 Excluding BC Hydro and Powerex, please identify the number of OATT customers who use BC Hydro's PTP transmission service who are located:

i) within BC Hydro's service area;
ii) outside of BC Hydro's service area, but within BC; and
iii) outside of BC Hydro's service area and outside of BC.

**RESPONSE:**

**The table below provides the number of OATT customers who use BC Hydro's Point-To-Point transmission service, by location, excluding BC Hydro and Powerex:**

| Location | Number of OATT Customers |
|---|---|
| **Within BC Hydro's service area** | **0** |
| **Outside of BC Hydro's service area, but within B.C.** | **1** |
| **Outside of BC Hydro's service area and outside of B.C.** | **21** |

**266.0 H. CHAPTER 9 – TRANSMISSION REVENUE REQUIREMENT**

**Reference: TRANSMISSION REVENUE REQUIREMENT**
**Exhibit B-1, p. 9-27; Appendix A, Schedule 3.4; Exhibit B-5, BCUC IR 163.1**
**External OATT revenue**

Page 9-27 of the Application states:

> The long-term PTP revenue is derived 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.

The table below prepared by BCUC staff summarizes the F2017 and F2018 actual, F2019 forecast and F2020 and F2021 plan short-term and long-term PTP transmission sales volumes and revenues using data provided in Schedule 3.4 of Appendix A to the Application:

| **($ million)** | **2017** | **2018** | **2019** | **2020** | **2021** |
|---|---|---|---|---|---|
| **[A]** External Revenue (Line 68) | 9.7 | 8.5 | 9.0 | 12.4 | 12.4 |
| **[B]** Total PTP Revenue (Line 69) | 90.4 | 99.4 | 96.3 | 113.3 | 114.2 |
| **% ([A]/[B])** | **10.7** | **8.6** | **9.3** | **10.9** | **10.9** |
| **GWh** | **2017** | **2018** | **2019** | **2020** | **2021** |
| **[C]** External LT PTP (Line 50) | 1,130 | 908 | 1,039 | 1,314 | 1,314 |
| **[D]** External ST PTP (Line 59) | 288 | 446 | 266 | 240 | 240 |
| **[E]** Total External PTP Volume **[C + D]** | 1,418 | 1,354 | 1,305 | 1,554 | 1,554 |
| **[F]** Total PTP Volume (Line 51 + Line 60) | 16,252 | 18,140 | 19,572 | 19,821 | 20,206 |
| **% ([E] + [F])** | **8.7** | **7.5** | **6.7** | **7.8** | **7.7** |

2.266.3 For each of the locations listed in the preceding IR, please identify how those customers use BC Hydro's PTP transmission service (i.e. to import to BC, export from BC, wheel through BC, wheel within BC, other). If applicable, please explain what "other" is.

**RESPONSE:**

**The table below provides the requested information.**

| Location | Number. of OATT Customers | Type of Use | Other (Rare Occurrences) |
|---|---|---|---|
| **Within BC Hydro's service area** | **0** | **N/A** | **N/A** |
| **Outside of BC Hydro's service area, but within B.C.** | **1** | **Export** | **N/A** |
| **Outside of BC Hydro's service area and outside of B.C.** | **21** | **Wheel through B.C.** | • **Export from B.C. (contracted with B.C.-located generator)**<br>• **Import to B.C. (for physical energy loss delivery on energy schedules when customer elects to self-supply real power losses per OATT Rate Schedule 10)**<br>• **Import to B.C. and Export from B.C. (mixed wheelthrough transaction)** |

**266.0 H. CHAPTER 9 – TRANSMISSION REVENUE REQUIREMENT**

**Reference: TRANSMISSION REVENUE REQUIREMENT**
**Exhibit B-1, p. 9-27; Appendix A, Schedule 3.4; Exhibit B-5, BCUC IR 163.1**
**External OATT revenue**

Page 9-27 of the Application states:

> The long-term PTP revenue is derived 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.

The table below prepared by BCUC staff summarizes the F2017 and F2018 actual, F2019 forecast and F2020 and F2021 plan short-term and long-term PTP transmission sales volumes and revenues using data provided in Schedule 3.4 of Appendix A to the Application:

| **($ million)** | **2017** | **2018** | **2019** | **2020** | **2021** |
|---|---|---|---|---|---|
| **[A]** External Revenue (Line 68) | 9.7 | 8.5 | 9.0 | 12.4 | 12.4 |
| **[B]** Total PTP Revenue (Line 69) | 90.4 | 99.4 | 96.3 | 113.3 | 114.2 |
| **% ([A]/[B])** | **10.7** | **8.6** | **9.3** | **10.9** | **10.9** |
| **GWh** | **2017** | **2018** | **2019** | **2020** | **2021** |
| **[C]** External LT PTP (Line 50) | 1,130 | 908 | 1,039 | 1,314 | 1,314 |
| **[D]** External ST PTP (Line 59) | 288 | 446 | 266 | 240 | 240 |
| **[E]** Total External PTP Volume **[C + D]** | 1,418 | 1,354 | 1,305 | 1,554 | 1,554 |
| **[F]** Total PTP Volume (Line 51 + Line 60) | 16,252 | 18,140 | 19,572 | 19,821 | 20,206 |
| **% ([E] + [F])** | **8.7** | **7.5** | **6.7** | **7.8** | **7.7** |

2.266.4 Excluding BC Hydro and Powerex, please complete the table below to provide the volume of PTP transmission used by OATT customers for each activity listed.

| GWh | 2017 | 2018 | 2019 | 2020 | 2021 |
|---|---|---|---|---|---|
| Import to BC | | | | | |
| Export from BC | | | | | |
| Wheel through BC | | | | | |
| Wheel within BC | | | | | |
| Other | | | | | |
| **Total** | **1,418** | **1,354** | **1,305** | **1,554** | **1,554** |

**RESPONSE:**

**The table below provides the volume of Point-To-Point transmission used by OATT customers for each activity listed, excluding BC Hydro and Powerex.**

| GWh | F2017 Actual | F2018 Actual | F2019 Actual | F2020 Evidentiary Update | F2021 Evidentiary Update |
|---|---|---|---|---|---|
| **Import to B.C.** | **0** | **0** | **0.39** | **0** | **0** |
| **Export from B.C.** | **0.10** | **0** | **0** | **0** | **0** |
| **Wheel through B.C.** | **1,406.59** | **1,350.69** | **1518.13** | **1,554** | **1,554** |
| **Wheel within B.C.** | **0** | **0** | **0** | **0** | **0** |
| **Other** | **11.78** | **14.46** | **14.46** | **0** | **0** |
| **Total** | **1,418** | **1,354** | **1,533** | **1,554** | **1,554** |

**266.0 H. CHAPTER 9 – TRANSMISSION REVENUE REQUIREMENT**

**Reference: TRANSMISSION REVENUE REQUIREMENT**
**Exhibit B-1, p. 9-27; Appendix A, Schedule 3.4; Exhibit B-5, BCUC IR 163.1**
**External OATT revenue**

In response to BCUC IR 163.1, BC Hydro stated:

> In each scenario, an Eligible Customer under section 1.12 of the Open Access Transmission Tariff (OATT) and BC Hydro's Becoming a BC Hydro Transmission Customer Business Practice, included as Attachment 1, would execute a Service Agreement per OATT Attachment B (Long-Term PTP) and/or an Umbrella Agreement per OATT Attachment A (Short-Term PTP) to become a BC Hydro Transmission Customer and to purchase transmission rights on BC Hydro's system in accordance with Part I (Common Service Provisions) and Part II (Point-To-Point Transmission Service) of the OATT.

2.266.5 Please provide the annual number of Service Agreements and Umbrella Agreements that BC Hydro has received from F2017 to F2019 from entities who want to become a BC Hydro transmission customer.

**RESPONSE:**

**The table below provides the requested information.**

| Fiscal Year | Number of Umbrella Agreements from New Customers | Number of Signed Service Agreements from New Customers | Number of Signed Service Agreements from Existing Customers |
|---|---|---|---|
| **F2017** | **0** | **0** | **3** |
| **F2018** | **1** | **0** | **2** |
| **F2019** | **0** | **0** | **4** |

**Once an Umbrella Agreement is executed, the Transmission Customer can purchase Short-Term Point-to-Point (PTP) transmission service on BC Hydro's Open Access Same-Time Information System (OASIS). A financial contract exists when a Transmission Service Request (TSR) is automatically confirmed on OASIS. However, when the Transmission Customer submits a TSR for Long-Term PTP transmission service, the TSR must be manually evaluated by BC Hydro to determine whether the TSR can be accommodated. If the TSR can be**

**accommodated, a Service Agreement is tendered to the Transmission Customer for execution. Once the Service Agreement is signed, the TSR is manually confirmed on OASIS.**

**While an Umbrella Agreement typically indicates a new Transmission Customer (although an existing Transmission Customer can update and replace their existing Umbrella Agreement), a Service Agreement can indicate either a new Transmission Customer or an existing Transmission Customer (e.g., a customer that already has an umbrella agreement and now wants to become a Long-Term PTP transmission service customer, or a customer with a Service Agreement who purchases additional transmission rights through another Service Agreement).**

**Accordingly, in the above table:**

- **The second column identifies the number of new entities who wanted to become a BC Hydro transmission customer by executing an Umbrella Agreement for Short-Term PTP transmission service. There was only one such new entity, and that was in fiscal 2018;**
- **The third column identifies the number of new entities who wanted to become a BC Hydro transmission customer for Long-Term PTP transmission service. There were no such new entities; and**
- **The fourth column identifies existing Transmission Customers who signed new Service Agreements for Long-Term PTP transmission service.**

**266.0 H. CHAPTER 9 – TRANSMISSION REVENUE REQUIREMENT**

**Reference: TRANSMISSION REVENUE REQUIREMENT**
**Exhibit B-1, p. 9-27; Appendix A, Schedule 3.4; Exhibit B-5, BCUC IR 163.1**
**External OATT revenue**

In response to BCUC IR 163.1, BC Hydro stated:

> In each scenario, an Eligible Customer under section 1.12 of the Open Access Transmission Tariff (OATT) and BC Hydro's Becoming a BC Hydro Transmission Customer Business Practice, included as Attachment 1, would execute a Service Agreement per OATT Attachment B (Long-Term PTP) and/or an Umbrella Agreement per OATT Attachment A (Short-Term PTP) to become a BC Hydro Transmission Customer and to purchase transmission rights on BC Hydro's system in accordance with Part I (Common Service Provisions) and Part II (Point-To-Point Transmission Service) of the OATT.

2.266.6 Please provide the annual number of new transmission customers from F2017 to F2019.

**RESPONSE:**

**The following table provides the annual number of new transmission customers from fiscal 2017 to fiscal 2019. As identified in BC Hydro's response to BCUC IR 1.266.5, there was only one new customer in fiscal 2018.**

| Fiscal Year | Number of Umbrella Agreements from New Customers | Number of Signed Service Agreements from New Customers |
|---|---|---|
| F2017 | 0 | 0 |
| F2018 | 1 | 0 |
| F2019 | 0 | 0 |

**266.0 H. CHAPTER 9 – TRANSMISSION REVENUE REQUIREMENT**

**Reference: TRANSMISSION REVENUE REQUIREMENT**
**Exhibit B-1, p. 9-27; Appendix A, Schedule 3.4; Exhibit B-5, BCUC IR 163.1**
**External OATT revenue**

In response to BCUC IR 163.1, BC Hydro stated:

> In each scenario, an Eligible Customer under section 1.12 of the Open Access Transmission Tariff (OATT) and BC Hydro's Becoming a BC Hydro Transmission Customer Business Practice, included as Attachment 1, would execute a Service Agreement per OATT Attachment B (Long-Term PTP) and/or an Umbrella Agreement per OATT Attachment A (Short-Term PTP) to become a BC Hydro Transmission Customer and to purchase transmission rights on BC Hydro's system in accordance with Part I (Common Service Provisions) and Part II (Point-To-Point Transmission Service) of the OATT.

2.266.7 Please discuss whether there are any constraints, such as transmission system capacity, which may impact the number of new transmission customers that BC Hydro can accommodate assuming they meet the eligibility requirements under the OATT.

**RESPONSE:**

**As a result of Available Transfer Capability constraints within Alberta, the B.C.>A.B. path has been restricted since the temporary suspension of Facilities Studies granted in BCUC Order No. G-110-08 and the directive to reduce Long-Term contracts for firm service from 785 MW to 480 MW included in BCUC Order No. G-103-09.**

**In accordance with BCUC Order No. G-103-09, BC Hydro has restricted the firm sales on the B.C.>A.B. path to 480 MW and offered the capacity of 305 MW from the cancelled contracts (785 MW to 480 MW) to the affected customers only as Conditional Firm Service.**

**As a result, there are currently 101 requests in the queue for Long-Term firm service on the B.C.>A.B. and U.S.>A.B. paths that cannot be accommodated at this time.**

**With the firm sales to Alberta limited to 480 MW, the Firm Available Transfer Capability on the B.C.>A.B. and U.S.>A.B. is fully subscribed and there is no offering of Short-Term Firm Point-to-Point Available Transfer Capability on these**

**paths. Non-Firm service can become available due to un-utilized firm transmission capacity on an hourly basis.**

**There are no other constraints to the provision of Long-Term Point-To-Point transmission service based on Transmission Service Requests that have been submitted by customers at this time. There are also no constraints to Transmission Service Requests from customers wishing to enter into Umbrella Agreements for Short-Term service.**

**267.0 H. CHAPTER 9 – TRANSMISSION REVENUE REQUIREMENT**

**Reference: TRANSMISSION REVENUE REQUIREMENT**
**Exhibit B-1, p. 9-16**
**Cost allocations to generation, transmission and distribution**

Footnote 340 on page 9-16 of the Application states:

> In 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 five 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.

2.267.1 Please confirm, or explain otherwise, that BC Hydro used the methodologies from its 2016 Cost of Service Study (contained in Appendix A of Order G-47-16) to allocate costs to its Transmission Revenue Requirement in this Test Period.

**RESPONSE:**

**The cost of service methodologies from Appendix A of BCUC Order No. G-47-16 are shown below, alongside a description of how they do or do not apply to the fiscal 2020 to fiscal 2021 Transmission Revenue Requirement.**

**The 2016 Cost of Service Study considered cost of service concepts related to BC Hydro's bundled electricity rates under its Electric Tariff, not its Open Access Transmission Tariff rates. As a result, a number of the 2016 Cost of Service Study methodological steps (e.g. classification, allocation) are not applicable to the Transmission Revenue Requirement.**

**In other cases, methodologies from the 2016 cost of service study may not be directly applicable to the fiscal 2020 to fiscal 2021 Transmission Revenue Requirement given changes to BC Hydro's business and financial model (e.g., changes to regulatory accounts and cost definitions).**

| Cost and Methodology Topic | Applicability to Transmission Revenue Requirement (TRR) |
|---|---|
| **1. Heritage Hydro Classification** | **Not Applicable. Classification between demand and energy is not a required methodological step in the calculation of the TRR, because Transmission costs are classified as 100 per cent capacity (demand).** |
| **1. Heritage Thermal Classification** | **Not applicable as described in item 1.** |
| **2. DSM Functionalization** | **Consistent with Appendix A of BCUC Order No. G-47-16, 5 per cent of DSM costs have been functionalized to Transmission in the TRR.** |
| **3. DSM Classification** | **Not applicable as described in item 1.** |
| **4. IPP Purchases Classification** | **Not applicable as described in item 1.** |
| **5. Distribution Classification** | **Not applicable as described in item 1.** |
| **6. Customer Care Classification** | **Not applicable as described in item 1.** |
| **7. IT costs Functionalization** | **Consistent with Appendix A of BCUC Order No. G-47-16, approximately thirty per cent (28.5 per cent) of IT costs have been functionalized to Transmission in the TRR.** |
| **8. IPP Capital Lease Costs Functionalization** | **Consistent with Appendix A of BCUC Order No. G-47-16, zero per cent of IPP Capital Lease Costs have been functionalized to Transmission in the TRR.** |
| **9. ERP Costs Functionalization** | **Consistent with Appendix A of BCUC Order No. G-47-16, zero per cent of ERP Costs have been functionalized to Transmission in the TRR.** |
| **10. Corporate Tax Functionalization** | **Consistent with Appendix A of BCUC Order No. G-47-16, 65 per cent per cent of corporate tax costs have been functionalized to Transmission in the TRR.** |
| **11. Corporate Depreciation Functionalization** | **Due to the changes in the organization structure of BC Hydro, the Corporate Services depreciation allocation in Appendix A of BCUC Order No. G-47-16 is not directly applicable to the TRR.**<br>**With the full adoption by BC Hydro of International Financial Reporting Standards in fiscal 2019, all capital related expenses are assigned based on Rate Base.** |

| Cost and Methodology Topic | Applicability to Transmission Revenue Requirement (TRR) |
|---|---|
| 12. Regulatory Accounts Functionalization | Heritage and Non-Heritage Deferral Account Classification is not applicable as described in item 1.<br>Consistent with Appendix A of BCUC Order No. G-47-16, 55 per cent of the provisions for the PCB Remediation Regulatory Account have been functionalized to Transmission in the TRR.<br>Consistent with Appendix A of BCUC Order No. G-47-16, 55 per cent of First Nations Regulatory Account recoveries have been functionalized to Transmission in the TRR.<br>The TRR uses a different methodology to functionalize Interest on Deferral and Regulatory Accounts compared to the methodology contemplated in the 2016 Cost of Service study. With the full adoption of International Financial Reporting Standards by BC Hydro in fiscal 2019, all capital related expenses are assigned based on Rate Base. In the financial schedules, Finance Charges including Interest on Regulatory Accounts are functionalized according to Rate Base as shown on lines 1 to 40 of Schedule 8.0 of Appendix A of the Application.<br>Rate Smoothing Regulatory Account Functionalization is not applicable to the TRR as the balance in the Rate Smoothing Regulatory Account was written-off in December 2018. |
| 13. Deferral Accounts Classification | Not applicable as described in item 1. |
| 14. SMI-related Costs Classification | Not applicable as described in item 1. |
| 15. Generation Demand Related Costs Allocation | Not applicable. Cost allocation for the purpose of the 2016 cost of service study was undertaken to allocate costs to BC Hydro's bundled electricity rates under its Electric Tariff, not its Open Access Transmission Tariff rates. |
| 16. Distribution Demand Costs Allocation | Not applicable as described in item 15. |
| 17. Metering Costs Allocation | Not applicable as described in item 15. |

**267.0 H. CHAPTER 9 – TRANSMISSION REVENUE REQUIREMENT**

**Reference: TRANSMISSION REVENUE REQUIREMENT**
**Exhibit B-1, p. 9-16**
**Cost allocations to generation, transmission and distribution**

Footnote 340 on page 9-16 of the Application states:

> In 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 five 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.

2.267.1 Please confirm, or explain otherwise, that BC Hydro used the methodologies from its 2016 Cost of Service Study (contained in Appendix A of Order G-47-16) to allocate costs to its Transmission Revenue Requirement in this Test Period.

2.267.1.1 If not confirmed, please identify any discrepancies and explain why.

**RESPONSE:**

**Please refer to BC Hydro's response to BCUC IR 2.267.1 where we compare the methodologies from the 2016 Cost of Service Study and Rate Class Segmentation Negotiated Settlement Agreement, as appended to BCUC Order No. G-47-16, to those used to allocate costs to the Transmission Revenue Requirement in this Test Period.**

**268.0 H. CHAPTER 9 – TRANSMISSION REVENUE REQUIREMENT**

**Reference: TRANSMISSION REVENUE REQUIREMENT**
**Exhibit B-1, Appendix A, Schedule 3.4; Exhibit B-5, BCUC IR 168.1**
**Scheduling and dispatch services**

In response to BCUC IR 168.1, BC Hydro stated the following reasons why scheduling and dispatch costs are not included in the allocation of PTP transmission costs to Powerex:

- Powerex provides scheduling and electronic tagging services to BC Hydro and does not charge BC Hydro for these services;
- BC Hydro, as a transmission customer, covers the cost of OATT scheduling and dispatch services for its own transmission system, and Powerex covers the cost of scheduling and e-tagging functions between balancing authorities; and
- These additional costs may result in some transactions not occurring, even though they are economic on a consolidated basis, which could result in a reduction to Powerex's net income, and all else equal, higher rates for BC Hydro's customers.

Line 37 of Schedule 3.4 in Appendix A to the Application shows that internal scheduling and dispatch charges reduce the Transmission Revenue Requirement by $3.7 million and $3.8 million in each of F2020 and F2021, respectively.

2.268.1 Please compare the F2017, F2018 and F2019 actual costs for the scheduling and electronic tagging services provided by Powerex to BC Hydro with the ancillary and dispatch charges not allocated to Powerex for the same period. Please discuss any differences.

**RESPONSE:**

**BC Hydro cannot provide the requested comparison as BC Hydro does not have any invoices or other applicable information upon which to estimate the fiscal 2017, fiscal 2018 and fiscal 2019 costs for the scheduling services provided by Powerex to BC Hydro.**

**BC Hydro does not allocate ancillary and dispatch charges to Powerex. If BC Hydro were to allocate these charges, a high level estimate of these charges is provided in the table below, for illustrative purposes only. As shown in the table below, BC Hydro estimates that BC Hydro's fiscal 2017, fiscal 2018 and fiscal 2019 ancillary and dispatch charges not allocated to Powerex were $0.2 million,**

**$0.4 million and $0.5 million, respectively. The basis for this estimate is discussed below.**

**Based on the Evidentiary Update, the total internal scheduling and dispatch charges on Line 46 of Schedule 3.4 of Appendix A are $4.0 million for fiscal 2020 and $4.2 million for fiscal 2021. These amounts represent forecasts of the total scheduling and dispatch charges for internal usage to be charged to BC Hydro as Network Customer under the OATT. BC Hydro self-supplies ancillary services so there are no ancillary services charges to BC Hydro as Network Customer under the OATT.**

**The following table provides an estimate of the portion of scheduling charges and ancillary services that could be associated with Powerex internal Point-To-Point (PTP) usage based on fiscal 2017 to fiscal 2019 actuals. However, as discussed in BC Hydro's response to BCUC IR 1.168.1, the Powerex PTP allocation is done on a total cost basis at the end of each month and not on a volume basis. Long-Term and Short-Term Point-To-Point services have different rates resulting in different costs but attract the same scheduling and dispatch charges on a volume basis. Therefore the following table provides a high level estimate only.**

| | Item | Reference | F2017 Actual | F2018 Actual | F2019 Actual |
|---|---|---|---|---|---|
| A | Scheduling Fee ($/MWh) | Sch. 3.4 L48 | 0.113 | 0.099 | 0.106 |
| B | Internal PTP Volumes (GWh) | Sch. 3.4 L49 + L58 | 14,834 | 16,786 | 15,702 |
| C | Total Internal Volume (GWh) | Sch. 3.4 L47 - L50 - L59 | 24,245 | 26,353 | 28,010 |
| D | Total Internal Scheduling Fee ($ million) | [D] = [A] x [C] | 2.7 | 2.6 | 3.0 |
| E | Powerex PTP Charges ($ million) | Sch. 3.4 L18 | 9.6 | 21.2 | 26.4 |
| F | Internal PTP Revenues ($ million) | Sch. 3.4 L67 | 80.7 | 90.9 | 96.4 |
| G | Estimated Powerex PTP Volume (GWh) | [G] = [B] x [E] / [F] | 1,771 | 3,922 | 4,300 |
| H | Estimated Scheduling Fee for Powerex PTP ($ million) | [H] = [G] x [A] | 0.2 | 0.4 | 0.5 |
| I | Ancillary Service Charges for Powerex PTP ($ million) | Self-Supplied by BC Hydro as Network Customer | 0 | 0 | 0 |

**268.0 H. CHAPTER 9 – TRANSMISSION REVENUE REQUIREMENT**

**Reference: TRANSMISSION REVENUE REQUIREMENT**
**Exhibit B-1, Appendix A, Schedule 3.4; Exhibit B-5, BCUC IR 168.1**
**Scheduling and dispatch services**

In response to BCUC IR 168.1, BC Hydro stated the following reasons why scheduling and dispatch costs are not included in the allocation of PTP transmission costs to Powerex:

- Powerex provides scheduling and electronic tagging services to BC Hydro and does not charge BC Hydro for these services;
- BC Hydro, as a transmission customer, covers the cost of OATT scheduling and dispatch services for its own transmission system, and Powerex covers the cost of scheduling and e-tagging functions between balancing authorities; and
- These additional costs may result in some transactions not occurring, even though they are economic on a consolidated basis, which could result in a reduction to Powerex's net income, and all else equal, higher rates for BC Hydro's customers.

Line 37 of Schedule 3.4 in Appendix A to the Application shows that internal scheduling and dispatch charges reduce the Transmission Revenue Requirement by $3.7 million and $3.8 million in each of F2020 and F2021, respectively.

2.268.2 Please explain why "these additional costs may result in some transactions not occurring, even though they are economic on a consolidated basis."

**RESPONSE:**

**The scheduling fee would act as an additional transaction cost to Powerex for any energy scheduled on the BC Hydro system. When considering whether it is profitable to move energy to a given point from the BC Hydro system (or vice versa), Powerex considers transaction costs. All other things being equal, higher transaction costs will reduce Powerex transaction volumes on the margin.**

**However, these transaction costs would not provide any incremental revenue to BC Hydro. From a ratepayer benefit perspective, a fee (cost) paid by Powerex is shown as revenue to BC Hydro transmission that is netted out on consolidation via intersegment revenues. The effect is that the underlying cost responsibility of the ratepayers is unchanged.**

**Therefore, raising the transactions costs to Powerex could result in fewer economic transactions occurring, resulting in lost trade income without any offsetting benefit in terms of lower transmission cost responsibility borne by ratepayers.**

**269.0 I. CHAPTER 10 – DEMAND SIDE MANAGEMENT**

**Reference: DEMAND-SIDE MANAGEMENT**
**Exhibit B-5, BCUC IR 174.1.1**
**Reallocation of funds during the Test Period**

BC Hydro stated in BCUC IR 174.1.1:

> BC Hydro's interpretation of the Utilities Commission Act is that BC Hydro is permitted to reallocate costs or resources between program areas and years without seeking prior BCUC approval.
>
> Under section 44.2 of the Utilities Commission Act, BC Hydro may file a statement of the expenditures on DSM that it has made or anticipates making during the test period. Section 44.2 provides the BCUC with the authority to accept or reject all or part of BC Hydro's DSM expenditures and approve rates under section 61 that recover those expenditures…

2.269.1 Please provide BC Hydro's view on the purpose and interpretation of a section 44.2 expenditure schedule acceptance, addressing the following elements:

i) Over or under expenditure on a portfolio basis;
ii) Over or under expenditure on a program basis;
iii) The impact of reallocations on portfolio cost-effectiveness, and the possible impacts on cost recovery under section 61 in the event of over or under expenditure;
iv) The ability of the BCUC to disallow over-expenditures that result in the adequacy or cost-effectiveness not being met; and
v) What consequences, if any, are appropriate to incent the utility to ensure that deviations from accepted expenditure schedules are in the public interest.

**RESPONSE:**

**It is BC Hydro's view that acceptance of an expenditure schedule through section 44.2 of the UCA indicates that the BCUC has found the expenditure schedule, as presented, to be in the public interest. If reasonably executed as described, it is reasonable to expect that the expenditures can be recovered through rates.**

**BC Hydro understands that a significant deviation from the expenditure breakdown shown in the expenditure schedule would not necessarily result in the same BCUC public interest determination, and therefore could result in cost**

**recovery risk. BC Hydro expects that the BCUC would look at the impact on adequacy requirements and cost-effectiveness metrics resulting from any significant deviation. BC Hydro anticipates that the cause of any expenditure deviation would also factor into the BCUC's considerations, such as whether expenditure deviations were the result of a decision by the utility, or by factors outside of its control such as customer project timing decisions or market events.**

**As described in BC Hydro's response to BCUC IR 1.174.1, managing the programs and overall portfolio during the test period may result in adjustments to ensure overall performance and portfolio balance. BC Hydro's annual DSM reports to the BCUC (provided in Appendix Z of the Application) provide a description of any expenditure or savings variances compared to the accepted expenditure schedule, and any mitigation measures undertaken or planned.**

**With respect to the specific points raised in this IR, BC Hydro provides the following views and comments:**

**(i) Expenditure variances at the portfolio level are subject to BCUC review following the filing of the annual DSM reports and during subsequent section 44.2 applications. If expenditures at the portfolio level are higher or lower than plan in a given year in the test period, the effects (i.e., amortization being higher or lower than plan) would not be reflected in current (i.e., test period) rates as recovery is based on the amortization of planned expenditures for the test period. For over expenditures, BC Hydro would be at risk of not receiving approval for recovery of those over expenditures. If there were under-expenditures driven by a BC Hydro decision (as opposed to customer-driven timing/decisions or market uptake), there could be cost recovery risk if the public interest of the expenditures was negatively impacted, such as if the portfolio was no longer cost-effective;**

**(ii) Expenditure variances at the program level are also subject to BCUC review following the filing of the annual DSM reports and during subsequent section 44.2 applications. It is expected that any program expenditure decisions could be reviewed for impact on the public interest, such as adequacy criteria;**

**(iii) Portfolio cost-effectiveness is one of the factors that the BCUC considers in its public interest determination under section 44.2. Expenditure reallocations could reduce the cost-effectiveness of the portfolio, and accordingly cost recovery under section 61 could be subject to review following the filing of the annual DSM reports and during section 44.2 applications;**

**(iv) If we made a decision that produced over expenditures which resulted in adequacy or cost-effectiveness criteria not being met, BC Hydro understands that a BCUC review of the impact of that decision could disallow those over expenditures; and**

**(v) The possibility of expenditure disallowance is a sufficient incentive for BC Hydro to manage deviations from the accepted expenditure schedules to maintain the public interest.**

**270.0 I. CHAPTER 10 – DEMAND SIDE MANAGEMENT**

**Reference: DEMAND-SIDE MANAGEMENT**
**Exhibit B-1, p. 7-57; Appendix AA, pp. 6–7;**
**Exhibit B-5, BCUC IR 179.1; UCA, RSBC 1996, c. 473, section 60(1)(b)(ii)**
**Measurement, verification and evaluation**

BC Hydro stated in response to BCUC IR 179.1:

> BC Hydro budgets for the expenditures it believes are necessary to deliver its plan, and expects to spend the planned expenditures. However, we also try to achieve the anticipated energy and associated capacity savings targets within each sector at the least cost. This has the potential to result in underspending during the test period, improving the cost-effectiveness of the DSM portfolio.

BC Hydro stated in Appendix AA to the Application:

> BC Hydro is a Crown corporation without an incentive mechanism that would make it profit from DSM impacts, and thus is not in a conflict of interest with respect to the evaluation or measurement and verification of DSM impacts. Without a DSM incentive mechanism, BC Hydro does not profit from the over-estimation of DSM impacts. This is in contrast to a number of other jurisdictions in North America, including California, where electricity is delivered by investor-owned utilities with incentive mechanisms for DSM. In these jurisdictions, utilities are in a conflict of interest with respect to the evaluation or measurement and verification of DSM impacts, since evaluation results influence incentive payments to utilities for DSM. In many of these jurisdictions, the majority of measurement and verification, and evaluation work is outsourced to contractors;

2.270.1 Given BC Hydro's statement regarding the absence of an incentive to over-estimate DSM impacts, please explain whether BC Hydro currently have incentives to maximize/optimize the amount of cost-effective DSM. If so, please elaborate on these incentives.

**RESPONSE:**

**The use of the term "incentive mechanism" in Appendix AA of the Application describes a situation where a utility receives a bonus or extra profit for achieving DSM energy savings targets. BC Hydro does not earn a return or incentive based**

**on achieving energy savings targets or maximizing the amount of cost-effective DSM that we pursue.**

**Instead, BC Hydro has objectives or requirements that inform the amount of cost-effective DSM that we plan for. As described in section 10.3 of Chapter 10 of the Application, DSM target setting is guided by:**

- **The interests of persons in British Columbia who receive or may receive service from BC Hydro;**
- **British Columbia's energy objectives as set out in the *Clean Energy Act*;**
- **Applicable IRP recommendations; and**
- **The Demand-Side Measures Regulation.**

**In addition, BC Hydro considers the Government of B.C.'s priorities around affordability and the CleanBC Plan.**

**Consideration of these objectives and requirements may lead to trade-offs rather than maximizing the level of cost-effective DSM. As discussed further in section 10.3.1.3 of Chapter 10 of the Application, these objectives and requirements led BC Hydro to maintain a moderation approach to the level of DSM in the test period.**

**270.0 I. CHAPTER 10 – DEMAND SIDE MANAGEMENT**

**Reference: DEMAND-SIDE MANAGEMENT**
**Exhibit B-1, p. 7-57; Appendix AA, pp. 6–7;**
**Exhibit B-5, BCUC IR 179.1; UCA, RSBC 1996, c. 473, section 60(1)(b)(ii)**
**Measurement, verification and evaluation**

In its Application, BC Hydro states that "interest is not charged to the DSM Regulatory Account…"

2.270.2 Please discuss whether the accrual of interest to the DSM Regulatory Account would have an impact on BC Hydro's decision-making regarding energy, system and load management. If yes, please elaborate. If no, please explain why there would be no impact.

**RESPONSE:**

**BC Hydro interprets the question as asking whether the accrual of interest to the DSM Regulatory Account impacts BC Hydro's decision making regarding DSM initiatives.**

**While interest is not applied to the DSM Regulatory Account, BC Hydro does incur interest related to the expenditures on DSM initiatives. These costs are recovered from ratepayers through Finance Charges. If BC Hydro were to apply interest to the DSM Regulatory Account, this would not have an impact on decision-making because those planning decisions are made based on the cost-effectiveness of the DSM initiatives.**

**270.0 I. CHAPTER 10 – DEMAND SIDE MANAGEMENT**

**Reference: DEMAND-SIDE MANAGEMENT**
**Exhibit B-1, p. 7-57; Appendix AA, pp. 6–7;**
**Exhibit B-5, BCUC IR 179.1; UCA, RSBC 1996, c. 473, section 60(1)(b)(ii)**
**Measurement, verification and evaluation**

Section 60(1)(b)(ii) of the UCA states: "In setting a rate under this Act, the commission must have due regard to the setting of a rate that provides to the public utility for which the rate is set a <u>fair and reasonable return</u> on any expenditure made by it to reduce energy demands."[1]

2.270.3 Please reconcile BC Hydro's statement that it is "without an incentive mechanism that would make it profit from DSM impacts" with section 60(1)(b)(ii) of the UCA that requires the BCUC to set a rate that provides the public utility with "a fair and reasonable return on any expenditure made by it to reduce energy demands."

**RESPONSE:**

**Please refer to BC Hydro's response to BCUC IR 2.270.1 which explains that the use of the term "incentive mechanism" in Appendix AA of the Application describes a situation where a utility receives a bonus or extra profit for achieving DSM energy savings targets. As we note in that response, there is no incentive mechanism that allows BC Hydro to earn a return or incentive based on energy savings performance.**

**BC Hydro's return on equity is prescribed by section 3 of Direction 8 as a specific dollar amount of $712 million per fiscal year for each of fiscal 2020 and fiscal 2021. From fiscal 2022 onwards, the BCUC will determine BC Hydro's return on equity.**

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[1] Emphasis added.

**271.0 I. CHAPTER 10 – DEMAND SIDE MANAGEMENT**

**Reference: DEMAND-SIDE MANAGEMENT**
**Exhibit B-1, Appendix AA, p. 2; Attachment 1, Section 1.1, p. 5;**
**Exhibit B-5, BCUC IR 188.2**
**Independence of DSM evaluation function**

Appendix AA to the Application states: "The purpose of the evaluation function is to refine estimates of DSM impacts and identify program improvements in a rigorous and neutral manner in support of DSM and Integrated Resource Plan (IRP) decisions, risk management, and stakeholder confidence."

In response to BCUC IR 188.2, BC Hydro stated:

> The roles and responsibilities of the external evaluation advisors are to:
>
> a) Review draft evaluation reports to ensure that BC Hydro evaluations utilize appropriate methodologies and align with industry practice and provide written comments to the evaluation team on all aspects of the evaluation project. Comments are to focus on the research design, input data, analytical methods, and alignment with industry practice and standards, and other topics as directed by BC Hydro.
> b) Participate in Evaluation Oversight Committee (EOC) meetings to present their review to EOC members. Final evaluation reports are reviewed and subject to approval by an EOC made up of BC Hydro staff representing business units with an interest in DSM and chaired by a staff person from outside the Conservation and Energy Management business unit. The external evaluation advisors participate in EOC meetings and act as a resource to Committee members. The EOC ensures that BC Hydro's DSM evaluations are objective, unbiased, and of sufficient quality.
> c) Review the final evaluation report and BC Hydro's response to comments on the draft report.
> d) Prepare a final Advisor's Memo on the Evaluation Report, which is appended to the final report. In this memo, advisors are asked to comment on the quality of the research design, the input data, and the analytical method, as well as how the methodology compares to industry practice.

Attachment 1 of Appendix AA to the Application summarizes the four milestone evaluations of DSM initiatives completed by BC Hydro in F2017.

2.271.1 Please provide a table showing all the milestone DSM evaluations completed since F2009. Please ensure the table includes the following information for each fiscal year:

i) Name of the DSM initiative(s) evaluated;
ii) Number of DSM initiatives evaluated vs. the total number of DSM initiatives in the portfolio;
iii) Indicate if an external DSM evaluation advisor was appointed to assist on the named initiative; and
iv) Name of the external advisor company used, if any.

**RESPONSE:**

**Please refer to the table below for the requested information for impact evaluations of codes and standards, rate structures and programs.**

**Historical Evaluation of DSM Initiatives**

| | F2010 | F2011 | F2012 | F2013 | F2014 | F2015 | F2016 | F2017 | F2018 | F2019 |
|---|---|---|---|---|---|---|---|---|---|---|
| DSM Initiatives Evaluated[1] | | | | | | | | | | |
| *Codes & Standards* | | | | | | | | | | |
| Codes & Standards | | X | X | | | | X | | X | X |
| *Rate Structures* | | | | | | | | | | |
| Residential | X | X | | | X | | | | X | |
| Commercial & Industrial Distribution[2] | | | | | X | X | | | | |
| Industrial | X | X | X | | | | | | | X |
| *Residential Sector Programs* | | | | | | | | | | |
| Behaviour | | X | | X | | | | | | |
| Refrigerator Buy-Back[3] | X | X | | X | | | | | | |
| Low Income | | X | X | | | | | | X | |

[1] **The number of DSM initiatives in the portfolio has changed since fiscal 2009, as many programs have consolidated what were once separate offers to customers. (As an example, consider the Retail program, which was once separate Lighting, Appliance and Electronics programs, but is now offered as one program). To be consistent across the time periods and with current program offerings and evaluations, both the program description and the evaluations are consolidated in one row and shown as one program and/or one evaluation.**

[2] **LGS/MGS conservation rate structure ended in fiscal 2017.**

[3] **Refrigerator Buyback Program ended in fiscal 2016.**

| | F2010 | F2011 | F2012 | F2013 | F2014 | F2015 | F2016 | F2017 | F2018 | F2019 |
|---|---|---|---|---|---|---|---|---|---|---|
| New Home[4] | | | | | | | X | | | |
| Home Renovation Rebate | X | | | X | | | | | | |
| Retail | X | X | X | X | | | | X | X | |
| *Commercial Sector Programs* | | | | | | | | | | |
| Leaders in Energy Management – Commercial | X | X | X | | X | X | | | | X |
| Leaders in Energy Management – Commercial (Continuous Optimization) | | | | | | | | X | | |
| New Construction | | | | | | | | X | | |
| *Industrial Sector Programs* | | | | | | | | | | |
| Leaders in Energy Management – Industrial (Transmission) | | X | X | X | | | X | X | | |
| Leaders in Energy Management – Industrial (Distribution) | | | X | | | | | | X | |

[4] **New Home Program ended in fiscal 2016.**

| | F2010 | F2011 | F2012 | F2013 | F2014 | F2015 | F2016 | F2017 | F2018 | F2019 |
|---|---|---|---|---|---|---|---|---|---|---|
| Load Displacement | | | | | | | | | | X |
| Number of DSM Initiatives Evaluated / Total Number of DSM Initiatives in Portfolio | 6/16 | 9/16 | 7/16 | 5/16 | 3/16 | 2/16 | 3/16 | 4/14 | 5/13 | 4/13 |
| Evaluation Advisor Used on Evaluation | Ed Vine<br>David Sumi | Ed Vine<br>Rafael Friedmann | Ed Vine<br>Rafael Friedmann | Ed Vine<br>Rafael Friedmann | Ed Vine<br>Rafael Friedmann<br>Steven Braithwait[5] | Ed Vine<br>Rafael Friedmann<br>Steven Braithwait[6] | Ed Vine<br>Rafael Friedmann | Ed Vine<br>Rafael Friedmann | Econoler<br>Rafael Friedmann<br>Steven Braithwait[7] | Econoler<br>Rafael Friedmann |

5 **Reviewed the LGS/MGS evaluation only.**
6 **Reviewed the LGS/MGS evaluation only.**
7 **Reviewed the RIB evaluation only.**

## 271.0 I. CHAPTER 10 – DEMAND SIDE MANAGEMENT

**Reference: DEMAND-SIDE MANAGEMENT**
**Exhibit B-1, Appendix AA, p. 2; Attachment 1, Section 1.1, p. 5;**
**Exhibit B-5, BCUC IR 188.2**
**Independence of DSM evaluation function**

Appendix AA to the Application states: "The purpose of the evaluation function is to refine estimates of DSM impacts and identify program improvements in a rigorous and neutral manner in support of DSM and Integrated Resource Plan (IRP) decisions, risk management, and stakeholder confidence."

In response to BCUC IR 188.2, BC Hydro stated:

> The roles and responsibilities of the external evaluation advisors are to:
>
> a) Review draft evaluation reports to ensure that BC Hydro evaluations utilize appropriate methodologies and align with industry practice and provide written comments to the evaluation team on all aspects of the evaluation project. Comments are to focus on the research design, input data, analytical methods, and alignment with industry practice and standards, and other topics as directed by BC Hydro.
> b) Participate in Evaluation Oversight Committee (EOC) meetings to present their review to EOC members. Final evaluation reports are reviewed and subject to approval by an EOC made up of BC Hydro staff representing business units with an interest in DSM and chaired by a staff person from outside the Conservation and Energy Management business unit. The external evaluation advisors participate in EOC meetings and act as a resource to Committee members. The EOC ensures that BC Hydro's DSM evaluations are objective, unbiased, and of sufficient quality.
> c) Review the final evaluation report and BC Hydro's response to comments on the draft report.
> d) Prepare a final Advisor's Memo on the Evaluation Report, which is appended to the final report. In this memo, advisors are asked to comment on the quality of the research design, the input data, and the analytical method, as well as how the methodology compares to industry practice.

Attachment 1 of Appendix AA to the Application summarizes the four milestone evaluations of DSM initiatives completed by BC Hydro in F2017.

2.271.1 Please provide a table showing all the milestone DSM evaluations completed since F2009. Please ensure the table includes the following information for each fiscal year:

2.271.1.1 If the external advisor company used is not the same every year since 2009, please explain why the external advisor company has changed and discuss BC Hydro's criteria for selecting an external advisor company.

**RESPONSE:**

**As indicated in BC Hydro's response to BCUC IR 2.271.1, BC Hydro has had long-term relationships with its external advisors. There have been two changes with external advisors since fiscal 2009. These are:**

- **David Sumi was replaced by Rafael Friedmann in fiscal 2011 because he changed consulting firms and his new firm could have been in a conflict of interest for other potential work on DSM for BC Hydro; and**
- **Ed Vine was replaced by Econoler in fiscal 2018 because of Ed Vine's retirement.**

**In addition to the standing external advisors, BC Hydro may also choose to bring in other industry experts to supplement their expertise. An example of this is for the Evaluation of the Residential Inclining Block Rate for fiscal 2013 to fiscal 2017, where Steven Braithwait of Christensen Associates Energy Consulting was used as an external advisor because of his experience in evaluating rate structures and price response.**

**Criteria used by BC Hydro to select the external advisor include:**

- **Free from conflict of interest, meaning that they were not currently (and had not been in the past) providing services to BC Hydro related to DSM program design or implementation;**
- **Extensive experience conducting and overseeing Demand-Side Management (DSM) evaluation work;**
- **Extensive and current knowledge of DSM evaluation methodologies;**
- **Subject matter expertise in the disciplines of statistics, engineering, social sciences, and/or economics; and**
- **Record of work with other utilities.**

**271.0 I. CHAPTER 10 – DEMAND SIDE MANAGEMENT**

**Reference: DEMAND-SIDE MANAGEMENT**
**Exhibit B-1, Appendix AA, p. 2; Attachment 1, Section 1.1, p. 5;**
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Attachment 1 of Appendix AA to the Application summarizes the four milestone evaluations of DSM initiatives completed by BC Hydro in F2017.

2.271.1 Please provide a table showing all the milestone DSM evaluations completed since F2009. Please ensure the table includes the following information for each fiscal year:

2.271.1.2 Please explain how BC Hydro determines which DSM initiatives should be evaluated each year and how often.

**RESPONSE:**

**BC Hydro determines which DSM initiatives are to be evaluated each year through an evaluation work plan that is updated annually and provides a two to three-year outlook on upcoming evaluations. The workplan is informed by the evaluation planning criteria, which are set out in the table below as well as an internal Evaluation Governance Committee, which provides input on the timing of evaluations relative to work needs.**

| Evaluations | Planning Criteria |
|---|---|
| **Impact - programs** | **Industrial Sector**<br>**For programs with less than 100 per cent verified projects:**<br>• **Every program within three years, subject to a decision on the value of an evaluation of the final years of a completed program**<br>**For programs with 100 per cent verified projects (e.g. Thermo-mechanical Pulp and Load Displacement):**<br>• **Every program within six years, gross savings only**<br>**Residential and Commercial Sectors**<br>• **75 per cent of cumulative reported savings within three years, and every program within six years, by sector (residential, commercial)**<br>• **Subject to a decision on the value of an evaluation of the final years of a completed program** |
| **Impact - rates** | **Each conservation rate once every three years** |
| **Impact – codes and standards** | **50 per cent of reported cumulative savings within three to six years** |
| **Process** | **At least one every two years** |

**271.0 I. CHAPTER 10 – DEMAND SIDE MANAGEMENT**

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> b) Participate in Evaluation Oversight Committee (EOC) meetings to present their review to EOC members. Final evaluation reports are reviewed and subject to approval by an EOC made up of BC Hydro staff representing business units with an interest in DSM and chaired by a staff person from outside the Conservation and Energy Management business unit. The external evaluation advisors participate in EOC meetings and act as a resource to Committee members. The EOC ensures that BC Hydro's DSM evaluations are objective, unbiased, and of sufficient quality.
> c) Review the final evaluation report and BC Hydro's response to comments on the draft report.
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Attachment 1 of Appendix AA to the Application summarizes the four milestone evaluations of DSM initiatives completed by BC Hydro in F2017.

2.271.2 Please provide a copy of the last three completed evaluation reports including the attached final advisor's memo on the evaluation report.

**RESPONSE:**

**The last three completed evaluation reports are:**

- **Television Market Evaluation: Fiscal 2015 to Fiscal 2018 (a copy can be found at the following link);**
- **Leaders in Energy Management – Commercial: Fiscal 2013 to Fiscal 2017 (a copy can be found at the following link); and**
- **Commercial Building Code Evaluation Report: September 2009 to December 2014 (a copy can be found at the following link).**

**The external advisors' final memos are included as Appendix B in each of these reports.**

**272.0 I. CHAPTER 10 – DEMAND SIDE MANAGEMENT**

**Reference: DEMAND-SIDE MANAGEMENT**
**BC Hydro F2017-F2019 RRA Decision, p. 85; Exhibit B-1-4, Attachment 2, DSM Audit Q1 F2017 Report, p. 4; Exhibit B-5, BCUC IR 12.4, 187.3, 187.4, 187.7**
**Independent audit of DSM program**

In the BC Hydro F2017-F2019 RRA Decision, the BCUC stated that “an independent assessment of the entire program could provide appropriate assurance that BC Hydro’s EM&V [Evaluation, Measurement and Verification] methods are effective and unbiased.”

In the DSM Audit Q1 F2017 report, BC Hydro states that the “[Audit] Criteria included BC Hydro policies, standards and procedures, and industry practices and protocols such as International Performance Measurement & Verification Protocol and the U.S. Department of Energy Uniform Methods Project Protocols” and that the “audit was conducted in conformance with the International Standards for the Professional Practice of Internal Auditing.”

In response to BCUC IR 12.4, BC Hydro stated:

> Standard 1300 of the Internal Standards for the Professional Practice of Internal Auditing explains the process and oversight involved for an entity to conform with the standards. Specifically, Standard 1300 states that: ... External assessments must be conducted at least once every five years by a qualified, independent assessor or assessment team from outside the organization.

In response to BCUC IR 187.3, BC Hydro stated:

> BC Hydro periodically engages external subject matter experts to assist Audit Services by providing expertise in a specialized area. Audit Services ensures audit standards are followed by managing the audit and overseeing the work of subject matter experts.

In response to BCUC IR 187.4, BC Hydro stated:

> Internal audits and external audits are not interchangeable. External audits are performed to provide an opinion on the external financial statements of the organization that the financial statements are prepared under a recognized financial reporting framework. Internal audits seek to evaluate and improve an organization’s operations by contributing to improvement of governance, risk management and control processes.

In response to BCUC IR 187.7 BC Hydro stated:

BC Hydro does not believe that an external DSM audit would be appropriate. As discussed in BC Hydro's response to BCUC IR 1.187.6, we believe our internal audits bring appropriate independence...

BC Hydro is confident in the Conservation and Energy Management business function and that our cycle of DSM internal audits appropriately reflects the associated risks. The increased cost of performing additional audits, with unknown benefits, outweighs the value from an audit of each expenditure application. Accordingly, BC Hydro does not support filing a DSM audit with each DSM expenditure application.

2.272.1 If internal and external assessment have different scopes, please discuss BC Hydro's interpretation of how to comply with Standard 1300 with respect to "External assessments must be conducted at least once every five years by a qualified, independent assessor or assessment team from outside the organization."

**RESPONSE:**

**Please refer to BC Hydro's response to BCUC IR 1.187.4 where we provide an explanation of the difference between Internal and External audit functions.**

**BC Hydro's internal audit functions are governed by Standard 1300 and its requirements to have a Quality Assurance and Improvement Program. Every five years, an external assessment by an independent assessor must be conducted to validate the independence and professional practices of BC Hydro's internal audit function. In the interim years, a self-assessment is required.**

**As a distinction, the external assessment is not applied to the audits performed by BC Hydro's internal audit function.**

**272.0 I. CHAPTER 10 – DEMAND SIDE MANAGEMENT**

**Reference: DEMAND-SIDE MANAGEMENT**
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> BC Hydro does not believe that an external DSM audit would be appropriate. As discussed in BC Hydro's response to BCUC IR 1.187.6, we believe our internal audits bring appropriate independence...
>
> BC Hydro is confident in the Conservation and Energy Management business function and that our cycle of DSM internal audits appropriately reflects the associated risks. The increased cost of performing additional audits, with unknown benefits, outweighs the value from an audit of each expenditure application. Accordingly, BC Hydro does not support filing a DSM audit with each DSM expenditure application.

2.272.2 Please discuss whether the DSM audit performed was focused on process and controls over the DSM program rather than on financial reporting.

**RESPONSE:**

**Yes, the DSM audit was focused on processes and controls for DSM rather than on financial reporting. The scope of the audit did include financial aspects such as reviewing controls over the monitoring and approval of program expenditures.**

**DSM expenditures are reported in BC Hydro's financial statements. BC Hydro's external auditors issued an unqualified audit opinion on the fiscal 2019 financial statements.**

**272.0 I. CHAPTER 10 – DEMAND SIDE MANAGEMENT**

**Reference: DEMAND-SIDE MANAGEMENT**
**BC Hydro F2017-F2019 RRA Decision, p. 85; Exhibit B-1-4, Attachment 2, DSM Audit Q1 F2017 Report, p. 4; Exhibit B-5, BCUC IR 12.4, 187.3, 187.4, 187.7**
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In the DSM Audit Q1 F2017 report, BC Hydro states that the "[Audit] Criteria included BC Hydro policies, standards and procedures, and industry practices and protocols such as International Performance Measurement & Verification Protocol and the U.S. Department of Energy Uniform Methods Project Protocols" and that the "audit was conducted in conformance with the International Standards for the Professional Practice of Internal Auditing."

In response to BCUC IR 12.4, BC Hydro stated:

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> BC Hydro periodically engages external subject matter experts to assist Audit Services by providing expertise in a specialized area. Audit Services ensures audit standards are followed by managing the audit and overseeing the work of subject matter experts.

In response to BCUC IR 187.4, BC Hydro stated:

> Internal audits and external audits are not interchangeable. External audits are performed to provide an opinion on the external financial statements of the organization that the financial statements are prepared under a recognized financial reporting framework. Internal audits seek to evaluate and improve an organization's operations by contributing to improvement of governance, risk management and control processes.

In response to BCUC IR 187.7 BC Hydro stated:

> BC Hydro does not believe that an external DSM audit would be appropriate. As discussed in BC Hydro's response to BCUC IR 1.187.6, we believe our internal audits bring appropriate independence...
>
> BC Hydro is confident in the Conservation and Energy Management business function and that our cycle of DSM internal audits appropriately reflects the associated risks. The increased cost of performing additional audits, with unknown benefits, outweighs the value from an audit of each expenditure application. Accordingly, BC Hydro does not support filing a DSM audit with each DSM expenditure application.

2.272.3 Please explain, including the timeline and milestone, what BC Hydro's current cycle of DSM internal audits entails.

**RESPONSE:**

**BC Hydro's Audit Services prepares a two-year audit plan based on areas of risk and exposure. A decision on when to complete the next DSM audit would depend on an assessment of associated risk in comparison to other areas of the organization.**

**There is no defined cycle of DSM internal audits. A two-year audit plan was prepared in May 2019 and based on an assessment of overall risk, the decision was made to not include a DSM internal audit in the next two years.**

**The next audit plan will be prepared in May 2021. At that time, a risk assessment will be performed and a further decision will be made on audits to be performed.**

## 272.0 I. CHAPTER 10 – DEMAND SIDE MANAGEMENT

**Reference: DEMAND-SIDE MANAGEMENT**
**BC Hydro F2017-F2019 RRA Decision, p. 85; Exhibit B-1-4, Attachment 2, DSM Audit Q1 F2017 Report, p. 4; Exhibit B-5, BCUC IR 12.4, 187.3, 187.4, 187.7**
**Independent audit of DSM program**

In the BC Hydro F2017-F2019 RRA Decision, the BCUC stated that "an independent assessment of the entire program could provide appropriate assurance that BC Hydro's EM&V [Evaluation, Measurement and Verification] methods are effective and unbiased."

In the DSM Audit Q1 F2017 report, BC Hydro states that the "[Audit] Criteria included BC Hydro policies, standards and procedures, and industry practices and protocols such as International Performance Measurement & Verification Protocol and the U.S. Department of Energy Uniform Methods Project Protocols" and that the "audit was conducted in conformance with the International Standards for the Professional Practice of Internal Auditing."

In response to BCUC IR 12.4, BC Hydro stated:

> Standard 1300 of the Internal Standards for the Professional Practice of Internal Auditing explains the process and oversight involved for an entity to conform with the standards. Specifically, Standard 1300 states that: ... External assessments must be conducted at least once every five years by a qualified, independent assessor or assessment team from outside the organization.

In response to BCUC IR 187.3, BC Hydro stated:

> BC Hydro periodically engages external subject matter experts to assist Audit Services by providing expertise in a specialized area. Audit Services ensures audit standards are followed by managing the audit and overseeing the work of subject matter experts.

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2.272.4 Please reconcile Standard 1300, which requires that external assessments be conducted at least once every five years by an independent assessor or team from outside the organization, with BC Hydro's view that an external DSM audit would not be appropriate.

**RESPONSE:**

**As discussed in BC Hydro's response to BCUC IR 2.272.1, the external assessment required by Standard 1300 relates to the independence and professional practices of an internal audit function.**

**Standard 1300 is not meant for oversight of specific audits performed by an internal audit function.**

**We believe the external assessment of BC Hydro's internal audit function demonstrates how it will be able to effectively perform the DSM audit and therefore, an external firm would not need to be hired.**

**272.0 I. CHAPTER 10 – DEMAND SIDE MANAGEMENT**

**Reference: DEMAND-SIDE MANAGEMENT**
**BC Hydro F2017-F2019 RRA Decision, p. 85; Exhibit B-1-4, Attachment 2, DSM Audit Q1 F2017 Report, p. 4; Exhibit B-5, BCUC IR 12.4, 187.3, 187.4, 187.7**
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BC Hydro is confident in the Conservation and Energy Management business function and that our cycle of DSM internal audits appropriately reflects the associated risks. The increased cost of performing additional audits, with unknown benefits, outweighs the value from an audit of each expenditure application. Accordingly, BC Hydro does not support filing a DSM audit with each DSM expenditure application.

2.272.5 Please provide BC Hydro's views on the merits of completing an audit of the overall DSM program, similar to that provided in Exhibit B-1-4, once every five years.

**RESPONSE:**

**Internal Audits are not planned on a cyclical basis. BC Hydro does not see value in committing to a DSM audit cycle every five years and believes that our current approach, described in our response to BCUC IR 2.272.3, which selects audits based on an assessment of associated risk in comparison to other areas of the organization, is appropriate.**

**Audit Services has performed four DSM audits (2002, 2003, 2009 and 2016). The next risk assessment and audit plan will be submitted to the Board in May 2021. At that time, consideration will be given to completing a further audit in this area.**

**273.0 I. CHAPTER 10 – DEMAND SIDE MANAGEMENT**

**Reference: DEMAND-SIDE MANAGEMENT**
**Exhibit B-1, pp. 10-1, 10-24; Table 10-4; Exhibit B-6, AMPC IR 5.6**
**DSM Program spend by sector**

On page 10-1 of the Application, BC Hydro notes that "[o]ur proposed demand-side measures expenditure schedule responds to the BCUC's Decision on our Previous Application by increasing expenditures for the residential sector by approximately 50 per cent…"

On page 10-24 of the Application, BC Hydro states that one of the modifications from the F2017 to F2019 DSM plan includes reducing the commercial and industrial program budgets, while remaining within the overall traditional DSM funding envelope.

In Table 10-4 of the Application, BC Hydro shows the following:

**Table 10-4 DSM Program Spend by Sector**

| | Residential (including low income) (%) | Commercial and light industrial[352] (%) | Large Industrial (%) |
|---|---|---|---|
| **BC Hydro percentage of DSM program spend by sector (excluding Thermo-Mechanical Pulp program)** | | | |
| F2014 to F2016 Actual | 17 | 51 | 32 |
| F2017 to F2018 Actual and F2019 Forecast | 19 | 57 | 24 |
| F2020 to F2021 Forecast | 30 | 38 | 32 |
| **BC Hydro Allocation of DSM costs for cost recovery purposes** | | | |
| Allocation of DSM costs | 40 | 35 | 25 |

In response to AMPC IR 5.6, BC Hydro stated:

> Accordingly, BC Hydro looked for opportunities to redirect funding to residential sector programs from elsewhere in the DSM portfolio. Commercial and industrial program expenditure forecasts were reviewed and reductions were identified to better align forecasts with expected spending.
>
> In addition, this reallocation of funding better aligns with the FACOS allocation that the BCUC referenced in its Decision on the Previous Application. BC Hydro's updated view of DSM program spend by sector can be found in Table 10-4 of Chapter 10 of the Application.

2.273.1 Please confirm, or explain otherwise, that in terms of the proportional share of DSM program spending, the allocation to Commercial and light industrial sector in the Test Period has declined by 19 percent, and the Large industrial sector (excluding the thermal-mechanical pulp [TMP] program) has increased by 8 percent since the F2017 to F2019 period.

**RESPONSE:**

**Confirmed.**

**273.0 I. CHAPTER 10 – DEMAND SIDE MANAGEMENT**

**Reference: DEMAND-SIDE MANAGEMENT**
**Exhibit B-1, pp. 10-1, 10-24; Table 10-4; Exhibit B-6, AMPC IR 5.6**
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>
> In addition, this reallocation of funding better aligns with the FACOS allocation that the BCUC referenced in its Decision on the Previous Application. BC Hydro's updated view of DSM program spend by sector can be found in Table 10-4 of Chapter 10 of the Application.

2.273.2 Aside from the increased expenditure in the Residential sector in response to the BCUC's decision regarding the F2017 to F2019 RRA, please discuss whether there were other factors that led to BC Hydro's current requested expenditure allocation between the sectors. If so, please identify these factors.

**RESPONSE:**

**BC Hydro considered the following factors with regards to the current requested expenditure allocation between sectors:**

- **The BCUC's Decision on the Previous Application, including the Fully Allocated Cost of Service allocation across sectors relative to the DSM program spend by sector;**
- **BC Hydro's Mandate Letter from the Government of B.C. which directed BC Hydro to implement affordability measures, such as expanded demand-side management programs targeted to low income ratepayers;**
- **The outcome of the Phase One of the Government of B.C.'s Comprehensive Review of BC Hydro which concluded that BC Hydro's proposal to increase the amount of spending for the residential sector and low-income ratepayers while keeping DSM expenditures at the same level overall was consistent with the government's focus on affordability; and**
- **A review of program expenditures forecasts including participation projections, technology costs, energy management activities, and customer barriers.**
  - **Based on this review, BC Hydro lowered its forecast of commercial sector incentive project submissions over the test period; and**
  - **In addition, for those commercial sector projects that are submitted, BC Hydro expects that lower incentives will be required due to lower technology costs, the mix of projects, and an increase in customer funded projects.**

**274.0 I. CHAPTER 10 – DEMAND SIDE MANAGEMENT**

**Reference: DEMAND-SIDE MANAGMENT**
**Exhibit B-5, BCUC IR 175.2**
**Cost-effectiveness and LRMC**

In response to BCUC IR 175.2, BC Hydro provided the long-run marginal cost (LRMC) value that would result in a Total Resource Cost (TRC) ratio of 1. Footnote notes that the benefit-cost ratios are based on expenditures and energy savings from F2020 to F2022 activities.

2.274.1 Please provide an updated version of the response provided in BCUC IR 175.2 based on expenditures and energy savings for the Test Period only (F2020-2021).

**RESPONSE:**

**The following table shows the LRMC values[1] that result in Total Resource Cost Benefit Cost Ratios (excluding Non-Energy Benefits) equal to one.**

**The threshold LRMC values shown in the table below for the Test Period (F2020-2021) have only minor changes from those presented in BC Hydro's response to BCUC IR 1.175.2. As shown in the table below, all DSM programs and the DSM portfolio would pass the TRC test with an LRMC of $52/MWh or higher, including delivery to the Lower Mainland.**

**For the Low Income Program, a calculation error was discovered in our response to BCUC IR 1.175.2, changing the original value of -27 to +10.**

**LRMC Value that results in Total Resource Cost Benefit Cost Ratio (excluding Non-Energy Benefits) = 1.0[1]**

| | **LRMC (Levelized $ per MWh)** |
|---|---|
| **Rate Structures** | |
| Residential Inclining Block Rate | n/a |
| General Service Rate | n/a |
| Transmission Service Rate | 71 |
| **Total Rate Structures** | **71** |

[1] **LRMC values reflect the cost of resources delivered to the Lower Mainland, which is BC Hydro's major load centre.**

| | **LRMC (Levelized $ per MWh)** |
|---|---|
| **DSM Programs** | |
| *Residential Sector* | |
| Low Income[2] | 10 |
| Non Integrated Areas[3] | 168 |
| Retail | (5) |
| Home Renovation Rebate | 52 |
| *Residential Sector Total*[4] | 25 |
| | |
| *Commercial Sector* | |
| LEM-C | 30 |
| New Construction | 36 |
| *Commercial Sector Total* | 31 |
| | |
| *Industrial Sector* | |
| LEM-I | 28 |
| Thermo-Mechanical Pulp[6] | n/a |
| *Industrial Sector Total* | 28 |
| | |
| **Total Programs**[4] | **28** |
| | |
| Energy Management Activities | n/a |
| Supporting Initiatives | n/a |
| Codes & Standards | n/a |
| | |
| **PORTFOLIO TOTAL**[4,5] | **48** |

**Notes:**

1. **Benefit-cost ratios are based on expenditures and energy savings from fiscal 2020 to fiscal 2021 activities.**
2. **Low Income value includes 40 per cent Non-Energy Benefits.**
3. **Non-Integrated Area value should be compared to the Non-Integrated Area LRMC of $300/MWh.**
4. **Residential Sector, Program and Portfolio Totals all include Low Income Non-Energy Benefits.**
5. **Energy management activities, supporting initiatives costs and codes and standards costs are included at the portfolio level. Capacity-focused DSM is not included in cost-effectiveness calculations.**
6. **TMP program activities originally planned for fiscal 2021 have been removed from the forecast in this response, consistent with the Evidentiary Update.**

**275.0 I. CHAPTER 10 – DEMAND SIDE MANAGEMENT**

**Reference: DEMAND-SIDE MANAGEMENT**
**Exhibit B-1, Appendix X, pp. 79–80; Exhibit B-5, BCUC IR 178.1, Attachment 1, pp. 1, 6**
**Cost-effectiveness & key program assumptions**

BC Hydro states on page 79 of Appendix X to the Application that "[r]anges indicate that there are sub-components within the initiatives that have different adjustment factors."

BC Hydro's response to BCUC IR 178.1 provided measure lives for each measure/technology/offer. Page 1 of Attachment 1 to BCUC IR 178.1 indicated that Window Film and Dryer Racks have measure lives of one year.

BC Hydro stated on page 6 of Attachment 1 to BCUC IR 178.1 that "behavioural measure" has a measure life of 1, 6 or 24 years.

2.275.1 Please provide additional details for the Dryer Rack measures, including BC Hydro's plans for ensuring savings persist for longer than one year.

**RESPONSE:**

**Within the Energy Conservation Assistance Program (ECAP), dryer racks have been modelled at one-year persistence. This is a conservative approach from a modelling perspective.**

**To encourage longer-term use of the dryer rack, ECAP participants are:**

- **Provided with information on the benefits of using a dryer rack; and**
- **Encouraged to sign up to receive regular communication about behavioural change opportunities. Longer-term persistence of behaviours is associated with ongoing communication and hanging clothes to dry is one of the topics that would be included in these communications.**

**275.0 I. CHAPTER 10 – DEMAND SIDE MANAGEMENT**

**Reference: DEMAND-SIDE MANAGEMENT**
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BC Hydro stated on page 6 of Attachment 1 to BCUC IR 178.1 that "behavioural measure" has a measure life of 1, 6 or 24 years.

2.275.2 Please explain if more than one intervention type is included under the "Behavioural measure" and indicate the measure life for each of the underlying interventions, if applicable.

**RESPONSE:**

**BC Hydro offers two interventions under the "Behavioural measure", Team Power Smart and the Energy Visualization Portlet. Team Power Smart is an opt-in program where participants can enroll in a reduction challenge where they receive information and education, and incentives if they achieve the required goals. The Energy Visualization Portlet provides customers with detailed feedback on their consumption, including comparisons to similar homes, which increases awareness and empowers them to look for opportunities to reduce their consumption.**

**Both Team Power Smart and Energy Visualization Portlet have the same measure life profiles of one, six or 24 years. The one, six and 24-year timeframes do not reflect different measures or interventions, rather they reflect the variation in participant engagement over time. Unlike product-based programs, where a one-time action to install a product (e.g., a light bulb) results in savings that persist over time, a behavioural action needs to be maintained in order to persist. BC Hydro remains actively engaged with the participants to ensure their savings are maintained over the long run. However, persistence assumptions reflect the fact that some participants will become disengaged and drop out of the program over time. We assume that 15 per cent of participants' energy savings have a**

**measure life of one year, 19 per cent have a measure life of six years, and the remaining 66 per cent have a measure life of 24 years.**

**BC Hydro has an evaluation of the Behavioural Program planned for fiscal 2020. BC Hydro will use the results from this evaluation to further inform program assumptions.**

**276.0 I. CHAPTER 10 – DEMAND SIDE MANAGEMENT**

**Reference: DEMAND-SIDE MANAGEMENT**
**Exhibit B-1, Appendix X, p. 30; Exhibit B-6, Ince IR 12.5; Zone II RPG IR 25.5**
**Energy Savings Kits**

BC Hydro states in Appendix X to the Application that Energy Savings Kits will be provided at pre-qualified events and will not require a BC Hydro account number to receive a kit.

BC Hydro stated in response to Ince IR 12.5:

> The pre-qualified events are intended to make it easy for households who meet the income qualifications to receive an Energy Saving Kit. At these events individuals receiving a kit do not need to declare their household income or provide their BC Hydro account number. At the event, our Community Outreach Team assists with the registration process and distributes the kits. […]
>
> BC Hydro considers the following when selecting events:
>
> […]
>
> Frequency – whether the organization has had an event in the past two years, where kits were distributed.

BC Hydro stated in response to Zone II RPG IR 25.5:

> BC Hydro does not conduct post-audits on customers who have received an Energy Saving Kit. We receive feedback on install rates through participant surveys and energy savings are verified through billing analysis.

2.276.1 Please discuss whether there are mechanisms in place to ensure that Energy Saving Kits (ESKs) are installed and to reduce the incidence of unused kits, particularly in the case of pre-qualified events where individuals do not need to provide their account number. If so, please describe the mechanisms.

**RESPONSE:**

**To encourage participants to install the products, the Energy Saving Kits (ESKs) include illustrated instructions on how to install the products as well as links to how-to-install videos. After receiving the kit, an email reminder is sent to**

**participants reminding them to install the products and to complete the survey. The survey includes questions on what products they installed, satisfaction with the products and the ordering process.**

**ESKs distributed at the pre-approved events are a small percentage of total kits distributed. Only 3 per cent of kits in fiscal 2020 have been distributed through ESK pre-approved events. The pre-approved events are intended to make it easier for qualified households to receive their kit. By hosting events at local community service organizations, there are no barriers for customers to receive a kit. Service organizations do not have to pre-promote the event to customers and remind them to bring their BC Hydro bill and no one is disappointed because they forgot to bring their bill. Clients can receive their kit during their visit to the community service provider.**

**It is unknown if this group will have different install rates than other ESK customers. To better understand this issue, the ESK survey will be updated to include a question on how they received their kit. This will enable the program to look at self-reported install trends between those receiving a kit at an event compared to those ordering their kit.**

**BC Hydro does not recommend auditing customer installations of ESKs. While these audits may provide further insight into install rates, the benefits need to be weighed against the drawbacks. The cost of sending an auditor to someone's home is significantly higher than the cost of an ESK. Also, the logistics of booking an appointment can be challenging as it can be difficult to reach low income customers and have them agree to an appointment and be home at the required time, particularly when there is no benefit of the visit to the customer. BC Hydro is also concerned that adding a requirement for a customer to agree to a post audit site visit may create a deterrent to their participation. While there may be some benefit gained from these visits, these do not outweigh the negative aspects.**

**276.0 I. CHAPTER 10 – DEMAND SIDE MANAGEMENT**

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2.276.1.1 Please explain how BC Hydro confirms that savings are realized, or that ESKs are installed effectively.

**RESPONSE:**

**BC Hydro tracks participation and uses engineering estimates to determine initial savings.**

**BC Hydro assumes a percentage of Energy Saving Kits (ESKs) measures will not be installed and reduces its initial energy savings by this percentage. The participant survey discussed in the response to BCUC IR 2.276.1 is used to inform assumed installation rates.**

**BC Hydro confirms that savings are realized through a program evaluation. The program evaluation methodology includes a billing analysis that verifies claimed savings are accurate. BC Hydro's 2018 evaluation of the Energy Saving Kit offer evaluated net savings to be higher than reported savings. Between fiscal 2011 and fiscal 2016 evaluated net savings from ESKs were 116 per cent of reported savings.**

**A summary of the evaluation finding is included in Appendix AA Attachment 2, page 16 of the Application.**

**277.0 I. CHAPTER 10 – DEMAND SIDE MANAGEMENT**

**Reference: DEMAND-SIDE MANAGEMENT**
**Exhibit B-1, pp. 2-30, 7-32; Table 10-10, 10-11, 10-12, pp. 10-26–10-27; Exhibit B-6, BCSEA IR 40.2; Direction to the BCUC Respecting Undertaking Costs, BC Reg. 77/2017**
**Approval of LCE expenditures**

On page 7-32 of the Application, BC Hydro requests for BCUC approval to defer low-carbon electrification expenditures to the DSM Regulatory Account, consistent with the Direction to the BCUC Respecting Undertaking Costs.

On page 2-30 of the Application, BC Hydro states that "[t]he BCUC must allow BC Hydro to defer [low-carbon electrification] expenditures to the DSM Regulatory Account."

Table 10-10 in the Application shows the planned expenditures for low-carbon electrification (LCE) for the Test Period:

**Table 10-10 Fiscal 2020 to Fiscal 2021 Expenditure Summary ($ million)**

| | F2020 Plan | F2021 Plan | Total |
|---|---|---|---|
| Rate Structures | 0.5 | 0.5 | 1.0 |
| Programs | | | |
| Residential | 18.4 | 19.7 | 38.1 |
| Commercial | 18.9 | 17.5 | 36.4 |
| Industrial | 26.5 | 26.9 | 53.4 |
| Total Programs (excluding TMP) | 63.7 | 64.1 | 127.8 |
| Capacity-focused | 6.9 | 4.3 | 11.1 |
| Supporting Initiatives | 19.8 | 20.2 | 40.0 |
| Thermo-Mechanical Pulp | 0 | 27.2 | 27.2 |
| Low-Carbon Electrification | 18.3 | 9.7 | 28.0 |
| Total Expenditures | 109.2 | 126.0 | 235.1 |

Tables 10-11 and 10-12 of the Application show that the traditional DSM expenditure is targeted at the pursuit of energy and capacity savings, while low-carbon electrification is shown separately in the tables as providing new load and capacity growth.

In response to BCSEA IR 40.2, BC Hydro stated:

> There are no further expenditures planned beyond activities and commitments in fiscal 2020. Phase Two of the Comprehensive Review will consider further roles for BC Hydro in supporting the CleanBC plan.

2.277.1 Please confirm, or explain otherwise, that BC Hydro is not seeking acceptance under section 44.2 of the UCA of the LCE expenditures shown in the 2nd to last row of Table 10-10. Please discuss.

**RESPONSE:**

**Confirmed. As discussed in section 2.6.4 of Chapter 2 of the Application, Section 18 of the *Clean Energy Act* requires the BCUC to allow BC Hydro to collect sufficient revenue to recover costs incurred for prescribed undertakings. As set out in Appendix Y of the Application, all of BC Hydro's Low Carbon Electrification expenditures are within one or more classes of undertakings prescribed under the Greenhouse Gas Reduction (Clean Energy) Regulation, issued under section 18 of the *Clean Energy Act*.**

**277.0 I. CHAPTER 10 – DEMAND SIDE MANAGEMENT**

**Reference: DEMAND-SIDE MANAGEMENT**
**Exhibit B-1, pp. 2-30, 7-32; Table 10-10, 10-11, 10-12, pp. 10-26–10-27; Exhibit B-6, BCSEA IR 40.2; Direction to the BCUC Respecting Undertaking Costs, BC Reg. 77/2017**
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> There are no further expenditures planned beyond activities and commitments in fiscal 2020. Phase Two of the Comprehensive Review will consider further roles for BC Hydro in supporting the CleanBC plan.

2.277.2 In BC Hydro's opinion, what role does the BCUC have in determining whether the individual LCE projects within the LCE program meet the definition under the Greenhouse Gas Reduction Regulation (BC Reg. 102/2012) (GGRR) to be considered a prescribed undertaking.

**RESPONSE:**

**Please refer to BC Hydro's response to BCUC IR 2.250.6, where we explain the BCUC's role in considering whether a project constitutes a prescribed undertaking under the GGRR.**

**277.0 I. CHAPTER 10 – DEMAND SIDE MANAGEMENT**

**Reference: DEMAND-SIDE MANAGEMENT**
**Exhibit B-1, pp. 2-30, 7-32; Table 10-10, 10-11, 10-12, pp. 10-26–10-27; Exhibit B-6, BCSEA IR 40.2; Direction to the BCUC Respecting Undertaking Costs, BC Reg. 77/2017**
**Approval of LCE expenditures**

On page 7-32 of the Application, BC Hydro requests for BCUC approval to defer low-carbon electrification expenditures to the DSM Regulatory Account, consistent with the Direction to the BCUC Respecting Undertaking Costs.

On page 2-30 of the Application, BC Hydro states that "[t]he BCUC must allow BC Hydro to defer [low-carbon electrification] expenditures to the DSM Regulatory Account."

Table 10-10 in the Application shows the planned expenditures for low-carbon electrification (LCE) for the Test Period:

**Table 10-10 Fiscal 2020 to Fiscal 2021 Expenditure Summary ($ million)**

| | F2020 Plan | F2021 Plan | Total |
|---|---|---|---|
| Rate Structures | 0.5 | 0.5 | 1.0 |
| Programs | | | |
| Residential | 18.4 | 19.7 | 38.1 |
| Commercial | 18.9 | 17.5 | 36.4 |
| Industrial | 26.5 | 26.9 | 53.4 |
| Total Programs (excluding TMP) | 63.7 | 64.1 | 127.8 |
| Capacity-focused | 6.9 | 4.3 | 11.1 |
| Supporting Initiatives | 19.8 | 20.2 | 40.0 |
| Thermo-Mechanical Pulp | 0 | 27.2 | 27.2 |
| Low-Carbon Electrification | 18.3 | 9.7 | 28.0 |
| Total Expenditures | 109.2 | 126.0 | 235.1 |

Tables 10-11 and 10-12 of the Application show that the traditional DSM expenditure is targeted at the pursuit of energy and capacity savings, while low-carbon electrification is shown separately in the tables as providing new load and capacity growth.

In response to BCSEA IR 40.2, BC Hydro stated:

> There are no further expenditures planned beyond activities and commitments in fiscal 2020. Phase Two of the Comprehensive Review will consider further roles for BC Hydro in supporting the CleanBC plan.

2.277.3 Given the different focus of the DSM program compared to the LCE program, please comment on BC Hydro's ability to report on these expenditures separately within the DSM Regulatory Account, and the advantages or disadvantages of doing so.

**RESPONSE:**

**BC Hydro does plan and report on LCE expenditures separately from DSM expenditures, as shown in Chapter 10 of the Application. BC Hydro does not currently report on LCE expenditures within the DSM Regulatory Account but could do so, if required.**

**The advantage of separately reporting LCE expenditures within the DSM Regulatory Account would be to allow the BCUC and interveners to distinguish between the amortization of DSM expenditures and the amortization of LCE expenditures. The disadvantage would be the additional work required to set up new codes and reclassify previous year amounts.**

**From a management perspective, BC Hydro does not see an advantage in separately reporting these expenditures within the DSM Regulatory Account because the amortization period of DSM expenditures and LCE expenditures are the same.**

**277.0 I. CHAPTER 10 – DEMAND SIDE MANAGEMENT**

**Reference: DEMAND-SIDE MANAGEMENT**
**Exhibit B-1, pp. 2-30, 7-32; Table 10-10, 10-11, 10-12, pp. 10-26–10-27; Exhibit B-6, BCSEA IR 40.2; Direction to the BCUC Respecting Undertaking Costs, BC Reg. 77/2017**
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Table 10-10 in the Application shows the planned expenditures for low-carbon electrification (LCE) for the Test Period:

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| | F2020 Plan | F2021 Plan | Total |
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| Programs | | | |
| Residential | 18.4 | 19.7 | 38.1 |
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| Industrial | 26.5 | 26.9 | 53.4 |
| Total Programs (excluding TMP) | 63.7 | 64.1 | 127.8 |
| Capacity-focused | 6.9 | 4.3 | 11.1 |
| Supporting Initiatives | 19.8 | 20.2 | 40.0 |
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| Low-Carbon Electrification | 18.3 | 9.7 | 28.0 |
| Total Expenditures | 109.2 | 126.0 | 235.1 |

Tables 10-11 and 10-12 of the Application show that the traditional DSM expenditure is targeted at the pursuit of energy and capacity savings, while low-carbon electrification is shown separately in the tables as providing new load and capacity growth.

In response to BCSEA IR 40.2, BC Hydro stated:

> There are no further expenditures planned beyond activities and commitments in fiscal 2020. Phase Two of the Comprehensive Review will consider further roles for BC Hydro in supporting the CleanBC plan.

2.277.4 Please reconcile the expenditure for LCE projects shown in Table 10-10 and BC Hydro's response to BCSEA IR 40.2 concerning the lack of further expenditures for LCE in F2021.

**RESPONSE:**

**In BC Hydro's response to BCSEA IR 1.40.2, we outlined that no further LCE expenditures were planned beyond activities and commitments in fiscal 2020.**

**To clarify, the commitments made to customers in fiscal 2020 and earlier include expenditures that will be incurred in fiscal 2021 and fiscal 2022 due to the length of time required for projects to reach completion. These future expenditures, which result from activity initiated in fiscal 2020 and earlier, are included in Table 10-10 of Chapter 10 of the Application.**

**New LCE activities beyond fiscal 2020 will be informed by the outcomes of Phase Two of the Government of B.C.'s Comprehensive Review of BC Hydro.**

**278.0 I. CHAPTER 10 – DEMAND SIDE MANAGEMENT**
**Reference: DEMAND-SIDE MANAGEMENT**
**Exhibit B-1, Appendix Y, p. 6**
**Initial LCE projects**

The paragraph on page 6 of Appendix Y which refers to both project 1 and project 2 appears to only contain details for project 2.

2.278.1 Please provide a description of the activities related to customer project 1, redacted as necessary.

**RESPONSE:**

**The public version of this response has been redacted to maintain confidentiality over customer information. The un-redacted version of the response is being made available to the BCUC only, in order to protect the customer's commercial interests.**

**The BC Hydro program activities are the same for Project 1 and Project 2. They are both with the same customer ([redacted]) but relate to different sites ([redacted]). The activities for both projects consist of providing incentive funding to the customer to assist in the acquisition, installation, and use of equipment that uses electricity to power natural gas production, instead of the customer burning their own gas to power their gathering, transport and processing operations.**

**279.0 I. CHAPTER 10 – DEMAND SIDE MANAGEMENT**

**Reference: DEMAND-SIDE MANAGEMENT**
**DSM Regulation; Exhibit B-1, Section 10.5.7, Table 10-15; Appendix Y, Table 3-2**
**BC Hydro LCE Program: energy management activities**

Under the DSM Regulation, "energy management program" means a program to assist customers to optimize energy use.

Table 10-15 of the Application outlines the forecast energy management activity expenditures in each DSM sector: Approximately $5 million annually for the Residential sector; $6 million for the Commercial sector; and $8 million for the Industrial sector.

Table 3-2 of Appendix Y to the Application provides the total expenditure on BC Hydro funded LCE Program components:

Table 3-2 – BC Hydro Funded Low Carbon Electrification Program Expenditures

| BC Hydro LCE Program | | Expenditures ($ million) | | | | | |
| --- | --- | --- | --- | --- | --- | --- | --- |
| GGRR Regulation Subsection | Program Component | 2018 | 2019 | 2020 | 2021 | 2022 | Total |
| 4(3)(a), 4(3)(b) | Energy Management Studies and Incentives | - | 1.51 | 3.10 | 7.00 | 2.49 | 14.11 |
| 4(3)(a) | Public Awareness | - | 0.60 | 0.91 | - | 0.00 | 1.51 |
| 4(3)(b) | Education & Training | - | 0.01 | 0.04 | - | - | 0.05 |
| 4(3)(c) | Research and Pilots | - | 0.01 | 0.10 | - | - | 0.11 |
| 4(3)(d) | Standards Enabler | - | 0.23 | 0.65 | - | - | 0.88 |
| **Program Total** | | - | **2.35** | **4.80** | **7.00** | **2.49** | **16.65** |

2.279.1 Please provide additional details on the types of activities included under BC Hydro's DSM energy management activities, and how they differ from the activities under the BC Hydro LCE Energy Management Studies and Incentives program component.

**RESPONSE:**

**The primary difference between LCE energy management studies and incentives and DSM energy management activities in the DSM plan are that the LCE studies and incentives are focused on specific fuel switching opportunities (from fossil fuels to BC Hydro grid electricity), whereas the DSM energy management**

**activities in the DSM plan look broadly at optimizing electricity usage with a focus on enabling electricity use reduction.**

**A summary of the DSM energy management activities is shown in the table below and detailed descriptions of the activities are located in Appendix X of the Application (Residential: pages 37-41, Commercial: pages 49-53, Industrial: pages 59-62).**

| Customer Sector | BC Hydro DSM Energy Management Activities |
|---|---|
| Residential | • Detailed consumption feedback<br>• Energy reduction challenges with membership<br>• Energy Management Coaching and Home Assessments<br>• BC Hydro Alliance of Energy Professionals<br>• External Workforce Capability Building<br>• Customer Information Support |
| Commercial | • Energy Management Assessment and Plan<br>• Energy Managers<br>• Investigative Energy Study & Building Optimization Study<br>• Energy Wise Network / Campaign in a Box<br>• BC Hydro Alliance of Energy Professionals<br>• External Workforce Capability Building<br>• Customer Information Support |
| Industrial | • Strategic Energy Management – Industrial Energy Manager<br>• Strategic Energy Management – Cohort Energy Manager<br>• Strategic Energy Management – Regional Energy Manager<br>• Energy Monitoring and Targeting<br>• Energy Audits<br>• BC Hydro Alliance of Energy Professionals<br>• External Workforce Capability Building |

**279.0 I. CHAPTER 10 – DEMAND SIDE MANAGEMENT**

**Reference: DEMAND-SIDE MANAGEMENT**
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| BC Hydro LCE Program | | Expenditures ($ million) | | | | | |
|---|---|---|---|---|---|---|---|
| GGRR Regulation Subsection | Program Component | 2018 | 2019 | 2020 | 2021 | 2022 | Total |
| 4(3)(a), 4(3)(b) | Energy Management Studies and Incentives | - | 1.51 | 3.10 | 7.00 | 2.49 | 14.11 |
| 4(3)(a) | Public Awareness | - | 0.60 | 0.91 | - | 0.00 | 1.51 |
| 4(3)(b) | Education & Training | - | 0.01 | 0.04 | - | - | 0.05 |
| 4(3)(c) | Research and Pilots | - | 0.01 | 0.10 | - | - | 0.11 |
| 4(3)(d) | Standards Enabler | - | 0.23 | 0.65 | - | - | 0.88 |
| **Program Total** | | **-** | **2.35** | **4.80** | **7.00** | **2.49** | **16.65** |

2.279.2 In the case of existing BC Hydro customers, please describe how the LCE energy management activities differ from the energy management activities currently offered to the three different sectors.

**RESPONSE:**

**Please refer to BC Hydro's response to BCUC IR 2.279.1 where we describe how LCE energy management activities differ from the energy management activities currently offered in the DSM Plan.**

**279.0 I. CHAPTER 10 – DEMAND SIDE MANAGEMENT**

**Reference: DEMAND-SIDE MANAGEMENT**
**DSM Regulation; Exhibit B-1, Section 10.5.7, Table 10-15; Appendix Y, Table 3-2**
**BC Hydro LCE Program: energy management activities**

Under the DSM Regulation, "energy management program" means a program to assist customers to optimize energy use.

Table 10-15 of the Application outlines the forecast energy management activity expenditures in each DSM sector: Approximately $5 million annually for the Residential sector; $6 million for the Commercial sector; and $8 million for the Industrial sector.

Table 3-2 of Appendix Y to the Application provides the total expenditure on BC Hydro funded LCE Program components:

Table 3-2 – BC Hydro Funded Low Carbon Electrification Program Expenditures

| BC Hydro LCE Program | | Expenditures ($ million) | | | | | |
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| 4(3)(a) | Public Awareness | - | 0.60 | 0.91 | - | 0.00 | 1.51 |
| 4(3)(b) | Education & Training | - | 0.01 | 0.04 | - | - | 0.05 |
| 4(3)(c) | Research and Pilots | - | 0.01 | 0.10 | - | - | 0.11 |
| 4(3)(d) | Standards Enabler | - | 0.23 | 0.65 | - | - | 0.88 |
| Program Total | | - | 2.35 | 4.80 | 7.00 | 2.49 | 16.65 |

2.279.2.1 Discuss the steps BC Hydro is taking to reduce duplication, or take advantage of synergies, between the DSM and LCE programs involving activities such as: public awareness; codes and standards; education; or training.

**RESPONSE:**

**BC Hydro has an established organization with experience, relationships and presence in the market place to deliver its traditional DSM initiatives. Rather than duplicate this for the purpose of Low Carbon Electrification (LCE), BC Hydro is**

**instead looking for synergies by considering LCE as incremental initiatives to our base of traditional DSM activities.**

**Examples of this approach are provided below as requested for public awareness, codes and standards, and education and training:**

- **Public Awareness: BC Hydro already has an established brand, communication channels, and relationships with trade allies (e.g., retailers). Customers are receptive to receiving energy related information from BC Hydro. We can approach LCE as an incremental initiative and use these components to deliver information and build awareness specific to LCE;**

- **Education and Training: BC Hydro has established relationships with a wide range of trade allies (e.g., retailers, contractors) that are key to the delivery of our traditional DSM initiatives because they support our customers in the purchase and installation of products and services. BC Hydro provides education and training for these trade allies so that they are equipped to help customers with decisions relating to energy use. Many of these same trade allies will be involved in the delivery of LCE initiatives. In these situations, BC Hydro can use the existing relationships and add LCE as an incremental component to the education and training offered as part of traditional DSM activities; and**

- **Codes and Standards: BC Hydro is active in the support of codes and standards activities to advance the adoption of efficient use of electricity. Through these activities, BC Hydro has established key relationships, holds positions on various standards committees, and works closely with all three levels of government as part of our traditional DSM activities. BC Hydro can use these relationships and committee positions to also introduce incremental LCE opportunities for consideration.**

**279.0 I. CHAPTER 10 – DEMAND SIDE MANAGEMENT**

**Reference: DEMAND-SIDE MANAGEMENT**
**DSM Regulation; Exhibit B-1, Section 10.5.7, Table 10-15; Appendix Y, Table 3-2**
**BC Hydro LCE Program: energy management activities**

Under the DSM Regulation, "energy management program" means a program to assist customers to optimize energy use.

Table 10-15 of the Application outlines the forecast energy management activity expenditures in each DSM sector: Approximately $5 million annually for the Residential sector; $6 million for the Commercial sector; and $8 million for the Industrial sector.

Table 3-2 of Appendix Y to the Application provides the total expenditure on BC Hydro funded LCE Program components:

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| GGRR Regulation Subsection | Program Component | 2018 | 2019 | 2020 | 2021 | 2022 | Total |
| 4(3)(a), 4(3)(b) | Energy Management Studies and Incentives | - | 1.51 | 3.10 | 7.00 | 2.49 | 14.11 |
| 4(3)(a) | Public Awareness | - | 0.60 | 0.91 | - | 0.00 | 1.51 |
| 4(3)(b) | Education & Training | - | 0.01 | 0.04 | - | - | 0.05 |
| 4(3)(c) | Research and Pilots | - | 0.01 | 0.10 | - | - | 0.11 |
| 4(3)(d) | Standards Enabler | - | 0.23 | 0.65 | - | - | 0.88 |
| **Program Total** | | - | **2.35** | **4.80** | **7.00** | **2.49** | **16.65** |

2.279.3 Please provide a breakdown of the expenditures under the BC Hydro LCE Energy Management Studies and Incentives program component detailed in Table 3-2.

**RESPONSE:**

**The expenditures for the LCE Energy Management Studies and Incentives component of the LCE Program can be categorized as follows:**

- **Funding to Customers and Potential Customers. These include:**
  - **Study or assessment funding to customers or potential customers to help them identify and develop project opportunities; and**
  - **Project incentive funding to reduce the cost of projects to assist customers or potential customers with the acquisition, installation, or use of equipment that uses electricity instead of other sources of energy that produce more greenhouse gas emissions.**
- **Costs to develop, implement and administer the study and incentive activities. These include:**
  - **Program management costs;**
  - **Technical reviews, measurement and verification; and**
  - **Customer and trade alliance engagement.**

**A breakdown of forecast expenditures is provided in the table below.**

| | | Expenditures ($ million) | | | | | |
|---|---|---|---|---|---|---|---|
| **Program Component** | **Activity** | **2018** | **2019** | **2020** | **2021** | **2022** | **Total** |
| **Energy Management Studies and Incentives** | **Energy Studies** | **-** | **0.79** | **0.63** | **-** | **-** | **1.42** |
| | **Incentives** | **-** | **0.14** | **0.73** | **6.73** | **2.44** | **10.04** |
| | **Program Management** | **-** | **0.32** | **0.99** | **-** | **-** | **1.31** |
| | **Technical Reviews, Measurement & Verification** | **-** | **0.08** | **0.23** | **0.27** | **0.05** | **0.63** |
| | **Customer & Trade Alliance Engagement** | **-** | **0.17** | **0.53** | **-** | **-** | **0.70** |
| **Total** | | **-** | **1.51** | **3.10** | **7.0** | **2.49** | **14.11** |

**280.0 I. CHAPTER 10 – DEMAND SIDE MANAGEMENT**

**Reference: DEMAND-SIDE MANAGEMENT**
**Exhibit B-5, BCUC IR 184.4**
**Codes and standards**

BC Hydro stated in response to BCUC IR 184.4:

> To clarify the language on page 10-17 of Chapter 10 of the Application, BC Hydro understands the adequacy requirement for DSM expenditures on activities in support of codes and standards development under the DSM regulation to be a minimum level, not a set level of effort. As such, BC Hydro's level of effort is determined by the activities required to meet long term market transformation goals. BC Hydro's long-term strategy is to move the market for both new and existing buildings in all residential and commercial customer segments to near-net zero performance over the long-term. As part of the DSM planning cycle, BC Hydro identifies the short-term initiatives and activities necessary to develop model building codes and product standards, to support the adoption of policies and regulations, and to build industry capacity to understand and comply with new and existing codes and standards. This planning process drives the allocation of resources to the codes and standards effort.

2.280.1 Is BC Hydro aware of any benchmarking data regarding utility expenditure in support of codes and standards in other jurisdictions? If so, please provide a summary.

**RESPONSE:**

**There are a limited number of utilities or program administrators who support codes and standards activities. As noted on page 7 of Appendix CC of the Application, this is because without appropriate policies that credit utilities with savings from codes and standards, utilities are dis-incentivized from supporting codes and standards as this raises the baseline from which traditional programs' energy savings are derived. This limits the jurisdictional information available on utility expenditures in support of codes and standards.**

**To respond to this IR, BC Hydro asked Cadmus to conduct a short review of the utilities in their report filed as Appendix CC of the Application to see what information was available on utility expenditures in support of codes and standards. Cadmus' findings were that there are a handful of jurisdictions that have expenditures on codes and standards programs, which range from a high of 9 per cent (program budget/total portfolio) for Hawaii and the Pacific Northwest, to a low of less than 1 per cent for Arizona. BC Hydro's codes and standards expenditures are within this range.**

**281.0 J. CHAPTER 11 – PERFORMANCE BASED REGULATION**

**Reference: PERFORMANCE BASED REGULATION**
**Exhibit B-5, BCUC IR 197.4; Exhibit B-1, Section 11.7.2, p. 11-60**
**Proposed consultation approach**

In response to BCUC IR 197.4, BC Hydro stated that:

> It is important for BC Hydro to inform and educate customers and the public about all regulatory approaches and frameworks through which BC Hydro is seeking approval from the BCUC.
>
> If PBR was adopted for BC Hydro, this would include PBR. Accordingly, BC Hydro would endeavor to educate customers and the public about PBR, by preparing an application that was as accessible as possible and by conducting workshops as required.
>
> While BC Hydro has had success engaging with customers on topics such as safety, capital investments and energy conservation, we expect that broad customer engagement on a complex topic such as PBR would be more challenging to undertake.

In the Application, BC Hydro describes the consultation process it would propose for implementing a Performance Based Regulation (PBR) plan. BC Hydro states that it “could conduct topic-specific workshops, including information presentations and a question and answer session” and identified several topics that may be appropriate for dedicated workshops.

2.281.1 Please describe in detail, what, if any, consultation has been done to date with customer groups regarding the designing of a PBR plan.

**RESPONSE:**

**BC Hydro has not proposed a PBR plan in this proceeding and has not conducted any consultation with customer groups regarding the design of a PBR plan for BC Hydro. BC Hydro’s concerns with regards to the adoption of PBR for BC Hydro are outlined in BC Hydro’s response to BCUC IR 1.197.3.**

**BC Hydro notes that many of the BCUC’s round two information requests with regards to PBR are focused on specific design attributes. In BC Hydro’s view, it is too early to address questions of this nature. The threshold issues of whether or when to adopt PBR for BC Hydro have not yet been addressed by stakeholders or**

**determined by the BCUC. Further, the design of a PBR plan relates to setting rates for a future test period that is not currently before the BCUC.**

**If the BCUC directed BC Hydro to file a PBR plan, BC Hydro would conduct consultation to inform the design of the PBR plan and would submit an application to the BCUC.**

**282.0 J. CHAPTER 11 – PERFORMANCE BASED REGULATION**

**Reference: PERFORMANCE BASED REGULATION**
**Exhibit B-5, BCUC IR 196.1, 197.1, 197.2, Exhibit B-1, Section 11.5.3, p. 11-49**
**Potential implementation timetable**

In Section 11.5.3 of the Application, BC Hydro states that “some base operating costs are beyond our control and would likely need to be included in a ‘Y’ factor.” BC Hydro then provides a list of examples of Y factors, followed by some examples where operating costs would also need to be adjusted for one-time events or increases through a “Z” factor.

> In response to BCUC IR 196.1, BC Hydro stated that: “If PBR were adopted for BC Hydro using fiscal 2021 as the base year, BC Hydro’s current expectation is that we would propose a PBR term of fiscal 2022 to fiscal 2026.”

In response to BCUC IR 197.1, BC Hydro stated that:

> BC Hydro believes that, given the prolonged period of time during which the BCUC’s jurisdiction over BC Hydro was limited, there is significant value in the greater level of review and accessibility associated with cost of service regulation, at this time…
>
> …delaying consideration of the adoption of PBR until there is a higher degree of certainty with respect to the base costs used to generate going-in rates may also be beneficial to all parties.

2.282.1 Please confirm, or explain otherwise, that the reference to using “fiscal 2021 as the base year” would apply to establishing both the base O&M and base capital?

**RESPONSE:**

**Not confirmed. BC Hydro has not proposed a PBR plan in this proceeding and has not defined a scope of cost components that would be included in the base for a PBR formula.**

**The base year for a PBR plan may or may not include capital. As discussed in BC Hydro’s response to BCUC IR 1.191.2, there is no consensus on an optimal PBR design for the treatment of capital expenditures and one potential option for managing capital under a PBR plan is for all capital costs to be excluded from the base for the PBR formula and assessed on a cost of service basis instead.**

**Notably, FortisBC's 2020-2024 Multi-Year Rate Plan Application to the BCUC proposes to determine the majority of its capital expenditures on a cost of service basis.**

**As discussed in BC Hydro's response to BCUC IR 2.281.1, BC Hydro believes it is too early to address questions with regards to specific PBR design attributes.**

**282.0 J. CHAPTER 11 – PERFORMANCE BASED REGULATION**

**Reference: PERFORMANCE BASED REGULATION**
**Exhibit B-5, BCUC IR 196.1, 197.1, 197.2, Exhibit B-1, Section 11.5.3, p. 11-49**
**Potential implementation timetable**

In Section 11.5.3 of the Application, BC Hydro states that "some base operating costs are beyond our control and would likely need to be included in a 'Y' factor." BC Hydro then provides a list of examples of Y factors, followed by some examples where operating costs would also need to be adjusted for one-time events or increases through a "Z" factor.

In response to BCUC IR 196.1, BC Hydro stated that: "If PBR were adopted for BC Hydro using fiscal 2021 as the base year, BC Hydro's current expectation is that we would propose a PBR term of fiscal 2022 to fiscal 2026."

In response to BCUC IR 197.1, BC Hydro stated that:

> BC Hydro believes that, given the prolonged period of time during which the BCUC's jurisdiction over BC Hydro was limited, there is significant value in the greater level of review and accessibility associated with cost of service regulation, at this time…
>
> …delaying consideration of the adoption of PBR until there is a higher degree of certainty with respect to the base costs used to generate going-in rates may also be beneficial to all parties.

2.282.2 Please explain why F2021 would be the appropriate base year, as opposed to any other historical year? Would it be appropriate to use some historical average to calculate a base O&M and base capital for the F2022 to F2026 period? Please discuss why or why not.

**RESPONSE:**

**Please refer to BC Hydro's response to BCUC IR 2.282.1 where we explain that BC Hydro has not proposed a PBR plan and has not defined a scope of cost components that would be included in the base for a PBR formula.**

**BC Hydro referenced the use of fiscal 2021 as the base year for a PBR plan because it would be the most current year available, if BC Hydro was directed to file its next Revenue Requirements Application under PBR.**

**Further, in the BCUC's Decision on the Previous Application, the BCUC stated:**

> **"The Panel recognizes that in some cases, comparing forecast cost increases to the rate of inflation may be considered an appropriate measure for evaluating the reasonableness of forecast cost increases in the test period. This method is likely suitable in situations where a regulator has consistently been empowered to oversee all aspects of the utility's forecast and historical expenditures through proceedings in which the underlying base costs were initially established. However, given the Commission's limited involvement in the approval of BC Hydro's recent revenue requirements, the Panel does not have a high degree of comfort in BC Hydro's starting point, being the 2016 base operating cost."**

**Accordingly, BC Hydro expects that a historical average that included fiscal years 2017 to 2019 would not be appropriate. As discussed in section 1.5.10 of Chapter 1 of the Application, in response to the BCUC's observation, we have provided significantly more information on our operating costs, relative to the Previous Application.**

**The specific approach to establishing the base for a PBR plan, including which year(s) to use or whether to use a historical average, should be determined through a PBR application proceeding.**

**In response to this information request, BC Hydro asked Dr. Weisman to provide an initial discussion on the selection of an appropriate base year for a PBR plan. Dr. Weisman's response is provided below.**

**<u>Response from Dr. Weisman</u>**

**The base year for the PBR regime should ideally provide the most accurate information as to what is expected to prevail over the ensuing years of the PBR regime. Currency of the data is a highly desirable attribute for the base year, which makes fiscal 2021 a natural starting point for the analysis (on the assumption that BC Hydro's rates for fiscal 2022 and subsequent fiscal years were to be set under PBR). Nonetheless, fiscal 2021 may include both positive and negative cost shocks that may not be expected to prevail in future years of the PBR regime. If so, assuming these shocks can be readily identified, it should be possible to develop an "adjusted fiscal 2021" base year for the PBR regime.**

**A historical average of years may have the advantage of smoothing out positive and negative shocks in a manner that reduces the judgement inherent in relying**

**upon any one particular year as the base year for the PBR regime. That said, it is not obvious that computing an average based on fiscal 2020 (inflation-adjusted) and fiscal 2021 would necessarily perform any better as a base year than using fiscal 2021 with the appropriate adjustments for positive and negative shocks. Moving even further back in time by incorporating years prior to fiscal 2020 in the historical average may be expected to further smooth the negative and positive shocks, but only at a significant cost in terms of loss of currency.**

**Lastly, if PBR is adopted for BC Hydro's next Revenue Requirements Application, the company will have operated under three different regulatory regimes over the course of three years. The risk is that such cost uncertainty would lock in a base year for the PBR regime that is not representative of what would be expected in subsequent years of the PBR regime. As a result, the regulated firm may be (exogenously) over-compensated or under-compensated and neither are desirable outcomes from a public policy perspective. Whether this risk is of sufficient concern to warrant deferring the adoption of PBR for a stipulated period of time is discussed in greater detail in BC Hydro's response to MOVEUP IR 1.3.7.**

**Any further analysis beyond the relatively broad issues identified herein moves into a level of granularity that is best reserved for a PBR application proceeding.**

**282.0 J. CHAPTER 11 – PERFORMANCE BASED REGULATION**

**Reference: PERFORMANCE BASED REGULATION**
**Exhibit B-5, BCUC IR 196.1, 197.1, 197.2, Exhibit B-1, Section 11.5.3, p. 11-49**
**Potential implementation timetable**

In Section 11.5.3 of the Application, BC Hydro states that “some base operating costs are beyond our control and would likely need to be included in a ‘Y’ factor.” BC Hydro then provides a list of examples of Y factors, followed by some examples where operating costs would also need to be adjusted for one-time events or increases through a “Z” factor.

In response to BCUC IR 196.1, BC Hydro stated that: “If PBR were adopted for BC Hydro using fiscal 2021 as the base year, BC Hydro’s current expectation is that we would propose a PBR term of fiscal 2022 to fiscal 2026.”

In response to BCUC IR 197.1, BC Hydro stated that:

> BC Hydro believes that, given the prolonged period of time during which the BCUC’s jurisdiction over BC Hydro was limited, there is significant value in the greater level of review and accessibility associated with cost of service regulation, at this time…
>
> …delaying consideration of the adoption of PBR until there is a higher degree of certainty with respect to the base costs used to generate going-in rates may also be beneficial to all parties.

2.282.3 Please confirm, or explain otherwise, that the proposal of a “fiscal 2021 as the base year” and the proposed implementation delay is meant to address the “consideration of the adoption of PBR until there is a higher degree of certainty with respect to the base costs used to generate going-in rates”?

**RESPONSE:**

**Not confirmed. BC Hydro is not proposing a PBR plan. A PBR plan covering fiscal 2022 to fiscal 2026, using fiscal 2021 as a base year, was intended to represent the earliest possible implementation timeline for a PBR plan. Obtaining a greater degree of certainty with respect to the base costs used to generate “going in” rates would require delaying the adoption of PBR beyond fiscal 2022.**

**Further, given the timetable for reviewing the Application, a PBR plan covering fiscal 2022 to fiscal 2026 may no longer be feasible. For further discussion on this timeline, please refer to BC Hydro’s response to BCUC IR 2.282.6.**

**282.0 J. CHAPTER 11 – PERFORMANCE BASED REGULATION**

**Reference: PERFORMANCE BASED REGULATION**
**Exhibit B-5, BCUC IR 196.1, 197.1, 197.2, Exhibit B-1, Section 11.5.3, p. 11-49**
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In Section 11.5.3 of the Application, BC Hydro states that “some base operating costs are beyond our control and would likely need to be included in a ‘Y’ factor.” BC Hydro then provides a list of examples of Y factors, followed by some examples where operating costs would also need to be adjusted for one-time events or increases through a “Z” factor.

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>
> …delaying consideration of the adoption of PBR until there is a higher degree of certainty with respect to the base costs used to generate going-in rates may also be beneficial to all parties.

2.282.3 Please confirm, or explain otherwise, that the proposal of a “fiscal 2021 as the base year” and the proposed implementation delay is meant to address the “consideration of the adoption of PBR until there is a higher degree of certainty with respect to the base costs used to generate going-in rates”?

2.282.3.1 Will using F2021 as the base year result in higher certainty in establishing the base going in rates? Please discuss.

**RESPONSE:**

**Using fiscal 2021 as the base year would not result in greater certainty in establishing the going-in rates under PBR. Please refer to BC Hydro’s response to BCUC IR 2.282.3 where we note that BC Hydro is not proposing a PBR plan and explain that the timeline provided was intended to represent the earliest possible implementation timeline for a PBR plan and may no longer be feasible.**

**282.0 J. CHAPTER 11 – PERFORMANCE BASED REGULATION**

**Reference: PERFORMANCE BASED REGULATION**
**Exhibit B-5, BCUC IR 196.1, 197.1, 197.2, Exhibit B-1, Section 11.5.3, p. 11-49**
**Potential implementation timetable**

In Section 11.5.3 of the Application, BC Hydro states that “some base operating costs are beyond our control and would likely need to be included in a ‘Y’ factor.” BC Hydro then provides a list of examples of Y factors, followed by some examples where operating costs would also need to be adjusted for one-time events or increases through a “Z” factor.

In response to BCUC IR 196.1, BC Hydro stated that: “If PBR were adopted for BC Hydro using fiscal 2021 as the base year, BC Hydro’s current expectation is that we would propose a PBR term of fiscal 2022 to fiscal 2026.”

In response to BCUC IR 197.1, BC Hydro stated that:

> BC Hydro believes that, given the prolonged period of time during which the BCUC’s jurisdiction over BC Hydro was limited, there is significant value in the greater level of review and accessibility associated with cost of service regulation, at this time…
>
> …delaying consideration of the adoption of PBR until there is a higher degree of certainty with respect to the base costs used to generate going-in rates may also be beneficial to all parties.

2.282.4 Please provide a sample calculation of the F2021 base operating costs, outlining the proposed Y-factor and Z-factor items, to determine BC Hydro’s base O&M.

**RESPONSE:**

**BC Hydro is unable to provide a sample calculation, as requested, for the following reasons:**

- **BC Hydro has not proposed a PBR plan in this proceeding. The design of a PBR plan should be informed by consultation with stakeholders and requires considerable input from experts;**
- **While section 11.5.3 of Chapter 11 of the Application provides some examples of Y-factor costs, BC Hydro has not conducted an in-depth review of its base operating costs to determine all of the costs that would need to be**

**included in a Y-factor. BC Hydro believes that it would be more appropriate to undertake this review as part of a PBR application process; and**

- **It is not possible to provide sample adjustments for Z-factor items to planned fiscal 2021 base operating costs because the Z-factor is meant to capture costs associated with unforeseen events which, by nature, are unplanned and would not be reflected BC Hydro's planned base operating costs.**

**282.0 J. CHAPTER 11 – PERFORMANCE BASED REGULATION**

**Reference: PERFORMANCE BASED REGULATION**
**Exhibit B-5, BCUC IR 196.1, 197.1, 197.2, Exhibit B-1, Section 11.5.3, p. 11-49**
**Potential implementation timetable**

In Section 11.5.3 of the Application, BC Hydro states that “some base operating costs are beyond our control and would likely need to be included in a ‘Y’ factor.” BC Hydro then provides a list of examples of Y factors, followed by some examples where operating costs would also need to be adjusted for one-time events or increases through a “Z” factor.

In response to BCUC IR 196.1, BC Hydro stated that: “If PBR were adopted for BC Hydro using fiscal 2021 as the base year, BC Hydro’s current expectation is that we would propose a PBR term of fiscal 2022 to fiscal 2026.”

In response to BCUC IR 197.1, BC Hydro stated that:

> BC Hydro believes that, given the prolonged period of time during which the BCUC’s jurisdiction over BC Hydro was limited, there is significant value in the greater level of review and accessibility associated with cost of service regulation, at this time…
>
> …delaying consideration of the adoption of PBR until there is a higher degree of certainty with respect to the base costs used to generate going-in rates may also be beneficial to all parties.

2.282.5 Please identify any topics which would be suited for a negotiated settlement process, should one be directed.

**RESPONSE:**

**As discussed further in BC Hydro’s response to BCUC IR 2.281.1, BC Hydro is not proposing a PBR plan and has not conducted any consultation with customer groups regarding the design of a PBR plan for BC Hydro. In BC Hydro’s view, as consultation with customer groups has not been conducted it is too early to identify any topics which may be suited to a negotiated settlement process. A consultation process would provide an early indication of areas where common agreement may be possible.**

**282.0 J. CHAPTER 11 – PERFORMANCE BASED REGULATION**

**Reference: PERFORMANCE BASED REGULATION**
**Exhibit B-5, BCUC IR 196.1, 197.1, 197.2, Exhibit B-1, Section 11.5.3, p. 11-49**
**Potential implementation timetable**

In BCUC IR 197.2, BC Hydro stated: "If PBR is adopted for BC Hydro, we expect that we would retain experts for all three topics during a PBR proceeding and that interveners would likely retain similar expertise."

2.282.6 Given BC Hydro's stated expectation of proposing a PBR term of F2022 to F2026, the considerations regarding stakeholder engagement discussed in Section 11.7.2 of the Application and the intent on engaging certain experts, what would be the most reasonable timing (by month and year) to conduct the engagement process, and the subsequent filing of a PBR plan for review by the BCUC. Please discuss and provide a proposed timetable.

**RESPONSE:**

**As discussed in BC Hydro's response to BCUC IR 2.282.3, BC Hydro is not proposing a PBR plan. While a PBR plan covering fiscal 2022 to fiscal 2026, using fiscal 2021 as a base year, was intended to represent the earliest possible implementation timeline for a PBR plan, it may no longer be feasible, given the timetable for reviewing the Application.**

**Specifically, if BC Hydro were to file its next Revenue Requirements Application, under PBR, by February 2021:**

- **The financial inputs for that application would need to be finalized by October 2020; and**
- **Consultation with customer groups, as outlined in section 11.7.2 of Chapter 11 of the Application, would need to be completed by no later than the end of July 2020 in order for the financial inputs to be finalized by October 2020.**

**Assuming that the consultation process would require approximately three months to prepare and conduct, this means that a decision on the adoption of PBR for BC Hydro would need to be made by April 2020. This may not align with the current timetable for reviewing the Application, given that the argument phase is unlikely to be concluded before mid-March 2020.**

**282.0 J. CHAPTER 11 – PERFORMANCE BASED REGULATION**

**Reference: PERFORMANCE BASED REGULATION**
**Exhibit B-5, BCUC IR 196.1, 197.1, 197.2, Exhibit B-1, Section 11.5.3, p. 11-49**
**Potential implementation timetable**

In Section 11.5.3 of the Application, BC Hydro provides a list of operating costs that it would exclude from base operating costs.

2.282.7 Please confirm, or explain otherwise, that BC Hydro would propose excluding these same operating costs from base O&M if the BCUC were to direct BC Hydro to file a PBR plan starting in 2022.

**RESPONSE:**

**Not confirmed. As stated in BC Hydro's response to BCUC IR 2.282.4, while section 11.5.3 provides some examples of Y-factor costs, BC Hydro has not conducted an in-depth review of its base operating costs to determine all of the costs that would need to be included in a Y-factor. BC Hydro believes that it would be more appropriate to undertake this review as part of a PBR application process.**

**282.0 J. CHAPTER 11 – PERFORMANCE BASED REGULATION**

**Reference: PERFORMANCE BASED REGULATION**
**Exhibit B-5, BCUC IR 196.1, 197.1, 197.2, Exhibit B-1, Section 11.5.3, p. 11-49**
**Potential implementation timetable**

In Section 11.5.3 of the Application, BC Hydro provides a list of operating costs that it would exclude from base operating costs.

2.282.7 Please confirm, or explain otherwise, that BC Hydro would propose excluding these same operating costs from base O&M if the BCUC were to direct BC Hydro to file a PBR plan starting in 2022.

2.282.7.1 Please list any other adjustments to base O&M that BC Hydro may propose and explain why.

**RESPONSE:**

**As stated in BC Hydro's response to BCUC IR 2.282.4, while section 11.5.3 provides some examples of Y-factor costs, BC Hydro has not conducted an in-depth review of its base operating costs to determine all of the costs that would need to be included in a Y-factor. BC Hydro believes that it would be more appropriate to undertake this review as part of a separate PBR application process, if PBR is adopted for BC Hydro.**

**283.0 J. CHAPTER 11 – PERFORMANCE BASED REGULATION**

**Reference: PERFORMANCE BASED REGULATION**
**Exhibit B-5, BCUC IR 191.2, Exhibit B-1, Section 11.5.1, Table 11-3**
**Capital expenditures**

In response to BCUC IR 191.2, BC Hydro listed several options it states are more likely to be appropriate for the management of capital expenditures under a PBR plan. BC Hydro also stated that:

> While the options below provide an initial indication of potential approaches to managing capital expenditures under a PBR plan, it is important to note Dr. Weisman's caution on page 46 of Appendix FF of the Application where he explains that there is no consensus on an optimal PBR design for the treatment of capital expenditures. Accordingly, we would want to give this issue further consideration in the context of an overall PBR plan design before providing a definitive preference.

In Section 11.5.1 of the Application, BC Hydro discusses the consideration for capital expenditures under a PBR. BC Hydro also provides a discussion and evaluation on each of the potential approach to managing capital expenditures in Table 11-3.

2.283.1 Please discuss how BC Hydro would approach establishing base capital. Please include a discussion of which year(s) would be most appropriate, what adjustments would need to be made and why.

**RESPONSE:**

**Please refer to BC Hydro's response to BCUC IR 2.282.1 where we state that BC Hydro has not proposed a PBR plan in this proceeding and has not defined a scope of cost components that would be subject to a PBR formula.**

**The base year for a PBR plan may or may not include capital. BC Hydro has not determined which approach would be most appropriate for BC Hydro or what adjustments may need to be made to base capital, if some capital costs were included in the scope of cost components subject to a PBR formula. In BC Hydro's view, it would be more appropriate to undertake this review as part of a PBR application process.**

**Please also refer to BC Hydro's response to BCUC IR 2.282.2 where Dr. Weisman discusses the selection of an appropriate base year for a PBR plan.**

**283.0 J. CHAPTER 11 – PERFORMANCE BASED REGULATION**

**Reference: PERFORMANCE BASED REGULATION**
**Exhibit B-5, BCUC IR 191.2, Exhibit B-1, Section 11.5.1, Table 11-3**
**Capital expenditures**

In response to BCUC IR 191.2, BC Hydro listed several options it states are more likely to be appropriate for the management of capital expenditures under a PBR plan. BC Hydro also stated that:

> While the options below provide an initial indication of potential approaches to managing capital expenditures under a PBR plan, it is important to note Dr. Weisman's caution on page 46 of Appendix FF of the Application where he explains that there is no consensus on an optimal PBR design for the treatment of capital expenditures. Accordingly, we would want to give this issue further consideration in the context of an overall PBR plan design before providing a definitive preference.

In Section 11.5.1 of the Application, BC Hydro discusses the consideration for capital expenditures under a PBR. BC Hydro also provides a discussion and evaluation on each of the potential approach to managing capital expenditures in Table 11-3.

2.283.2 Please also discuss the existing regulatory approach under the BCUC's mandate (i.e. CPCN, capital expenditure filings) and how these current processes would or would not apply in a PBR framework for BC Hydro.

**RESPONSE:**

**The primary mechanism for the BCUC to review projects on a prospective basis is through major project filings (i.e., BC Hydro's Certificate of Public Convenience and Necessity "CPCN" and section 44.2 applications). These proceedings are usually detailed and complex, involve numerous interveners and are resource intensive for the parties involved. Accordingly, in BC Hydro's view, it is reasonable and appropriate for the BCUC to limit this detailed and in-depth public interest review to significant projects, as is currently the BCUC's practice.**

**For those projects that are not the subject of a major project application because they do not meet a filing threshold or have not otherwise been directed by the BCUC to require a CPCN, revenue requirements applications provide an avenue for the BCUC to review and test BC Hydro's planned capital additions for the test period.**

**BC Hydro is currently seeking approval of its proposed 2018 Capital Filing Guidelines through the BCUC's Review of Regulatory Oversight and Capital Expenditures and Projects proceeding. These guidelines set major project thresholds that indicate when a CPCN for significant extension projects is required and document BC Hydro's commitment to file for section 44.2 acceptance of non-extension project expenditure schedules that exceed the major project thresholds.**

**BC Hydro would expect major project filings to continue regardless of whether BC Hydro is regulated under cost of service regulation or PBR.**

**Accordingly, if the BCUC establishes thresholds for when a CPCN is required, it may be appropriate to consider how criteria may be aligned to allow for a specific "adder" or "carve out" within a PBR plan for projects that have obtained a CPCN. As discussed on page 11-46 of Chapter 11 of the Application, in the absence of such an approach, the funding envelope produced by the PBR formula could be too small or too large.**

**Table 11-3 of Chapter 11 of the Application provides a discussion of options for the treatment of capital expenditures in PBR plans. These options entail complex trade-offs between the incentives provided, the degree of regulatory oversight and the level of certainty that funding will be sufficient to support the required investment.**

**The approach to managing capital under the PBR plan may have implications with regards to the level of regulatory oversight of BC Hydro's planned capital additions and expenditures, through revenue requirements applications.**

**For example, if the approach to managing capital under the PBR plan prioritizes strong incentives by providing BC Hydro with more autonomy over its capital expenditures and projects in exchange for BC Hydro assuming more risk, then BC Hydro would expect less regulatory oversight of its planned capital additions and expenditures under PBR, relative to a typical revenue requirements application.**

**284.0 J. CHAPTER 11 – PERFORMANCE BASED REGULATION**

**Reference: PERFORMANCE BASED REGULATION**
**Exhibit B-5, BCUC IR 193.1**
**Regulatory accounts**

In response to BCUC IR 193.1, BC Hydro stated that:

> …the regulated firm under PBR should bear limited financial responsibility for events outside of its control… whereas a fundamental property of PBR is that the regulated firm bears greater risk in exchange for the prospect of greater reward, this does not imply that the regulated firm should bear all of the risk under PBR. Reflexively eliminating or reducing variance accounts and recovery mechanisms may cause the regulated firm to bear excessive risk.

2.284.1 Is it BC Hydro's view that the entirety of its deferral and regulatory accounts serve the purpose of reducing risk for "events outside of its control"? Please discuss.

**RESPONSE:**

**No, BC Hydro does not consider that the entirety of its deferral and regulatory accounts serve the purpose of reducing risk for events outside of its control.**

**As outlined in section 7.5 of Chapter 7 of the Application, BC Hydro has five types of regulatory accounts, which are consistent with the BCUC Regulatory Account Filing Checklist. Table 7-2 of Chapter 7 of the Application categorizes BC Hydro's regulatory accounts into these five types. Not all five types of accounts relate to uncontrollable variances. For example, benefit matching accounts seek to match the recovery of costs with the period of benefit to ratepayers.**

**BC Hydro has 17 variance accounts (i.e., Cost of Energy Variance Accounts, Other Cash Variance Accounts and Non-Cash Variance Accounts) which are intended to capture variances between forecast costs or revenues and actual costs or revenues. Most of these accounts relate to variances that are beyond BC Hydro's control. For example, the Storm Restoration Costs Regulatory Account and the Total Finance Charges Regulatory Account, capture variances that occur due to factors outside of BC Hydro's control such as weather or interest rates, respectively.**

**In BC Hydro's response to BCUC IR 1.193.1, Dr. Weisman explains why the adoption of PBR should not inherently reduce the number of variance accounts and notes that if the number of variance accounts were reduced, this increased**

**risk for the utility would be reflected in an increased cost of capital and therefore, higher rates for consumers, holding all other factors constant.**

**BC Hydro has seven benefit matching accounts, three non-cash provisions and two IFRS Transition Accounts and is requesting BCUC approval to close the existing Rate Smoothing Regulatory Account. As discussed in section 11.5.8 of Chapter 11 of the Application, the adoption of PBR would not change the period of time over which the benefit of a particular service or asset accrues to ratepayers, the requirement for loss provision liabilities or the potential for non-controllable financial impacts from a change in the accounting standards applicable to BC Hydro.**

**Accordingly, BC Hydro does not believe that the adoption of PBR should prompt a change to its regulatory accounts.**

**284.0 J. CHAPTER 11 – PERFORMANCE BASED REGULATION**

**Reference: PERFORMANCE BASED REGULATION**
**Exhibit B-5, BCUC IR 193.1**
**Regulatory accounts**

In response to BCUC IR 193.1, BC Hydro stated that:

> …the regulated firm under PBR should bear limited financial responsibility for events outside of its control… whereas a fundamental property of PBR is that the regulated firm bears greater risk in exchange for the prospect of greater reward, this does not imply that the regulated firm should bear all of the risk under PBR. Reflexively eliminating or reducing variance accounts and recovery mechanisms may cause the regulated firm to bear excessive risk.

2.284.2 Please explain in detail how “eliminating or reducing variance accounts and recovery mechanisms may cause the regulated firm to bear excessive risk.” How does BC Hydro measure excessive risk? Please discuss the trigger mechanisms that would identify when a utility is bearing excessive risk.

**RESPONSE:**

**Eliminating or reducing variance accounts and recovery mechanisms would cause a utility to assume financial responsibility for events outside of its control, exposing the utility to excessive risk if such exposure resulted in material variances to planned amounts.**

**The same basic rationale for regulatory accounts applies under both cost of service regulation and PBR. Under either approach, BC Hydro would expect that similar considerations would apply in determining how much uncontrollable risk should be assumed by the utility.**

**In BC Hydro’s response to BCUC IR 1.193.1, Dr. Weisman explains why the adoption of PBR should not inherently reduce the number of variance accounts and notes that if the number of variance accounts were reduced, this increased risk for the utility would be reflected in an increased cost of capital and therefore, higher rates for consumers, holding all other factors constant.**

**284.0 J. CHAPTER 11 – PERFORMANCE BASED REGULATION**

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**Exhibit B-5, BCUC IR 193.1**
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> …the regulated firm under PBR should bear limited financial responsibility for events outside of its control… whereas a fundamental property of PBR is that the regulated firm bears greater risk in exchange for the prospect of greater reward, this does not imply that the regulated firm should bear all of the risk under PBR. Reflexively eliminating or reducing variance accounts and recovery mechanisms may cause the regulated firm to bear excessive risk.

2.284.3 In BC Hydro's view, at what point would the proliferation of regulatory and deferral accounts become a disincentive for the utility to find efficiencies and reduce costs? Please discuss the economic triggers that would identify when this might become a concern for a utility on PBR?

**RESPONSE:**

**As Dr. Weisman explains in BC Hydro's response to BCUC IR 1.193.1, the utility should bear limited financial responsibility for events outside its control. Otherwise, the utility would assume greater risk without any corresponding benefits in terms of stronger incentives.**

**Regulatory accounts established for this purpose ensure that ratepayers pay the actual cost and that the utility (including its shareholder) and ratepayers are not unduly rewarded or penalized, due to uncontrollable factors.**

**In BC Hydro's view, this allocation of risk does not provide a disincentive for a utility to find efficiencies or reduce costs. Rather, it recognizes that a utility's efforts to find efficiencies and reduce costs must be focused on the utility's controllable costs.**

**As discussed in section 5.5.2 of Chapter 5 of the Application, BC Hydro has limited base operating cost increases by offsetting increases to non-controllable costs with reductions to controllable costs.**

**285.0 J. CHAPTER 11 – PERFORMANCE BASED REGULATION**

**Reference: PERFORMANCE BASED REGULATION**
**Exhibit B-5, BCUC IR 195.3**
**Potential key performance indicators**

In response to BCUC IR 195.3, BC Hydro stated that:

> If the BCUC decides to adopt PBR for BC Hydro following this proceeding, BC Hydro has suggested that fiscal 2021 be used as the base year. This means that the first year under a PBR plan would be fiscal 2022, which is also the first year where the BCUC would have jurisdiction to determine BC Hydro's allowed net income.

2.285.1 Please discuss whether the BCUC's process to determine BC Hydro's allowed net income in F2022 should be conducted prior to, in tandem with, or subsequent to the BCUC's review of a potential PBR plan from BC Hydro.

**RESPONSE:**

**BC Hydro believes that the BCUC's process to determine BC Hydro's allowed net income in fiscal 2022 and subsequent fiscal years should be conducted prior to the completion of the BCUC's review of BC Hydro's next Revenue Requirements Application regardless of whether that application is reviewed under cost of service regulation or PBR. Specifically, and on a preliminary basis, BC Hydro expects that it could accommodate the following timeline:**

- **Spring 2020 – BC Hydro submits a cost of capital application to determine BC Hydro's allowed net income in fiscal 2022 and subsequent fiscal years;**
- **February 2021 – BC Hydro submits a Revenue Requirements Application reflecting BC Hydro's proposal for allowed net income;**
- **Spring 2021 – BCUC Decision on BC Hydro's allowed net income; and**
- **Summer 2021 – BC Hydro submits Evidentiary Update to Revenue Requirements Application to reflect the BCUC's Decision on BC Hydro's allowed net income, if different from BC Hydro's proposal.**

**In BC Hydro's view, the BCUC's process to determine BC Hydro's allowed net income in fiscal 2022 and subsequent fiscal years should not be conducted in tandem with or subsequent to the BCUC's review of BC Hydro's next Revenue Requirements Application. Under these timelines, the BCUC would likely not make a decision on BC Hydro's allowed net income for fiscal 2022 until after fiscal year 2022 has completed. This could require a retrospective adjustment to customer bills and may cause unnecessary rate instability.**

**286.0 J. CHAPTER 11 – PERFORMANCE BASED REGULATION**

**Reference: PERFORMANCE BASED REGULATION**
**Exhibit B-5, BCUC IR 198.1**
**Cost of Service (COS) compared to PBR**

In response to BCUC IR 198.1, BC Hydro stated that "PBR for Hydro Quebec Distribution is currently experiencing some public acceptance challenges" and that:

> The Government of Quebec and Hydro Quebec have been under significant public pressure to return all efficiency gains achieved, both under PBR and under the prior cost of service regime, to ratepayers. The public and political pressure to return efficiency gains to ratepayers is well-documented in Quebec media - with some media in Quebec describing efficiency gains as customers being 'overcharged.'

BC Hydro also provided a news article from the Montreal Gazette as support of this position.

BC Hydro then also referenced Dr. Weisman's explanation "that the success of PBR may be less certain in the case of Crown Corporations because it requires a greater degree of coordination between government and regulatory governance structures."

2.286.1 Please discuss and provide relevant references, in addition to the above news article, to any regulatory filings as a result of attempting to address these concerns. Please outline any resulting changes and amendments to Hydro Quebec's existing PBR plan, as a result of these (or any other) regulatory changes.

**RESPONSE:**

**On June 12, 2019, the Government of Quebec filed at the National Assembly *Bill 34: An Act to simplify the process for establishing electricity distribution rates*, which calls into question the future of PBR for Hydro-Québec. Attachment 1 to this response provides a copy of Bill 34. Under Bill 34:**

- **Electricity distribution rates would be set by government and adjusted for inflation from 2021 to 2024; and**
- **The Régie de l'énergie will no longer be required to establish a performance-based regulatory mechanism for Hydro-Québec in its activities as an electricity power distributor and carrier.**

**The measures set out in Bill 34 reflect the government's intention to reimburse Hydro-Québec customers for part of the perceived "overpayments" that were collected over the last few years. The government's proposal for 2020 provides for a rate freeze that should generate savings of nearly $1 billion for Hydro-Québec customers and a reimbursement of approximately $500 million to customers (related to accounting mechanisms that will no longer apply under the new framework).**

**The development of a PBR plan for Hydro-Quebec Distribution and Hydro-Quebec Transmission has occurred in stages over a five year period and is not yet complete. With the filing of Bill 34, it is not yet known whether the Régie will proceed with the final stages.**

**The Régie de l'énergie has regulated Hydro Quebec Transmission since 1998 and Hydro Quebec Distribution since 2000.**

**Both Hydro Quebec Transmission and Hydro Quebec Distribution were initially regulated under cost of service regulation. On a yearly basis, they filed a Tariff Request at the Régie using 4 months of actual costs and eight months of projected costs.**

**Between 2008 (which marked the beginning of the recession in Quebec, at which time electricity demand went down dramatically) and 2014, Hydro-Quebec generated $1.4 billion in earnings variances, which were referenced by the media as customers being "overcharged". Hydro-Quebec responded that these amounts were savings associated with productivity increases.**

**With the election of a new government in 2012, a Bill was introduced to amend *The Régie de l'énergie Act* and add a new requirement for the Régie to establish a performance-based regulatory mechanism for Hydro-Québec in its activities as an electricity power distributor and carrier.**

**Following this requirement, the Régie launched a multi-year regulatory process to implement PBR.**

**In 2014, in Decision D-2014-034, the Régie adopted a MTÉR (earning sharing mechanism) which was implemented in 2017. The first 100 basis points of surplus earnings are shared evenly between customers and Hydro-Quebec Distribution. For earnings in excess of 100 basis points, 75 per cent are assigned to customers while Hydro-Quebec Distribution retains 25 per cent.**

**In 2017, in Decision D-2017-043, the Régie approved a multi-year rate plan for Hydro-Quebec Distribution featuring a revenue cap with an inflation – X + customer growth formula.**

**In 2018, in Decision D-2018-067, the Régie used a judgement-based, non-scientific approach to set an X-factor of 0.3 per cent and ordered Hydro-Quebec Distribution**

**to prepare a total factor productivity study to potentially inform the X-factor for the last year of the PBR plan. For further discussion on how the X-factor can be determined under a PBR plan, please refer to BC Hydro's response to BCUC IR 1.190.1.**

**The Régie de l'énergie was set to decide on which methodology to adopt to conduct the total factor productivity study this fall. However, with the filing of Bill 34 and its expected adoption, the study may not be required.**

# NATIONAL ASSEMBLY OF QUÉBEC

FIRST SESSION FORTY-SECOND LEGISLATURE

Bill 34

## An Act to simplify the process for establishing electricity distribution rates

Introduction

Introduced by
Mr. Jonatan Julien
Minister of Energy and Natural Resources

Québec Official Publisher
2019

**EXPLANATORY NOTES**

*This bill amends provisions concerning electricity distribution rates and various obligations imposed on Hydro-Québec and the Régie de l'énergie.*

*The bill amends the Hydro-Québec Act to provide that, as of 1 April 2020, electricity distribution rates will be the ones set out in Schedule I to that Act. Unless otherwise provided, the prices of those rates will be adjusted for the four years following the year in which they are set. The electricity distribution rates must be published on Hydro-Québec's website and in the* Gazette officielle du Québec*.*

*The Act respecting the Régie de l'énergie is also amended to provide that Hydro-Québec must apply to the Régie de l'énergie to request it to set new electricity distribution rates, or modify the existing rates, every five years. Hydro-Québec may also apply to the Régie de l'énergie to request it to set a new rate or modify existing ones during that five-year period, but only to the extent that certain circumstances warrant such an application and the Government has made an order stating its concerns with respect to the application.*

*Under the bill, Hydro-Québec is no longer required to obtain the authorization of the Régie de l'énergie for its infrastructure investment projects and the other reorganization initiatives of the electricity distribution network, or to submit its commercial programs to the Régie for approval. The Régie de l'énergie is no longer required to establish a performance-based regulation to ensure efficiency gains by the electricity distributor and the electricity carrier. However, Hydro-Québec is required to send the Régie de l'énergie, every year, the information set out in the Act respecting the Régie de l'énergie.*

*Lastly, the bill contains consequential, penal and transitional provisions, including a provision requiring Hydro-Québec to grant, before 1 April 2020, a rebate on electricity distribution rates.*

**LEGISLATION AMENDED BY THIS BILL:**

– Hydro-Québec Act (chapter H-5);

– Act respecting the Régie de l'énergie (chapter R-6.01);

– Act respecting municipal and private electric power systems (chapter S-41).

# Bill 34

## AN ACT TO SIMPLIFY THE PROCESS FOR ESTABLISHING ELECTRICITY DISTRIBUTION RATES

THE PARLIAMENT OF QUÉBEC ENACTS AS FOLLOWS:

HYDRO-QUÉBEC ACT

**1.** Section 22.0.1 of the Hydro-Québec Act (chapter H-5) is amended

(1) by replacing the first paragraph by the following paragraph:

"The rates for the distribution of electric power by the Company are those set out in Schedule I. The rates are composed of all prices, their conditions of application and the computation methods applicable to the billing of the electric power and services provided by the Company.";

(2) by inserting "the first paragraph and" after "notwithstanding" in the second paragraph.

**2.** The Act is amended by inserting the following sections after section 22.0.1:

"**22.0.1.1.** The rate prices set out in Schedule I are adjusted by operation of law on 1 April each year, by a rate corresponding to the annual change in the overall average Québec consumer price index without alcoholic beverages, tobacco products and recreational cannabis for the 12-month period ending on 30 September of the year preceding that for which the rate prices are to be adjusted, except Rate L, whose price is to be adjusted according to the formula $A \times [1 + B]$.

In the formula in the first paragraph, the letter A represents the rate price of Rate L set out in Schedule I as at 31 March preceding the adjustment, and the letter B represents the rate corresponding to the annual change in the overall average Québec consumer price index without alcoholic beverages, tobacco products and recreational cannabis for the 12-month period ending on 30 September of the year preceding that for which the price for Rate L is to be adjusted, multiplied by 0.65.

Notwithstanding the first paragraph, rate prices are not adjusted

(1) in the year in which the Régie fixes or modifies the rates under section 48.2 of the Act respecting the Régie de l'énergie (chapter R-6.01);

(2) in the year in which the Régie modifies the price of that rate on 1 April of that year under section 48.3 of the Act respecting the Régie de l'énergie; and

(3) in the year following the one in which the Régie fixed or modified that rate after 1 April under sections 48.3 and 48.4 of the Act respecting the Régie de l'énergie.

The Régie shall publish, in the *Gazette officielle du Québec*, the schedule modified following the adjustment provided for in this section. Based on the published schedule, the Minister of Justice shall ensure that the rates set out in Schedule I are updated in the Compilation of Québec Laws and Regulations.

"**22.0.1.2.** The Company shall publish on its website the electric power distribution rates set out in Schedule I."

**3.** Section 26 of the Act is amended by replacing "tariff" by "rate set out in Schedule I or".

**4.** The Act is amended by adding the following schedule at the end:

"SCHEDULE I
"(*Section 22.0.1*)

"ELECTRIC POWER DISTRIBUTION RATES

The components of the rates, other than the components set out in this schedule, are those approved by the Régie de l'énergie in its Decision D-2019-037 dated 22 March 2019.

| Rate | Description | Price |
|---|---|---|
| D | System access charge per day | 40.64¢ |
| | First 40 kWh per day | 6.08¢ |
| | Remaining consumption | 9.38¢ |
| DP | First 1,200 kWh per month | 5.88¢ |
| | Remaining consumption | 8.94¢ |
| | Demand charge, summer period (> 50 kW) | $4.59 |
| | Demand charge, winter period (> 50 kW) | $6.21 |
| | Minimum monthly bill – single-phase | $12.18 |
| | Minimum monthly bill – three-phase | $18.27 |
| DM | System access charge per day, times the multiplier | 40.64¢ |
| | First 40 kWh per day, times the multiplier | 6.08¢ |
| | Remaining consumption | 9.38¢ |
| | Demand charge, summer period (> 50 kW or 4 kW × multiplier) | $6.21 |
| | Demand charge, winter period (> 50 kW or 4 kW × multiplier) | $6.21 |

| | | |
|---|---|---|
| DT | System access charge per day, times the multiplier | 40.64¢ |
| | Energy price: T° ≥ -12°C or -15°C | 4.37¢ |
| | Energy price: T° < -12°C or -15°C | 25.55¢ |
| | Demand charge, summer period (> 50 kW or 4 kW × multiplier) | $6.21 |
| | Demand charge, winter period (> 50 kW or 4 kW × multiplier) | $6.21 |
| Additional electricity – Photosynthesis | Floor price (¢/kWh): Average price at Rate M (2nd block) for 25 kV and 100% load factor | 5.59¢ |
| Winter Credit Option – Rate D | Credit for energy curtailed (per kWh) | 50.00¢ |
| Flex D | System access charge per day | 40.64¢ |
| | During the winter period: | |
| | First 40 kWh per day, outside critical peak events | 4.28¢ |
| | Remaining consumption, outside critical peak events | 7.36¢ |
| | Consumption during critical peak events | 50.00¢ |
| | During the summer period: | |
| | First 40 kWh per day | 6.08¢ |
| | Remaining consumption | 9.38¢ |
| G | System access charge per month | $12.33 |
| | Demand charge (> 50 kW) | $17.64 |
| | First 15,090 kWh per month | 9.90¢ |
| | Remaining consumption | 7.62¢ |
| | Minimum monthly bill – single-phase | $12.33 |
| | Minimum monthly bill – three-phase | $36.99 |
| G Short-term contract | Increase in system access charge and minimum monthly bill | $12.33 |
| | Increase in monthly demand charge (winter period) | $6.03 |
| Winter activities | Reference index as at March 31, 2006: 1.08<br>2% increase on April 1 of each year starting in 2006 | |
| Winter Credit Option – Rate G | Credit for energy curtailed (per kWh) | 50.00¢ |
| Flex G | System access charge per month | $12.33 |
| | During the winter period: | |
| | Consumption outside critical peak events | 8.26¢ |
| | Consumption during critical peak events | 50.00¢ |
| | During the summer period: | |
| | All consumption | 9.90¢ |
| | Minimum monthly bill – single-phase | $12.33 |
| | Minimum monthly bill – three-phase | $36.99 |

| | | |
|---|---|---|
| M | Demand charge | $14.58 |
| | First 210,000 kWh per month | 5.03¢ |
| | Remaining consumption | 3.73¢ |
| | Minimum monthly bill – single-phase | $12.33 |
| | Minimum monthly bill – three-phase | $36.99 |
| M Short-term contract | Increase in minimum monthly bill | $12.33 |
| | Increase in monthly demand charge (winter period) | $6.03 |
| G9 | Demand charge | $4.23 |
| | Energy price | 10.08¢ |
| | Minimum monthly bill – single-phase | $12.33 |
| | Minimum monthly bill – three-phase | $36.99 |
| | Increase for low power factor | $10.35 |
| G9 Short-term contract | Increase in minimum monthly bill | $12.33 |
| | Increase in monthly demand charge (winter period) | $6.03 |
| GD | Demand charge | $5.28 |
| | Energy price, summer period | 6.25¢ |
| | Energy price, winter period | 15.51¢ |
| | Minimum monthly bill – single-phase | $12.33 |
| | Minimum monthly bill – three-phase | $36.99 |
| Running-in for New Equipment – Medium Power | 4% increase in average price | |
| Equipment Testing – Medium Power | Multiplier (per kWh):10 | |
| Interruptible Electricity Option – Medium Power | Option I: | |
| | Fixed nominal credit, winter period (per kW) | $13.00 |
| | Variable nominal credit for each of the first 20 interruption hours (per kWh) | 20.00¢ |
| | Variable nominal credit for each of the next 20 interruption hours (per kWh) | 25.00¢ |
| | Variable nominal credit for each of the 60 subsequent interruption hours (per kWh) | 30.00¢ |
| | Option II: | |
| | Fixed nominal credit, winter period (per kW) | $9.10 |
| | Variable nominal credit for each interruption hour (per kWh) | 20.00¢ |

| | | |
|---|---|---|
| Interruptible Electricity Option – Medium Power | Option I:<br>Penalty (per kW)<br>Option II:<br>Penalty (per kW) | <br>$1.25<br><br>$0.50 |
| Additional Electricity Option – Medium Power | Floor price (¢/kWh):<br>Average price at Rate M (2nd block) for 25 kV and 100% load factor | 5.59¢ |
| Industrial Revitalization Rate – Medium Power | Floor price (¢/kWh):<br>Rate M 2nd block energy price | 3.73¢ |
| BR | Consumption associated with the first 50 kW of maximum power demand (per kWh) | 11.04¢ |
| | Consumption associated with maximum power demand in excess of 50 kW (per kWh) | 20.69¢ |
| | Remaining consumption (per kWh) | 16.27¢ |
| | Minimum monthly bill – single-phase | $12.33 |
| | Minimum monthly bill – three-phase | $36.99 |
| Flex M | Demand charge | $14.58 |
| | During the winter period: | |
| | Consumption outside critical peak events | 3.17¢ |
| | Consumption during critical peak events | 50.00¢ |
| | During the summer period: | |
| | First 210,000 kWh per month | 5.03¢ |
| | Remaining consumption | 3.73¢ |
| | Minimum monthly bill – single-phase | $12.33 |
| | Minimum monthly bill – three-phase | $36.99 |
| Flex G9 | Demand charge | $4.23 |
| | During the winter period: | |
| | Consumption outside critical peak events | 8.10¢ |
| | Consumption during critical peak events | 50.00¢ |
| | During the summer period: | |
| | All consumption | 10.08¢ |
| | Minimum monthly bill – single-phase | $12.33 |
| | Minimum monthly bill – three-phase | $36.99 |
| | Increase for low power factor | $10.35 |
| L | Demand charge | $12.90 |
| | Energy price | 3.28¢ |
| | Daily optimization charge | $7.56 |
| | Monthly optimization charge | $22.68 |
| LG | Demand charge | $13.26 |
| | Energy price | 3.46¢ |
| H | Demand charge | $5.31 |
| | Energy consumed outside winter weekdays | 5.36¢ |
| | Energy consumed on winter weekdays | 18.08¢ |

| | | |
|---|---|---|
| LD (Firm option) | Demand charge<br>Energy consumed outside winter weekdays<br>Energy consumed on winter weekdays | \$5.31<br>5.36¢<br>18.08¢ |
| LD<br>(Non-firm option) | Demand charge per day for<br>planned interruptions<br>Demand charge per day for<br>unplanned interruptions<br>Energy price<br>Monthly maximum – Demand charge | <br>\$0.53<br><br>\$1.06<br>5.36¢<br>\$5.31 |
| LD<br>(Non-firm option) | Price for consumption during<br>unauthorized period (per kWh) | <br>50.00¢ |
| Running-in for New Equipment (12 or more consumption periods) | 4% increase in the average price<br>Minimum increase in the average price: 1% | |
| Running-in for New Equipment (fewer than 12 consumption periods) | 4% increase in the average price | |
| Running-in for New Equipment | Price for consumption during<br>unauthorized period (per kWh) | <br>50.00¢ |
| Equipment Testing – Large Power | Multiplier (per kWh) | 10.00¢ |
| LP | Annual fixed charge | \$1,000 |
| LP | Price for unauthorized consumption<br>of energy (per kWh) | <br>50.00¢ |
| Interruptible Electricity Option – Large Power | Option I:<br>Fixed nominal credit, winter period<br>(per kW)<br>Variable nominal credit for each<br>of the first 20 interruption hours<br>(per kWh)<br>Variable nominal credit for each<br>of the next 20 interruption hours<br>(per kWh)<br>Variable nominal credit for each<br>of the 60 subsequent interruption<br>hours (per kWh)<br>Option II:<br>Fixed nominal credit, winter period<br>(per kW)<br>Variable nominal credit for each<br>interruption hour (per kWh) | <br><br>\$13.00<br><br><br>20.00¢<br><br><br>25.00¢<br><br><br>30.00¢<br><br><br>\$6.50<br><br>20.00¢ |

| | | |
|---|---|---|
| Interruptible Electricity Option – Large Power | Option I:<br>Penalty (per kW)<br>Amount for the determination of the maximum penalty (per kW)<br>Option II:<br>Penalty (per kW)<br>Amount for the determination of the maximum penalty (per kW) | <br>$1.25<br><br>$5<br><br>$0.60<br><br>$2.50 |
| Additional Electricity Option – Large Power | Floor price (¢/kWh): Average price at Rate L for 120 kV and 100% load factor | 4.67¢ |
| Additional Electricity Option – Large Power | Consumption beyond reference power during unauthorized period (per kWh) | 50.00¢ |
| Economic Development Rate | Initial rate reduction of 20% | |
| Industrial Revitalization Rate – Large Power | Floor price (¢/kWh):<br>Rate L energy price | <br>3.28¢ |
| Industrial Revitalization Rate – Large Power | Consumption beyond reference power during unauthorized period (per kWh) | 50.00¢ |
| DN | System access charge per day, times the multiplier<br>First 30 kWh per day, times the multiplier<br>Remaining consumption<br>Demand charge, summer period (> 50 kW or 4 kW × multiplier)<br>Demand charge, winter period (> 50 kW or 4 kW × multiplier) | 40.64¢<br>6.08¢<br>41.43¢<br>$6.21<br>$6.21 |
| G, G9, M, MA Off-Grid Systems | Penalty on energy | 78.31¢ |
| MA – Structure | Heavy diesel power plant (per kW exceeding 900 kW)<br>Heavy diesel power plant (per kWh exceeding 390,000 kWh)<br>All other cases (per kW exceeding 900 kW)<br>All other cases (per kWh exceeding 390,000 kWh) | $31.41<br>21.70¢<br>$61.71<br>42.69¢ |

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|---|---|---|
| MA – Energy price revision | A – Heavy diesel power plant: operating and maintenance costs (per kWh) | 2.79¢ |
| | B – Heavy diesel power plant: energy cost set for 2006 (per kWh): 11.57¢ | |
| | C – Average price of No. 6 diesel (2% S) for the Montréal area | variable |
| | D – Average reference price of No. 6 diesel (2% S) (per barrel): $58.20 | |
| | E – All other cases: operating and maintenance costs (per kWh) | 2.79¢ |
| | F – All other cases: energy cost set for 2006 (per kWh): 26.44¢ | |
| | G – Average price of No. 1 diesel for the Montréal area | variable |
| | H – Average reference price of No. 1 diesel (per litre): 61.51¢ | |
| Net Metering for Customer-Generators – Option III | Price for electricity injected – heavy diesel power plant (per kWh) | 17.00¢ |
| | Price for electricity injected – light diesel power plant (per kWh) | 33.00¢ |
| | Price for electricity injected – arctic diesel power plant (per kWh) | 48.00¢ |
| Interruptible Electricity Option with Advance Notice – Off-Grid Systems | Fixed credit (per kW) | $6.00 |
| Interruptible Electricity Option with Advance Notice – Off-Grid Systems | Variable credit components: | |
| | A – Operating and maintenance costs (per kWh) | 2.76¢ |
| | B – Energy cost for the reference year 2012 (per kWh):<br>– north of the 53rd parallel: 54.50¢<br>– south of the 53rd parallel: 35.50¢ | |
| | C – Average price of No. 1 diesel for the Montréal area | variable |
| | D – Average reference price of No. 1 diesel (per litre): 87.66¢ | |
| Interruptible Electricity Option Without Advance Notice – Off-Grid Systems | Credit (per kW) | $1.20 |
| | Maximum credit (per kW) | $33.33 |
| F | Demand charge per month | $44.76 |

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|---|---|---|
| Public lighting (general service) | Energy price | 10.36¢ |
| Public lighting (complete service) | Sodium-vapor: 5,000 lumens (or 70 W) per luminaire<br>Sodium-vapor: 8,500 lumens (or 100 W) per luminaire<br>Sodium-vapor: 14,400 lumens (or 150 W) per luminaire<br>Sodium-vapor: 22,000 lumens (or 250 W) per luminaire | $22.50<br>$24.41<br>$26.46<br>$31.05 |
| Public lighting (complete service) | Light-emitting diode: 6,100 lumens (or 65 W) per luminaire | $23.19 |
| Sentinel (with poles) | 7,000 lumens (or 175 W) per luminaire<br>20,000 lumens (or 400 W) per luminaire | $41.61<br>$54.84 |
| Sentinel (without poles) | 7,000 lumens (or 175 W) per luminaire<br>20,000 lumens (or 400 W) per luminaire | $32.70<br>$47.13 |
| Credit for supply at medium or high voltage | Voltage equal to or greater than 5 kV, but less than 15 kV<br>Voltage equal to or greater than 15 kV, but less than 50 kV<br>Voltage equal to or greater than 50 kV, but less than 80 kV<br>Voltage equal to or greater than 80 kV, but less than 170 kV<br>Voltage equal to or greater than 170 kV | $0.612<br>$0.981<br>$2.190<br>$2.679<br>$3.540 |
| Credit for supply for domestic rates | Voltage equal to or greater than 5 kV | 0.241¢ |
| Adjustment for transformation losses | Monthly discount on the demand charge | 17.76¢ |
| VISILEC Service | Monthly charge | $89.00 |
| VIGIELIGNE Service | Annual charge for a first licence<br>Additional charge for a second or third licence<br>Charge for each additional licence | $2,400<br>$600<br>$120 |
| SIGNATURE Service (basic service) | Annual charge per delivery point | $5,250 |
| SIGNATURE Service (complementary options) | Annual charge for harmonics tracking<br>Annual charge for dashboard<br>Annual charge for review of indicators and load behaviour analysis | $5,000<br>$500<br>$5,000 |

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ACT RESPECTING THE RÉGIE DE L'ÉNERGIE

**5.** Section 25 of the Act respecting the Régie de l'énergie (chapter R-6.01) is amended

(1) in the first paragraph,

(*a*) by inserting "except when fixing or modifying the rates and conditions for the distribution of electric power by the electric power distributor, or section" after "48," in subparagraph 1;

(*b*) by striking out subparagraph 4;

(2) by inserting "fixing or modifying the rates and conditions for the distribution of electric power by the electric power distributor or when" after "when" in the second paragraph.

**6.** Section 48 of the Act is amended

(1) in the first paragraph,

(*a*) by striking out "for the distribution of electric power by the electric power distributor or";

(*b*) by inserting "or the conditions for the distribution of electric power by the electric power distributor" after "storage of natural gas";

(*c*) by striking out the last sentence;

(2) by inserting the following paragraphs after the first paragraph:

"The Régie shall fix or modify the rates for the distribution of electric power by the electric power distributor in the cases provided for in any of sections 48.2 to 48.4. To that end, it may request any relevant document or information from the electric power distributor.

For the purposes of this section, the Régie may, in particular, require the electric power carrier, the electric power distributor or a natural gas distributor to file a modification proposal.";

(3) by inserting "under the first paragraph or any of sections 48.2 to 48.4" after "Applications" in the first sentence of the second paragraph.

**7.** Section 48.1 of the Act is repealed.

**8.** The Act is amended by inserting the following sections after section 48.1:

"**48.2.** The electric power distributor shall apply to the Régie to request it to fix rates or modify the rates set out in Schedule I to the Hydro-Québec Act (chapter H-5) on 1 April 2025 and subsequently every five years.

"**48.3.** Notwithstanding section 48.2, the electric power distributor may apply to the Régie, before the deadline specified in that section, to request it to modify any rate set out in Schedule I to the Hydro-Québec Act (chapter H-5) where the following conditions are met:

(1) the electric power distributor has presented a report to the Government showing that due to special circumstances it will no longer be able to meet its obligation under section 24 of the Hydro-Québec Act; and

(2) the Government, after analyzing the report, makes an order indicating to the Régie its economic, social and environmental concerns with respect to the distributor's application.

"**48.4.** Notwithstanding section 48.2, before the deadline specified in that section, the electric power distributor may apply to the Régie to request it to fix a rate not set out in Schedule I to the Hydro-Québec Act (chapter H-5) and the necessary modifications to the existing rates to apply the new rate, where the following conditions are met:

(1) the electric power distributor has presented a report to the Government showing the necessity of fixing a new rate; and

(2) the Government, after analyzing the report, makes an order indicating to the Régie its economic, social and environmental concerns with respect to the distributor's application.

"**48.5.** For the purposes of section 48.3 or 48.4, the Government may require any relevant information from the electric power distributor.

"**48.6.** Any decision made by the Régie under any of sections 48.2 to 48.4 amends Schedule I to the Hydro-Québec Act (chapter H-5) accordingly. Such a decision includes the modified schedule.

The Régie shall publish the modified schedule in the *Gazette officielle du Québec*, specifying the date on which it takes effect. Based on the published schedule, the Minister of Justice shall ensure that Schedule I is updated in the Compilation of Québec Laws and Regulations."

**9.** Section 53 of the Act is amended

(1) by inserting "or set out in Schedule I to the Hydro-Québec Act (chapter H-5)" after "Government" in the first paragraph;

(2) by inserting “or set out in Schedule I to the Hydro-Québec Act” after “Government” in the second paragraph.

**10.** Section 54 of the Act is amended by inserting “or set out in Schedule I to the Hydro-Québec Act (chapter H-5)” after “Government”.

**11.** Section 73 of the Act is amended

(1) by striking out “, the electric power distributor” in the introductory clause of the first paragraph;

(2) by striking out “electric power distributor or” in subparagraph 1 of the second paragraph.

**12.** Section 74 of the Act is amended

(1) in the first paragraph,

(*a*) by striking out “the electric power distributor or of”;

(*b*) by replacing “leurs” in the French text by “ses”;

(2) by striking out the second paragraph.

**13.** Section 75 of the Act is amended by striking out “or distributor” in the introductory clause.

**14.** The Act is amended by inserting the following section after section 75:

“**75.1.** Each year, at the time determined by the Régie, the electric power distributor shall send the Régie the information referred to in Schedule II.”

**15.** Section 116 of the Act is amended by striking out “the electric power carrier or” in subparagraph 4 of the second paragraph.

**16.** Section 117 of the Act is amended

(1) by striking out “or distributor” in the second paragraph;

(2) by inserting the following paragraph after the second paragraph:

“The electric power distributor, if it fails to send the Régie the information referred to in Schedule II or sends false information, is liable to the penalties prescribed in the first paragraph.”

**17.** The Act is amended by adding the following schedule at the end:

“SCHEDULE II
“(*Section 75.1*)

“INFORMATION TO BE SENT BY THE ELECTRIC POWER DISTRIBUTOR

1. Developments in the competitiveness of electricity rates in large North American cities;

2. Record of customer complaints;

3. Developments regarding service quality indicators and update on promotional activities;

4. Report on the electricity distributor’s compliance with the Code of Conduct;

5. Update on the use of Interruptible Electricity Options and the Additional Electricity Option;

6. Update on costs relating to sales and purchases of fuel electricity and transmission services, and to load retention rates, retirement, unforeseen circumstances in off-grid systems, major outages, changes to accounting policies, and the demand response program for the business market;

7. Update on the neutralization use account – Review of useful lives;

8. Developments regarding the regulatory asset relating to any supply contract suspension agreement;

9. Update on dispositions of immovables;

10. Update on investments;

11. Capitalization rates, cost and description of the electricity distributor’s debt;

12. Update on supply contracts;

13. Particulars concerning sources of supply, actual supply and demand and distribution loss rates;

14. Report on the use of the exemption from using the tendering process for short-term supply contracts;

15. List of and update on energy efficiency interventions and costs relating to Transition énergétique Québec;

16. Changes in the workforce, measured in full-time equivalent units;

17. History of sales, sales revenue, number of customer accounts and electricity consumption; and

18. Number of kilometres of distribution lines by voltage level."

ACT RESPECTING MUNICIPAL AND PRIVATE ELECTRIC POWER SYSTEMS

**18.** The Act respecting municipal and private electric power systems (chapter S-41) is amended by replacing "fixed by the Board" by "set out in Schedule I to the Hydro-Québec Act (chapter H-5)" in the following provisions:

(1) the second paragraph of section 8;

(2) the first paragraph of section 17.1.

TRANSITIONAL AND FINAL PROVISIONS

**19.** The provisions of the Hydro-Québec Act (chapter H-5) and the Act respecting the Régie de l'énergie (chapter R-6.01) continue to apply, as they read before being amended by this Act, to case R-4045-2018 currently before the Régie de l'énergie.

Any decision rendered by the Régie in that case amends Schedule I to the Hydro-Québec Act accordingly. Such a decision includes the modified schedule.

The Régie must publish the modified schedule in the *Gazette officielle du Québec*, specifying the date on which it takes effect. Based on the published schedule, the Minister of Justice must ensure that Schedule I is updated in the Compilation of Québec Laws and Regulations.

**20.** The electricity distribution rates fixed or modified by the Régie de l'énergie in its Decision D-2019-037 dated March 22, 2019 apply until 31 March 2020 and may not be modified subject to the modifications that are necessary due to a decision of the Régie de l'énergie with respect to case R-4045-2018.

**21.** Despite section 20 of this Act, section 22.0.1 of the Hydro-Québec Act and sections 48, 53 and 54 of the Act respecting the Régie de l'énergie, Hydro-Québec must grant, before 1 April 2020, a rebate on electricity distribution rates, in proportion to the amounts cumulated in its variance accounts as at 31 December 2019.

**22.** This Act comes into force on (*insert the date of assent to this Act*), except sections 1 to 4, paragraphs 2 and 3 of section 6 and sections 8 to 10 and 18, which come into force on 1 April 2020.

**286.0 J. CHAPTER 11 – PERFORMANCE BASED REGULATION**

**Reference: PERFORMANCE BASED REGULATION**
**Exhibit B-5, BCUC IR 198.1**
**Cost of Service (COS) compared to PBR**

In response to BCUC IR 198.1, BC Hydro stated that "PBR for Hydro Quebec Distribution is currently experiencing some public acceptance challenges" and that:

> The Government of Quebec and Hydro Quebec have been under significant public pressure to return all efficiency gains achieved, both under PBR and under the prior cost of service regime, to ratepayers. The public and political pressure to return efficiency gains to ratepayers is well-documented in Quebec media - with some media in Quebec describing efficiency gains as customers being 'overcharged.'

BC Hydro also provided a news article from the Montreal Gazette as support of this position.

BC Hydro then also referenced Dr. Weisman's explanation "that the success of PBR may be less certain in the case of Crown Corporations because it requires a greater degree of coordination between government and regulatory governance structures."

2.286.2 Please provide a discussion on what the Government of Quebec, Hydro Quebec and the regulator has done to address these concerns. Please include relevant references to support this discussion.

**RESPONSE:**

**Please refer to BC Hydro's response to BCUC IR 2.286.1 where we outline the actions taken by the Government of Quebec that will have implications for Hydro-Quebec's PBR plan.**

**287.0 J. CHAPTER 11 – PERFORMANCE BASED REGULATION**

**Reference: PERFORMANCE BASED REGULATION**
**Exhibit B-5, BCUC IR 189.3**
**Revenue cap**

In response to BCUC IR 189.3, BC Hydro stated that "…because BC Hydro is not motivated by the prospect of higher earnings, the adoption of PBR may not provide the same 'carrot' incentives for efficient performance as would be the case for an investor-owned utility."

2.287.1 Please confirm, or explain otherwise, if the absence of motivation for the prospect of higher earnings is the same under COS as it is under PBR. If confirmed, please explain why the adoption of PBR would be different from the use of COS, with regards to the motivation for efficient performance.

**RESPONSE:**

**Confirmed.**

**The two key determinants of whether a utility is motivated by the prospect of higher net income are the mandate provided by its shareholders and the design of the utility's performance pay mechanisms.**

**As discussed in section 11.8.4 of Chapter 11 of the Application, the Government of B.C. expects BC Hydro to achieve its allowed net income target, not to exceed it.**

**As discussed by Dr. Weisman in BC Hydro's response to MOVEUP IR 1.3.1, in the case of Crown Corporations, there is no guarantee that the corporate board in combination with senior management would necessarily design performance pay mechanisms that would cause the managers of the firm to be motivated by the prospect of higher net income.**

**As Dr. Weisman explains on page 8 of Appendix FF of the Application, under PBR, the utility is able to retain the savings they discover, until rates are re-based but under cost of service regulation, the utility typically does not retain efficiency gains for a prolonged period of time. Consequently, shareholders of an investor-owned utility may provide more of a mandate to pursue higher profits under PBR compared to cost of service regulation.**

**However, assuming a utility's mandate and performance pay structure is the same in both cases, the difference between cost of service regulation and PBR with regards to the motivation for efficient performance, depends on the design of the**

**PBR plan and the regulatory commitment to PBR. The adoption of PBR does not automatically result in stronger incentives. For further discussion, please refer to BC Hydro's response to BCUC IR 1.200.1.**

**Accordingly, as Dr. Weisman concludes on page 63 of Appendix FF of the Application: "If the PBR regime is not developed in accordance with sound economic principles or there is not a strong commitment to the fundamental tenets of PBR on the part of either the regulator or the government, the significant resources required to design and implement a PBR regime would be difficult to justify. The adoption of PBR may simply fail the cost-benefit test under these conditions."**