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British Columbia Hydro and Power Authority

F2022 Revenue Requirements Application

Decision
and Order G-187-21

Public Version

June 17, 2021

Before:
D. M. Morton, Panel Chair
T. A. Loski, Commissioner
R. I. Mason, Commissioner

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Executive Summary

On December 22, 2020, the British Columbia Hydro and Power Authority (BC Hydro or the Authority) filed its Revenue Requirements Application (RRA) requesting approval, from the British Columbia Utilities Commission (BCUC), of rates for the fiscal 2022 (F2022) test period (Test Period) (Application).

The Application contains several requests, including a request for approval of interim and permanent rates reflecting a 1.16 percent general rate increase and changes to the Open Access Transmission Tariff (OATT) rates effective April 1, 2021.

By order dated January 5, 2021, the BCUC, among other things, approved on an interim basis the requested rate increase of 1.16 percent and the requested F2022 OATT rates, effective April 1, 2021. In this Decision, the Panel approves, among other things, and on a permanent basis, the requested 1.16 percent rate increase and the F2022 OATT rates applied for, subject to the adjustments resulting from the determinations and directives contained in the Decision. These adjustments arise from the following:

1. The requested depreciation rates for electric vehicle (EV) charging stations, as set out in Undertaking No. 19, are denied.
2. BC Hydro's request to recover from the Electric Vehicle Costs Regulatory Account each year the forecast interest charged to the account each year is denied. Further, the Panel also denies BC Hydro's request to, starting in F2022, recover the forecast account balance at the end of a test period over the next test period. The Panel also directs BC Hydro to remove from its revenue requirement all F2022 costs related to its EV charging stations that meet the definition of a prescribed undertaking under the Greenhouse Gas Reduction Regulation and defer these costs to the Electric Vehicle Costs Regulatory Account.
3. The Panel directs BC Hydro to increase its F2022 forecast revenue by the estimated value of the low carbon fuel credits that it plans to transfer to other parties, if any, during F2022.
4. The Panel directs BC Hydro to amend its forecast for interconnection revenue in F2022 to $4.6 million, the same figure as its most recent forecast for F2021, and to make any corresponding adjustments to forecast costs required to generate this level of interconnection revenue.

The review of this Application proceeded by way of a Streamlined Review Process. Unlike previous RRAs, the F2022 RRA was filed for a one-year test period as a result of the submissions made during the F2020 to F2021 RRA proceeding. The BCUC had expressed a desire to realign the timing of BC Hydro's RRAs, so that the applications can be submitted earlier to allow for sufficient remaining time in the period under review to facilitate BC Hydro's implementation of directives within that period. The BCUC thus directed BC Hydro to file a one-year "gap year" RRA for F2022 by December 2020, to be reviewed through a streamlined process. Therefore, streamlining the F2022 RRA process facilitates the new regulatory cycle commencing with the next RRA, which BC Hydro expects to file in August 2021.

In the Application, BC Hydro requests that certain information related to Mandatory Reliability Standards (MRS) be made available only to the BCUC due to the highly security sensitive nature of the information. The Panel acknowledges that BC Hydro is particularly sensitive and vulnerable to external threats if security risks are exposed, such as if information about violations were to be published prior to the mitigation of these violations.

Information from these incidents could potentially expose a path of entry for those who may wish to do harm to the system. Therefore, the Panel agrees that it is appropriate that certain Critical Infrastructure Protection (CIP) and cybersecurity information be made available only to the BCUC, in order to safeguard the Bulk Electric System.

However, any decisions around the confidentiality of CIP program spending, confirmed violations, and penalty assessments, if any, should be left for future BCUC panels to decide based on the facts and circumstances and in accordance with the process set out in the BCUC's Rules of Practice and Procedure. The Panel therefore declines to make determinations at this time regarding the review of confidential MRS information and certain cybersecurity information in future RRAs.

1.0 Introduction

1.1 The Application

On December 22, 2020, the British Columbia Hydro and Power Authority (BC Hydro or the Authority) filed its Revenue Requirements Application (RRA) requesting approval, from the British Columbia Utilities Commission (BCUC), of rates for the fiscal 2022 (F2022) test period (Test Period) (Application).

The Application contains several requests, including a request for approval of interim and permanent rates reflecting a 1.16 percent general rate increase and changes to the Open Access Transmission Tariff (OATT) rates effective April 1, 2021.[1]

In the Application, BC Hydro also requests certain information in the Application be held on a confidential basis due to the customer-specific and/or commercially sensitive nature of the information. Regarding certain information related to Mandatory Reliability Standards (MRS), BC Hydro requests this information be available only to the BCUC due to the highly security sensitive nature of the information.[2]

Unlike previous RRAs, the F2022 RRA was filed for a one-year test period as a result of the submissions made during the F2020 to F2021 RRA proceeding (Previous RRA Proceeding). The BCUC had expressed a desire to realign the timing of BC Hydro's RRAs, so that the applications can be submitted earlier to allow for sufficient remaining time in the period under review to facilitate BC Hydro's implementation of directives within that period. The BCUC thus directed BC Hydro to file a one-year "gap year" RRA for F2022 by December 2020, to be reviewed through a streamlined process.[3] Streamlining the F2022 RRA process will facilitate the new regulatory cycle commencing with the next RRA (F2023 RRA),[4] which BC Hydro expects to file in August 2021.[5]

1.2 The Applicant

BC Hydro is a Crown corporation established under the *Hydro and Power Authority Act* and its owner and sole shareholder is the Government of British Columbia (B.C.).[6] The organization is one of the largest energy suppliers in Canada, generating and delivering electricity to 95 percent of B.C.'s population and serving over 4 million people.[7]

BC Hydro's mission is to safely provide customers with reliable, affordable and clean electricity throughout B.C. This mission recognizes BC Hydro's responsibility to keep rate increases as low as possible, especially given the economic challenges caused by the COVID-19 pandemic. At the same time, BC Hydro states the importance of ongoing investment for safe, reliable and cost-effective service now and in the future.[8]

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[1] Exhibit B-2, pp. 1-1, 1-17.

[2] Exhibit B-2, Cover Letter, pp. 1–2.

[3] BC Hydro F2020 to F2021 RRA, BCUC Decision, pp. (iii), 185.

[4] BC Hydro expects its Fiscal 2023 RRA to cover multiple years. In the proceeding to review BC Hydro's Performance Based Regulation Report, BC Hydro proposed a three-year test period, covering fiscal years 2023 to 2025.

[5] Exhibit B-2, p. 1-2.

[6] Exhibit B-2, p. 1-1.

[7] Exhibit B-2-2, Appendix Q, "British Columbia Hydro and Power Authority 2021/22–2023/24 Service Plan," p. 5.

[8] Exhibit B-2, p. 1-1.

1.3 Approvals Sought

BC Hydro outlined its original approvals sought in Section 1.4 of the Application. An additional approval concerning the establishment of a regulatory account to capture any variances between the actual and forecast F2022 return on equity amount was sought and later withdrawn.[9] Another additional approval sought concerning the depreciation rates used for electric vehicle charging stations was added subsequent to BC Hydro's filing of responses to Review Session undertakings.[10] The final approvals sought are listed in the table below, along with the reference to sections of this Decision where the Panel addresses and makes determinations on the various requests:

Table 1: Approvals Sought

Approval Sought	Location in this Decision
Approve a permanent general rate increase of 1.16 percent, effective April 1, 2021, for F2022, as set out in Appendix Y, Table 1 of the Application.	Section 3.0
Approve changes to BC Hydro's OATT rates, as set out in Chapter 9, Table 9-4 and Appendix Y, Table 2 of the Application, effective April 1, 2021.	Section 4.8.1
Recover the balances in the Cost of Energy Variance Accounts through the Deferral Account Rate Rider (DARR) using the DARR table mechanism as described in Chapter 7, Section 7.2.1.2 of the Application; specifically, starting in F2022 and on an ongoing basis, set the DARR percentage effective April 1 of a given year based on the percentage in the DARR table mechanism corresponding to the forecast net balance of the Cost of Energy Variance Accounts at the end of the preceding fiscal year. Following this approach, the DARR percentage would be set at 0 percent as of April 1, 2021 for F2022.	Section 4.5.1
Defer the variances arising in F2022 as a result of any changes determined in the depreciation study to the Amortization of Capital Additions Regulatory Account, with interest charges and recovery of these amounts being on the same basis as previously approved for this account.	Section 4.5.2
Continue to defer any variances between forecast and actual dismantling costs in F2022 to the Dismantling Cost Regulatory Account; continue to apply interest to the balance of the account each year based on BC Hydro's current weighted average cost of debt; continue to recover the forecast interest charged to the account each year from the account each year; and continue to recover the forecast account balance at the end of a test period over the next test period.	Section 4.5.3
Recover amounts deferred to the Project Write-off Costs Regulatory Account in respect of completed fiscal years over the next test period, starting in F2022 and on an ongoing basis, subject to BCUC review and approval of the recovery of these amounts; apply interest to the balance of the account based on BC Hydro's current weighted average cost of debt; and, recover actual interest charged to the account for amounts related to any completed fiscal years over the next test period.	Section 4.5.3

[9] Exhibit B-4, BCUC IR 60.1; Exhibit B-11, p. 1; BC Hydro Reply Argument, Part Eight: Other Revenue Requirements, p. 36.
[10] Exhibit B-9, BC Hydro Undertaking No. 19, pp. 2 to 3.

Establish an Electric Vehicle Costs Regulatory Account to defer any actual operating costs, amortization, and cost of energy amounts related to electric vehicle charging stations that meet the definition of a prescribed undertaking under the Greenhouse Gas Reduction Regulation (GGRR) for F2020 and F2021; apply interest to the balance of the account based on BC Hydro's current weighted average cost of debt and recover the forecast interest charged to the account each year from the account each year; and, starting in F2022, recover the forecast balance at the end of a test period over the next test period, until such time that the actual amounts deferred to the account for F2020 and F2021 are recovered in rates.	Section 4.9.2.1
Close the Rock Bay Remediation Regulatory Account at the end of F2022.	Section 4.5.3
Set depreciation rates of certain property, plant and equipment at the Burrard synchronous condense facility for F2022 as set out in Chapter 8, Table 8-2, and as described in Chapter 8, Section 8.2.1 of the Application.	Section 4.9.1
Set depreciation rates for electric vehicle charging stations, as set out in Undertaking No. 19.	Section 4.9.2.2
Amortize the assets within the infrastructure rights asset class over a 35-year useful life, as described in Chapter 8, Section 8.2.2 of the Application.	Section 4.9.1
Pursuant to section 44.2 of the *Utilities Commission Act,* accept the proposed Demand Side Management (DSM) expenditure schedule of $82.2 million, as set out in Chapter 10 of the Application.	Section 4.6.1

1.4 Regulatory Process and Participants

On December 18, 2020, the BCUC established and subsequently amended the regulatory timetable for the review of the Application, which included intervener registration, one round of information requests (IR), a Review Session, BC Hydro's Review Session Undertakings, and final and reply arguments.[11]

By order dated January 5, 2021, the BCUC, among other things, approved on an interim basis the requested rate increase of 1.16 percent and the requested F2022 OATT rates, effective April 1, 2021.[12]

On March 4, 2021, BC Hydro held its web-based Review Session to introduce and present the Application and provide the registered interveners and the BCUC with an opportunity to ask follow-up questions to issues arising in the presentation and to the IRs that had been previously answered in the proceeding. The Review Session continued on March 5, 2021 as the agenda had not been covered in full the previous day. The participants included BC Hydro and registered interveners who wished to participate. The confidential matters of the Application were addressed during the in-camera session that followed the main session. The entire Review Session was transcribed, and the non-confidential parts of the transcripts were made available to the public on the proceeding's webpage.

[11] Exhibit A-2, Order G-345-20; Exhibit A-6, Order G-91-21.
[12] Exhibit A-3, Order G-1-21.

Requests for access to confidential information were not received by the BCUC during the course of the proceeding.

There were thirteen registered interveners and one interested party to this proceeding. The registered interveners were:

- BC Sustainable Energy Association (BCSEA);
- Movement of United Professionals (MoveUP);
- Kwadacha Nation and Tsay Keh Dene Nation, together the Zone II Ratepayers Group (Zone II RPG);
- FortisBC Energy Inc. and FortisBC Inc. (FortisBC);
- Randal Hadland (Hadland);
- Roger Bryenton (Bryenton);
- Richard McCandless (McCandless);
- Residential Customer Intervener Association (RCIA);
- Commercial Energy Consumers Association of British Columbia (CEC);
- Clean Energy Association of B.C. (CEABC);
- Association of Major Power Customers of British Columbia (AMPC);
- British Columbia Old Age Pensioners' Organization et al. (BCOAPO); and
- Canadian Manufacturers and Exporters (CM&E).

The BCUC also received 7 letters of comment from members of the public.

1.5 Decision Framework

The remaining sections of the Decision are organized into 3 sections. First, Section 2.0 outlines the legal and legislative framework relevant to the Application. Section 3.0 provides an overview of the rate changes requested in the Application and the Panel's determination. Finally, Section 4.0 discusses the key issues in the Application and generally follows the organization of the Application, as follows:

- Section 4.1 discusses the load forecast, which includes discussion of the accuracy to date of the COVID-19 Scenario A load forecast, changes to the load forecast methodology compared to the October 2018 load forecast presented in the Previous RRA, and issues raised regarding the load forecast beyond the Test Period;
- Section 4.2 discusses cost of energy, which includes discussion of the cost of energy components and the difference between the forecast costs previously approved for F2021 and the forecast actual costs for F2021;
- Section 4.3 discusses operating costs, which includes discussion of cybersecurity, vegetation management and the discount rate used for current pension service costs;
- Section 4.4 discusses capital costs, in particular the forecast capital additions and expenditures, the cancellation of the Asset Investment Planning Tool project, and the currency date of the capital plan and budget;

- Section 4.5 discusses the regulatory account changes requested in the Application, other than the Electric Vehicle Costs Regulatory Account;
- Section 4.6 discusses the DSM expenditure schedule requested for acceptance in the Application, as well as the concern raised by Zone II RPG regarding the delays in implementing DSM in the Non-Integrated Area;
- Section 4.7 discusses BC Hydro's electrification plan and the Low Carbon Electrification programs;
- Section 4.8 discusses the Transmission Revenue Requirement and the Open Access Transmission Tariff, as well as a concern raised by BCOAPO regarding the interconnection revenues forecast; and
- Section 4.9 discusses the depreciation rates requested in the Application, requests and issues raised regarding BC Hydro's EV charging stations, and concerns raised by AMPC regarding BC Hydro's debt management strategy.

2.0 Legal and Legislative Framework

The BCUC is generally guided by the details and the limitations set out in various legislation pertaining to BC Hydro, including the *Hydro and Power Authority Act*, the *Clean Energy Act* (CEA), and the *Utilities Commission Act* (UCA) including relevant regulations. Although, some regulations continue to have an impact on this Application, others that may have been relevant to the Previous RRA have no impact on BC Hydro's current Test Period.

Hydro and Power Authority Act

BC Hydro explains that it acts as an agent of the Government of B.C. and reports to the Government through the Minister of Energy, Mines, and Low Carbon Innovation and that the Minister of Finance is the fiscal agent of BC Hydro. [13] The *Hydro and Power Authority Act* also sets out certain provisions of the UCA that are not applicable to BC Hydro, including restraint of capital and the adequacy requirements for BC Hydro's long term resource and conservation planning.[14]

Clean Energy Act

BC Hydro states that sections 2, 7, 8, and 18 of the CEA continue to have direct relevance for its RRAs before the BCUC. These include considerations for British Columbia's energy objectives; certain BC Hydro projects, programs, contracts and expenditures that are exempt from BCUC review; and the allowances for BC Hydro to collect sufficient revenue to recover costs incurred for implementing prescribed undertakings.[15]

The Greenhouse Gas Reduction Regulation (GGRR) sets out various classes of prescribed undertakings, including low carbon electrification infrastructure projects, low carbon electrification programs and expenditures, and electric vehicle charging stations.

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[13] Exhibit B-2, p. 2-2.

[14] Exhibit B-2, p. 2-6.

[15] Exhibit B-2, p. 2-5; Prescribed undertakings are projects, programs, contracts or expenditures prescribed for the purpose of reducing greenhouse gas emissions in BC, as defined in the *Greenhouse Gas Reduction Regulation*.

Since the Previous RRA was filed with the BCUC, BC Hydro states there has been a change to the CEA in that the concept of expenditures for export has been removed, therefore the BCUC must refrain from considering expenditures for export when setting BC Hydro's rates. This change continues the effect of section 6 of Direction No. 8 to the BCUC.[16]

Utilities Commission Act

BC Hydro states that there have been three additions to the UCA since the Previous RRA was filed with the BCUC:

- Section 1(2), which states that the UCA does not apply to Powerex Corp. (Powerex). This change is reflected in section 8 of Direction No. 8 to the BCUC;
- Section 44.1 (2.1), which states that BC Hydro does not need to file a long-term resource plan before February 28, 2021; and
- Section 58.1, which states that the BCUC may not set rates for BC Hydro for the purpose of changing the revenue-cost ratio for a class of customers except on application by BC Hydro. This change was reflected in section 5 of Direction No. 8 to the BCUC.

BC Hydro submits that sections 5, 6, and 8 of Direction No. 8 to the BCUC continue to be in effect.[17]

Other Regulations

In the Application, BC Hydro also provides a table, spanning over six pages, summarizing all the regulations in effect or that have been amended to impact its revenue requirements in the Test Period.[18] Details of these regulations can be found in Table 2-1 starting on page 2-7 of the Application.

Subsequent Amendments

On March 29, 2021, subsequent to the close of evidence in this proceeding, BC Hydro filed a letter[19] with the BCUC with respect to new amendments to Direction No. 8 to the BCUC, (Order in Council No. 172) deposited March 22, 2021. BC Hydro states that the amendments to Direction No. 8 are relevant to two items in this proceeding, however none of which has an impact to the proposed F2022 revenue requirements. In particular:

a) Section 3 of Direction No. 8 has been amended so that, for F2022 and F2023, the BCUC must set rates to allow BC Hydro to collect sufficient revenue in each fiscal year to enable BC Hydro to achieve an annual rate of return on deemed equity that would yield a distributable surplus of $712 million. BC Hydro had already included this $712 million in its forecast revenue requirement.

b) In setting rates for BC Hydro, the BCUC must subtract from the costs to be recovered in rates, an amount equal to the net incomes, for the fiscal year, of Powerex Corp. and Powertech Labs Inc., as forecast by BC Hydro for that fiscal year. BC Hydro states that its forecast revenue requirement in the Application is already consistent with this direction.

[16] Exhibit B-2, p. 2-6.
[17] Exhibit B-2, pp. 2-4 to 2-5.
[18] Exhibit B-2, Table 2-1, pp. 2-7 to 2-12.
[19] Exhibit B-11.

3.0 Overall Determination on Rates

In the Application, BC Hydro requests approval for the following rate changes:

- A general rate increase of 1.16 percent, effective April 1, 2021, for F2022; and
- F2022 OATT rates, effective April 1, 2021, as set out in Table 9-4 of the Application.

For the reasons laid out in Section 4.0 of this Decision, the Panel finds BC Hydro's forecast revenue requirement for the F2022 test period to be reasonable, with the exception of certain components of the revenue requirement as identified and discussed in the remainder of this Decision.

Therefore, the Panel approves the requested rates, subject to the adjustments resulting from the determinations and directives contained in this Decision.

BC Hydro is directed to re-calculate its revenue requirements based on the Panel's determinations in this Decision, in a compliance filing within 30 days of this Decision (Compliance Filing). BC Hydro is directed to include in its Compliance Filing, a revised Appendix A to the Application and updated rate schedules, reflecting the BCUC's Decision and accompanying Order. The Panel further directs BC Hydro to file a copy of this Compliance Filing and any responses to BCUC staff questions related to the Compliance Filing in the proceeding to review BC Hydro's F2023 RRA, either as an appendix to the RRA or as a separate exhibit.

4.0 Revenue Requirement – Key Issues

The Panel reviews BC Hydro's revenue requirement components to determine whether the forecasts presented are reasonable within the context of the Test Period and the legislative parameters as outlined in Section 2.0 of the Decision, and whether the approvals sought will support just and reasonable rates, as required by sections 59 and 60 of the UCA.

When setting the Test Period rates, certain B.C. Government directions and legislation give little or no discretion to the BCUC and even though these items form part of BC Hydro's revenue requirements for the Test Period, the Panel must approve them in accordance with the applicable Government directions and legislation. The relevant Government directions and legislation are discussed throughout the Decision as they arise in the sections below.

The requested rates reflect a total revenue requirement of $5,211.7 million for F2022.[20] BC Hydro submits the F2022 revenue requirements forecast is "characterized by continuity from the Fiscal 2020 to Fiscal 2021 RRA in most areas" and "reflects ongoing fiscal discipline and targeted investment in system reliability and resilience."[21]

[20] Exhibit B-2-2, Appendix A, Schedule 1.0, Line 34.

[21] BC Hydro Final Argument, p. 1.

4.1 Load Forecast

BC Hydro seeks approval of the Test Period revenue requirement based on its COVID-19 Scenario A load forecast. The F2022 load forecast is shown below:[22]

Figure 1: F2022 Load Forecast

Line		F2017 Actual	F2018 Actual	F2019 Actual	F2020 RRA	F2020 Actual	F2020 Diff	F2021 RRA	F2021 Forecast	F2021 Diff	F2022 Plan
	Column	1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
	Domestic Energy Sales (GWh)										
1	Residential	18,068	18,150	18,000	17,751	17,993	242	17,927	18,765	837	18,856
2	Light Industrial and Commercial	18,968	18,874	19,007	18,631	18,692	60	18,744	17,908	(836)	18,909
3	Large Industrial	13,176	13,433	13,874	13,527	13,383	(145)	13,203	12,033	(1,170)	12,982
4	Irrigation	80	79	79	97	72	(25)	99	73	(27)	79
5	Street Lighting	232	229	225	288	212	(76)	291	223	(68)	213
6	New Westminster & Tongass	464	466	463	585	465	(120)	591	481	(110)	497
7	Fortis	589	551	435	683	586	(97)	695	667	(28)	602
8	Seattle City Light	318	312	309	389	307	(82)	388	310	(78)	310
9	Liquefied Natural Gas	0	6	22	6	16	9	0	0	0	0
10	Other				0	205	205	0	0	0	0
11	Total	51,895	52,102	52,413	51,958	51,931	(27)	51,940	50,459	(1,481)	52,448

BC Hydro prepared a comprehensive 20-year load forecast (the March 2020 Load Forecast) over the winter of 2019 and spring of 2020. The March 2020 Load Forecast was completed prior to the onset of impacts associated with the COVID-19 pandemic. [23] To address those potential impacts, BC Hydro subsequently developed two scenarios in April 2020 that were used to inform decisions based on two potential outcomes, referred to as COVID-19 Scenario A and COVID-19 Scenario B. Scenario A is 3 percent below the March 2020 Load Forecast for F2022, and Scenario B is 13 percent below the March 2020 Load Forecast for F2022.[24] The figure below, replicated from the Application, explains the timeline and key assumptions of the two COVID-19 Scenarios:[25]

Figure 2: Timeline and Key Assumptions for Covid-19 Scenarios A and B

<table>
<tr><td></td><td colspan="12">Fiscal 2021</td><td colspan="12">Fiscal 2022</td><td colspan="12">Fiscal 2023</td></tr>
<tr><td></td><td>Apr</td><td>May</td><td>Jun</td><td>Jul</td><td>Aug</td><td>Sep</td><td>Oct</td><td>Nov</td><td>Dec</td><td>Jan</td><td>Feb</td><td>Mar</td><td>Apr</td><td>May</td><td>Jun</td><td>Jul</td><td>Aug</td><td>Sep</td><td>Oct</td><td>Nov</td><td>Dec</td><td>Jan</td><td>Feb</td><td>Mar</td><td>Apr</td><td>May</td><td>Jun</td><td>Jul</td><td>Aug</td><td>Sep</td><td>Oct</td><td>Nov</td><td>Dec</td><td>Jan</td><td>Feb</td><td>Mar</td></tr>
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<tr><td>A</td><td colspan="2">Measures</td><td colspan="7">Slow Recovery</td><td colspan="27">Revised Long Term Projection</td></tr>
<tr><td>B</td><td colspan="5">Measures</td><td colspan="12">Targeted Measures</td><td colspan="7">Slower Recovery</td><td colspan="12">Revised Long Term Projection</td></tr>
</table>

BC Hydro's load forecast methodology is further explained in Appendix D to the Application and in response to BCUC IR 10.1 series.

4.1.1 Accuracy to date of COVID-19 Scenario A

The COVID-19 Scenario A load forecast is 0.7 percent higher than the actual load between April 2020 to January 31, 2021, with the residential actual load being 1 percent below forecast, commercial & light industrial actual load being 2.3 percent above forecast, and the large industrial actual load being 1.1 percent above forecast.[26]

[22] Exhibit B-2-2, Appendix A, Schedule 14.0.

[23] Exhibit B-2, p. 3-1.

[24] Exhibit B-2, p. 3-8.

[25] Exhibit B-2, Figure 3-3, p. 3-7.

[26] Exhibit B-5, Zone II RPG IR 3.1.

Table 2: Covid-19 Scenario A Load Forecast

	Apr. 2020	May 2020	Jun 2020	Jul. 2020	Aug. 2020	Sep. 2020	Oct. 2020	Nov. 2020	Dec. 2020	Jan. 2021	F2021 10 Months YTD
Actuals vs COVID-19 Scenario A (GWh)	(98)	(52)	79	63	40	83	164	82	(294)	221	288
Residential	(131)	(69)	4	21	57	57	118	26	(285)	46	(157)
Commercial & Light Industrial	49	35	84	74	(4)	99	54	(7)	(122)	70	331
Large Industrial	(16)	(17)	(9)	(32)	(12)	(74)	(8)	64	113	106	114
Actuals vs COVID-19 Scenario A (%)	(2.5)	(1.4)	2.2	1.7	1.1	2.4	4.2	1.9	(5.7)	4.7	0.7
Residential	(8.2)	(5.2)	0.3	1.7	4.8	5.0	8.4	1.4	(12.0)	2.3	(1.0)
Commercial & Light Industrial	3.8	2.8	6.5	5.3	(0.3)	7.3	3.7	(0.5)	(7.0)	4.3	2.3
Large Industrial	(1.6)	(1.7)	(0.9)	(3.1)	(1.2)	(7.4)	(0.8)	6.4	11.0	10.3	1.1

Positions of Parties

BC Hydro submits in its Final Argument that the high degree of uncertainty in F2022, and the existence of a regulatory account to capture variances, also means there is limited, if any, benefit from updating the forecast.[27] The BCUC should find that COVID-19 Scenario A is an appropriate basis for setting rates in F2022.[28]

None of the interveners raised any issues with BC Hydro's load forecast for setting rates for F2022.

Panel Determination

The Panel accepts the load forecast filed by BC Hydro and finds it appropriate to use COVID-19 Scenario A as a basis for setting permanent rates for F2022.

There is uncertainty at the best of times when predicting load and the COVID-19 pandemic exacerbates this uncertainty. While, as BC Hydro points out, the deferral account does help to mitigate potential variances, in times of extreme variance such an account can be a source of intergenerational inequity.

That said, there is no evidence available to the Panel of a more accurate forecast. The COVID-19 Scenario A load forecast is 0.7 percent higher than the actual load between April 2020 to January 31, 2021. The forecast over-predicted residential demand by about 1 percent while under forecasting commercial and industrial classes demand. The COVID-19 Scenario A forecast is also 3 percent below the pre-pandemic F2022 forecast. Given the course of the pandemic, the Panel considers that there is a likelihood that F2022 demand will increase, at least somewhat, over F2021, although it may be unlikely to achieve the pre-pandemic forecast.

[27] BC Hydro Final Argument, p. 12.
[28] BC Hydro Final Argument, p. 12.

If the COVID-19 Scenario A forecast were to be adjusted down for F2022, the result, all else equal, would be an increase in the F2022 rate. The Panel does not consider that the likelihood of a continued reduction in demand, compared to the forecast, warrants such an adjustment.

4.1.2 Changes from the October 2018 load forecast presented in the F2020 to F2021 RRA

In this section, changes from the October 2018 load forecast that was presented in the Previous RRA are discussed. These changes include the load forecasting methodology for codes and standards, electric vehicles and uncertainty bands. This section also discusses the improvements to BC Hydro's load forecasting methodology planned for F2022.

Codes and Standards

BC Hydro's load forecast methodology includes adjustments to account for the overlap between savings included in BC Hydro's Statistically Adjusted End Use (SAE) model results and savings derived from BC Hydro's DSM Plan. This overlap results because of energy savings from codes and standards that are reflected in both the DSM plan and in the U.S. Energy Information Administration assumptions embedded in the SAE model.[29]

BC Hydro states that in 2019, Navigant Inc. completed an independent review of the overlap in codes and standards in the U.S. Energy Information Administration projections with those within BC Hydro's DSM plan. The review determined that there were some end use technologies that appeared in both the SAE model and the DSM plan. Accordingly, the March 2020 Load Forecast has been adjusted to improve alignment between the two approaches.[30] BC Hydro explains that the effect of this adjustment is an increase in the load forecast.[31] In response to BCUC IR 10.2, BC Hydro shows that the codes overlap adjustment make up 127 GWh out of 18,836 GWh for the residential sector COVID-19 Scenario A load forecast and 92 GWh out of 14,366 GWh for the commercial sector COVID-19 Scenario A load forecast in F2022.[32] BCUC staff calculates that amounts to 0.7 percent[33] and 0.6 percent[34] for the residential and commercial sector F2022 load forecast, respectively. There has been no adjustment to the March 2020 code and standards overlap under COVID-19 Scenario A and COVID-19 Scenario B for F2022.[35]

Electric Vehicles

The March 2020 Load Forecast uses a new methodology for Electric Vehicles (EVs), relative to the October 2018 methodology. This change was implemented to reflect the CleanBC Plan's approach to light-duty EVs; specifically, to incorporate the *Zero-Emission Vehicles Act* (ZEV Act), which was enacted on May 30, 2019. The ZEV Act stipulates percentage targets for new light-duty vehicle sales in B.C. Accordingly, the low-EV scenario in the March 2020 Load Forecast uses these requirements as a floor for EV adoption. In contrast, the high-EV scenario assumes the natural uptake of EVs will be higher than the minimum requirements set out in the ZEV

[29] Exhibit B-2, p. 3-2.
[30] Exhibit B-2, pp. 3-2 to 3-3.
[31] Exhibit B-5, CEABC IR 3.6.
[32] Exhibit B-4, BCUC IR 10.2
[33] 127 GWh / 18,836 GWh = 0.7%.
[34] 92 GWh / 14,366 GWh = 0.6%.
[35] Exhibit B-4, BCUC IR 10.2.

Act, as the purchase costs decline, and consumers' preferences change over time. The reference EV forecast used to develop the revenue forecast for the F2022 RRA is developed by taking the average of the high and low EV forecasts.[36] On the other hand, in the October 2018 Load Forecast, BC Hydro prepared a mid and high EV forecast, but did not prepare an EV low load forecast.[37] BC Hydro states its EV stock turnover model is described in Appendix O of BC Hydro's Previous RRA, and is summarized in response to CEC IR 14.2.[38] An overview of the EV load forecast methodology is provided under Section 9 of Appendix D to the Application.[39]

BC Hydro compares the EV energy forecast between the October 2018 and March 2020 Load Forecasts in the table below: [40]

Table 3: October 2018 and March 2020 EV Load Forecasts

The table below shows the October 2018 and March 2020 Electric Vehicle (EV) stock and load forecasts and their associated variances.

Fiscal year	Forecast	EV Stock (No. of vehicles)	EV Energy Forecast (GWh)
F2020	October 2018 Load Forecast	24,299	77
	March 2020 Load Forecast	44,797	114
	March 2020 vs October 2018 (%)	84	49
F2021	October 2018 Load Forecast	32,553	105
	March 2020 Load Forecast	71,996	204
	March 2020 vs October 2018 (%)	121	95
F2022	October 2018 Load Forecast	45,080	146
	March 2020 Load Forecast	109,357	319
	March 2020 vs October 2018 (%)	143	118

In response to BCUC IR 10.2, BC Hydro shows that the EV load addition makes up 271 GWh out of 18,836 GWh for the residential sector COVID-19 Scenario A load forecast and 48 GWh out of 14,366 GWh for the commercial sector COVID-19 Scenario A load forecast in F2022.[41] BCUC staff calculates this amounts to 1.4 percent[42] and 0.3 percent[43] of the residential and commercial sector F2022 load forecast, respectively. There has been no adjustment to the March 2020 EV load addition forecast under COVID-19 Scenario A and COVID-19 Scenario B for F2022.[44]

[36] Exhibit B-2, p. 3-3.
[37] BC Hydro F2020 to F2021 RRA, Exhibit B-1, Appendix O, p. 109.
[38] Exhibit B-5, CEC IR 14.2.
[39] Exhibit B-2-2, Appendix D, pp. 14 to 16.
[40] Exhibit B-5, BCOAPO IR 18.1.
[41] Exhibit B-4, BCUC IR 10.2.
[42] 271 GWh / 18,836 GWh = 1.4%.
[43] 48 GWh/ 14,366 GWh = 0.3%.
[44] Exhibit B-4, BCUC IR 10.2.

Load Forecast Uncertainty Bands

In the October 2018 Load Forecast and prior, BC Hydro used a Monte Carlo model to develop uncertainty bands around the combined distribution and transmission forecasts, and then added the discrete EV high, reference, and low forecasts. BC Hydro describes what it characterizes as an improvement in the March 2020 Load Forecast. This improvement uses a Monte Carlo model to develop the uncertainty bands around the distribution load only and uses discrete high and low cases for transmission load, to fully capture the load variability within the large industrial sector.[45] BC Hydro states the new approach creates asymmetrical uncertainty bands around the energy and peak reference forecasts and also widens the bands.[46]

Planned Improvements to the Load Forecast Methodology

BC Hydro states it continues to evaluate and improve its methods and processes, with a focus on load forecast performance. Some of the improvements planned for F2022 include:[47]

- Conducting a review of processes and models for the large industrial forestry sub-sector;
- Developing and implementing a new EV model, which expands the forecasting capability to include medium and heavy-duty vehicles;
- Implementing a residential stock and flow model of B.C. specific end-use efficiency projections, to be used in conjunction with our current SAE models;
- Improving BC Hydro's understanding of DSM code & standards overlap and DSM persistence versus what may already be accounted for in BC Hydro's SAE models;
- Expanding research using smart meter infrastructure data to potentially develop more granular forecast methods within the diverse commercial sector; and
- Reviewing BC Hydro's Monte Carlo model and uncertainty band performance and improvements.

BC Hydro states detailed work planning for the Load Forecast department that normally takes place through to March of each year is not yet complete. While it has identified six areas of improvement it plans to incorporate into future forecasts, their timing will depend on the higher priority resource demands to produce new forecasts, updates, scenarios, and support internal groups. BC Hydro notes that it will base its F2023 RRA on its most recent December 2020 Load Forecast. The results of these improvement activities will be incorporated into future load forecast cycles.[48]

Panel Determination

The Panel appreciates the initiative by BC Hydro to improve its load forecasting methodology. We note that one result of this improvement, widening the uncertainty bands, underlines the variability potential of the load.

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[45] Exhibit B-2, pp. 3-3 to 3-4.
[46] Exhibit B-2, p. 3-5.
[47] Exhibit B-2, p. 3-5.
[48] Exhibit B-4, BCUC IR 9.1.

No intervener commented specifically on this load forecasting methodology change and no IRs explored it further. In particular, there is no evidence available to the Panel concerning how much more accurate the forecast is, or whether that accuracy is statistically significant. It is our view, that given the inherent uncertainties and errors related to forecast modelling, where possible, models should be back tested. Back-testing provides an assessment of the predictive power of a model.

For this reason, BC Hydro is directed to back-test and compare whether developing uncertainty bands around the distribution load only and using discrete high and low cases for transmission load versus the previous methodology improved the accuracy of its large industrial load forecast. BC Hydro is further directed to provide the results of the back-test run over the five previous load forecasts to the BCUC by December 31, 2021.

A breakdown of the difference between the low, mid, and high EV forecast for F2022 is not available in evidence. In the Previous RRA, BC Hydro explained that it believes there is an asymmetrical risk (i.e., there is more upside potential than downside) for future EV stock and load, and attributed its beliefs to a number of factors, including the introduction of the CleanBC plan, the ZEV legislation as part of the CleanBC Plan, the federal government's introduction of a new EV incentive program, and the Government of B.C.'s additional $41.5 million toward a rebate program for the purchase of eligible EVs after the October 2018 load forecast was finalized.[49] The BCUC encouraged BC Hydro to closely monitor the impact of government policy on emission reduction, customer uptake on government incentives and any impact conservation and efficiency may have on the EV forecast in preparing its future load forecasts.[50] We encourage BC Hydro to provide further commentary on the impact of government policy on EV load in the F2023 RRA.

The Panel appreciates the breakout of the EV energy forecast. However, it would be helpful if there was some historical context provided. **Therefore, BC Hydro is directed to provide the historical actuals or estimated actuals related to EV energy consumption over the five previous load forecasts (i.e. F2017 to F2021) in the F2023 RRA.**

4.1.3 Load Forecast Beyond the Test Period

CEABC is concerned that the March 2020 Load Forecast used for this Application excludes much of the necessary electrification loads required to achieve the greenhouse gas (GHG) reduction goals targeted by the Government in its CleanBC Plan. CEABC submits BC Hydro's March 2020 Load Forecast only includes the first level of electrification activities, captioned "Load Forecast – Reference case."[51] CEABC looks forward to BC Hydro being able to incorporate the Navius findings as soon as possible, as the Reference Case in all of its future activities and plans, including its F2023 RRA, and certainly in its Integrated Resource Plan (IRP) due to be filed for review in December 2021.[52]

CEABC is also concerned that both adjustment scenarios are predicting a persistent reduction that extends to F2024 and F2025. It is only about a 1 percent decline in overall combined load, but it is all confined to the Large

[49] BC Hydro F2020 to 2021 RRA, BCUC Decision, p. 18.
[50] BC Hydro F2020 to 2021 RRA, BCUC Decision, p. 19.
[51] CEABC Final Argument, p. 3.
[52] CEABC Final Argument, p. 5.

Industrial sector, where it constitutes almost a 5 percent reduction. This is a very significant predicted reduction and CEABC suggests that it should be thoroughly examined in the F2023 RRA.[53]

In reply, BC Hydro submits that CEABC is focused primarily on load forecasting over the longer term. In 2020, BC Hydro completed a comprehensive load forecast update. This forecast, the December 2020 Load Forecast, will be provided in the F2023 RRA and the 2021 IRP. BC Hydro's electrification plan will also be included in the F2023 RRA. BC Hydro further submits its long-term load forecast, and its alignment with the long-term goals of the CleanBC plan, are best addressed as part of the review of BC Hydro's 2021 IRP.[54]

AMPC points out that this RRA process was structured to readjust the overall general BC Hydro rate review schedule. It supports this scheduling effort because "rate changes should be tested before occurring and announced with sufficient notice to allow customer planning. Broad use of interim rates introduces uncertainty to customer finances and operations."[55] However, AMPC further submits that "[e]lectricity is a significant portion of AMPC members' operating expenses, and changes in electricity pricing drive business planning and process adjustments. AMPC accordingly requests BC Hydro to return to its past practices of providing 10-year load and rate forecasts. This will help support large customers' business and capital planning processes."[56]

Panel Discussion

The F2022 load forecast has been subject to limited review, due to the somewhat truncated regulatory process used for this "gap year." For example, we have not reviewed the effect of weather normalization when comparing actual usage during the previous "pandemic year."

We note the submissions of AMPC and CEABC with regard to a more comprehensive load forecast. While we are of the view that the lack of such a forecast should not delay the approval of this Application, we agree with the value of such a forecast in the F2023 RRA and we encourage BC Hydro to provide a more comprehensive load forecast for the F2023 RRA to provide better context for the review of that application.

The Previous RRA Decision included the following directives regarding items for BC Hydro to address in the F2023 RRA:

- Directive 2: The Panel directs BC Hydro to provide in the fiscal 2023 RRA an analysis of i) any difference in elasticity between nominal versus real changes in price in the short-term and ii) any difference in elasticity between a price increase versus a price decrease. (page 13)
- Directive 3: The Panel directs BC Hydro to replicate the Test Period large industrial load forecast using the probability-weighting approach used in the May 2016 load forecast, and to report on how the performance of the Test Period large industrial load forecast compares under the probability weighted approach versus the binary approach in its fiscal 2023 RRA. (page 18)
- Directive 4: The Panel further directs BC Hydro to investigate the source of any load forecast variance for the Test Period and to report on this in the fiscal 2023 RRA, and where possible, clearly distinguish the

[53] CEABC Final Argument, p. 3.
[54] BC Hydro Reply Argument, p. 6.
[55] AMPC Final Argument, p. 1.
[56] AMPC Final Argument, p. 1.

extent of any variance that is attributable to and independent from the COVID-19 pandemic, respectively. (page 21)

The Panel endorses the BCUC directives 2, 3 and 4 from the Previous RRA Decision and nothing in the approvals provided in this Decision change the requirement to file this information as previously directed.

4.2 Cost of Energy

BC Hydro forecasts Cost of Energy of $1,670.1 million in F2022, per the table below:[57]

Table 4: Cost of Energy Forecast (Integrated System and Non-Integrated Areas)

Cost of Energy ($million)	Schedule Reference	F2020 RRA	F2020 Actual	F2021 RRA	F2021 Forecast	F2022 Plan
		1	2	3	4	5
Heritage Energy	4.0 L32	351.2	358.8	317.7	288.6	350.6
Non-Heritage Energy[1]	4.0 L37	1,332.4	1,353.1	1,447.2	1,423.1	1,511.5
Market Energy	4.0 L44	184.4	99.0	(98.4)	(128.1)	(191.9)
Total	4.0 L45	1,867.9	1,810.9	1,666.5	1,583.7	1,670.1

BC Hydro notes customers will only pay the actual costs of energy and not the planned costs. This is because the BCUC has previously approved the Cost of Energy Variance Accounts to capture any variances so that customers only pay for the actual energy costs. Variances between planned and actual costs of energy are deferred to the Heritage Deferral Account, the Non-Heritage Deferral Account, or the Biomass Energy Program Variance Regulatory Account.

BC Hydro states its total F2022 Plan Cost of Energy is effectively unchanged compared to the F2021 Plan.[58] BC Hydro states its Energy Studies methodology has not changed from the methodology used in the Previous RRA other than updates to reflect the 2020 Transfer Pricing Agreement (TPA).[59] Changes related to the 2020 TPA are further elaborated under the Market Energy sub-section below.

The following subsections of the Decision discuss the various components that make up the Cost of Energy, namely Heritage, Non-Heritage and Market Energy.

[57] Exhibit B-2, Table 4-1, p. 4-5.
[58] Exhibit B-2, p. 4-5.
[59] Exhibit B-2, p. 4-4.

4.2.1 Cost of Energy Components

4.2.1.1 Heritage Energy

Table 5: Cost of Heritage Energy[60]

Cost of Heritage Energy ($ million)	Schedule Reference	F2020 RRA	F2020 Actual	F2021 RRA	F2021 Forecast	F2022 Plan
		1	2	3	4	5
Water Rentals	4.0 L27	329.3	331.6	323.2	331.0	375.4
Natural Gas for Thermal Generation	4.0 L28	7.5	7.1	8.5	8.2	11.8
Domestic Transmission - Other	4.0 L29	24.5	24.8	24.4	25.7	25.5
Columbia River Treaty Related Agreements	4.0 L30	15.0	37.7	(11.7)	(34.2)	(19.0)
Remissions and Other	4.0 L31	(25.2)	(42.4)	(26.7)	(42.1)	(43.2)
Total	4.0 L32	351.2	358.8	317.7	288.6	350.6

BC Hydro forecasts increases to Heritage Energy costs of $32.9 million, primarily related to Water Rentals. Total water rental fees are forecast to increase by $52.2 million in the F2022 Plan compared to the F2021 Plan, mainly due to higher hydro generation volumes in calendar year 2020 as a result of high inflows in the Peace and Columbia regions.[61]

On the other hand, BC Hydro forecasts higher planned revenue in the F2022 Plan than the F2021 Plan from the Non-Treaty Storage Agreement and a short-term coordination agreement related to the Libby Coordination Agreement related to the operation of the Columbia River Treaty reservoirs in Canada.[62] BC Hydro elaborates that when BC Hydro releases water from its Non-Treaty account, Bonneville Power Administration (Bonneville) will see extra generation at the Federal projects in the U.S. downstream on the Columbia River. As a result, Bonneville credits BC Hydro for the incremental energy valued at the Mid-C market price at the time of release.[63]

BC Hydro explains the higher planned revenue in the F2022 Plan is due to the lower amount of planned storage in F2022, which is due to a higher starting account balance at the beginning of F2022.[64] The F2021 forecast revenue is higher than the F2021 Plan for the same reason.[65] BC Hydro explains that the storage and release decisions under the coordination agreements will vary each year due to changes in market prices, operational constraints, and the initial volume in the accounts at the beginning of the year. BC Hydro further explains forecasts of the coordination agreement storage balances are produced through BC Hydro's monthly Energy Studies process, which optimizes the operation of the storage flexibility provided under these agreements, considering a range of market prices, inflows, and constraints. The price forecast is a key driver of the forecast storage balances. The Energy Studies methodology for forecasting the coordination agreements operations has

[60] Exhibit B-2, Table 4-2, p. 4-6.
[61] Exhibit B-2, p. 4-7.
[62] Exhibit B-2, p. 4-9.
[63] Exhibit B-5, CEABC IR 12.2.
[64] Exhibit B-2, p. 4-9; Exhibit B-4, BCUC IR 14.1.
[65] Exhibit B-2, p. 4-9.

not changed since the Previous RRA and was reviewed as part of a 2018 Internal Audit of the Energy Studies, which was provided in Appendix DD to the Previous RRA.[66]

BC Hydro states the *Water Sustainability Act* specifies remissions that are available to be applied against water rental payments. These remissions are compensation for restrictions or regulations imposed on the licensee arising from water use plans. The re-development project at John Hart and the anticipated water license renewal at Bridge River were expected to result in a decrease to BC Hydro's eligibility for remissions at the time that the F2021 Plan was prepared. However, remissions for these projects were subsequently approved by the Government of B.C. and therefore are included in the total remissions planned for F2022.[67]

4.2.1.2 Non-Heritage Energy

Table 6: Cost of Non-Heritage Energy[68]

Cost of Heritage Energy ($ million)	Schedule Reference	F2020 RRA	F2020 Actual	F2021 RRA	F2021 Forecast	F2022 Plan
		1	2	3	4	5
IPPs and Long-Term Commitments¹	4.0 L33	1,294.7	1,314.0	1,410.8	1,388.7	1,475.7
Non-Integrated Area	4.0 L34	30.5	31.3	30.2	26.1	27.4
Gas & Other Transportation	4.0 L35	3.7	4.5	2.5	5.2	4.9
Water Rentals (Waneta 2/3)	4.0 L36	3.7	3.3	3.7	3.2	3.5
Total	4.0 L37	1,332.4	1,353.1	1,447.2	1,423.1	1,511.5

BC Hydro further provides a breakdown of the independent power producer (IPP) and Long-Term Commitments line item in the table above by call process in Table 4-6 of the Application.[69]

BC Hydro states the forecast increases to Non-Heritage Energy costs of $64.3 million are primarily related to IPPs and Long-Term Commitments. BC Hydro explains the increase in cost is primarily associated with existing EPAs, with increased forecast energy deliveries as permitted under existing agreements, and new IPP projects under existing EPAs reaching commercial operation.[70]

In terms of IPP contracts, BC Hydro states it does not have any active programs for the procurement of new energy resources from IPPs. Other than Biomass Energy Program renewal electricity purchase agreements (EPAs), the only other EPA renewals to be filed with the BCUC as of the date of the Application and the end of the Test Period are the Hluely Lake EPA renewal (for the Dease Lake Non-Integrated Area) and potentially an EPA renewal for a small run-of-river hydro project. BC Hydro also expects a small number of potential new First Nations energy projects, including two potential EPAs remaining from the Standing Offer Program that are part of Impact Benefit Agreements with BC Hydro and/or are mature projects that have significant First Nations involvement.[71]

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[66] Exhibit B-2, p. 4-4.
[67] Exhibit B-2, p. 4-10.
[68] Exhibit B-2, Table 4-5, p. 4-11.
[69] Exhibit B-2, p. 4-13.
[70] Exhibit B-2, p. 4-12.
[71] Exhibit B-2, pp. 4-2 to 4-3.

For variances in the Non-Integrated Area (NIA), BC Hydro explains that energy volumes in the NIA are relatively stable with a slight decrease expected in the F2022 RRA Plan. Variations in costs are largely driven by fluctuations in fuel prices for BC Hydro's diesel generation facilities. Fuel prices are based on the Annual Energy Outlook Report issued by the U.S. Energy Information Administration.[72] To the extent that diesel prices ultimately differ from the forecast prices, the variance will be captured in the Non-Heritage Deferral Account for future recovery from, or refund to, ratepayers.[73]

Total forecast gas and other transportation costs for the F2022 Plan are $4.9 million, an increase of $2.4 million from the F2021 Plan. The increase is largely due to higher costs for certain wheeling agreements, including one wheeling agreement which was not included in the F2021 Plan as the contract had expired and there were no forecast costs for a renewal agreement. This wheeling agreement was renewed in F2020.[74] BC Hydro further provides a breakdown of this cost increase in its confidential response to BCUC IRs 16.1 and 16.2.

4.2.1.3 Market Energy

Table 7: Cost of Market Energy - based on 2003 TPA[75]

Cost of Energy ($ million)	Schedule Reference	F2020 RRA	F2020 Actual	F2021 RRA	F2021 Forecast	F2022 Plan
		1	2	3	4	5
TPA Reference Agreement		**2003 TPA**	**2003 TPA**	**2003 TPA**		
Market Electricity Purchases	4.0 L38	150.6	133.1	43.7		
Surplus Sales	4.0 L39	(0.4)	(1.0)	(165.1)		
Net Purchases (Sales) from Powerex	4.0 L42	33.1	(35.2)	6.1		
Domestic Transmission – Export	4.0 L43	1.1	2.0	17.0		
Total	4.0 L44	184.4	99.0	(98.4)		

Table 8: Cost of Market Energy - based on 2020 TPA[76]

Cost of Energy ($ million)	Schedule Reference	F2020 RRA	F2020 Actual	F2021 RRA - Reclassified	F2021 Forecast	F2022 Plan
		1	2	3	4	5
TPA Reference Agreement				**2020 TPA**	**2020 TPA**	**2020 TPA**
System Imports	4.0 L40			153.9	37.8	77.1
System Exports	4.0 L41			(269.2)	(211.0)	(296.5)
Domestic Transmission – Export	4.0 L43			17.0	45.1	27.5
Total	4.0 L44	0.0	0.0	(98.4)	(128.1)	(191.9)

The costs associated with the use of BC Hydro's transmission system for System Export pursuant to the OATT are referred to as Domestic Transmission – Exports. Under the 2003 TPA, these costs were determined based on the

[72] Exhibit B-2, p. 4-15.

[73] Exhibit B-2, pp. 4-15 to 4-16.

[74] Exhibit B-2, p. 4-16; Exhibit B-4, BCUC IR 16.1.

[75] Exhibit B-2, Table 4-8, p. 4-19.

[76] Exhibit B-2, Table 4-9, p. 4-19.

forecast percentage of Surplus Sales relative to the total of Surplus Sales and trade related sales, using the historical average unit transmission cost for domestic exports. Under the 2020 TPA, since these activities are no longer separated, BC Hydro's forecast annual system surplus relative to forecast System Exports is used in the calculation of BC Hydro's domestic transmission costs. BC Hydro's annual system surplus, which was filed confidentially, is shown below:

Table 9: Annual System Surplus[77]

(GWh)	F2021 RRA	F2021 Forecast	F2022 Plan
Annual System Surplus	[redacted]		

BC Hydro states Market Energy costs have decreased by $93.5 million compared to the F2021 Plan, largely due to lower System Imports and higher System Exports driven by higher water inflows.[78]

Transfer Pricing Agreement

The 2020 TPA came into effect on April 1, 2020, replacing the previous TPA (2003 TPA). BC Hydro has submitted the 2020 TPA to the BCUC under section 71 of the UCA and it was being reviewed through a separate proceeding.[79] However, on March 22, 2021, the Government of British Columbia deposited Order in Council (OIC) No. 172, which amends Direction No. 8 to the BCUC and states, in part, that "[t]he commission may not exercise its powers under section 71 (1) (b) and (3) of the Act in respect of the transfer pricing agreement."

BC Hydro explains the categorization of Market Energy in the Application differs from the Previous RRA due to the 2020 TPA between BC Hydro and Powerex. The classification of energy transactions has changed from "Market Electricity Purchases,"[80] "Surplus Sales,"[81] and "Net Purchase (Sales) from Powerex"[82] under the 2003 TPA, to "System Exports"[83] and "System Imports"[84] under the 2020 TPA.[85] BC Hydro states it is not possible to provide the transactions under the 2020 TPA in the categorization that was used under the 2003 TPA. However, BC Hydro can report on the historic actual system imports/exports divided into flexible and non-flexible (i.e. according to the format in the 2020 TPA) in subsequent RRAs as an additional level of visibility and granularity.[86]

BC Hydro submits there is no difference between the accounting under the 2020 TPA and the 2003 TPA. BC Hydro further submits that "[w]hile transactions under the 2020 TPA are categorized differently than under the

[77] Exhibit B-5-1, BCOAPO IR 24.4.1; BC Hydro explains that publication of the information could be useful for third parties to determine the depth of BC Hydro's energy needs and its potential import and export requirements.
[78] Exhibit B-2, p. 4-19.
[79] Exhibit B-2, p. 4-17.
[80] Represented market purchases of electricity from Powerex by BC Hydro to meet domestic load requirements.
[81] Represented sales of electricity by BC Hydro to Powerex, when BC Hydro generation exceeded domestic load requirements
[82] Represented purchases and sales between BC Hydro and Powerex for the purpose of trade related activities. These were presented on a net basis.
[83] Represents sales of electricity to Powerex by BC Hydro.
[84] Represents purchases of electricity by BC Hydro from Powerex and thermal generation run for Powerex.
[85] Exhibit B-2, pp. 4-16 to 4-17.
[86] Exhibit B-4, BCUC IR 17.1.

2003 TPA, the nature of the transactions has not changed. BC Hydro is still financially accountable for the sale of surplus energy and the purchase of energy to meet domestic load requirements, while Powerex is still financially accountable for purchases and sales to generate Trade Income."[87]

Positions of Parties

BC Hydro states that the Cost of Energy is effectively unchanged compared to the F2021 Plan. Increases in cost of Heritage and Non-Heritage Energy are largely offset by decreases in the cost of Market Energy.[88] BC Hydro submits that its planned Cost of Energy is reasonable and appropriate for the purpose of setting rates for the Test Period.[89]

None of the interveners raised any issues with BC Hydro's cost of energy forecast for setting rates for F2022. Other commentary made by interveners are addressed below.

BCOAPO is concerned about the loss of transparency in terms of BC Hydro's inability to separate out imports/exports made for purposes of trade related activities versus those associated with the sale/purchase of electricity in circumstances where B.C. generation was insufficient to meet/in excess of domestic requirements. Of particular concern is the apparent inability under the 2020 TPA to identify the market purchases of electricity to meet domestic requirements. In BCOAPO's view, reliance on market purchases for domestic supply exposes BC Hydro to additional supply and price risks and it is important to understand these in the context of setting rates.[90] BCOAPO submits that as part of its Decision regarding BC Hydro's F2022 rates, the BCUC should direct BC Hydro to examine ways this information can continue to be provided in future RRAs and/or request that the issue be considered as part of the BCUC's upcoming review of the 2020 TPA.[91]

BC Hydro explains in its Reply Argument that as a result of the 2020 TPA, which came into effect on April 1, 2020, hourly net imports and exports are no longer distinguished as between energy purchases and sales to meet domestic requirements, and energy purchases and sales for Powerex trade activity using the residual system capability (i.e. Trade Account transactions under the 2003 TPA). While the 2020 TPA does not conduct an hourly allocation, it does distinguish between flexible imports/exports and non-flexible imports/exports and sets out how BC Hydro's actual Annual Flexible Surplus/Deficit is determined. BC Hydro can identify the cost of market purchases of electricity to meet domestic requirements based on the 2020 TPA pricing methodology and provide this information based on the actual outcomes in subsequent RRAs.[92]

The RCIA recommends that in future applications, BC Hydro should provide a more comprehensive and quantified explanation of the relationship between increased water rental costs due to above average inflows and the corresponding energy cost offsets resulting from reduced market imports and/or increased market exports enabled by the increased inflows.[93]

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[87] Exhibit B-2, p. 4-18.
[88] BC Hydro Final Argument, p. 13.
[89] BC Hydro Final Argument, p. 13.
[90] BCOAPO Final Argument, p. 24.
[91] BCOAPO Final Argument, p. 25.
[92] BC Hydro Reply Argument, p. 8.
[93] RCIA Final Argument, p. 8.

In BC Hydro's Reply Argument, BC Hydro explains that due to the way water rentals are billed, costs do not occur in the same year as the generation. Water rental fees on the generation of energy are calculated as the actual energy output of the license holder from the prior calendar year multiplied by the current year water rental rates. Accordingly, the generation in calendar 2020 determines costs in F2022. For this reason, there is no direct link between the $52.2 million increase in the Cost of Heritage Energy and the $93.5 million decrease in the cost of Market Energy forecast for F2022 relative to F2021. The higher hydro generation in calendar year 2020 corresponds in part with a decrease in System Imports in F2021 relative to the forecast.[94] As BC Hydro prepares the F2023 RRA, it will consider RCIA's feedback and look for opportunities to provide a more detailed explanation.[95]

Panel Determination

The Panel finds the F2022 Cost of Energy to be reasonable.

BC Hydro submits that the Cost of Energy for F2022 "is effectively unchanged compared to the F2021 Plan." While this is true, the F2021 RRA forecast was based on higher pre-pandemic load forecasts. The actuals tell a different story.

A simple calculation, as shown in the table below, indicates the Cost of Energy has increased 5.4 percent over the 2021 forecast. Of this increase, 3.9 percent can be explained by the increase in load forecast, which the Panel accepted in the previous section of this Decision.

Table 10: Increase in Cost of Energy

Year	Load GWh	Cost $	Cost $/ GWh
2021 Forecast	**50,459**	**$1,584,000,000**	**$31,391**
2022 Budget	**52,448**	**$1,670,000,000**	**$31,841**
Increase	**3.9%**	**5.4%**	**1.4%**

Therefore, the unit cost per unit of energy has increased by 1.4 percent.

While the Panel finds the Cost of Energy reasonable for the basis of setting a rate for F2022, we are nevertheless concerned about the increase in the unit cost of energy and recommend that this issue be further examined in the F2023 RRA.

[94] BC Hydro Reply Argument, p. 7.
[95] BC Hydro Reply Argument, p. 8.

With respect to BC Hydro's comment that "customers will only pay the actual costs of energy and not the planned costs" (emphasis added) the Panel agrees, and it is for this reason that we are comfortable approving the Cost of Energy in this case. However, that statement suggests only one side of the story. Customers will pay more if the actual cost of energy exceeds the planned cost of energy. This is because the risk of a difference between the actual and planned cost of energy is considered to be beyond the control of BC Hydro's management, and therefore is not borne by BC Hydro's shareholder.

The Panel certainly agrees that some, if not many, of the costs of energy are beyond management's control. For example, the market costs of imported (and exported surplus) energy are, as is the amount of rainfall received. However, there are some decisions that are within management control, such as:

- When to import and when to self generate;
- Maintenance schedule of generation assets that will affect when units are available and also the life of the asset; and
- Long term planning decisions that affect generation availability and costs.

Accordingly, the BCUC focuses its attention on these elements of the Cost of Energy that are within management's control. Much of BC Hydro's long-term planning and medium-term operational decisions are based on a suite of models. In the Previous RRA, the BCUC reviewed a recent audit of these models and posed a number of questions to BC Hydro including questions about optimization criteria and various other operational aspects of the supply of energy for BC Hydro's ratepayers.

BC Hydro was directed to provide this information on cost of energy in the F2023 RRA and the F2020 to F2021 RRA Compliance Filing. This information has not been introduced into evidence in this proceeding. However, the Previous RRA Decision,[96] the F2020 to F2021 RRA Compliance Filing,[97] and BC Hydro's response to BCUC questions on the F2020 to F2021 RRA Compliance Filing[98] as referenced under this section are publicly available on the BCUC website.

Because of the limited review of this F2022 RRA, we have not fully pursued further any of the evidence in the F2020 to F2021 RRA Compliance Filing or the responses to the BCUC questions. We therefore recommend that in the F2023 RRA the following issues be further examined:

> Directive 9 of the Previous RRA Decision states:
>
> > BC Hydro is directed to file the following with the BCUC, by six months from the date of this Decision:
> >
> > 1) a summary of the model improvements required;
> >
> > 2) a plan to fully update the models in the monthly Energy Studies; and

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[96] https://www.bcuc.com/Documents/Proceedings/2020/DOC_59355_2020-10-02-BCH-F2020-F2021-RRA-Decision.pdf

[97] https://www.bcuc.com/Documents/Proceedings/2021/DOC_61069_2020-12-01-BCH-F2020-21RRA-Compliance-to-G-246-20-Directives-.pdf

[98] https://www.bcuc.com/Documents/Proceedings/2021/DOC_62011_2021-04-01-BCH-F20-F21RRA-Compliance-to-BCUC-Staff-IR-1.pdf

3) a plan to have an independent third party test the Market Model.

Directive 10 of the Previous RRA Decision states:

> BC Hydro is directed to file with the BCUC, as part of its compliance filing, its plan to review the recommendations and priorities on back testing and benchmarking that were expected to be completed in June 2020.

In compliance with Directives 9 and 10, BC Hydro provided its plan and timeline on model improvement and back testing under Section 3.4.1 and 3.4.2 of the F2020 to F2021 RRA Compliance Filing. BC Hydro further provides an additional submission dated April 1, 2021, which elaborates on the timeline and cost to complete each component of its Energy Studies Model review. The timeline is replicated in the table below.[99]

Table 11: Summary of Improvements to the Energy Studies Models (Update to Table 3-15 in the Compliance Filing)

Ref	Directive Tasks		FY22 Q1	FY22 Q2	FY22 Q3	FY22 Q4	FY23 Q1	FY23 Q2	FY23 Q3	FY23 Q4	FY24 Q1	FY24 Q2	FY24 Q3	FY24 Q4	FY25 Q1	FY25 Q2	FY25 Q3	FY25 Q4	FY26 Q1	FY26 Q2	FY26 Q3	FY26 Q4	FY27 Q1	FY27 Q2	FY27 Q3	FY27 Q4
		Revenue Requirements	■	■	■	■	■								■	■	■	■	■							
2.1.1	#9(2)	ESM Efficiency	■	■	■	■																				
2.1.1	#9(2)	ESM Data Transfer	■	■	■	■	■																			
2.1.2	#9(2)	Peace Optimizer							■	■	■	■	■	■												
2.1.3	#9(2)	SOPHOS Upgrades											■	■	■	■	■	■								
2.1.4	#9(2)	Load Variabiltiy Model	■	■																						
2.1.5	#9(2)	Three Reservoir SDP															■	■	■	■	■	■	■	■		
2.1.6	#9(2)	Cloud Computing (AWS)	■	■	■	■																				
2.1.7	#9(2)	Ultralight (Short Term Model)	■	■	■	■	■	■																		
3	#9(3)	Market Model (Review)					■	■	■	■																
4	#10	Benchmarking	■	■	■	■	■	■	■	■	■	■	■													
4	#10	Backtesting												■	■	■	■	■								

While we appreciate the responses provided by BC Hydro to the BCUC's questions posed in the Previous RRA, we are concerned about the length of time it will take to complete the benchmarking and back testing – approximately 5 years from the current date. Some of this delay may be due to the model updates and reviews scheduled in F2022 and F2023. We recommend that this schedule be reviewed in more detail in the F2023 RRA. **Therefore, BC Hydro is directed to provide, in its F2023 RRA, an update on the timeline referenced in Table 11, herein, and explain any changes to the timeline.**

In this Application, BC Hydro states that the format of Market Energy in the Application differs from the Previous RRA due to the 2020 TPA between BC Hydro and Powerex.[100] This makes comparison between past and future periods difficult. However, BC Hydro submits that it can report on the historic actual system imports/exports divided into flexible and non-flexible (i.e. according to the format in the 2020 TPA) in subsequent RRAs as an

[99] https://www.bcuc.com/Documents/Proceedings/2021/DOC_62010_2021-04-01-BCH-F20-F21-RRA-Decision-Compliance-Directives-9-and-10.pdf, Table 1, p. 3.
[100] Exhibit B-2, pp. 4-16 to 4-17.

additional level of visibility and granularity.[101] **In our view, this is helpful and we direct that in the F2023 RRA, BC Hydro report on the historic actual system imports/exports divided into flexible and non-flexible (i.e. according to the format in the 2020 TPA).**

BC Hydro is also directed to identify the cost of market purchases of electricity to meet domestic requirements based on the 2020 TPA pricing methodology and provide this information based on the actual outcomes in the F2023 RRA.

4.2.1 Difference between F2021 RRA and F2021 Forecast

BC Hydro notes that the F2021 RRA values are based on BC Hydro's June 2019 forecast costs, which were the basis for the Evidentiary Update in the Previous RRA; whereas the F2021 Forecast values are based on actuals up to August 2020 and represent a year-end forecast of costs, as of August 2020.[102] Moreover, F2022 Plan values are based on August 2020 forecast costs.[103]

Panel Determination

A decrease in Heritage Energy cost between F2021 RRA and F2021 Forecast appears to be due to higher revenues from Columbia River Treaty Agreements and Remissions. The amount of costs from water rental, Natural Gas for Thermal Generation, and the Domestic Transmission components of Heritage Energy remain consistent between F2021 RRA and F2021 Forecast.

A decrease in F2021 Forecast compared to F2021 RRA in Non-Heritage Energy is largely driven by a decrease in IPP cost, which reflects the expected generation volume of existing IPP contracts.

As for Market Energy, BC Hydro anticipates an increase in annual system surplus in F2021 Forecast, which explains the corresponding decrease in System Imports, resulting in an overall reduction in market energy cost. Based on the evidence on the record, there is no further information as to why BC Hydro forecasts a spike in annual system surplus in F2021 at the time the forecast was updated in August 2020.

It is routine for BC Hydro to include an appendix in each RRA explaining any variance between forecast and actual cost of energy in the past fiscal year(s). This Application did not provide such a table. Further there is no actual F2021 cost of energy, only forecast. **The Panel directs BC Hydro to include the actual cost of energy information for F2021 in the F2023 RRA.**

4.3 Operating Costs

In the Previous RRA Decision, the BCUC accepted BC Hydro's forecast operating costs for F2020 and F2021, however it expressed concerns over certain areas where cost cutting may have been too aggressive or where needed increases were put on hold. As a result the BCUC directed BC Hydro to address the adequacy of its cyber security programs, mandatory reliability standards (MRS) and vegetation management funding in its F2022 RRA.[104] BC Hydro submits that it has responded to these comments and directives in the Application, noting its

[101] Exhibit B-4, BCUC IR 17.1.
[102] Exhibit B-5, CEC IR 21.2.
[103] Exhibit B-5, CEC IR 21.3.
[104] BC Hydro F2020 to F2021 RRA, Order G-246-20 and accompanying decision, Executive Summary, p. (v); Section 4.3.4, p. 71; Section 4.3.5, p. 73.

approach continued to focus on cost control while investing in areas it foreshadowed in the last proceeding and that were identified in the Previous RRA Decision as meriting further investment.[105]

BC Hydro is requesting recovery of $1.357 billion in operating costs for F2022, a $130.5 million (or 10.6 percent) increase over the amount approved for F2021.[106] BC Hydro separates its operating costs into different categories and refers to the operating costs included in the revenue requirement for recovery in rates as "current operating costs." Current operating costs include:[107]

(i) Base operating costs, which are costs for personnel, materials and external services that are incurred in the day to day operations, and are net of recoveries, capitalized costs and reclassification adjustments;

(ii) operating costs that BC Hydro does not have direct control over, such as IPP capital leases, capital overhead that can no longer be capitalized under International Financial Reporting Standards (IFRS), costs related to the 2017 Waneta Transaction and Customer Crisis Fund. These costs together with base operating costs are referred to as net operating costs by BC Hydro; and

(iii) operating costs incurred in prior periods to be recovered in the current period based on each regulatory account's established recovery mechanism.

Base operating costs are in BC Hydro's view the relevant measure for the assessment of its efforts to control operating costs because they are limited to the normal day to day operations.[108]

BC Hydro forecasts $905.1 million in base operating costs for F2022, an increase of $98.7 million (or 12.2 percent) compared to the amount approved for F2021. BC Hydro submits it has held base operating budgets across all Key Business Units at current levels, with the exception of the targeted investments in reliability (i.e. cybersecurity programs, MRS and vegetation management) and uncontrollable cost pressures that are increasing due to changing market conditions.[109] Other cost pressures have been largely offset through trainee savings due to reduced apprentice intakes, in-housing of the reliability coordinator function from Peak Reliability, lease accounting changes and capital overhead savings as a result of increased costs eligible for capitalization. BC Hydro has also managed its cost pressures through the implementation of a wage freeze for executive, management and professional employees and re-deploying personnel to emergent issues as part of its response to the COVID-19 pandemic.[110]

The following figure from the Application provides a visual breakdown of the planned increases in base operating costs from F2021, as approved in the Previous RRA Decision, to F2022. The base operating cost increases are categorized into reliability investments, uncontrollable costs and other net costs.[111]

[105] Exhibit B-2, Section 5.2, p. 5-5; Section 5.5, p. 5-10.

[106] Exhibit B-2, Appendix A, Schedule 5.0, line 39, 51 and 76; percentage calculated by BCUC Staff: (F2022 Plan/F2021 RRA)-1) x 100 = (1,357.2 million / 1,226.7 million – 1) x 100 = 10.6%.

[107] Exhibit B-2, Section 5.5.1, pp. 5-13 and 5-14, Table 5-3; Section 5.5.5, p. 5-22.

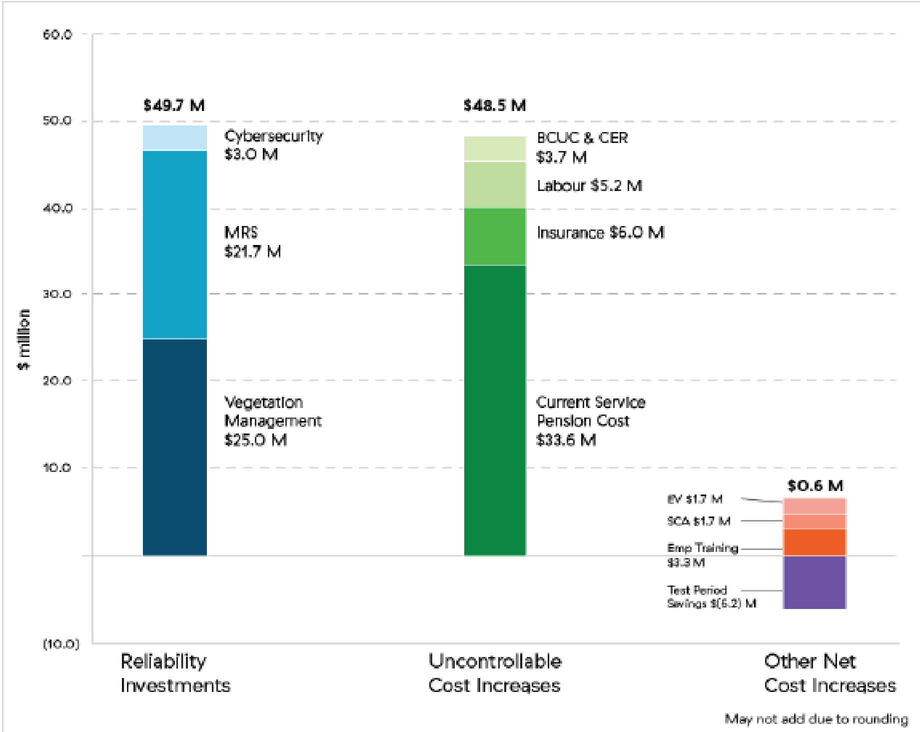
[108] Exhibit B-2, Section 5.1, p. 5-1, footnote 77; Section 5.5.1, pp. 5-13 and 5-14, Table 5-3.

[109] Exhibit B-2, Section 5.1, p. 5-1; BC Hydro Final Argument, p. 16.

[110] Exhibit B-2, Section 5.0, p. 5-1 and 5-2; BC Hydro Final Argument, p. 16.

[111] Exhibit B-2, Section 5.5.2, p. 5-15, Figure 5-3.

Figure 3: Fiscal 2022 Base Operating Cost Changes



Positions of Parties

Apart from RCIA and AMPC, interveners either support or do not oppose BC Hydro's level of planned operating costs.

RCIA takes issue with the apparent presumption that all base costs from the Previous RRA are not subject to testing, and only those areas in which increases are proposed require defense in this proceeding.[112]

In reply, BC Hydro submits that the F2022 RRA focused on incremental changes from F2021 planned base operating costs due to the timing and structure of the proceeding as determined by the BCUC in the Previous RRA Decision. The Previous RRA Decision noted there was general consensus among the parties that the F2022 RRA and proceeding should be streamlined to reflect a "gap" or transitional year.[113] In addition, BC Hydro states the two most recent RRA proceedings (F2017 to F2019 RRA and F2020 to F2021 RRA) have incorporated a significant review process. And in response to the BCUC's finding in the F2017 to F2019 RRA, the F2020 to F2021 RRA included details on the inputs into BC Hydro's base operating costs and the focus was on the starting point of these costs, as opposed to solely a comparison of costs relative to inflation.[114]

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[112] RCIA Final Argument, Section 4.1.2, p. 9.
[113] BC Hydro F2020 to F2021 RRA, Order G-246-20 and accompanying decision, Section 5.11, pp. 186 to 188; BC Hydro Reply Argument, Part Five, Section B, p. 10.
[114] BC Hydro Reply Argument, p. 11.

AMPC contends that "a least cost approach should remain the starting point to BC Hydro's system investment and planning, with any expenditures above this amount first undergoing analysis that identifies the costs, benefits and risks associated with expenditures and potential alternatives."[115]

In reply, BC Hydro submits it employs a budgeting and planning process for both base operating costs and capital, that weigh competing priorities and incorporate top-down constraints to balance low rates and BC Hydro's longer-term stewardship role.[116]

Panel Determination

While the Panel accepts the operating costs for F2022, it acknowledges that the increase in base operating costs is both significant and potentially lasting. A large component of the increase is to fund reliability investments, essential for the protection of the Bulk Electric System. The cost and work effort associated with implementing and maintaining compliance with mandatory reliability standards have increased over time, and the level of investment is not expected to be reduced in the near term. Accordingly, these upward cost pressures will raise the baseline level of operating costs for future RRAs. The Panel does not want BC Hydro to lose sight of the importance of continually evaluating the effectiveness of these expenditures and expects BC Hydro to demonstrate the prudency of controllable costs while being mindful of the affordability of its rates.

With respect to RCIA's comments regarding the focus on incremental base operating costs in this proceeding, the Panel acknowledges the concerns raised but agrees with BC Hydro that the F2022 RRA was designed for an expedited review and may not have allowed for a thorough investigation into the historically approved level of operating expenditures, unlike BC Hydro's Previous RRA. The Panel anticipates that the F2023 RRA will be a more appropriate proceeding for RCIA to fully test the baseline level of operating costs including any incremental changes.

The Panel is reluctant to accept AMPC's proposal that the "least cost approach" should be the starting point for all of BC Hydro's system investment and planning, as this approach is not always practical for the provision of safe and reliable service. The Panel considers BC Hydro's budgeting process involving top-down and bottom-up elements goes beyond the examination of incremental changes from the prior year and continues to be reasonable for forecasting operating costs. Therefore, for these reasons, the Panel finds the F2022 operating costs requested for recovery to be reasonable.

The following subsections discuss some of the key areas of concern identified in the Previous RRA, namely cybersecurity, vegetation management, as well as discuss current service pension costs as they are a significant driver to the increase in base operating costs.

4.3.1 Cybersecurity

As BC Hydro notes, cybersecurity is the practice of securing digital systems against unauthorized access and potential loss of data or disruption to a business.[117] Cybersecurity risks not only affect BC Hydro but could also impact the operation of the Bulk Electric System (BES). MRS, and specifically Critical Infrastructure Protection (CIP) standards mitigate specific cybersecurity risks of the BES and BC Hydro is required to comply with those

[115] AMPC Final Argument, Section II, p. 3.
[116] BC Hydro Reply Argument, p. 14.
[117] Exhibit B-2, p. 5-78.

standards. While most CIP standards relate to cybersecurity, the CIP standards also include physical security standards, specifically standards to protect the physical security of transmission stations and substations and their primary control centres.[118] BC Hydro submits that the planned investment for its cybersecurity program is independent from the planned investments to achieve and maintain compliance with CIP standards, which are part of MRS.[119]

The following subsections discuss MRS related cybersecurity expenditures, non-MRS related cybersecurity expenditures, and the confidentiality treatment of MRS information.

4.3.1.1 Mandatory Reliability Standards Cybersecurity including CIP related expenditures

BC Hydro's F2022 budget for MRS related cybersecurity, CIP standards and other MRS standards is $44.2 million.[120] This amount includes an operating cost increase of $21.7 million and an increase of 21.5 full-time equivalents (FTEs) as compared to the F2021 budget, which BC Hydro submits is necessary to maintain and achieve compliance with MRS. This proposed operating cost includes $0.4 million towards the implementation of the next version of CIP standards.[121] BC Hydro contends that the incremental costs outlined for MRS are non-discretionary.[122] BC Hydro also submits that it anticipates further expansion of its MRS program and investments in future years as new standards and iterations of existing standards are implemented.[123] BC Hydro also submits that it continues to implement new versions of standards which will require ongoing investment in future years.[124]

BC Hydro submits that it will be working to achieve compliance in certain areas where necessary mitigation activities have been identified, in conjunction with the Western Electricity Coordinating Council (WECC) in F2022. As compliance related matters are subject to confidentiality requirements under the BCUC MRS Compliance Rules, this information is filed confidentially to the BCUC only.[125]

Of the $21.7 million increase in operating costs due to MRS compliance spending, BC Hydro is planning to invest [redacted]

On December 18, 2020, [redacted]

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[118] https://www.nerc.com/pa/Stand/Pages/CIPStandards.aspx
[119] Exhibit B-2, pp. 5-78 to 5-79.
[120] Exhibit B-5, pdf pp. 179 to 180.
[121] Exhibit B-2, Section 5.5.3, p. 5-17.
[122] Exhibit B-2, Section 5.6, p. 5-24.
[123] Exhibit B-2, Section 5.6, p. 5-25.
[124] Exhibit B-2, Section 5.6, p. 5-33.
[125] Exhibit B-2, Section 5.6, p. 5-32.
[126] Exhibit B-2-4, Section 3, p. 5.
[127] Exhibit B-2-4, Section 4, p. 6.

[redacted] On December 18, 2020, the BCUC issued [redacted]

BC Hydro submits that the [redacted]

Positions of Parties

BCSEA submits that BC Hydro's proposed increase in spending on MRS in F2022 is justified as compliance with MRS is mandatory and essential to the protection of the BES.[131] The CEC submits that BC Hydro has reasonably documented the need for the nearly $22 million in operating costs in F2022.[132] Zone II RPG submits that it takes no position on BC Hydro's proposed operating costs as it did not have access to the confidential information filed with the BCUC.[133]

In RCIA's view, simply stating that WECC has approved the proposed mitigation activities does not demonstrate that they are the most cost-effective solutions because WECC does not have a mandate to evaluate the cost-effectiveness of the proposed mitigations but rather WECC is only concerned that entities are taking effective actions to address MRS-deficiencies and non-compliances.[134]

BCOAPO submits that while it has no concerns about BC Hydro's proposed F2022 spending on MRS related activities, it recommends that the BCUC direct BC Hydro to include considerations of efficiency as part of BC Hydro's next internal audit.[135]

In reply, BC Hydro disagrees with BCOAPO's recommendation that the BCUC direct BC Hydro to perform an MRS Efficiency Audit. BC Hydro states that the nature of the audit BCOAPO is contemplating would exceed the BCUC's jurisdiction as it is aimed at directing how the company is managed.[136]

Panel Determination

Interveners submit that BC Hydro has not demonstrated sufficient evidence that the associated spending to achieve compliance with MRS standards is optimal or non-discretionary. Interveners also state that simply stating that WECC has approved the proposed mitigation activities does not demonstrate that they are the most cost-effective solutions.

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[128] Exhibit A2-1, p. 7.

[129] Exhibit B-6, Confidential BC Hydro responses to BCUC IR 1, p. 54.

[130] Exhibit B-6, Confidential BC Hydro responses to BCUC IR 1, p. 50.

[131] BCSEA Final Argument, p. 7.

[132] CEC Final Argument, p. 13.

[133] Zone II RPG Final Argument, p. 4.

[134] RCIA Final Argument, p. 11.

[135] BCOAPO Final Argument, p. 28.

[136] BC Hydro Reply Argument, pp. 17 to 18.

The Panel agrees with interveners that WECC does not have a mandate to evaluate the cost-effectiveness of proposed mitigation plans and, as the BCUC's administrator, its role is to ensure an entity's compliance with the MRS program, and any non-compliances are mitigated effectively and quickly. While WECC has not evaluated the cost-effectiveness of the proposed investment on MRS, it is the role of the BCUC, as the regulator, to evaluate the reasonableness of expenditures, including MRS expenditures. The Panel disagrees with BC Hydro that the BCUC does not have the jurisdiction to direct an audit of program expenditures. However, it is the Panel's view that it would be premature to do so at this time.

As indicated in the Previous RRA Decision, the BCUC has issued two Notices of Penalty to BC Hydro for CIP violations. The Notices of Penalty levied administrative penalties totalling approximately $1 million.[137] BC Hydro has confidentially filed detailed information on the specific costs related to achieving compliance with MRS. Due to the confidential nature of utility programs to meet CIP standards, it is difficult to evaluate the cost-effectiveness of BC Hydro's proposed budget compared to other entities with a similar size and footprint. [redacted] The Panel has reviewed the proposed investments for MRS after considering BC Hydro's recent non-compliance of CIP violations and finds the investments are not only warranted but required to safeguard the BES. Therefore, the Panel finds the $21.7 million increase for MRS related expenditures, including CIP standards to be reasonable.

4.3.1.2 Non-MRS Cybersecurity Related Expenditures

The BCUC, in the Previous RRA Decision, directed BC Hydro to address the adequacy of its cybersecurity programs with respect to its distribution and head office systems.[138]

In the F2022 budget, BC Hydro has proposed an increase of $3.0 million which includes the cost of 4 FTEs. This additional funding along with reallocated internal resources will result in a total base operating budget for cybersecurity of $8.0 million.[139] BC Hydro submits that this planned funding for cybersecurity in F2022 will improve BC Hydro's ability to withstand and respond to cyber threats and attacks.[140]

BC Hydro submits that investment in cybersecurity is required to protect the expanding complexity of its cyber assets, which range from computing and storage equipment, networks, software, data to end point devices such as phones and laptops. BC Hydro also submits that cyber attacks are growing in volume and sophistication, and includes nation-state attacks, phishing campaigns and ransomware attacks that use sophisticated approaches to deploy malware into software.[141]

BC Hydro submits that additional funds and FTEs are required to:[142]

- Enhance cybersecurity practices and functions in Operational Technology areas, specifically Industrial Control Systems as identified in the Office of the Auditor General (OAG) audit;

[137] Order R-30-19; and Order R-18-20.
[138] Exhibit B-2, p. 5-6.
[139] Exhibit B-2, Section 1.3.5, p. 1-9.
[140] BC Hydro Final Argument, p. 37.
[141] Transcript Vol. 1, pp. 35 to 36.
[142] Exhibit B-2, pp. 5-84 to 5-85.

- Enhance identify and access management processes, practices and tools to improve cybersecurity controls for electronic and physical access;
- Enhance and extend monitoring and detection to address the evolving cyber threat landscape;
- Provide cybersecurity thought leadership and improve training and awareness programs for employees and contractors;
- Extend regular risk assessments and penetration testing across expanding digital and cloud environments; and
- Enhance response plans to identify specific scenarios and test through scheduled exercises as BC Hydro continues to evolve its response plans in line with evolving threats.

In March 2019, the OAG submitted an audit report on BC Hydro's cybersecurity practices and controls related to its Industrial Control Systems.[143] BC Hydro submits that it has been implementing recommendations from internal audits, self-assessments, the OAG audit of BC Hydro's Operating Technology, and an external assessment of BC Hydro's Industrial Control Systems. BC Hydro submits that many of the recommendations are already addressed and the F2022 plan includes funding to address outstanding recommendations.[144]

Positions of Parties

During the in-camera portion of the Review Session, BC Hydro submits [redacted]

BC Hydro submits that because it is in the process of developing detailed [redacted]

BC Hydro also submits that [redacted] BC Hydro considers that the [redacted]

The CEC, BCSEA and Zone II RPG submit that the risk of cyber attacks on BC Hydro is real and significant and recommends that the BCUC approve the increased expenditure on cybersecurity.[148]

BCOAPO submits that it recognizes that information about cybersecurity is sensitive which limits the extent to which BC Hydro can publicly discuss it. BCOAPO submits that it ultimately relies on the BCUC Panel to assess the reasonableness of the proposed F2022 budget for cybersecurity.[149]

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[143] Exhibit B-2, Section 5.8.4, p. 5-84.
[144] BC Hydro Final Argument, p. 37.
[145] Confidential Transcript Vol. 2A, pp. 30 to 31.
[146] Confidential Transcript Vol. 2A, pp. 28 to 29.
[147] Confidential Transcript Vol. 2A, pp. 58 to 60.
[148] CEC Final Argument, p. 17; BCSEA Final Argument, p. 8; Zone II RPG Final Argument, p.4
[149] BCOAPO Final Argument, p. 32.

RCIA submits that while it does not dispute BC Hydro's need to address increasing cybersecurity threats, it does not agree that sufficient evidence has been provided publicly to demonstrate that the associated spending increase is optimal. RCIA submits that it does not have sufficient information to conclude that the spending on cybersecurity is appropriate and cost-effective.[150]

In reply, BC Hydro submits that despite RCIA's opposition, it has filed a significant amount of supporting evidence on the public record and only the most sensitive cybersecurity information was submitted confidentially to the BCUC.[151]

MoveUP submits that it is concerned about a recent cyber attack on a BC Hydro subsidiary, Powertech Labs, and recommends that the BCUC request BC Hydro to provide a detailed confidential report on the Powertech Labs attack including how it arose, how it was detected and how it was responded to, how future attacks can be avoided and the lessons learned from it.[152]

In reply, BC Hydro submits it is reporting to the BCUC confidentially about the Powertech Labs incident and an upcoming report will address lessons learned.[153]

Panel Determination

The Panel notes that BC Hydro has provided information on the public record on the specific program areas where it plans to invest to strengthen its cybersecurity functions. The Panel finds that there is sufficient evidence to warrant additional investments in BC Hydro's cybersecurity program given the increasing volume and sophistication of cyber threats. Therefore, the Panel finds the $8.0 million for cybersecurity expenditures to be reasonable.

Cybersecurity incidents present risks to BC Hydro and to the people and businesses of B.C. A public utility requires effective mechanisms to not only detect potential cybersecurity incidents, but also requires the ability to quickly respond to an incident and enact a plan to recover should an incident occur. These plans should be in place prior to the incident occurring.

While portions of BC Hydro's operations that are part of the North American BES are protected by MRS, the Panel remains concerned that other areas such as distribution, back office systems and other assets that are not protected by MRS provide potential cybersecurity vulnerabilities. With the increasing number of cybersecurity breaches such as the cybersecurity attack on the SolarWinds Orion platform, the recent Colonial Pipeline attack[154] and the attack on BC Hydro's subsidiary, Powertech Labs, the Panel considers that BC Hydro should afford the same or similar level of protection across all of BC Hydro's cyber assets.

The Panel notes that BC Hydro's F2022 plan as it relates to MRS and cybersecurity [redacted]

[150] RCIA Final Argument, p. 15

[151] BC Hydro Reply Argument, p. 26.

[152] MoveUP Final Argument, pp. 2 to 3.

[153] BC Hydro Reply Argument, p. 27.

[154] https://www.cbc.ca/news/business/pipeline-colonial-cyberattack-ransonware-1.6020315

[redacted] The Panel considers that BC Hydro [redacted]

The Panel is concerned BC Hydro has not completed a company-wide cyber risk assessment of all its cyber assets. **Therefore, the Panel, directs BC Hydro to undertake a Cyber Risk Assessment of all of its cyber assets and to notify the BCUC of any action that has been or needs to be taken on any immediate or time-sensitive concerns. BC Hydro is directed to file a Cyber Risk Assessment Report to the BCUC confidentially within 3 months of the issuance of this Decision.**

Since BC Hydro's information technology platforms interface with at least some of its subsidiaries, BC Hydro is directed to develop a company-wide, comprehensive Cyber Security Plan that encompasses BC Hydro and its subsidiaries and third-parties with whom it interfaces. BC Hydro is directed to develop the Cyber Security Plan informed by the Cyber Risk Assessment Report, and to file the plan to the BCUC confidentially within 1 year of issuance of this Decision.

4.3.1.3 Confidentiality Treatment of MRS and Certain Cybersecurity Information

In the Application, certain information related to MRS and investments related to non-MRS cybersecurity was filed confidentially and was made available only to the BCUC. BC Hydro submits that this approach was necessary due to the highly security sensitive nature of the information.[155] Certain interveners raised concerns with BC Hydro's approach and made submissions regarding the confidentiality treatment of MRS information in future proceedings.

AMPC states that given the short timelines of this proceeding, it did not seek to access the confidential MRS material filed with the BCUC in this proceeding but expects to review MRS costs in the future. AMPC also submits that it is concerned by BC Hydro's comments in the oral hearing that any requests to participate in MRS matters through confidential undertakings would be unworkable and should be rejected by the BCUC. AMPC states that it can add value and expertise in the review of MRS-related costs and other jurisdictions have found mechanisms to review these costs and practices.[156]

RCIA submits that while it understands why some aspects of MRS ought to be kept confidential to prevent signaling vulnerabilities that could be exploited by malicious actors, BC Hydro has not compellingly demonstrated that every aspect of MRS must be kept secret from ratepayers. RCIA submits that future applications should provide effective mechanisms to enable ratepayers to review costs associated with MRS standards, including any proposed capital and operating investments and rationale for why the proposed mitigation plans are the most cost-effective. RCIA further submits that to the extent possible and without compromising system security, BC Hydro should be required to report on at least the number of non-compliances, including trends over time, levels of concerns, actions taken to mitigate these issues while taking efforts to control associated costs.[157]

[155] Exhibit B-2, Cover Letter, pp. 1 to 2.
[156] AMPC Final Argument, p. 7.
[157] RCIA Final Argument, p. 11.

Similar to BC Hydro's planned investments in MRS, RCIA takes issue with the confidentiality around BC Hydro's cybersecurity budgeting and reporting process and submits that it does not have enough information to conclude that the spending on cybersecurity is appropriate and cost-effective.[158] RCIA also recommends that future applications provide more effective mechanisms to enable ratepayers to understand why the proposed operating investments are needed and why the selected mitigations proposed for implementation are the most cost-effective way to address the deficiencies. [159]

In reply, BC Hydro states that sensitive information was submitted confidentially to the BCUC because of the risk of inadvertent disclosure and the potential harm to BC Hydro and ratepayers from this disclosure could be very significant and the risk and implications outweighed the public benefit in additional circulation to interveners.[160]

BC Hydro submits that any advanced ruling on interveners' ability to access confidential MRS information on future RRAs would be procedurally improper and that issue should be left for future BCUC panels to decide based on the facts and circumstances at that time. BC Hydro also submits that the majority of the planned MRS operating costs are for mitigation plans developed in conjunction with WECC and that BC Hydro has no flexibility on timing in the implementation of these mitigation plans.[161]

BC Hydro also submits that CIP related information is security sensitive and has severe consequences of disclosure for BC Hydro and British Columbians and neighbouring jurisdictions and the most effective way to reduce significant exposure is to limit access to information. BC Hydro further submits that some of the information filed in this proceeding, whether CIP or otherwise is deemed to be confidential by the BCUC's MRS Compliance Monitoring Program.[162]

BC Hydro also submits that pursuant to the BCUC's MRS Compliance Monitoring Program, information relating to an entity's Alleged Violation will be treated as confidential, unless and until the BCUC confirms the Alleged Violation and the BCUC considers that disclosure would not relate to a cyber-security incident or otherwise jeopardize the security of the BES.[163]

Panel Discussion

The Panel accepts that in general ratepayers should be able to review and understand why proposed operating and capital investments are required to maintain compliance with MRS. However, given the confidential nature of utility programs to meet CIP standards, the Panel must exercise its discretion and take into account all relevant factors. A careful balance must be struck between the desirability of an open and transparent review process and safeguarding the safety and reliability of the BES.

As BC Hydro notes, information relating to an entity's Alleged Violation under the BCUC MRS Compliance Monitoring Program will be treated as confidential, unless and until the BCUC confirms the Alleged Violation and the BCUC considers that disclosure would not jeopardize the security of the BES.

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[158] RCIA Final Argument, p. 15
[159] RCIA Final Argument, p. 15.
[160] BC Hydro Reply Argument, p. 26.
[161] BC Hydro Reply Argument, pp. 15 to 16
[162] BC Hydro Reply Argument, p. 16.
[163] BC Hydro Reply Argument, p. 16.

Interveners have submitted that future applications should provide more effective mechanisms to enable ratepayers to understand the cause of BC Hydro's non-compliance across a range of MRS standards and why the proposed operating and capital investments are needed. In addition, program spending designed to mitigate future non-CIP violations should be public and subject to review in future RRAs, unless BC Hydro provides a compelling reason otherwise.

The Panel, however, acknowledges that BC Hydro is particularly sensitive and vulnerable to external threats if security risks are exposed, such as if information about violations were to be published prior to the mitigation of these violations. Information from these incidents could potentially expose a path of entry for those who may wish to do harm to the system. Therefore, the Panel agrees that it is appropriate that certain CIP and cybersecurity information be kept confidential to safeguard the BES.

The Panel agrees with BC Hydro that any decisions around the confidentiality of CIP program spending, confirmed violations, and penalty assessments, if any, should be left for future BCUC panels to decide based on the facts and circumstances and in accordance with the process set out in the BCUC's Rules of Practice and Procedure. **The Panel therefore declines to make determinations at this time regarding the review of confidential MRS information in future Revenue Requirement Applications.**

Similarly, the Panel agrees with BC Hydro that certain sensitive cybersecurity information ought to remain confidential due to the risk of inadvertent disclosure and potential harm to BC Hydro, its ratepayers, and the public. The Panel considers that any decisions around the confidentiality of cybersecurity investments, whether CIP related or otherwise, should be left for a future BCUC panel to decide based on the facts and circumstances and in accordance with the process set out in the BCUC Rules of Practice and Procedure. **The Panel therefore declines to make a determination at this time regarding the confidentiality treatment of cybersecurity investments in future Revenue Requirement Applications.**

4.3.2 Vegetation Management

The BCUC, in the Previous RRA Decision, directed BC Hydro to address the adequacy of its vegetation management funding.[164] BC Hydro submits that vegetation cleared over a decade ago during a period of heightened activity has now regrown to a size that poses a risk to the system. Furthermore, cost pressures have increased, and climate change is impacting growth rates and the health of vegetation across the province. In the past few years, reliability has been impacted by the continued vegetation growth which has now reached a critical level whereby a new Vegetation Management Strategy (VMS) is required.[165]

In the F2022 budget BC Hydro has proposed an approximately 50 percent increase in vegetation management expenditures. The incremental costs include spending for the transmission system, the distribution system, the implementation of a Light Detection and Ranging (LiDAR) program and the addition of planning resources.[166] The proposed budget represents the maximum effort BC Hydro believes it can prudently manage in a single year without introducing market inefficiencies.[167] BC Hydro submits that it will develop a new VMS in F2022 with the goals of addressing the current accumulation of vegetation and moving to a sustained level whereby there is no

[164] Exhibit B-2, p. 5-34.
[165] Exhibit B-2, pp. 5-35, 5-47.
[166] Exhibit B-2, Table 5-11, p. 5-39.
[167] Exhibit B-4, BCUC IR 36.2, p. 1.

future re-accumulation, improving visibility of vegetation across the system, optimizing delivery of services, seeking economies of scale in the market, expanding its suite of metrics and maintaining compliance with regulatory, safety and reliability standards.[168] F2022 is considered by BC Hydro to be a transitional year whereby the changes proposed to occur during the Test Period will bring further insight into the development of the new VMS.[169]

BC Hydro's proposed F2022 budgeted expenditures for vegetation management are set out in Table 12 below.[170]

Table 12: Vegetation Management Budget

$ millions*	**F2021**	**F2022****	**Change**	**% Change**
Transmission (incl. LiDAR)	17.8	37.3	19.6	110%
Transmission	*17.8*	*33.3*	*15.6*	*87%*
LiDAR	-	*4.0*	*4.0*	-
Distribution	30.6	36.1	5.6	18%
Planning Resources	-	0.9	0.9	-
Total (before recoveries)	48.4	74.4	26.0	54%
Telus Distribution Recoveries	(6.1)	(6.9)	(0.8)	13%
Total Net of Recoveries	42.2	67.4	25.2	60%

*Some totals may not add due to rounding

**F2022 includes labour rate increase

The following subsections discuss vegetation management activities regarding the transmission system including the LiDAR program, the distribution system, the new VMS, and vegetation management compliance activities with respect to MRS requirements.

4.3.2.1 Transmission System Vegetation Management including the LiDAR Program

BC Hydro's proposed F2022 budgeted expenditures for transmission-related vegetation management, including LiDAR are $37.3 million, which represents an increase of approximately $19.6 million. Spending on the transmission system comprises 76 percent of the incremental budget with 60 percent dedicated to transmission clearing and an additional 16 percent for the LiDAR program. BC Hydro submits that most of the vegetation management budget increase is directed towards the transmission system with incremental funding of $15.6 million over the F2021 plan and the addition of LiDAR which represents a new on-going expenditure of $4 million.[171] In BC Hydro's view, the use of LiDAR in vegetation management is considered a common industry practice and will allow for dynamic modelling in order to identify and target the highest risk areas on the transmission system. The addition of the LiDAR program will allow for a complete system view every five years by covering 20 percent of the system annually.[172] BC Hydro indicates that B.C. is one of the most densely

[168] Exhibit B-2, p. 5-49.
[169] Exhibit B-2, p. 5-50.
[170] Exhibit B-2, Table 5-11, p. 5-39.
[171] Exhibit B-2, Table 5-11, p. 5-39.
[172] Exhibit B-2, p. 5-56.

forested jurisdictions in North America, yet has presented evidence from benchmarking studies demonstrating that it has placed in the 3rd quartile, nearing the 4th quartile with respect to transmission right-of-way clearing.[173] In the Application, evidence was also filed exhibiting an increasing trend in transmission vegetation related outages commencing in F2016, due primarily to significant windstorms.[174]

During the review session, when asked about the greater allocation of the incremental budget to the transmission system over the distribution system, Mr. Kumar acknowledged that the distribution system has historically had a larger impact on customer reliability over the transmission system and this was further supported by reliability data submitted on the record.[175] He contends however, that there is an urgency to address the vegetation management accumulation on the transmission system and further states that, "although rare," a grow-in on the transmission system could cause an outage of significant consequence.[176] The increased expenditures in the F2022 plan are therefore expected to allow BC Hydro to address immediate areas of risk on the transmission system, while preventing the vegetation accumulation from growing any further. The budget as submitted, includes a plan to clear 6,900 hectares of vegetation on the transmission system, 300 hectares more than the sustainable level, which should aid in addressing the 18,000 hectare accumulation.[177] Additionally, relative spending compared to peers will likely increase in F2022, assuming that others remain constant.[178]

4.3.2.2 Distribution System Vegetation Management

BC Hydro's proposed F2022 budgeted expenditures for distribution-related vegetation management before recoveries are $36.1 million, which represents an increase of approximately $5.6 million or 18 percent. BC Hydro states that it has experienced increased outages due to vegetation on the distribution system and that the cumulative cost pressures and impacts from climate change must be proactively addressed.[179] Reliability data for the distribution systems demonstrated an increasing System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI) directly related to vegetation.[180]

BC Hydro also provided benchmarking data comparing its distribution reliability performance and spending per customer against its peers. The evidence shows that BC Hydro was placed in the lower quartiles over multiple years in terms of reliability performance and distribution vegetation management spending per customer is presently less than half the average of its utility peers.[181] With respect to rural districts, evidence was submitted demonstrating an increasing frequency and duration of outages over the F2016 to F2020 period.[182] According to BC Hydro, trees are the single largest cause of rural SAIFI and SAIDI average recorded hours, followed by planned outages and adverse weather.[183]

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173 Exhibit B-2, p. 5-40, Figure 5-8, p. 5-60.
174 Exhibit B-2, Figure 5-5, p. 5-54.
175 BC Hydro F2022 RRA, Transcript Vol. 2, pp. 298 to 299; Exhibit B-4, IR 38.1, p. 2.
176 BC Hydro F2022 RRA, Transcript Vol. 2, p. 299.
177 Exhibit B-2, pp. 5-60 to 5-61, Exhibit B-2, p. 5-58.
178 Exhibit B-4, BCUC IR 32.12, p. 2.
179 Exhibit B-2, p. 5-48.
180 Exhibit B-4, BCUC IR 38.1, pp. 1 to 2.
181 Exhibit B-4, BCUC IR 32.11, p. 3; BCUC IR 40.3, pp. 2 to 3.
182 Exhibit B-4, BCUC IR 40.4, pp. 1 to 2.
183 Exhibit B-4, BCUC IR 40.4.1, p. 2.

Under the F2022 budget, BC Hydro intends to focus its distribution vegetation management program on returning to on-cycle delivery, increased fire prevention, addressing hazard trees and moving to unit-based contracts.[184] BC Hydro believes that the proposed $5.6 million increase in spending on the distribution system will allow for its program to return to a level that is more sustainable over the long-term.[185]

4.3.2.3 New Vegetation Management Strategy

Although a new VMS will be forthcoming in F2022, the proposed budget will help to inform the new strategy and future budgets. The introduction of LiDAR, the clearing of the current accumulation and the continued engagement in market processes will be areas of focus for F2022 and the new VMS.[186] BC Hydro submits that it intends to develop new metrics by which it will measure the effectiveness of its new VMS, many of which are already measured though peer benchmarking and industry comparisons.[187] Such metrics will include cost effectiveness, reliability performance (with respect to impacts from vegetation), safety performance, compliance with standards and regulations and risk profiles through the development of a risk model. During the review session BC Hydro clarified that the new VMS would not be ready for review prior to the F2023 RRA filing and that both documents would be filed concurrently with the BCUC.[188]

4.3.2.4 Vegetation Management Compliance Activities

On September 9, 2019, by Order R-18-19, the BCUC ordered that a Compliance Violation Investigation (CVI) of BC Hydro's compliance with FAC-003, Transmission Vegetation Management, was warranted. WECC, as MRS administrator for the BCUC, conducted a CVI between September 11, 2019 and March 26, 2020. The resulting findings of WECC were filed on June 19, 2020 in a CVI report addressed to the BCUC.

On January 20, 2021, BC Hydro was [redacted] During the in-camera session, BC Hydro submitted [redacted] BC Hydro is currently [redacted]

Positions of Parties

BCSEA, CEC, BCOAPO, Zone II RPG and MoveUP support BC Hydro's proposed F2022 vegetation management budget.[191] BCOAPO submits that ideally the new VMS would have preceded any significant increase in spending,

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[184] Exhibit B-2, p. 5-73.
[185] Exhibit B-2, p. 5-64.
[186] Exhibit B-2, p. 5-55.
[187] Exhibit B-4, BCUC IR 39.8, p. 1.
[188] BC Hydro F2022 RRA, Transcript Vol. 2, p. 307.
[189] Exhibit B-6, Confidential BCUC IR 6.1, p. 2.
[190] BC Hydro F2022 RRA, Transcript Vol. 2A, pp. 42 to 43.
[191] BCSEA Final Argument, p. 7; CEC Final Argument, pp. 15 to 16; BCOAPO Final Argument, p. 31; Zone II RPG Final Argument, p. 4; MoveUP Final Argument, p. 2.

but acknowledged that at current levels, it would still take several years to clear the accumulation of hazard tress.[192]

Both AMPC and RCIA take exception to various aspects of BC Hydro's proposed vegetation management budget. AMPC claims that BC Hydro's approach to the budget is "inconsistent with the direction that the Commission provided to BC Hydro" through Directive 22 of the Previous RRA, to focus primarily on increased spending on the distribution system. It submits that it would be appropriate instead to apply an inflationary adjustment to BC Hydro's forecast transmission vegetation management costs and only approve distribution vegetation maintenance costs that reflect the BCUC's concerns from the Previous RRA. Given a new VMS is still forthcoming and AMPC's submission that it was not able to fully test BC Hydro's expenses due to broader procedural and confidentiality issues, it does not believe a 50 percent general increase in costs has been justified.[193] Furthermore, because interveners were not able to provide their own evidence in this proceeding, AMPC submits that an asymmetrical nature of evidence was created in BC Hydro's favour. Rather than performing the maximum level of effort that can be managed, AMPC proposes that BC Hydro focus instead on least-cost efforts and levels that can be sustained year-over-year while maintaining reliability standards and safe operations.[194] It further advocates for a benchmarking approach to be used before any costs are approved.[195]

In reply, BC Hydro disagrees with AMPC's interpretation of Directive 22 and submits that the directive did not limit vegetation management increases to inflation, but rather identified that an inflationary adjustment could be appropriate for certain expenditures. Furthermore, it claims that the BCUC did not purport to determine allowed operating expenses for F2022, which was not a matter before them in that proceeding, but rather it was identifying a simplified approach that could be used in a "gap year" application.[196] It also disagrees with AMPC's characterization that Directive 22 applies solely to the distribution system, and it submits that the Previous RRA Decision included multiple references to MRS standards and the transmission system.[197]

RCIA also opposes BC Hydro's proposed vegetation management budget and believes that the evidence filed "demonstrates that the vegetation management work has been somewhat neglected, or at least de-emphasized as a corporate concern, over the past dozen years."[198] RCIA also submits that BC Hydro has not "compellingly demonstrated why the efforts in F2006 to F2009 were able to be achieved by short term gradual increases" while a new 50 percent spending increase must be extended indefinitely to achieve the same results, based on BC Hydro's view that future expenditures will most likely not decrease.[199] The proposed spending is near the upper limit of what BC Hydro has submitted that it can reasonably manage and RCIA is concerned that it "presents a high risk of inefficient spending."[200] RCIA argues that BC Hydro has not demonstrated that it is prudent to increase vegetation management spending by 50 percent in a single year and to hire 18 additional permanent FTEs prior to a final revised VMS. It believes costs are being incurred and personnel is being hired

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192 BCOAPO Final Argument, p. 31.
193 AMPC Final Argument, p. 4.
194 AMPC Final Argument, p. 6.
195 AMPC Final Argument, pp. 5 to 6.
196 BC Hydro Reply Argument, pp. 19 to 20.
197 BC Hydro Reply Argument, p. 20.
198 RCIA Final Argument, p. 13.
199 RCIA Final Argument, p. 13; Exhibit B-4, BCUC IR 32.9, p. 2.
200 RCIA Final Argument, p. 14.

prior to having a properly developed plan in place and recommends that vegetation management funding be limited to the F2021 forecast until the new VMS has been finalized and approved by the BCUC.[201]

In response to RCIA's claim that BC Hydro has not justified its proposed budget and its recommendation to limit funding to the F2021 plan, BC Hydro submits that this course of action would be harmful in that it has already spent an additional $3.6 million above plan in F2020 and anticipates spending an additional $8.8 million in F2021 above plan.[202] Given the unplanned incremental expenditures from F2020-F2021 and the vegetation accumulation that still exists, BC Hydro believes it would be unreasonable to expect that its financial requirements could decrease in F2022. Furthermore, limiting incremental funding would lead to grow-ins and could cause detrimental impacts to distribution reliability and public safety.[203]

BC Hydro states that the fact that the new VMS has not yet been issued is an unpersuasive rationale for RCIA's position against the proposed budget, as the immediate priority of any strategy will be to address the accumulation of vegetation which is expected to take a few years.[204] BC Hydro believes it has provided ample evidence for the proposed cost increases which is reinforced by benchmarking evidence that shows current spending below its utility peers.[205] It also submits that future spending will be informed by a suite of metrics and targets that will be developed under the new VMS in line with the benchmarking approach recommended by AMPC.[206]

Both AMPC and RCIA have questioned the efficacy of BC Hydro's proposed spending and BC Hydro counters that the size of the proposed budget is scaled to the amount of work that it can achieve efficiently without impacting market rates.[207] Furthermore, it disagrees with RCIA's characterization that it has failed to maintain the gains from the F2006 to F2009 clearing and that it has realized the benefits from those activities over the last decade, but "once the overall canopy reaches a critical height, the only option is to clear the canopy again."[208]

Panel Determination

The Panel acknowledges that BC Hydro's proposed F2022 budget responds clearly to the BCUC's directive in the Previous RRA decision to ensure it addresses the adequacy of its vegetation management funding. An approximate 50 percent increase in the vegetation management budget is a sizeable increase. However, the reliability risk posed by continued accumulation on the transmission system and the potential resulting impact on the distribution system, as described by BC Hydro, is of high significance.

The proposed F2022 budget allocates 60 percent of the incremental amount to the transmission system and an additional 16 percent to the implementation of an on-going LiDAR program, which will primarily serve the transmission system's vegetation management.[209] The Panel is in support of addressing the vegetation accumulation risk on the transmission system and the implementation of LiDAR, which is considered common industry practice; however, with at least 76 percent of new spending directed towards activities supporting the

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[201] RCIA Final Argument, p. 14.
[202] BC Hydro Reply Argument, p. 21.
[203] BC Hydro Reply Argument, p. 21.
[204] BC Hydro Reply Argument, p. 22.
[205] BC Hydro Reply Argument, p. 23.
[206] BC Hydro Reply Argument, p. 24.
[207] BC Hydro Reply Argument, p. 24.
[208] BC Hydro Reply Argument, p. 23.
[209] Exhibit B-2, p. 5-39.

transmission system, the Panel questions whether BC Hydro is adequately supporting the distribution system's vegetation management. BC Hydro has made clear on the record that its priority in F2022 is the transmission system due to potential of a high-consequence outage and the Panel appreciates this position. Nevertheless, due to the fact that BC Hydro submits that the distribution system has a higher contribution towards reliability and that such concerns were raised by the BCUC in the Previous RRA Decision, there is concern that the proposed budget may not fully address the distribution system's needs. The Panel, however, does not agree with AMPC's interpretation of Directive 22, in that the intended focus of the F2022 vegetation management budget was to be the distribution system in isolation and that inflation was to be the basis of any future increase, and the Panel accepts that increases to the transmission budget are appropriate.

The Panel supports BC Hydro's implementation of a LiDAR program. We accept that, LiDAR being a common industry practice, BC Hydro operating in "one of the most densely forested jurisdictions in North America" and the effects of climate change on vegetation growth, together provide indication that it would be a beneficial part of a transition to a sustainable clearing cycle. While the LiDAR program represents an on-going expense that will be borne by future ratepayers, BC Hydro has adequately justified its use and its experience with the technology through its use on transmission line rating studies gives the Panel greater confidence in its potential effectiveness.

Throughout the proceeding, questions were raised by parties regarding BC Hydro's proposed level of effort, in order to fully understand the capacity constraints affecting its ability to deliver greater progress in reducing vegetation risk to both the transmission and distribution system. The Panel recognizes that the proposed budget is the maximum that BC Hydro believes it can prudently manage and that engaging in a greater level of effort could result in inefficiencies stemming from market challenges. The Panel also acknowledges RCIA's concern with respect to BC Hydro's foreshadowing of a new increased baseline for vegetation management spending. However, the Panel accepts, based on benchmarking and reliability evidence, that the status quo over the previous twelve years has not been sustainable and has led to an environment of increased risk. Given an accumulation of 18,000 hectares above the sustainable level currently exists and that BC Hydro submits that it will operate at capacity for the F2022 year, the Panel wishes to better understand, through the new VMS, how BC Hydro plans to clear the accumulation on the transmission system in a timely fashion.

The Panel accepts that the F2022 will represent a transitional year for BC Hydro's vegetation management program and will lay the foundations for its new VMS. AMPC and RCIA expressed concern in regard to the efficacy of approving a significant increase in the vegetation management budget prior to the filing of the new VMS. The Panel is cognizant of this unconventional approach which presents difficulty in measuring cost efficiency, nevertheless it believes BC Hydro has successfully justified its plan in maintaining that activities presented in the F2022 budget would be priorities of any new VMS. Given the substantial allocation to the transmission system as compared to the distribution system in the proposed F2022 budget, the Panel would like BC Hydro to, in its forthcoming new VMS, elaborate on its long term plan to address vegetation risk and reliability on the distribution system.

With respect to [redacted] the Panel acknowledges that at the present time [redacted] BC Hydro has made it clear [redacted]

[redacted] The Panel understands these [redacted]

The Panel acknowledges, as raised by AMPC and RCIA, that the truncated review process for the Application did not give interveners the opportunity to submit evidence regarding vegetation management, nor were requests for access to related confidential material received. While it is unfortunate that the Application had to be reviewed in a truncated process, it was necessary in order to balance the need for a more comprehensive multi-year review for the next RRA.

Similar to its position regarding the confidentiality of MRS Cybersecurity matters, the Panel considers the confidentiality of MRS-related vegetation management activities should be left for a future BCUC panel to decide based on the facts and circumstances and in accordance with the process set out in the BCUC's Rules of Practice and Procedure.

The Panel supports BC Hydro's commitment to reducing vegetation risk and improving reliability on its transmission and distribution systems and looks forward to receiving BC Hydro's new VMS which will assist in moving it to a sustainable clearing program. The Panel notes that WECC has recently completed a CVI into BC Hydro's FAC-003, Transmission Vegetation Management, which may result in the need for additional resources in order to address potential issues identified in the CVI. With the view that F2022 is a transitional year for the vegetation management program, that BC Hydro is maximizing its capacity for effort in this area and that it must address any potential issues raised in the CVI, the Panel finds the requested vegetation management budget to be reasonable.

Given the importance of a new long-term vegetation management plan which will inform future RRAs, BC Hydro is directed to file with the BCUC, the new Vegetation Management Strategy in the F2023 RRA and any revisions to it thereafter.

In addition, to assist with monitoring the vegetation management budget, the Panel directs BC Hydro to provide in future RRAs a breakdown of the vegetation management budget in a format similar to that provided in Table 5-11 of the Application and expanded to include historical costs for the most recent five years.

4.3.3 Discount Rate Used for Current Pension Service Costs

Apart from the investments in mandatory reliability standards, almost all of the remaining planned operating cost increase is associated with uncontrollable factors, with the most significant factor being current service costs. Current service costs relate to BC Hydro's pension plan and are increasing by $33.6 million in F2022.[211]

Current service costs are sensitive to changes in the market discount rate. A decrease in the discount rate will increase current service costs, while an increase in the discount rate will decrease current service costs. Current service costs are for future pension benefits earned by employees in the current year and are determined by BC Hydro's external actuary. The present value of future pension benefits earned by employees in the current year

[210] BC Hydro F2022 RRA, Transcript Vol. 2A, pp. 42 to 43.

[211] BC Hydro Final Argument, Part Five, Section G, p. 39.

are determined using the market discount rate at the date of the forecast. The market discount rate is based on AA Canadian Corporate bond yields.[212] Changes in the discount rate are market driven and outside of BC Hydro's control.[213] The increase in current service costs is primarily due to the 74 basis points decrease in the discount rate from 3.33 percent[214] in F2021 to 2.59 percent[215] in F2022.[216]

Positions of Parties

Apart from RCIA and AMPC, interveners are silent with respect to the uncontrollable cost increases, inclusive of pension cost increases. RCIA and AMPC advocate for determining forecast current service pension costs based on a five-year average discount rate.[217]

AMPC submits that the current methodology "results in large rate swings which are affected by timing choices that have no impact on the actual service being provided to ratepayers." And that these costs should be stabilized by the BCUC directing the use of a five-year average discount rate.[218]

RCIA states that it is not convinced that the discount rate used to calculate the F2022 current service pension costs has been developed in a "manner representative of the actual future pension servicing costs BC Hydro needs to face" and that the methodology "calculates BC Hydro's long-term pension obligations using a discount rate that is heavily influenced by the current short-term interest rate of AA Canadian Corporate bonds, and as such is subject to unnecessary volatility." RCIA submits that the BCUC should direct BC Hydro to use a discount rate developed using multi-year rate trends (e.g., 5-year historical trend) rather than based on a single point in time. And in the absence of better information, RCIA contends that BC Hydro should be required to use the F2021 discount rate of 3.83 percent.[219]

In Reply, BC Hydro notes that the BCUC has considered, and rejected, the five-year average approach in each of the last two RRA proceedings and that it is appropriate to set rates for F2022 based on the BCUC approved methodology, as BC Hydro has done. BC Hydro submits that the timing of the updated discount rate analysis is consistent with past RRAs.[220]

Panel Determination

The Panel acknowledges that for the purposes of setting the F2022 rates, BC Hydro is following the methodology previously approved by the BCUC and is appropriately calculating pension costs based on the most recent available discount rate at the time the forecast is prepared.

With respect to AMPC's and RCIA's comments regarding the discount rate to forecast current service pension costs, the Panel notes that there is insufficient evidence on the record in this proceeding with respect to the potential impact of their proposed changes. Nonetheless, the Panel does not see how using a discount rate that prioritizes stabilizing pension costs would produce costs that better represent BC Hydro's actual future pension

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[212] Exhibit B-2, Section 5.11.5, p. 5-103.
[213] Exhibit B-2, Section 5.5.3, Table 5-5, p. 5-18.
[214] Based on discount rates at March 31, 2019.
[215] Based on discount rates at July 31, 2020.
[216] Exhibit B-2, Section 5.5.3, Table 5-5, p. 5-18.
[217] AMPC Final Argument, Section I, p. 2.; RCIA Final Argument, Section 4.5.2, pp. 16 to 17.
[218] AMPC Final Argument, pp. 2 to 3.
[219] RCIA Final Argument, Section 4.5.2, pp. 16 to 17.
[220] BC Hydro Reply Argument, p. 27.

servicing costs. Further, there is a lack of evidence to support using historic discount rates in place of more current information to forecast future pension costs.

The Panel is not persuaded by AMPC or RCIA's proposal, and declines to direct BC Hydro to change its methodology as suggested by AMPC and RCIA. The Panel finds the F2022 current pension service costs to be reasonable.

4.4 Capital Costs

The Panel's review of the forecast capital additions and forecast capital expenditures in the Test Period is to determine whether the forecasted amounts are reasonable within the one-year Test Period and to determine whether the approvals sought comply with sections 59 to 61 of the UCA as well as other elements of the legal and legislative framework as summarized in Section 2.0 of the Decision. The Panel also evaluates BC Hydro's system performance and safety over time to ensure no asset deterioration is occurring.

BC Hydro submitted a streamlined capital section in the Application to accommodate the shortened timeline for review.[221] BC Hydro sets out its proposed capital additions and capital expenditures during the Test Period in Chapter 6 of the Application, and states that the forecasts are derived from its F2021 to F2030 Capital Plan. BC Hydro states that forecast capital additions and expenditures for the Test Year are lower than the prior year due to completion of major capital projects in F2021, and that its capital planning process remains substantially the same as that submitted in its Previous RRA.[222]

4.4.1 Forecast Capital Additions and Expenditures

BC Hydro states the forecast capital additions are the capital investments that are affecting rates during the Test Period and occur when the capital assets enter service.[223] BC Hydro's actual capital additions for F2020, its forecast capital additions for F2021 and its planned capital additions for the Test Year are set out in the following table:[224]

[221] Exhibit B-2, p. 6-4.
[222] Exhibit B-2, p. 6-1.
[223] Exhibit B-2, p. 6-1.
[224] Exhibit B-2, Table 6-2, p. 6-7.

Table 13: Actual and Planned Capital Additions (F2020 to F2022)

($ millions)	F2020		F2021		F2022
	RRA	Actual	RRA	Forecast	Plan
Generation					
Growth	2.7	-	-	-	-
Sustaining	312.0	359.5	297.0	244.3	272.4
Total Generation (Schedule 13, Line 13)	314.7	359.5	297.0	244.3	272.4
Site C Project (Schedule 13, Line 17)	27.9	12.9	189.4	197.5	-
Transmission					
Growth	97.9	88.0	83.3	92.3	168.1
Sustaining	195.9	111.6	146.3	191.4	272.6
Total Transmission (Schedule 13, Line 15)	293.8	199.7	229.6	283.7	440.7
Distribution					
Growth	306.9	307.6	344.2	325.3	301.7
Sustaining	195.3	162.0	196.5	199.0	201.2
Total Distribution (Schedule 13, Line 16)	502.2	469.6	540.7	524.3	502.9
Business Support					
Technology (Schedule 13, Line 18)	147.6	93.7	75.5	143.4	94.3
Properties (Schedule 13, Line 19)	39.9	44.3	55.6	60.8	59.8
Fleet / Other (Schedule 13, Line 20)	64.9	56.4	71.3	74.4	75.2
Total	1,391.0	1,236.1	1,459.1	1,528.3	1,445.2
Less: Contribution in Aid	(146.1)	(140.5)	(165.8)	(165.7)	(187.2)
TOTAL	1,244.9	1,095.6	1,293.2	1,362.7	1,258.0

BC Hydro states that capital expenditures represent "spending incurred on capital assets that will not affect rates until the capital assets enter service, which may be in the same fiscal year or a future fiscal year."[225] BC Hydro's proposed capital expenditures in the Test Period are set out in the following table:[226]

225 Exhibit B-2, p. 6-1.

226 Exhibit B-2, Table 6-1, p. 6-6.

Table 14: Actual and Planned Capital Expenditures (F2020 to F2022)

($ millions)	F2020		F2021		F2022
	RRA	Actual	RRA	Forecast	Plan
Generation					
Growth (Schedule 13, Line 1)	3.2	2.6	-	4.6	5.0
Sustaining (Schedule 13, Line 3)	341.8	302.5	435.5	346.6	383.4
Total Generation	345.1	305.1	435.5	351.2	388.4
Site C Project (Schedule 13, Line 8)	1,530.0	1,619.1	1,535.5	1,626.0	1,361.0
Transmission					
Growth (Schedule 13, Line 4)	185.0	159.6	198.9	101.2	142.9
Sustaining (Schedule 13, Line 5)	222.6	223.3	286.5	270.3	325.6
Total Transmission	407.6	382.9	485.4	371.5	468.5
Distribution					
Growth (Schedule 13, Line 6)	300.0	339.7	284.6	343.2	306.7
Sustaining (Schedule 13, Line 7)	187.5	176.2	176.8	175.9	219.3
Total Distribution	487.5	515.9	461.4	519.1	526.1
Business Support					
Technology (Schedule 13, Line 9)	95.6	133.0	56.0	71.2	69.2
Properties (Schedule 13, Line 10)	58.9	56.4	55.3	65.1	75.6
Fleet / Other (Schedule 13, Line 11)	63.6	59.0	75.1	82.0	70.3
Total	2,988.3	3,071.4	3,104.1	3,086.0	2,959.0
Less: Contribution in Aid	(157.8)	(178.8)	(148.4)	(159.7)	(214.2)
TOTAL	2,830.5	2,892.6	2,955.7	2,926.4	2,744.8

BC Hydro lists the following 16 projects that "have planned total capital expenditures greater than the materiality threshold for inclusion in Appendix J, have capital expenditures or additions in the Test Period, and were not included in Appendix J in the Previous Application" (Additional Projects):[227]

- La Joie – Dam Improvements, p. 6-26
- Ash River – Generator Replacement, p. 6-29
- Mica – U1-U4 Circuit Breaker and Iso-Phase Bus Replacement, p. 6-29
- Mica – U1-U2 Turbine Overhaul, p. 6-29
- Mica – Upgrade HVAC System, p. 6-29
- Mica – Upgrade 600 V Circuit Breakers, p. 6-29
- Bridge River 2 – Strip and Recoat Penstock 2 Interior, p. 6-30
- G.M. Shrum – U5 Stator Replacement, p. 6-30
- Bear Mountain Terminal – T4 Transformer Addition, p. 6-37
- North Montney Region – Electrification, p. 6-38
- Kamloops – Area Reinforcement, p. 6-38

[227] Exhibit B-2, pp. 6-26 to 6-63, and listed in Exhibit B-4, BCUC IR 1.43.1.

- Patricia – Substation Upgrade, p. 6-46
- Various Sites – NERC CIP-003v7 Implementation, p. 6-47
- Port Alberni – Substation Refurbishment, p. 6-48
- Various Sites – Microwave Radio Replacement, p. 6-51
- Vancouver Island – Saltspring 25F61 Submarine Cable Extension to North Pender Island (VI-GUL-005), p. 6-63

BC Hydro submits that it recently cancelled the Asset Investment Planning Tool project due to escalating project costs.[228] The Asset Investment Planning Tool project is discussed in further detail in Section 4.4.2 of this Decision.

In the Application, BC Hydro provides several statistics to measure its safety and system performance over time: lost time injury frequency, all injury frequency, dam safety vulnerability index, SAIFI, SAIDI, customer satisfaction index on reliability and average availability factor. Performance on some of these factors is linked to goals set and reported in BC Hydro's Service Plan.[229]

Lost Time Injury Frequency and All Injury Frequency

BC Hydro provides the following lost time injury frequency and all injury frequency results:[230]

[228] Exhibit B-2, p. 6-8.
[229] Exhibit B-2-2, Appendix Q.
[230] Exhibit B-4, BCUC IR 54.8.

Figure 4: Lost Time Injury Frequency and All Injury Frequency

Lost Time Injury Frequency comparable metrics: BC Hydro and CEA comparable utilities (Note: CEA is to calendar year and BC Hydro is to fiscal year)

LTIF	BC Hydro	CEA
F2012	1.02	0.85
F2013	1.27	0.65
F2014	1.11	0.5
F2015	1.02	0.57
F2016	1.2	0.57
F2017	1.08	0.4
F2018	0.94	0.59
F2019	0.92	0.432
F2020	0.96	-

All Injury Frequency comparable metrics: BC Hydro and CEA comparable utilities (Note: CEA is to calendar year and BC Hydro is to fiscal year)

AIF	BC Hydro	CEA
F2012	1.76	1.65
F2013	2.32	1.23
F2014	2	0.92
F2015	1.99	1.4
F2016	2.22	1.59
F2017	2.06	1.41
F2018	2.05	1.43
F2019	2.25	1.472
F2020	2.02	-

The information provided above shows that BC Hydro's Lost Time Injury Frequency and All Injury Frequency are consistently higher than the Canadian Electricity Association average.

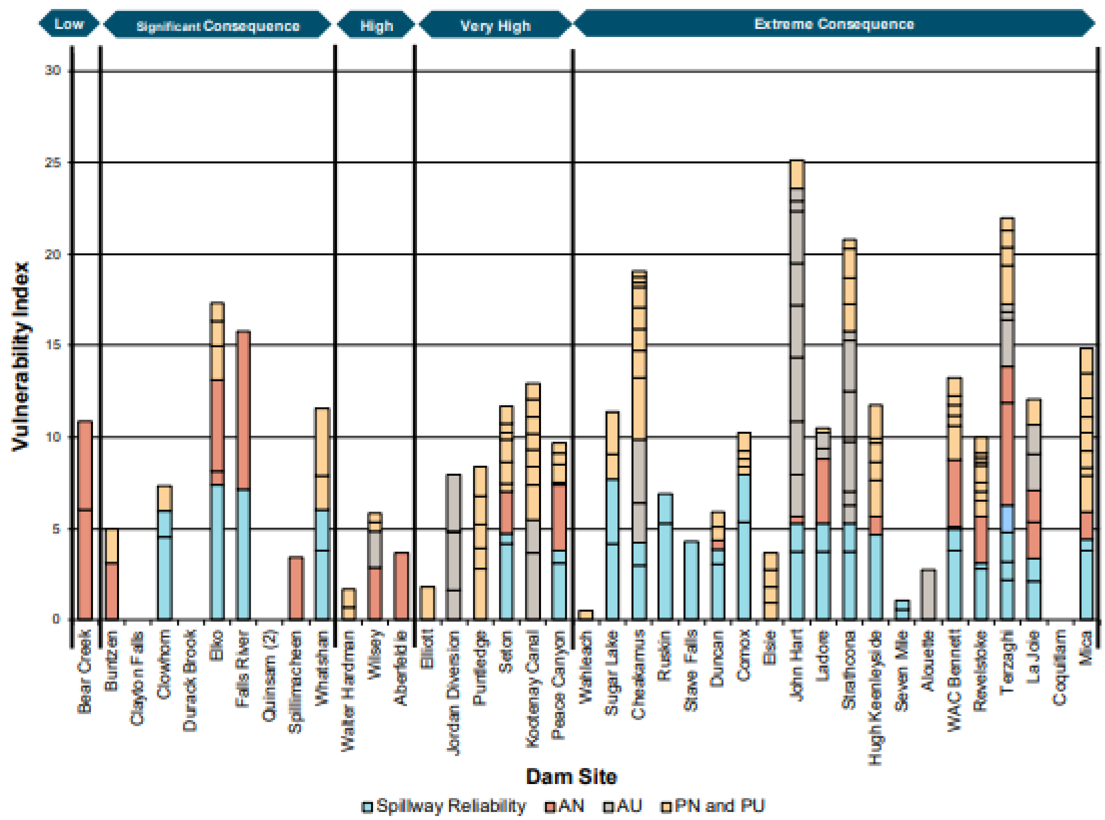
<u>Dam Safety and Vulnerability Index</u>

BC Hydro characterizes the risks to its dams by the extent to which the dam system deviates from what is considered current good practice through development of a Vulnerability Index, which characterizes the degree of concern that exists with respect to the integrity of the dam. The development of the Index is informed by BC Hydro's institutional knowledge, by guidelines such as those published by the Canadian Dam Association and the International Commission on Large Dams, and by interactions with other dam owners, regulators and external reviewers. The scheme is set up such that, at some point in the future, the calculation can be converted into a probability of failure. For each dam, the Vulnerability Indices associated with each deficiency are aggregated and charted to provide an overall Vulnerability Index for the dam. BC Hydro tracks each dam's Vulnerability Index over time and tracks its overall portfolio Vulnerability Index.[231]

[231] Exhibit B-4, BCUC IR 53.2.

BC Hydro provides its dam safety vulnerability index as at December 31, 2020, which shows the vulnerability of each of BC Hydro's dams, grouped by consequence level, in the following graph:[232]

Figure 5: Dam Safety Vulnerability Index for BC Hydro Dams at December 31, 2020

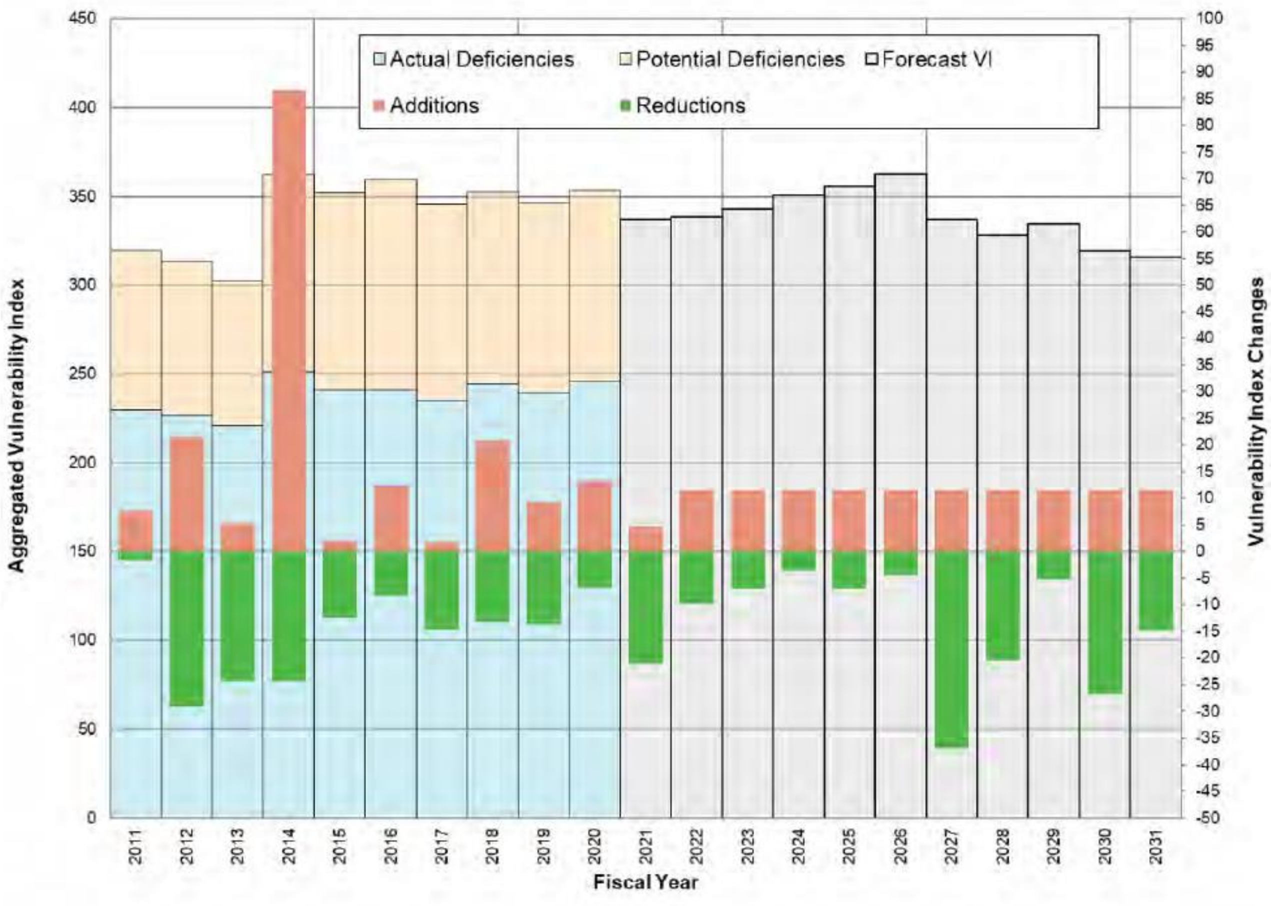


BC Hydro's Aggregated Dam Safety Vulnerability Index (VI) Forecast to F2031 is provided in the following graph:[233]

[232] Exhibit B-4, Figure 1, BCUC IR 53.2.

[233] Exhibit B-4, Figure 1, BCUC IR 53.3.

Figure 6: Aggregated Dam Safety Vulnerability Index Forecast to F2031



BC Hydro explains:[234]

> The forecast of the Aggregate Vulnerability Index is based on an annual forecast of reductions and additions. The forecast of reductions includes Vulnerability Index reductions attributable to the completion of planned capital projects. Not included in the forecast are reductions that are achieved each year through the completion of investigations and unplanned projects to address urgent deficiencies. Forecast additions occur when deficiencies and vulnerabilities are identified and updated through BC Hydro's ongoing dam safety program that includes constant monitoring and estimation of risks and threats. The forecast of Vulnerability Index additions is based on a historical average from the past five years of 11.5 per year. The Aggregate Vulnerability Index forecast is represented as a combined Aggregate Vulnerability Index and does not distinguish between Actual and Potential Deficiencies.

BC Hydro states it manages its dams so that there is "no significant deterioration in the risk position and the overall level of risk is kept within limits considered to be tolerable" and adds that the historical and forecast Vulnerability Index for the BC Hydro dam fleet "shows no significant deterioration in risk position over time."[235]

[234] Exhibit B-4, BCUC IR 53.3.

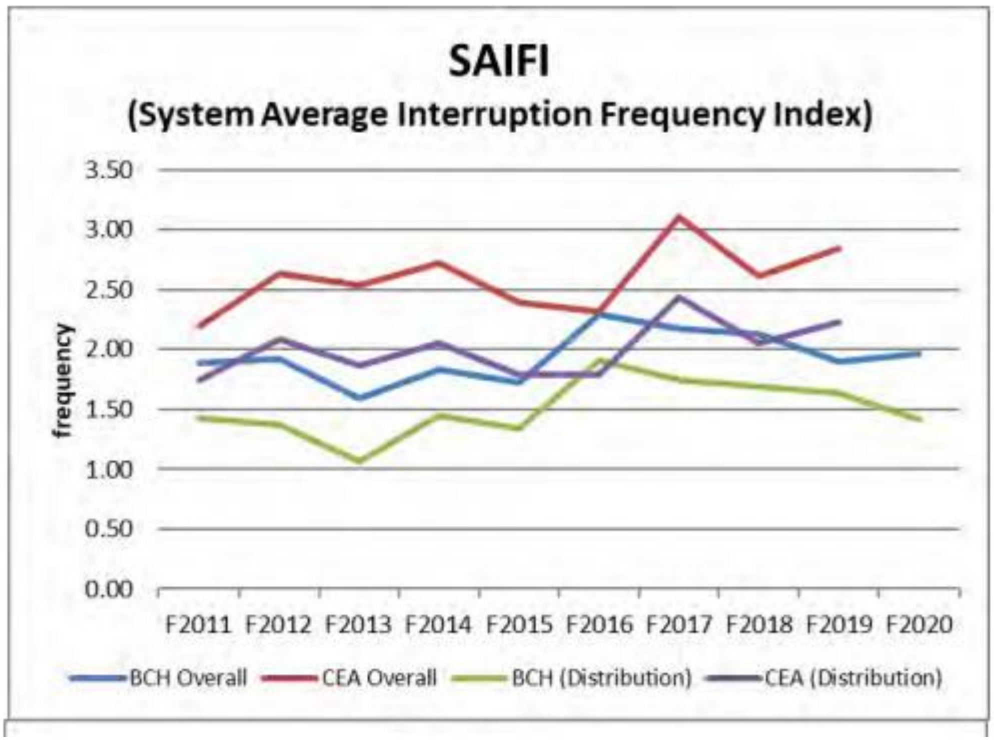
[235] Exhibit B-4, BCUC IR 53.3.

BC Hydro states that its dam safety projects are prioritized in four stages: first, dams are ranked in terms of the total vulnerability index for each dam; second, consideration is given to whether there are concerns at lower ranked dams that warrant earlier attention; third, economy, cost, availability of resources and availability of alternative risk controls are considered; and fourth, BC Hydro considers "strategic investments in assets and other operational considerations."[236]

Reliability Indices

BC Hydro provides the System Average Interruption Frequency Index (SAIFI) data for its overall and distribution-related outages in the following graph:[237]

Figure 7: System Average Interruption Frequency Index

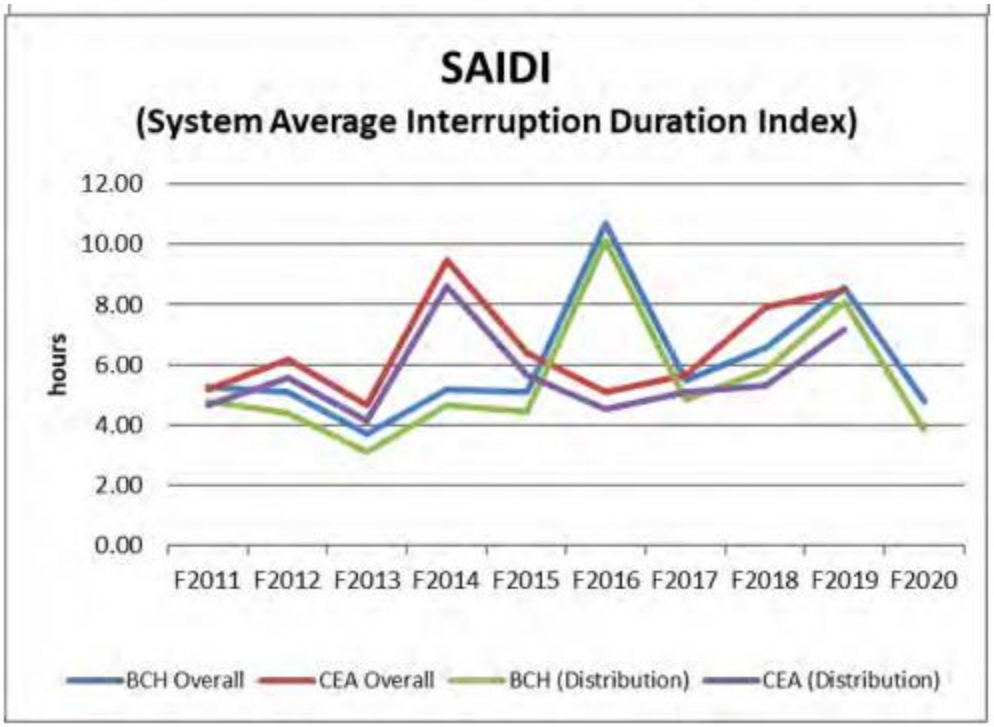


The graph above shows that BC Hydro's overall performance on SAIFI is consistently better than the CEA average, since F2016. However, the F2020 results show an increase in interruption frequency over the prior year.

BC Hydro provides the System Average Interruption Duration Index (SAIDI) data for its overall and distribution-related outages in the following graph:[238]

[236] Exhibit B-4, BCUC IR 53.2.
[237] Exhibit B-2-2, Appendix T, p. 8.
[238] Exhibit B-2-2, Appendix T, p. 8.

Figure 8: System Average Interruption Duration Index



The graph above shows that BC Hydro's overall performance on SAIDI improved in F2020, over prior years.

BC Hydro provides its normalized reliability indices:[239]

Table 15: Reliability Indices - BC Hydro Overall - Normalized using IEEE 2.5 Beta Method

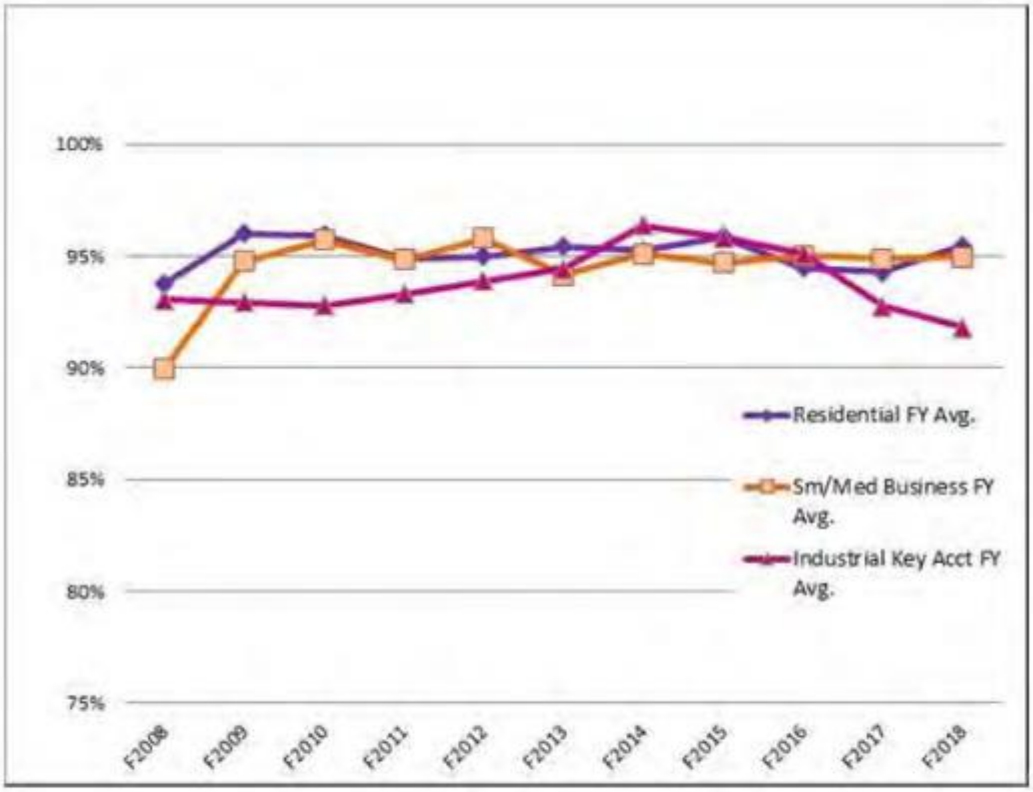
Year	BC Hydro Overall – Normalized using IEEE 2.5 Beta method				
	SAIFI	SAIDI	CAIDI	CEMI-4 (%)	%ASAI
F2011	1.61	3.83	2.38	15.26	99.956
F2012	1.67	3.89	2.34	15.37	99.956
F2013	1.46	3.33	2.28	10.45	99.962
F2014	1.68	4.14	2.46	12.52	99.953
F2015	1.35	3.37	2.49	10.13	99.962
F2016	1.60	3.42	2.14	14.00	99.961
F2017	1.88	4.37	2.33	16.43	99.950
F2018	1.67	3.94	2.36	14.55	99.955
F2019	1.39	3.21	2.32	10.65	99.963
F2020	1.68	3.56	2.12	14.59	99.959

The normalized SAIFI and SAIDI results show improvement in system performance between F2017 and F2019. F2020 results show a decline in system performance since F2019.

[239] Exhibit B-2-2, Appendix T, Table 3, p. 6.

BC Hydro provides its customer satisfaction index on reliability:[240]

Figure 9: Customer Satisfaction Index on Reliability



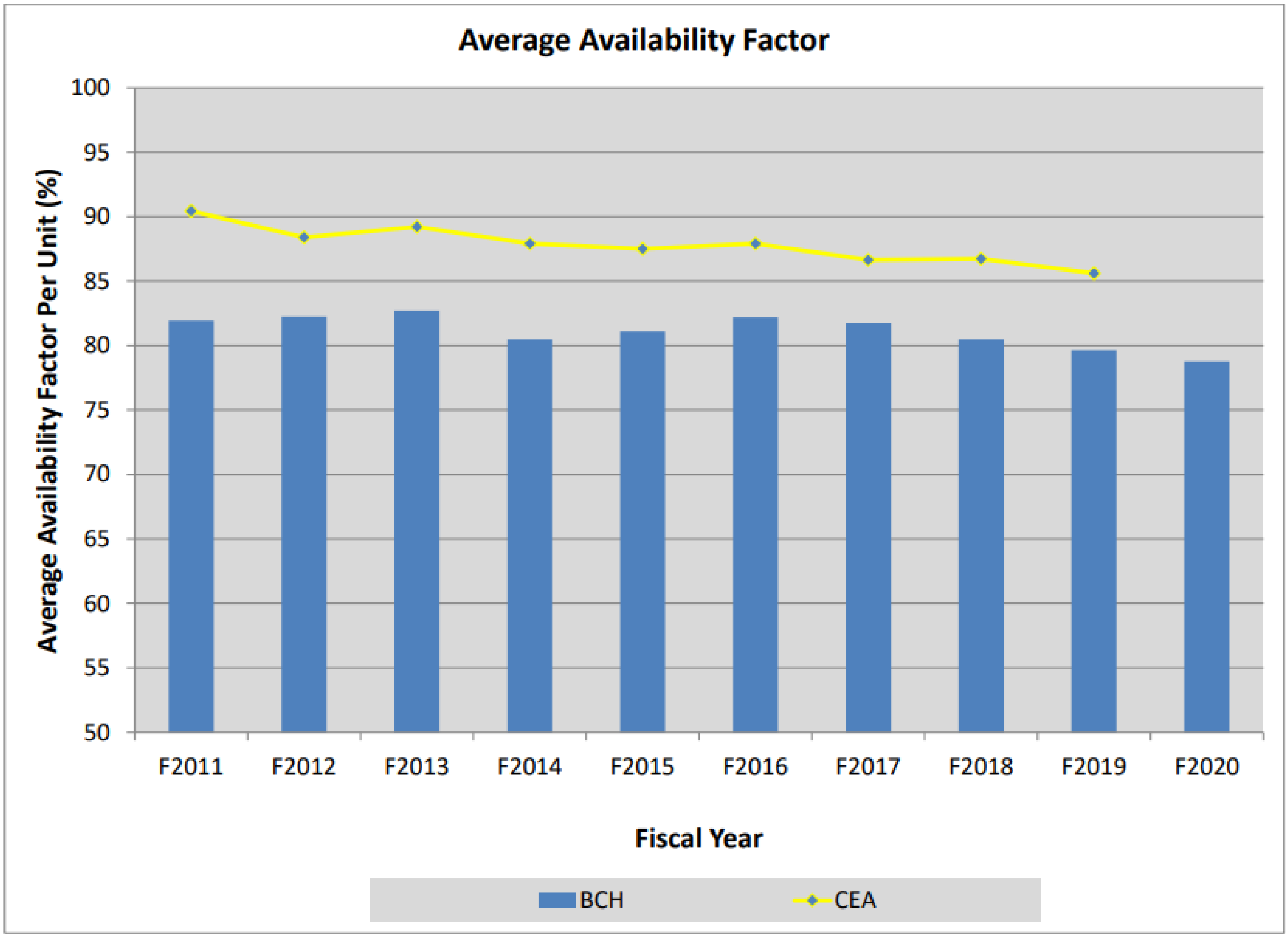
The customer satisfaction index on reliability statistics for industrial customers shows a decline in satisfaction from F2014 through F2018. Results are not shown for the years after F2018.

BC Hydro provides its average availability factor, one of its reliability indices, compared to the Canadian Electricity Association results for hydroelectric units:[241]

[240] Exhibit B-2-2, Appendix S, Figure 6-10, p. 10.

[241] Exhibit B-2-2, Appendix T, p. 15.

Figure 10: Average Availability Factor



The graph above shows BC Hydro's average availability factor per unit percentage is consistently lower than the Canadian Electricity Association average and shows a declining trend since F2016.

Positions of Parties

BC Hydro submits that its capital forecast for the Test Period "provides an appropriate basis for setting rates" and is the outcome of its "robust capital planning and delivery processes, which are unchanged from the processes that the BCUC found to be reasonable" in the Previous RRA Decision.[242]

BC Hydro submits that its planned capital additions and expenditures for the Test Period are lower than the amounts planned for F2021, primarily due to the completion of major projects in F2021. BC Hydro adds that the updated load forecasts support its previous decision to moderate investments to expand and reinforce the power system; however, new growth investments continue to be required for both distribution and transmission infrastructure.[243]

[242] BC Hydro Final Argument, p. 41.
[243] BC Hydro Final Argument, p. 44.

BC Hydro submits the planned capital investments for the Test Period promote safety, reliability and resilience, while respecting affordability for customers.[244]

BC Hydro submits that maintaining reliability remains a priority, and that the system is performing well. BC Hydro adds that its unadjusted SAIDI and SAIFI trends are "as strong as, or better than, the Canadian Electricity Association (CEA) composite," and that the reliability scores in its customer satisfaction index indicate customers "continue to be satisfied with the level of reliability." BC Hydro acknowledges that its average availability factor has been trending downward, but submits this is not a concern as this is due to an increase in planned outages for maintenance.[245]

BC Hydro submits its steady improvement in controlling safety risks and mitigating hazards is illustrated by the downward trend in its lost time injury frequency targets. Further, BC Hydro submits it manages its dams so there is "no significant deterioration in the risk position and the overall level of risk is kept within tolerable limits."[246]

BC Hydro submits that the BCUC should not direct BC Hydro to file a Certificate of Public Convenience and Necessity (CPCN) for any of the 16 projects added to Appendix J this year because they are either underway and below the appropriate CPCN threshold, or are future projects with no project cost or start date for construction.[247]

BCOAPO has no issues with BC Hydro's proposed capital expenditures or capital additions.[248] BCSEA agrees that BC Hydro's capital investments continue to balance affordability with system performance and risk, and that the BCUC should not require BC Hydro to submit CPCN applications for any of the 16 projects not reviewed in the Previous RRA.[249]

Bryenton submits that BC Hydro consistently over-estimates its capital expenditures and that setting the budget "closer to probable actual numbers" removes the need for a rate increase,[250] and that the "desired outcome" of BC Hydro's Capital Plan should be to "eliminate or minimize any rate increase."[251] Bryenton further submits that BC Hydro should consider waiving depreciation during the COVID-19 pandemic, and should not "stick strictly to rigid accounting practices."[252]

BC Hydro submits that it is sensitive to affordability, but that it must balance this with system performance and the need to safely manage its assets. BC Hydro adds that an arbitrary reduction in its planned capital budgets could compromise its ability to manage systems risks and performance and to maintain asset health, which would be imprudent. BC Hydro submits that waiving depreciation is not a reasonable option as this would violate accounting rules, increase financing costs and arbitrarily defer expenses to future years.[253]

[244] BC Hydro Final Argument, p. 41.
[245] BC Hydro Final Argument, p. 45.
[246] BC Hydro Final Argument, p. 46.
[247] BC Hydro Final Argument, p. 48.
[248] BCOAPO Final Argument, pp. 39 to 41.
[249] BCSEA Final Argument, pp. 9 to 10.
[250] Bryenton Final Argument, p. 1.
[251] Bryenton Final Argument, p. 4.
[252] Bryenton Final Argument, p. 4.
[253] BC Hydro Reply Argument, pp. 29 to 30.

RCIA submits that "BC Hydro's claims that its existing capital planning and delivery processes are robust, well-established and effective has not been substantiated in this proceeding" as a result of BC Hydro not providing evidence to demonstrate it is addressing the capital investment process deficiencies the Asset Investment Planning Tool were expected to mitigate.[254]

BC Hydro submits that RCIA's argument is without merit, and that delaying investment in the Asset Investment Planning Tool until it is cost-effective to do so does not impair BC Hydro's existing capital processes.[255]

RCIA submits that the "significant Site C project schedule delays and cost increases" undermine the credibility of BC Hydro's claim its capital delivery processes are robust.[256]

BC Hydro submits RCIA's assertions are not supported by the evidence. BC Hydro notes that the Site C project is unique in BC Hydro's portfolio, and has not been the focus of this proceeding, adding that there is not evidence that schedule delays or cost increases on the Site C project are due to any failure of BC Hydro's capital delivery processes. BC Hydro submits that the BCUC examined BC Hydro's evidence on capital planning and delivery processes in the Previous RRA proceeding and found them to be reasonable, and they remain the same.[257]

The CEC submits that the BCUC should approve BC Hydro's capital plan, subject to the CEC's concerns about the Asset Investment Planning Tool and performance metrics. The CEC also agrees with BC Hydro that no CPCNs should be required for the projects "that are well below the CPCN threshold."[258]

The CEC submits that BC Hydro's metrics for analyzing its project delivery performance lack "benefit accountability for the budgeted cost," and it is difficult to determine if BC Hydro might "intentionally or inadvertently overestimated its budget, or otherwise allowed for excessive spending." The CEC submits that ongoing analysis of additional metrics, including benefits and budgets, would be useful for long-term tracking.[259]

Panel Determination

For the following reasons, the Panel finds that BC Hydro's forecast capital additions and capital expenditures for F2022 are reasonable.

The BCUC found in the Previous RRA proceeding that BC Hydro's capital planning processes were reasonable, and the Panel sees no evidence that these processes have changed since the BCUC made that finding, and thus sees no reason to find the processes are no longer reasonable.

The Panel does not agree with RCIA's submission that BC Hydro's capital processes are not demonstrably robust simply because BC Hydro is not proceeding to implement the Asset Investment Planning Tool. There is no evidence in this proceeding of any material deficiency in BC Hydro's capital planning process.

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[254] RCIA Final Argument, p. 18.
[255] BC Hydro Reply Argument, p. 33.
[256] RCIA Final Argument, p. 19.
[257] BC Hydro Reply Argument, pp. 30 to 31.
[258] CEC Final Argument, p. 27.
[259] CEC Final Argument, p. 22.

With respect to project delivery, the Panel accepts BC Hydro's position that the Site C project is unique in BC Hydro's capital investment portfolio and that the project's schedule and budget challenges do not undermine confidence in BC Hydro's standard capital planning and delivery processes. Excluding the Site C project, BC Hydro's actual capital costs were $160.2 million or 2.23 percent lower than its originally approved expected costs in the period from F2016 to F2020. The Panel agrees with BC Hydro that RCIA's assertions regarding its capital delivery processes are unsupported by evidence beyond the Site C project.

The Panel is satisfied that BC Hydro's forecast capital additions and expenditures balance risks to system performance, safety and asset deterioration while containing costs as far as it deems prudent.

In the Previous RRA decision, the BCUC explained that it has no mandate to consider the affordability of BC Hydro's rates. Thus, in that decision, the BCUC interpreted BC Hydro's "balance of system performance, risk and affordability" as "balancing risks to system performance and asset deterioration while containing costs as far as it deems prudent."[260] In this Application, BC Hydro explicitly introduces the notion of safety into its submissions on capital expenditures, which the Panel considers appropriate. Thus, the Panel assesses whether BC Hydro's forecast capital expenditures and additions balance risks to system performance, safety and asset deterioration while containing costs as far as it deems prudent.

BC Hydro has also introduced in this proceeding the notion that its capital spending is intended to promote "reliability and resilience."[261] The Panel does not disagree, but notes that in the Previous RRA BC Hydro merely referred to reliability[262] or alternatively system performance.[263] The Panel encourages BC Hydro to define resilience in its F2023 RRA if it wishes the BCUC to consider resilience as a factor in its deliberations.

BC Hydro proposes reducing its capital additions from $1,362.7 million forecast in F2021 to a forecast of $1,258.0 million in F2022, and its capital expenditures from $2,926.4 million forecast in F2021 to a forecast of $2,744.8 million in F2022, and explains that these reductions are primarily due to the completion of major projects in F2021.[264] The Panel acknowledges that the level of capital additions and expenditures may vary from year to year depending on the timing of capital projects, but assesses proposed capital spending reductions by ensuring there is no evidence that, over time, system performance, safety and asset deterioration are being compromised as a result of inappropriate reductions to the level of capital spending.

The Panel is satisfied that BC Hydro's worker safety has not deteriorated materially since it started moderating capital spending in the F2020 to F2021 period. BC Hydro's long-term injury frequency increased between F2019 and F2020, but all-injury frequency has declined in the same period. However, the Panel is concerned that BC Hydro's results on both measures remain significantly above the Canadian Electricity Association average. In the Previous RRA the BCUC directed BC Hydro to evaluate in the F2023 RRA its safety data to determine whether it could achieve more aggressive lost time injury frequency and lost time injury duration targets, and if so, the additional costs, if any, that achieving such more aggressive targets may entail.[265] Because the F2023 RRA will be filed shortly, the Panel makes no further direction at this time with regard to BC Hydro's injury statistics.

[260] BC Hydro F2020 to F2021 RRA, BCUC Order G-246-20 and Decision, p. 86.
[261] BC Hydro Final Argument, p. 44.
[262] E.g. F2020 to F2021 RRA, Exhibit B-1, p. 6-7.
[263] E.g. F2020 to F2021 RRA, Exhibit B-1, p. 6-20.
[264] From tables in evidence above.
[265] BC Hydro F2020 to F2021 RRA, Order G-246-20 and Decision, p. 74.

The Panel notes BC Hydro's statement in its Final Argument, "The downward trend in Lost Time Injury Frequency targets illustrates BC Hydro's steady improvement in controlling safety risks and mitigating hazards,"[266] and expects BC Hydro to explain in its F2023 RRA how a declining trend in <u>targets</u> demonstrates a steady improvement in controlling safety risks and mitigating hazards when BC Hydro's lost-time injury frequency results actually worsened between F2019 to F2020 (from 0.92 to 0.96).

The Panel is satisfied with BC Hydro's analysis and mitigation of risks associated with dam safety, based on the forecast stability of BC Hydro's aggregate dam safety vulnerability index values from F2021 to F2031. To ensure the BCUC may continue to evaluate BC Hydro's dam safety, **the Panel directs BC Hydro to file its dam safety vulnerability index for all dams and its aggregate dam safety vulnerability index in the F2023 RRA**. **Further, the Panel directs BC Hydro to file a long-term capital plan for ensuring the sustainable safety of all its dams by December 31, 2021**.

With respect to system performance, BC Hydro submits that its system is "performing well". However, to the Panel, the evidence presents a mixed picture of system reliability. The frequency of system interruptions, measured by the overall SAIFI results[267] shows continuous improvement from a peak in F2016 to F2019, but deteriorates in F2020. The duration of system interruptions, measured by the overall SAIDI results[268] has improved in F2020 over F2019, reversing a deteriorating trend from F2017 to F2019. The normalized SAIFI and SAIDI results,[269] in contrast, indicate that system performance has declined between F2019 and F2020, reversing an improving trend from F2017 to F2019. BC Hydro's average availability factor per unit has been in steady decline since F2016, and is consistently below the average for Canadian Electricity Association survey respondents.

The conflicting evidence does not show a clear trend in system performance in any direction. However, the Panel is concerned that BC Hydro's previous reduction in sustainment capital spending may be contributing to a reduction in system reliability. The Panel recommends that the BCUC examine BC Hydro's system reliability statistics when the F2021 data become available to determine whether a declining trend in system performance is emerging.

The Panel also notes that BC Hydro's customer satisfaction index on reliability shows a continuous decline in reported satisfaction from industrial key accounts between F2014 and F2018, the most recent period for which statistics are available, which appears to be accelerating after F2016. **The Panel directs BC Hydro to provide updated figures for the customer satisfaction index on reliability in the F2023 RRA**.

The Panel considers there is no requirement at this time for BC Hydro to submit CPCNs for any of the Additional Projects, because they are either underway and below the appropriate CPCN threshold, or are future projects with no project cost or start date for construction yet available. The BCUC will review the future projects in a future RRA proceeding when more information is available.

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[266] BC Hydro Final Argument, p. 46.
[267] Exhibit B-2-2, Appendix T, p. 8.
[268] Exhibit B-2-2, Appendix T, p. 8.
[269] Exhibit B-2-2, Appendix T, p. 6.

4.4.2 Asset Investment Planning Tool

In the Previous RRA, BC Hydro discussed the Asset Investment Planning Tool project, an IT project with an estimated cost of $5.3 to $9.3 million. The stated purpose of the project was to improve capital planning and evaluation of project risks and benefits.[270] In the Previous RRA Decision, the BCUC stated that the decision to pursue the Asset Investment Planning Tool project is a management decision and encouraged BC Hydro to pursue the project if it appears cost-effective.[271]

BC Hydro recently cancelled the Asset Investment Planning Tool project after considering the cost-effectiveness of the project based on new information on the expected total project cost. BC Hydro concluded it would be more cost-effective to pursue this project following the consolidation of BC Hydro's asset data repositories and implementation of an enterprise asset management platform. BC Hydro states it was concerned for the availability of internal subject matter expertise to successfully support the project given other corporate wide priorities. BC Hydro states it will revisit the need for a similar investment when greater benefit can be derived, and it continues to improve its capital planning process.[272]

In an internal Cancellation Memo, BC Hydro states:[273]

> This project has been on hold since June 2019 due to resource unavailability…The identified business requirements and objectives of the business case are still valid. When the project was on hold, the project team revisited the business case. When considered within the overall technology roadmap for BC Hydro, it would be more beneficial to pursue this project at a later date when key foundation functionality is available within the organization, such as enterprise asset and work management. In addition, the availability of subject matter expertise to successfully support the project is limited given other corporate wide priorities including compliance and regulatory proceedings.

In its business case, BC Hydro states the justification for the project:[274]

> With an aging asset Infrastructure and enterprise Investment demands that exceed financial and other constraints, the existing processes and multitude of tools used to plan BC Hydro's large and complex portfolio of asset Investments require enhancement. BC Hydro requires consistent and scalable processes with dedicated, enabling tools to justify its investments and demonstrate that it is maximizing business value from those investments. This project will develop and Implement an investment value framework and an enterprise solution for asset Investment planning. The project will increase the business value derived from $2B per year of capital Investments, limit the need for manual processes to update and prioritize Investments, reduce the time required to develop investment scenarios and drive consistency and transparency for BC Hydro's approach to asset investment planning.

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[270] Exhibit B-5, CEC IR 35.1.

[271] BC Hydro F2020 to F2021 RRA, BCUC Decision to Order G-246-20, p. 80.

[272] Exhibit B-2, pp. 6-14 to 6-15.

[273] Exhibit B-5, RCIA IR 30.1, Attachment 1, p. 1.

[274] Exhibit B-5, CEC IR 35.1, Attachment 1, p. 4.

In explaining the urgency of the project in its business case, BC Hydro stated: "Proceeding now is essential to ensuring that BC Hydro can develop, test and fully implement the new capabilities ahead of the F20+."[275]

Positions of Parties

The CEC notes that the justification in the business case for the Asset Investment Planning Tool appears to suggest the project addressed "significant issues, is very important in managing BC Hydro's complex portfolio of asset investments, and the urgency of implementation is high." The CEC finds disturbing the change in discussion of the value of the project between the business case and this proceeding, and does not find credible BC Hydro's suggestion that it sincerely intends to follow through with the planning tool in future. The CEC considers it puzzling that BC Hydro finds it not cost-effective to pursue a project to improve cost-effectiveness, and submits that indefinite deferral is not an appropriate option.[276]

BC Hydro submits that it is not cost-effective to implement the Asset Investment Planning Tool at this time, primarily because without first implementing BC Hydro's Enterprise Asset Management software, the Asset Investment Planning Tool would require periodic manual data migration from existing IT systems. In addition, BC Hydro has ongoing constraints with the subject matter experts given other corporate priorities.[277]

BC Hydro notes that the BCUC agreed in the Previous RRA proceeding that the decision to proceed with the Asset Investment Planning Tool is a management decision over which the BCUC has no jurisdiction. However, BC Hydro submits that the BCUC can take comfort in BC Hydro's track record of continually seeking improvements to its capital planning and delivery processes, and will "advance" the Asset Investment Planning Tool project when it is cost effective to do so.[278]

Panel Discussion

In the Previous RRA Decision the BCUC observed that it had no jurisdiction over BC Hydro's decision whether or not to implement the Asset Investment Planning Tool; this remains the case today.

The Panel acknowledges the CEC's observation that BC Hydro has previously extolled the benefits of the Asset Investment Planning Tool project. However, the project's business case suggests that Asset Investment Planning Tool would provide incremental efficiencies and cost savings rather than address fundamental flaws in BC Hydro's capital planning processes. The Panel does not find it implausible for BC Hydro to conclude that the Asset Investment Planning Tool project is not presently cost-effective; if the cost of a project exceeds its expected benefits, the project may not be cost-effective even though the purpose of the project is cost-effectiveness. Ironic, perhaps, but not implausible.

That said, BC Hydro appears to have been inconsistent as to whether it is delaying or cancelling the project. In its reply argument, BC Hydro refers to delaying the investment in the Asset Investment Planning Tool until it is cost-effective to do so,[279] yet in response to RCIA's IR, BC Hydro refers to its "decision to cancel the project."[280] The

[275] Exhibit B-5, CEC IR 35.1, Attachment 1, p. 6.
[276] CEC Final Argument, pp. 23 to 26.
[277] BC Hydro Reply Argument, p. 31.
[278] BC Hydro Reply Argument, pp. 32 to 33.
[279] BC Hydro Reply Argument, p. 33.
[280] Exhibit B-5, RCIA IR 30.1.

Panel would appreciate clarity in the F2023 RRA proceeding with respect to the exact status of the Asset Investment Planning Tool project.

Further, if BC Hydro is indeed cancelling the project and plans to recover any of its project costs in the future from ratepayers, then the Panel expects to see the costs included in the Project Write-Off Costs Regulatory Account in a future RRA along with explanations as to why the amounts should be recoverable. In particular, the Panel requests BC Hydro to explain the prudency of its project expenditures given BC Hydro's explanation that the project is not cost-effective because its Enterprise Asset Management software needs to be implemented first.

4.4.1 Capital Plan and Budget Updates

BC Hydro states its Capital Plan is the latest approved version that is available for supporting the capital-related evidence in the Application. The currency date of the Capital Plan refers to the month that a forecast was taken for all active projects used in the development of the plan. The currency date is April 2019 for Power System, Properties, and Fleet capital plan forecasts and July 2019 for Technology. BC Hydro presented the Capital Plan to the Capital Projects Committee of its Board of Directors on November 1, 2019. The Capital Plan was subsequently reviewed by the Board of Directors as part of BC Hydro's 5-Year Financial Forecast in January 2020.[281]

Projects cancelled since April 2019 remain on the capital budgets, even though capital expenditures are not taking place in the Test Period. BC Hydro states, as of the currency date of the Capital Plan, the Metro North Transmission, Peace to Kelly Lake Capacitors and Revelstoke Install Unit 6 projects were still on-going and the forecasts for these projects included capital expenditures in F2022. BC Hydro made the decision to cancel the Metro North Transmission and Peace to Kelly Lake Capacitors projects as well as defer the Revelstoke Install Unit 6 project, and other projects, after the currency date of the plan.[282]

BC Hydro explains that its timing has been adjusted to support the revised schedule for the revenue requirements applications, including this Application and the F2023 RRA which will be submitted in August 2021. BC Hydro states that its Capital Plan provides a reasonable estimation for the amortization and finance charges related to BC Hydro's capital investments and that the Amortization of Capital Additions Regulatory Account will capture any differences between forecast and actual amortization of capital additions for future refund to, or recovery from, ratepayers. BC Hydro states it is currently preparing a new capital plan using a January 2021 currency date and will use this new Capital Plan as the basis for all capital related evidence throughout the F2023 RRA, including providing an update for F2022.[283]

Panel Discussion

The Panel is concerned that the forecasts in BC Hydro's most-recently approved Capital Plan are no more current than April 2019 (July 2019 for technology capital). We acknowledge that this proceeding is a transitional RRA, but it appears that no capital plan had been approved between April 2019 and December 22, 2020, when the current Application was filed. The Panel expects BC Hydro to have its Capital Plan approved annually, and that the Capital Plan submitted with the F2023 RRA will have been updated and approved more recently than April 2019.

[281] Exhibit B-2, pp. 6-10 to 6-11.

[282] Exhibit B-4, BCUC IR 45.1.

[283] Exhibit B-4, BCUC IR 45.1.

4.5 Deferral and Other Regulatory Accounts

In the Application, BC Hydro discusses each of its deferral and regulatory accounts, and provides a description of the account, its balance, history and the existing or proposed recovery mechanism.[284]

BC Hydro's actual and forecast net deferral and regulatory account balances for F2020 to F2022 are as follows:[285]

Table 16: Summary of Deferral and Regulatory Account Balances

	($ million)	F2020 Actual	F2021 Forecast	F2022 Forecast
		1	2	3
1	Opening Balance	4,193	5,004	6,266
2	Additions	932	414	97
3	Interest	17	22	24
4	Recoveries / Other	(138)	827	(341)
5	Net Change	811	1,262	(220)
6	Closing Balance	5,004	6,266	6,047

As shown in the table above, BC Hydro's forecast net balance of its deferral and regulatory accounts at the end of F2022 is $6.047 billion, which is an increase of $1.043 billion from its F2020 actual balance. The increase in the forecast F2022 balance is primarily due to additions to the Non-Current Pension Costs Regulatory Account and the Debt Management Regulatory Account caused by changes in uncontrollable factors, such as discount rates and interest rates.[286] In Table 7-3 of the Application, BC Hydro presents the F2020 actual and F2021 to F2026 forecast balances of its regulatory accounts. The table shows that the total net balance is forecast to decline to $4.8 billion by the end of F2026.

All of BC Hydro's regulatory accounts have either approved or proposed recovery mechanisms, with the exception of three regulatory accounts as a recovery mechanism is not yet required: the Mining Customer Payment Plan Regulatory Account, the Customer Crisis Fund Regulatory Account and the Site C Regulatory Account. BC Hydro expects to propose a recovery mechanism for the Mining Customer Payment Plan Regulatory Account and the Customer Crisis Fund Regulatory Account in its F2023 RRA. BC Hydro plans to request a recovery mechanism for the Site C Regulatory Account in a future RRA when the project is in-service.[287]

BC Hydro also notes that the COVID-19 pandemic has impacted, and is expected to continue to impact, its regulatory accounts.[288]

In the Application, BC Hydro is requesting approval for three changes related to existing regulatory accounts, a recovery mechanism for one regulatory account, the establishment of one new regulatory account and the

[284] Exhibit B-2-2, Appendix U.
[285] Exhibit B-2, Section 7.4, Table 7-2, p. 7-16.
[286] Exhibit B-2, Section 7.4, p. 7-16.
[287] Exhibit B-2, Section 7.4, p. 7-19.
[288] Exhibit B-2, Section 7.5, pp. 7-20 to 7-21.

closing of one existing regulatory account. The following table summarizes BC Hydro's requests and where in this Decision those requests are discussed:

Table 17: Summary of Regulatory Account Requests

	Requested Change	Section of the Decision
1	Cost of Energy Variance Accounts Recover the balances in the Cost of Energy Variance Accounts through the Deferral Account Rate Rider (DARR) using the DARR table mechanism as described in Chapter 7, Section 7.2.1 of the Application. Specifically, starting in F2022 and on an ongoing basis, the DARR percentage effective April 1 of a given year is set based on the percentage in the DARR table mechanism corresponding to the forecast net balance of the Cost of Energy Variance Accounts at the end of the preceding fiscal year.	Section 4.5.1
2	Amortization of Capital Additions Regulatory Account Defer the variances arising in F2022 as a result of any changes determined in the depreciation study to the Amortization of Capital Additions Regulatory Account, with interest charges and recovery of these amounts being on the same basis as previously approved for this account.	Section 4.5.2
3	Dismantling Cost Regulatory Account Continue to defer any variances between forecast and actual dismantling costs in F2022 to the Dismantling Cost Regulatory Account; continue to apply interest to the balance of the account each year based on BC Hydro's current weighted average cost of debt; continue to recover the forecast interest charged to the account each year from the account each year; and, continue to recover the forecast account balance at the end of a test period over the next test period.	Section 4.5.3
4	Project Write-Off Costs Regulatory Account Recover amounts deferred to the Project Write-off Costs Regulatory Account in respect of completed fiscal years over the next test period, starting in F2022 and on an ongoing basis, subject to BCUC review and approval of the recovery of these amounts; apply interest to the balance of the account based on BC Hydro's current weighted average cost of debt; and, recover actual interest charged to the account for amounts related to any completed fiscal years over the next test period.	Section 4.5.3
5	Electric Vehicle Costs Regulatory Account Establish an Electric Vehicle Costs Regulatory Account to defer any actual operating costs, amortization, and cost of energy amounts related to electric vehicle charging stations that meet the definition of a prescribed undertaking under the GGRR for F2020 and F2021; apply interest to the balance of the account based on BC Hydro's current weighted average cost of debt and recover the forecast interest charged to the account each year from the account each year; and, starting in F2022, recover the forecast balance at the end of a test period over the next test period, until such time that the actual amounts deferred to the account for F2020 and F2021 are recovered in rates.	Section 4.9.2.1
6	Rock Bay Remediation Regulatory Account Close the Rock Bay Remediation Regulatory Account at the end of F2022.	Section 4.5.3

4.5.1 Cost of Energy Variance Accounts

BC Hydro is requesting to recover the balances in the Cost of Energy Variance Accounts through the DARR using the DARR table mechanism as described in Chapter 7, Section 7.2.1 of the Application. Specifically, starting in F2022 and on an ongoing basis, the DARR percentage effective April 1 of a given year is set based on the percentage in the DARR table mechanism corresponding to the forecast net balance of the Cost of Energy Variance Accounts at the end of the preceding fiscal year.

BC Hydro has five Cost of Energy Variance Accounts: the Heritage Deferral Account, the Non-Heritage Deferral Account, the Load Variance Regulatory Account, the Biomass Energy Program Variance Regulatory Account, and the Trade Income Deferral Account. These accounts capture the differences between forecast and actual revenues and energy costs for future recovery or refund to ratepayers. These differences are largely non-controllable and can be positive or negative.

The Cost of Energy Variance Accounts are typically recovered or refunded to ratepayers using the DARR. In the Previous RRA Decision, the BCUC approved BC Hydro's request to reduce the DARR from 5 percent to 0 percent, effective April 1, 2019, and amortize or refund the net credit balance of the Cost of Energy Variance accounts over the F2020 to F2021 test period.[289]

In this Application, BC Hydro is requesting to return to the DARR table mechanism approved by the BCUC in the F2009 to F2010 RRA to recover or refund the balances in the Cost of Energy Variance Accounts on an ongoing basis. The exception to the mechanism approved in the F2009 to F2010 RRA is that BC Hydro is proposing to determine the level of the DARR based on the forecast net balance of the Cost of Energy Variance Accounts at the end of the preceding fiscal year, instead of the actual net balance at the middle of the preceding fiscal year. For example, BC Hydro is proposing the DARR percentage for F2022 be based on the forecast net balance at March 31, 2021 instead of the actual net balance at September 30, 2020. BC Hydro submits that determining the level of the DARR based on the forecast net balance at the end of the preceding fiscal year uses more up-to-date information at the time the RRA is prepared than using the mid-year balance. This is because the forecast net balance at the end of the preceding fiscal year considers amortization and forecast additions and reductions to the Cost of Energy Variance Accounts for the remaining six months of the fiscal year.[290]

The following table presents the DARR table mechanism that was approved by the BCUC in the F2009 to F2010 RRA that BC Hydro is currently requesting to use on an ongoing basis, starting in F2022.

[289] BC Hydro F2020 to F2021 RRA Decision, p. 129, Directive 43.

[290] Exhibit B-2, pp. 7-3 to 7-4.

Table 18: Deferral Account Rate Rider Table Mechanism[291]

Forecast Net Balance at the end of the Preceding Fiscal Year		% Rate Rider Effective Following April 1
> $ million	<= $ million	
-	(500)	(5.0)
(500)	(450)	(4.5)
(450)	(400)	(4.0)
(400)	(350)	(3.5)
(350)	(300)	(3.0)
(300)	(250)	(2.5)
(250)	(200)	(2.0)
(200)	(150)	(1.5)
(150)	(100)	(1.0)
(100)	(50)	(0.5)
(50)	0	0.0
0	50	0.0
50	100	0.5
100	150	1.0
150	200	1.5
200	250	2.0
250	300	2.5
300	350	3.0
350	400	3.5
400	450	4.0
450	500	4.5
500	-	5.0

The forecast net balance of the Cost of Energy Variance Accounts at the end of F2021 is a credit of $14 million, and as such, based on the proposed DARR table mechanism above, would result in the DARR being set at 0 (zero) percent for F2022.[292]

BC Hydro has not considered alternatives to the proposed DARR mechanism in this Application. However, it notes that two alternatives were considered in the F2012 to F2014 RRA, which it had concluded were either not a satisfactory way to clear the balances, created more volatility or were more administratively complex than the proposed mechanism.[293]

BC Hydro's modelling shows that the proposed DARR table mechanism clears balances of $250 million, $500 million and $750 million within 4 to 6 years. However, balances that exceed $1 billion would take more than 6 years to clear.[294] In Undertaking No. 23, BC Hydro provided an analysis of what the impact in the past 10 years would have been under three DARR methodologies: (1) the proposed DARR table mechanism, (2) amortizing the COE Variance Accounts over a 3-year period, and (3) amortizing the COE Variance Accounts over a 5-year period. The analysis showed that the proposed DARR table mechanism and amortizing over 5 years produced similar bill impacts in most years, while amortizing over 3 years produced more volatility in bill impacts.[295]

[291] Exhibit B-2, Table 7-1, p. 7-5.
[292] Exhibit B-2, p. 7-4.
[293] Exhibit B-4, BCUC IR 55.1.
[294] Exhibit B-5, BCSEA IR 13.1.
[295] Exhibit B-9, Undertaking No. 23.

In the BCUC's Decision to BC Hydro's F2009 to F2010 RRA, the BCUC accepted the DARR table mechanism because it found that it presents a more structured approach to clearing the net balances, meets the stated objectives, and the estimated 4 to 6 year amortization period is reasonable.[296]

Positions of Parties

In BC Hydro's view, the proposed DARR table mechanism continues to be a reasonable mechanism for clearing the net balances in the Cost of Energy Variance Accounts. BC Hydro notes that the proposed mechanism was reviewed in past BCUC proceedings and the BCUC's previous conclusion remains accurate. This is because the mechanism will:[297]

1) Minimize intergenerational inequity by being responsive to the changing net balance in the Cost of Energy Variance Accounts;
2) Maintain rate stability for customers to the extent practicable; and
3) Be administratively simple and transparent.

BC Hydro submits that incremental increases or decreases of 0.5 percent based on the forecast balance increases (or decreases) of $50 million as presented in the DARR table mechanism clears the balances in the Cost of Energy Variance accounts over a reasonable period of time, while maintaining rate stability. Further, the cap of +/- 5 percent avoids the potential for rate shock.[298]

BC Hydro clarifies that although the DARR table mechanism will provide a structured approach to setting the DARR, the BCUC retains the ability to alter the DARR proposed and/or the DARR mechanism in future applications when circumstances warrant. This is because BC Hydro will always need to obtain BCUC approval of its proposed rate increases, including the DARR, in future RRAs. BC Hydro also submits that it would always identify the proposed DARR in its RRAs.[299]

BCSEA supports the proposed DARR table mechanism.[300] BCOAPO has no issues with using the proposed DARR mechanism, but suggests the approval be worded such that parties and future panels do not interpret the approval as precluding the consideration of other approaches when subsequent years' general rate increases depart materially from inflation or expectations.[301]

AMPC, on the other hand, recommends the Panel defer ruling on the continued use of the DARR and the methodology until BC Hydro's F2023 RRA, "in order to allow BC Hydro's proposal and methodology to be fully reviewed for continued relevance and fairness." AMPC submits that since this current proceeding was streamlined, interveners did not have an opportunity to file evidence that could assess whether the 5 percent cap proposed could result in rate shock or "otherwise have a material adverse effect on overall rate competitiveness." AMPC submits that the BCUC should not reapprove the use of the DARR without considering alternative approaches in evidence.[302]

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[296] BC Hydro F2010 RRA Decision, p. 172.
[297] Exhibit B-2, p. 7-6; BC Hydro Final Argument, pp. 51 to 52.
[298] BC Hydro Final Argument, p. 51.
[299] BC Hydro Final Argument, p. 52.
[300] BCSEA Final Argument, pp. 4, 10.
[301] BCOAPO Final Argument, p. 43.
[302] AMPC Final Argument, pp. 15 to 17.

In reply, BC Hydro notes that section 75 of the UCA is clear that the BCUC is not bound by its previous decisions and therefore, it is not necessary to explicitly state in the order that approval of the DARR mechanism would not preclude consideration of other approaches in the future if circumstances warrant. Similarly, AMPC is not precluded from raising alternative approaches in future proceedings since the BCUC "retains discretion to alter [the DARR and/or mechanism] in future applications if circumstances warrant." Therefore, it is not necessary to defer ruling on the continued use of the DARR and methodology as it "remains a reasonable mechanism for clearing the net balances in the COE Variance Accounts."[303]

Panel Determination

Although the Panel agrees that the proposed DARR table mechanism has some merits for continuing on an ongoing basis, the Panel recognizes that the streamlined manner in which the Application was reviewed meant that not all of the significant issues related to the mechanism could be examined fully. In particular, the Panel is not persuaded that the 5 percent cap proposed in the DARR table mechanism is necessary to avoid the potential for rate shock. While the Panel recognizes that the proposed cap could provide some certainty to ratepayers, it is nonetheless concerned that the proposed cap could result in significant Cost of Energy Variance Account balances not being cleared quickly enough.

Given the relatively low net balance currently in the Cost of Energy Variance Accounts and BC Hydro's request for a 0 percent DARR for F2022, which is effectively a continuation of the DARR that was approved in the Previous RRA Decision, the Panel finds that deferring the ruling on the continued use of the DARR methodology until BC Hydro's F2023 RRA would not have any significant adverse impact on BC Hydro or its ratepayers. **Therefore, the Panel approves the recovery of the balances in the Cost of Energy Variance Accounts through the proposed DARR table mechanism for F2022 only. Using this approach, the DARR percentage is set at 0 percent as of April 1, 2021 for F2022.**

4.5.2 Amortization of Capital Additions Regulatory Account

BC Hydro is requesting to defer the variances arising in F2022 as a result of any changes determined in the depreciation study to the Amortization of Capital Additions Regulatory Account, with interest charges and recovery of these amounts being on the same basis as previously approved for this account.[304]

In accordance with Directive 36 from the Previous RRA Decision, BC Hydro is conducting a depreciation study, which it expects to complete during F2022. Any changes in asset useful life and salvage value percentage resulting from the recommendations in the depreciation study will result in variances in depreciation expense from what was forecast in the Application for F2022.[305] BC Hydro explains that the variances are primarily due to the timing of the depreciation study relative to the timing of the Application. It does not have a preliminary indication of the magnitude of the impacts resulting from the depreciation study, however, it notes that the variances could be positive or negative, significant and are not within its control.[306]

[303] BC Hydro Reply Argument, p. 35.
[304] Exhibit B-2, p. 7-7.
[305] Exhibit B-2, pp. 7-6 to 7-7.
[306] Exhibit B-4, BCUC IR 56.1, 56.2, 56.4.

BC Hydro submits that the last time it had completed a depreciation study, the BCUC granted deferral treatment for similar variances arising from a depreciation study.[307]

BC Hydro also submits that it will identify the F2022 impacts related the depreciation study after F2022 is complete and will provide those impacts during the F2023 RRA proceeding. It will file the depreciation study in its F2023 RRA and in that application, it will request BCUC approval of the new depreciation rates recommended in the study and the recovery of the deferred amounts in rates as part of its overall revenue requirements.[308]

BC Hydro proposes to defer the variances to the Amortization of Capital Additions Regulatory Account because the account already exists, has an approved recovery mechanism, and the impacts of the depreciation study are similar in nature to the variances already deferred to the account.[309]

The Amortization of Capital Additions Regulatory Account was established by Order G-16-09 and captures the variances between forecast and actual amortization of capital additions. Interest is applied to this account based on BC Hydro's weighted average cost of debt and forecast interest is recovered from the account each year.[310] Deferral to this account would result in the deferred amounts being amortized evenly over each year of the next test period.[311] BC Hydro submits that establishing a new deferral account with a longer amortization period could allow for better tracking of the amounts and reduce the impact on rates but increase intergenerational equity issues.[312]

Positions of Parties

BC Hydro submits that its proposal ensures that its customers will only pay the actual depreciation expense during the F2022 Test Period.[313]

Interveners either support or do not take a position on BC Hydro's proposal to defer variances arising from any changes recommended in the depreciation study to the Amortization of Capital Additions Regulatory Account.[314] However, BCOAPO recommends deferring the decision on the recovery period until the F2023 RRA because the number of years in the next test period has not been confirmed.[315]

In reply, BC Hydro submits that its proposed approach "ensures that the balance is continually cleared with minimal intergenerational inequity." Further, approval would be consistent with past orders and would not preclude the BCUC from directing a different recovery period in the future if circumstances warrant. Therefore, BCOAPO's concern is best addressed in the next proceeding.[316]

Panel Determination

Since the recommendations in the depreciation study could result in significant variances that are not within BC Hydro's control, the Panel finds it reasonable to defer these variances in a regulatory account. However, given

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307 Exhibit B-4, BCUC IR 56.5; BC Hydro Review of the F2007 and F2008 Revenue Requirements Application, Order G-143-06.
308 Exhibit B-4, BCUC IR 56.7.1.
309 Exhibit B-2, p. 7-7.
310 Exhibit B-2-2, Appendix U, p. 24.
311 Exhibit B-4, BCUC IR 56.3.
312 Exhibit B-4, BCUC IR 56.3.1.
313 BC Hydro Final Argument, p. 49.
314 BCOAPO Final Argument, p. 44; BCSEA Final Argument, p. 11.
315 BCOAPO Final Argument, p. 44.
316 BC Hydro Reply Argument, pp. 34 to 35.

that the magnitude of the variances resulting from the recommendations in the depreciation study will not be known until the study is filed for review in BC Hydro's F2023 RRA, the recovery mechanism should be reviewed at that time. Capturing the variances in a separate regulatory account would facilitate a different recovery mechanism from the existing Amortization of Capital Additions Regulatory Account if the circumstances warrant. Further, a separate regulatory account would also allow for better tracking of the amounts. **Therefore, the Panel directs BC Hydro to establish a new regulatory account to capture the variances arising in F2022 as a result of any changes to the depreciation expense determined in the depreciation study, with interest charges being on the same basis as previously approved for the Amortization of Capital Additions Regulatory Account. The Panel further directs BC Hydro to propose a recovery mechanism for this new regulatory account in its F2023 RRA.**

4.5.3 Remaining Regulatory Account Requests

In the Application, BC Hydro also requests approvals with respect to the Dismantling Cost Regulatory Account, the Project Write-off Costs Regulatory Account, the Rock Bay Remediation Regulatory Account, and the Electric Vehicle Costs Regulatory Account. The Electric Vehicle Costs Regulatory Account is discussed in Section 4.9.2.1 of this Decision.

Dismantling Cost Regulatory Account

BC Hydro is requesting to continue to defer any variances between forecast and actual dismantling costs in F2022 to the Dismantling Cost Regulatory Account. It is also requesting to continue to apply interest to the balance of the account each year based on its current weighted average cost of debt, continue to recover the forecast interest charged to the account each year from the account each year, and continue to recover the forecast account balance at the end of a test period over the next test period.[317]

The Dismantling Cost Regulatory Account was established by Order G-47-18 and captures the variances between forecast and actual dismantling costs. The account has been in use since F2017, and in the Previous RRA Decision, the BCUC approved the continued use of the account for F2020 to F2021.[318]

Due to the increases in dismantling costs, the Previous RRA Decision directed BC Hydro to provide in its F2022 RRA, an assessment of whether its current practice of expensing dismantling costs as they occur would result in intergenerational inequity and to provide options on how to better promote intergenerational equity. The BCUC also directed BC Hydro to include a net salvage study in its depreciation study.[319]

BC Hydro submits that the net salvage report is required to analyze and compare the different approaches (i.e. its current practice of expensing these costs as they are incurred versus a net salvage cost approach). Therefore, BC Hydro proposes to assess the options in the F2023 RRA proceeding when the depreciation and net salvage study is complete and filed with the BCUC and, in the meantime, continue to defer any dismantling costs.[320]

[317] Exhibit B-2, p. 7-10.
[318] BC Hydro F2020 to F2021 RRA, Decision, Directive 39.
[319] BC Hydro F2020 to F2021 RRA, Decision, Directive 39.
[320] Exhibit B-2, pp. 7-9 to 7-10.

Project Write-off Costs Regulatory Account

BC Hydro is requesting approval to recover amounts deferred to the Project Write-off Costs Regulatory Account in respect of completed fiscal years over the next test period, starting in F2022 and on an ongoing basis, subject to BCUC review and approval of the recovery of these amounts. It is also requesting to apply interest to the balance of the account based on its current weighted average cost of debt, and recover the actual interest charged to the account for amounts related to any completed fiscal years over the next test period.[321]

In the Previous RRA Decision, the BCUC disallowed the recovery of project write-offs on a forecast basis, but stated that it would consider an approach that would allow the BCUC and other parties the opportunity to review the reasonableness of these costs prior to their recovery from ratepayers.[322] As a result, subsequent to the Previous RRA Decision, the BCUC approved the establishment of the Project Write-off Costs Regulatory Account to capture the portion of actual project write-offs that BC Hydro believes recovery from ratepayers is appropriate.[323]

Accordingly, BC Hydro has deferred $9.3 million in actual project write-off costs for F2020, which it is seeking to recover in F2022.[324] Total project write-offs in F2020 were $11.9 million. BC Hydro is not seeking to recover $2.6 million of this amount because it does not believe it would be reasonable for ratepayers to pay for these costs as it is not certain of the prudence of its actions resulting in these costs.[325]

Rock Bay Remediation Regulatory Account

BC Hydro is requesting approval to close the Rock Bay Remediation Regulatory Account at the end of F2022 as the balance will be fully amortized at that time.[326]

The Rock Bay Remediation Regulatory Account was established by Order G-75-11 to defer expenditures related to the remediation of BC Hydro's Rock Bay property. BC Hydro submits that the remediation was completed in F2019 and it is not forecasting the deferral of any further remediation costs.[327]

Positions of Parties

Interveners either support or do not take a position on these requests.[328]

Panel Determination

The Panel approves the following requests with respect to BC Hydro's regulatory accounts:

- **To continue to defer any variances between forecast and actual dismantling costs in F2022 to the Dismantling Cost Regulatory Account; continue to apply interest to the balance of the account each**

[321] Exhibit B-2, p. 7-12.
[322] BC Hydro F2020 to F2021 RRA, Decision, Directives 32 and 33.
[323] BC Hydro Application with Respect to Directives 28 and 33 of the BC Hydro F2020 to F2021 RRA Decision, Order G-337-20.
[324] Exhibit B-2, p. 7-11, Appendix L, p. 4.
[325] Exhibit B-2, Appendix L, p. 4; Exhibit B-4, BCUC IR 58.1.
[326] Exhibit B-2, p. 7-14.
[327] Exhibit B-2, p. 7-14.
[328] BCSEA Final Argument, p. 12; BCOAPO Final Argument, pp. 44 to 46.

year based on BC Hydro's current weighted average cost of debt; continue to recover the forecast interest charged to the account each year from the account each year; and, continue to recover the forecast account balance at the end of a test period over the next test period.

The Panel accepts that the net salvage report is required to analyze and compare the different approaches to recovering forecast dismantling costs and accepts that the net salvage report would be filed in BC Hydro's F2023 RRA.

- **To recover amounts deferred to the Project Write-off Costs Regulatory Account in respect of completed fiscal years over the next test period, starting in F2022 and on an ongoing basis, subject to BCUC review and approval of the recovery of these amounts; apply interest to the balance of the account based on BC Hydro's current weighted average cost of debt; and, recover actual interest charged to the account for amounts related to any completed fiscal years over the next test period.**

  The Panel accepts that the $9.3 million of actual project write-off costs incurred in F2020 should be recovered from ratepayers. Applying interest to the balance of the account based on BC Hydro's current weighted average cost of debt is consistent with BC Hydro's approach to its other regulatory accounts that attract interest.

The Panel approves the closure of the Rock Bay Remediation Regulatory Account at the end of F2022, or a subsequent fiscal year, when the account balance is zero.

The Panel accepts that the balance in this account is anticipated to be zero at the end of F2022 and BC Hydro does not plan to continue using this account. However, in the event that the balance is not zero by the end of F2022, this account should be closed when the balance reaches zero.

4.6 Demand Side Management

BC Hydro requests acceptance pursuant to section 44.2 of the UCA of the proposed DSM expenditure schedule of $82.2 million in F2022.[329]

Legislative Framework for Assessment of DSM Expenditure Schedules

Pursuant to section 44.2(3) of the UCA, after reviewing an expenditure schedule, the BCUC, subject to subsections (5.1) and (6), must accept the schedule if the BCUC considers that making the expenditures referred to in the schedule is in the public interest, or reject the schedule. The BCUC may also accept or reject part of an expenditure schedule, pursuant to section 44.2(4) of the UCA.

Section 44.2(5.1) of the UCA sets out the relevant factors[330] that the BCUC must consider in its review of BC Hydro's DSM expenditure schedule. In considering whether to accept BC Hydro's expenditure schedule, the BCUC must consider the following:

- the interests of persons in British Columbia who receive or may receive service from the authority;

[329] Exhibit B-2, p. 1-20; p. 10-2.

[330] Section 44.2(5.1)(c) addresses the extent to which the expenditure schedule is consistent with applicable requirements of Section 19 of the *Clean Energy Act*, which deals with the construction or purchase of clean or renewable resources. This section is not considered to be directly relevant factor when considering an expenditure schedule for demand side measures.

- British Columbia's energy objectives;
- BC Hydro's 2013 IRP; and
- the extent to which the demand-side measures are cost-effective within the meaning prescribed by the Demand-Side Measures Regulation (DSM Regulation).

Section 4 of the DSM Regulation[331] defines the process for determining cost-effectiveness of the demand-side measures for the purposes of section 44.2(5.1)(d) of the UCA.

Section 4(6) of the DSM Regulation provides:

> The commission may not determine that a proposed demand-side measure is not cost effective on the basis of the result obtained by using a ratepayer impact measure test to assess the demand-side measure.

4.6.1 Proposed DSM Schedule

BC Hydro states that DSM refers to "the broad concept of helping customers manage their electricity use," and consists of "traditional DSM," encouraging customers to reduce and/or shift the timing of their electricity consumption, and "low carbon electrification [LCE]," which encourages customers to switch to electricity from higher carbon sources of energy.[332]

BC Hydro submits the proposed DSM expenditure schedule for F2022 continues to provide broad customer access to conservation and energy management opportunities, while managing the overall level of expenditures to limit forecast rate increases as BC Hydro continues to be in an energy surplus position.[333]

In line with Directive 46 of the Previous RRA Decision, future levels of DSM expenditure beyond F2022 will be explored further in the next IRP.[334]

BC Hydro seeks BCUC acceptance of the following DSM expenditure schedule for the F2022 Test Period:[335]

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[331] B.C. Reg. 326/2008, as amended by B.C. Reg. 117/2017, available at https://www.bclaws.gov.bc.ca/civix/document/id/complete/statreg/10_326_2008
[332] Exhibit B-2, p. 10-1.
[333] Exhibit B-2, p. 10-1.
[334] Exhibit B-2, pp. 10-1, 10-7.
[335] Exhibit B-2, Table 10-4, p. 10-9.

Table 19: F2021 and F2022 Expenditure Summary ($ million)

	F2021 RRA	F2021 Forecast	F2022 Plan
Rate Structures	0.5	0.5	0.5
Programs			
Residential	19.7	19.8	21.0
Commercial	17.5	17.1	16.6
Industrial	26.9	21.6	20.8
Total Programs	64.1	58.5	58.4
Capacity-focused	4.3	3.6	2.9
Supporting Initiatives	20.2	19.9	20.5
Total Traditional DSM	**89.1**	**82.4**	**82.2**
Low-Carbon Electrification	7.7[240]	7.6	15.5
Total Expenditures	**96.8**	90.0	97.6

In addition to the traditional DSM activities outlined above which are aimed at reducing energy use, BC Hydro is forecasting expenditures of $15.5 million on LCE undertakings in F2022.[336] The Direction to the BCUC Respecting Undertaking Costs[337] requires the BCUC to allow BC Hydro to defer the costs incurred for prescribed undertakings as defined under section 4 (3) (a), (b), (c) or (d) of the GGRR to the DSM Regulatory Account.[338] BC Hydro submits the LCE expenditures continue the activities that BC Hydro described in the Previous RRA and that the BCUC accepted as prescribed undertakings.[339] These expenditures and the broader electrification plan currently under development are addressed further in Section 4.7.

DSM expenditures generally reflect a continuation of activities approved for F2020 and 2021, but have been adjusted for F2022 to reflect historical results, impacts of COVID-19, and new market information. The majority of reductions in plan expenditures are due to lower allocations to the industrial sector, where uptake has been below plan in recent years.[340]

There has been an overall reduction in new incremental energy savings for F2022 compared to previous years, due mostly to reductions in Codes & Standards. These reductions in energy savings were anticipated in the DSM plan provided in the Previous RRA, and reflects a decline in remaining opportunities from previously adopted lighting regulations. BC Hydro does not see a need to ramp up DSM program savings to keep overall savings consistent, given the current energy surplus.[341] While industrial expenditures have been below plan, energy savings have been approximately on-plan as a result of strong participation in the Industrial Strategic Energy Management initiative, which enables energy savings at a lower cost.[342]

[336] Exhibit B-2, p. 10-2.

[337] Direction to the BCUC Respecting Undertaking Costs (B.C. Reg. 77/2017).

[338] Exhibit B-2, p. 2-11; p. 10-23; BC Hydro Final Argument, pp. 56, 64.

[339] Exhibit B-2, p. 10-2.

[340] Exhibit B-4, BCUC IR 69.1; Exhibit B-2, p. 10-11.

[341] Exhibit B-3, BCUC IR1.69.2.

[342] Exhibit B-2, pp. 10-4 to 10-5.

BC Hydro provides its forecast energy savings from traditional DSM and its forecast energy growth from LCE in the table below.[343]

Table 20: F2021 and F2022 Energy (GWh/year) Impact Summary

	F2021 RRA	F2021 Forecast	F2022 Plan
New Incremental Energy Savings (GWh/year)			
Codes and Standards	411	405	259[241]
Rate Structures	118	119	119
Programs			
Residential	36	39	41
Commercial	52	48	43
Industrial	136	136	127
Total Programs	224	222	210
Total New Incremental Energy Savings	753	747	588
New Incremental Load Growth (GWh/year)			
Low-Carbon Electrification	61	65	148

Capacity-focused DSM has the potential to reduce or shift electricity consumption in order to optimize system capacity and reduce the amount of infrastructure and electricity that needs to be acquired in the future. Since F2017, BC Hydro has completed a variety of capacity-focused pilots and trials to provide information to inform the savings potential and cost-effectiveness of different technologies and approaches, including ongoing work on "Non-Wires" or "demand response" alternatives. Expenditures in 2022 continue to pilot the use of the demand response management system, refine the management of the initiatives, conduct monitoring and tracking, and add new technologies and solutions as required for the specific local substations. BC Hydro intends to incorporate the learnings from these pilots into the DSM capacity resource options being developed for the IRP.[344]

BC Hydro provides its forecast capacity savings from traditional DSM and its forecast capacity growth from LCE in the table below[345]

[343] Exhibit B-2, Table 10-5, p. 10-10.
[344] Exhibit B-2, pp. 10-12 to 10-13.
[345] Exhibit B-2, Table 10-6, p. 10-10.

Table 21: F2021 and F2022 Associated Capacity (MW) Impact Summary

	F2021 RRA	F2021 Forecast	F2022 Plan
New Incremental Associated Capacity Savings (MW)			
Codes and Standards	88	88	51
Rate Structures	14	9	9
Programs			
Residential	10	11	11
Commercial	8	8	6
Industrial	16	16	15
Total Programs	34	35	33
Total New Incremental Energy Savings	136	133	93
New Incremental Associated Capacity Growth (MW)			
Low-Carbon Electrification	9	10	29

BC Hydro provides the breakdown of its forecast DSM costs across customer classes in the following table, stating that this is similar to that presented in the Previous Application, which the BCUC determined to be reasonable:[346]

Table 22: DSM Program Spend by Sector

	Residential (including low income) (%)	Commercial and light industrial (%)	Large Industrial (%)
BC Hydro percentage of DSM program spend by sector (excluding TMP program)			
F2020 to F2021 RRA	30	38	32
Fiscal 2022 Forecast	36	35	29
BC Hydro Allocation of DSM costs for cost recovery purposes			
Allocation of DSM costs	40	35	25

As part of ongoing responses to Directive 47 of the Previous RRA Decision, BC Hydro's Application included a section on Non-Integrated Area program activities, providing information on the progress of the NIA program in F2020[347] and during F2021.[348] BC Hydro commits to reporting further on the progress of the NIA program as part of the annual DSM report, and in the F2023 RRA.[349]

In line with Directive 51 of the Previous RRA, BC Hydro confirmed that no transfers between program areas during F2020 and 2021 were made beyond the allowed levels,[350] and no transfers from the previous to current test period are anticipated.[351]

[346] BC Hydro Final Argument, p. 56; Exhibit B-2, Table 10-7, p. 10-11.
[347] Exhibit B-2-2, Appendix W, pp. 7 to 8.
[348] Exhibit B-2-2, Appendix M, p. 12.
[349] Exhibit B-2, p. 10-7.
[350] BC Hydro F2020 to F2021 RRA, Decision, pp. 152 to 153.
[351] Exhibit B-2, p. 10-8.

Panel Determination

The Panel finds that BC Hydro's proposed "traditional" DSM expenditure schedule for the Test Period is in the public interest, and accepts the DSM expenditure schedule of $82.2 million in F2021 under section 44.2 of the UCA.

As discussed in the following subsections, the Panel has considered all the relevant matters provided for in section 44.2 (5.1) of the UCA, namely:

- the interests of persons in BC who receive or may receive service from BC Hydro;
- B.C.'s energy objectives;
- BC Hydro's long-term resource plan approved under section 4 of the CEA; and
- cost-effectiveness within the meaning prescribed by regulation.

For the reasons laid out in the following subsections, the Panel finds that BC Hydro's proposed "traditional" DSM expenditure schedule is in the interests of persons in B.C. who receive or may receive service from BC Hydro, is consistent with and supports the relevant energy objectives set out in the CEA, and is cost-effective within the meaning prescribed by regulation. Further, as discussed in subsection 4.6.2.3 below, the Panel has considered BC Hydro's 2013 IRP and considers alignment with it and the proposed DSM expenditure schedule to be moot.

4.6.2 Is the DSM Expenditure Schedule in the Public Interest?

Pursuant to section 44.2(3) of the UCA, the BCUC must accept the DSM expenditure schedule if it concludes after review that making the expenditures is in the public interest.

We review below the extent to which the proposed DSM expenditure schedule addresses the relevant requirements of section 44.2(5.1)(a), (b), and (d) of the UCA.

4.6.2.1 Interests of Persons in British Columbia who Receive or may Receive Service from the Authority

The Panel must consider whether BC Hydro's DSM expenditure schedule is in the interests of persons in British Columbia who receive or may receive service from BC Hydro.

According to BC Hydro its DSM expenditures for F2022 reflect activities similar to those in the Previous RRA, which the BCUC found to be in the interests of persons in B.C. who receive or may receive service from BC Hydro.[352] They continue to reflect a broad and cost effective range of traditional DSM initiatives that provide energy savings and capacity benefits and provide customers with the opportunity to save electricity and lower their bills, while reducing BC Hydro's revenue requirements. BC Hydro submits its proposed DSM expenditures therefore continue to be in the interest of persons who receive or may receive service.[353]

[352]BC Hydro F2020 to F2021 RRA, Decision , p. 139.
[353] Exhibit B-2, p. 10-15.

Positions of Parties

BC Hydro submits its traditional DSM Plan meets the factors the BCUC must consider when deciding to accept a DSM expenditure schedule.[354]

The CEC is the only party suggesting that BC Hydro's DSM plan be denied. It submits that BC Hydro's moderation approach is "essentially a transfer of DSM spending from commercial rate classes to the residential rate class." The CEC does not consider the reduction in proposed DSM spending on commercial rate classes to be acceptable, citing BC Hydro's evidence showing that DSM programs for the commercial rate classes have the highest cost-benefit ratio of all rate groups and the lowest total resource cost. The CEC submits the BCUC should deny BC Hydro's DSM spending plan, and state it would accept a DSM spending plan that provides more balanced spending for commercial rate classes.[355]

BC Hydro submits that the CEC's request to deny the DSM spending plan should be rejected. The CEC made the same arguments in the previous proceeding, and BC Hydro cites the previous decision's determination.[356] BC Hydro submits that the planned commercial expenditures of $16.6 million are not materially different than the $17.5 million planned for F2021, with $0.5 million of the difference due to the impact of the COVID-19 pandemic, and that the breakdown of DSM costs across customer classes is similar to that presented in the Previous RRA, which the BCUC determined to be reasonable. BC Hydro acknowledges that there are opportunities for cost effective DSM in the commercial sector and will be considering future levels of DSM spending in the 2021 IRP.[357]

BCSEA submits that BC Hydro's DSM expenditure schedule is in the interests of current and future BC Hydro customers, although BCSEA would like to see BC Hydro pursue "all cost-effective DSM savings." BCSEA accepts that BC Hydro has reasonably adjusted its DSM spending on industrial programs but regrets the diminished levels of expenditure. BCSEA strongly supports BC Hydro's F2022 deep retrofit feasibility study aimed at a whole building approach, and the programs aimed at low-income customers and housing providers.[358]

Zone II RPG agrees with BC Hydro's 2022 DSM Expenditure Schedule, and with BC Hydro's Moderation Strategy for the integrated area for the time-being until the next IRP is developed. It also agrees with BC Hydro that the moderation strategy is not appropriate for the non-integrated areas, and submits that "NIA community plans and information gathered during BC Hydro's implementation of the NIA DSM program should determine target level of energy savings for the NIA program."[359]

Zone II RPG encourages BC Hydro to "more fully develop the DSM evaluation methods for the NIA so that cost effectiveness of future DSM in the NIA can be better evaluated," including "additional benefits, such as natural gas benefits and capacity benefits."[360]

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[354] BC Hydro Final Argument, pp. 61 to 62.
[355] CEC Final Argument, pp. 34 to 42.
[356] BC Hydro Reply Argument, pp. 42 to 43.
[357] BC Hydro Reply Argument, p. 44.
[358] BCSEA Final Argument, pp. 15 to 19.
[359] Zone II RPG Final Argument, p. 5.
[360] Zone II RPG Final Argument, p. 5.

BC Hydro submits that it has already included the "40 percent adder" under the DSM Regulation into the cost-effectiveness analysis for the NIA, adding, however, that DSM programs in the NIA are already cost-effective.[361]

Zone II RPG is concerned with continuing delays in implementing DSM in the NIA, citing BC Hydro's evidence of actual / forecast DSM savings and expenditures both being below plan in F2020, F2021 and F2022.[362]

BC Hydro submits that it has already taken steps to increase participation in the NIA, including hiring a relationship manager in June 2019 and creating a dedicated program for the NIA communities. It acknowledges that the timing of DSM activities in the NIA has shifted in response to provincial health orders and local health protocols as a result of the COVID-19 pandemic. BC Hydro has plans in F2022 for activities to assist in the continued ramp-up in the NIA and Indigenous communities and to help mitigate the impacts of the pandemic.[363]

Zone II RPG submits that BC Hydro should prioritize DSM in the NIA, given the importance of reducing the usage of diesel. In the absence of BC Hydro's diesel reduction strategy, which awaits Phase 2 of the Provincial Government's Comprehensive Review of BC Hydro, which has apparently been delayed due to the COVID-19 pandemic, Zone II RPG submits that BC Hydro should "focus on reducing diesel reliance in all sectors," including fast-tracking LED streetlights. Zone II RPG adds that BC Hydro should consider the implications of offering EV charging stations in NIA communities where the electricity is generated by diesel.[364]

BC Hydro submits that it is working on a range of diesel-reduction activities in the NIA but recognizes there is more work ahead. [365]

BCOAPO has no issues with BC Hydro's proposed F2022 DSM Expenditure Schedule.[366]

MoveUP notes the DSM plan is proposing continuity, treading water pending the new IRP.[367]

CEABC is in favour of encouraging the most efficient use of energy[368] and agrees with BC Hydro that a moderation strategy with respect to DSM measures is appropriate.[369]

However, CEABC points to the anomaly that while cost-effective DSM measures reduce the overall revenue requirement that BC Hydro must recover, it does not follow that rates will decrease as a result. Rather, CEABC submits that rates in general will have to rise whenever the reduction in overall load is greater than the reduction in revenue requirement, and that this explains BC Hydro's moderation strategy. CEABC submits that DSM measures should be "aggressively coupled with other initiatives" designed to market the saved electricity to other customers, thus avoiding a net loss in load and billing revenues, while still assuring efficient use of electricity.[370]

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[361] BC Hydro Reply Argument, p. 44.
[362] Zone II RPG Final Argument, pp. 5 to 6.
[363] BC Hydro Reply Argument, pp. 44 to 45.
[364] Zone II RPG Final Argument, pp. 7 to 8.
[365] BC Hydro Reply Argument, p. 45.
[366] BCOAPO Final Argument, p. 62.
[367] MoveUP Final Argument, p. 2.
[368] CEABC Final Argument, p. 5.
[369] CEABC Final Argument, p. 9.
[370] CEABC Final Argument, pp. 5 to 7.

CM&E submits that, while customers should be encouraged to use electricity more efficiently because it saves them money, while BC Hydro has a surplus of electricity DSM spending "does not make business sense." Every kWh of energy saved reduces BC Hydro's revenue by around 11 cents, compared to the value of 4 cents which the surplus energy has on the US market. CM&E submits that BC Hydro should "continue to spend resources to motivate customers to be more efficient," but it should also encourage customers to use electricity to avoid generating greenhouse gases.[371]

BC Hydro submits that CM&E's point is unclear. It submits that it uses a market price of $33/MWh to compare to the net levelized utility cost, and as such even surplus energy resulting from DSM would have a positive impact on BC Hydro's revenue requirements. BC Hydro acknowledges that DSM spending may still result in increased rates, but submits that its moderation approach ensures that its DSM spending makes business sense.[372]

Bryenton submits DSM expenditures should be higher, and not moderated.[373]

RCIA submits that BC Hydro's proposed level of DSM expenditure is not justified in light of the additional energy that will be available from Site C. RCIA submits that BC Hydro should defer "any significant additional investments in DSM," and consider instead investing in "increased storage capacity or developing customized seasonal load rates" to use surplus energy.[374]

BC Hydro submits that RCIA does not provide a convincing rationale for its position, and adds that the moderation approach "continues to strike a reasonable balance," and remains the appropriate approach until the 2021 IRP, where future levels of DSM will be examined.[375]

Panel Determination

The Panel finds, pursuant to section 44.2(5.1) of the UCA, that the proposed "traditional" DSM expenditure schedule is in the interests of persons in B.C. who receive or may receive service from BC Hydro.

In support of the proposed DSM expenditures, in F2022, the proposed DSM programs are forecast to produce incremental energy savings of 210 GWh and capacity savings of 33 MW, thereby reducing BC Hydro's revenue requirement. Program participants are able to reduce their energy spending, and all ratepayers stand to gain from postponing capital investments as a result of capacity savings. The proposed DSM programs broadly cover all rate groups, and the proportion of DSM spending in each rate group aligns with the proportion of costs which are allocated to each rate group.

That said, the Panel acknowledges that these benefits come at a cost to ratepayers, who are also persons in B.C. who receive or may receive service from BC Hydro. As CEABC and CM&E note, while BC Hydro's revenue requirement may be reduced as a result of DSM spending, rates may increase due to decreased load. The Panel considers it is in the interests of BC Hydro's ratepayers for the utility's rates to remain affordable. Uncompetitive commercial and industrial rates may lead to reduced economic activity and employment in the province, and

[371] CM&E Final Argument, p. 3.
[372] BC Hydro Reply Argument, p. 41.
[373] Bryenton Final Argument, p. 3.
[374] RCIA Final Argument, p. 23.
[375] BC Hydro Reply Argument, p. 40.

may also hinder electrification efforts. Unaffordable residential rates may lead to undesirable social consequences such as increased poverty.

The BCUC has previously noted the importance of affordability of rates both to BC Hydro's long-term viability as a corporation and as an issue of public policy, while acknowledging that the BCUC's powers to consider affordability are limited when setting just and reasonable rates.[376] However, when considering requests for approval of DSM spending under section 44.2 of the UCA, the test is whether the proposed expenditure schedule is in the public interest, and for this reason the BCUC may consider the effect of DSM spending on the affordability of BC Hydro's rates.

In the interests of affordability of rates, the Panel supports BC Hydro's continued moderation of DSM spending and disagrees that increased DSM spending is appropriate at this time, either on all cost-effective DSM programs as supported by the BCSEA, or on commercial rate classes as proposed by the CEC. In the Panel's view, the continuation of BC Hydro's moderation approach to DSM spending is an acceptable balancing of the interests of its current and future ratepayers in F2022. There is no evidence that the proposed DSM expenditures for F2022 will lead directly to unaffordable rates, and the Panel accepts the benefits to the system of capacity savings and the benefits of energy savings to DSM program participants.

BC Hydro states that its future levels of DSM spending will be explored in its next IRP,[377] which the BCUC has directed must be filed by December 31, 2021.[378] The Panel is satisfied that the IRP will provide an opportunity for the BCUC to examine BC Hydro's DSM spending in the wider context of its energy supply and demand, and to consider issues such as affordability.

The Panel agrees with BC Hydro that CEABC introduced new evidence in its final argument.[379] The Panel has disregarded this part of CEABC's submission, and encourages CEABC to introduce its evidence at the appropriate time in future proceedings.

The Panel disagrees with the CEC's position that BC Hydro's moderation approach is a transfer of DSM spending from commercial rate classes to the residential rate class. Regardless of historical DSM spending on commercial and light industrial customer classes, together these rate classes are forecast to receive 35 percent of DSM spending in F2020 and are allocated 35 percent of DSM spending for cost recovery purposes, which the Panel considers to be equitable.

The Panel also disagrees with RCIA's position that BC Hydro's proposed level of DSM spending is unjustified given the current energy surplus in B.C. The Panel is satisfied that some level of energy-focused DSM spending is justified, for example to satisfy government regulations and to maintain public awareness of energy efficiency for future times when energy may not be in such surplus.

The Panel agrees with BC Hydro that capacity-focused DSM "has the potential to be used to reduce or shift electricity consumption in order to optimize system capacity and reduce the amount of infrastructure and electricity that needs to be acquired in the future," and supports BC Hydro's evaluation of demand response

[376] BC Hydro F2020 to F2021 RRA, Decision, pp. 194 to 195.
[377] Exhibit B-2, p. 10-1.
[378] Order G-28-21.
[379] E.g. CEABC Final Argument, p. 8, table of "Summary PV data."

techniques and "offers that shift customer consumption" (time-of-use rates).[380] We also agree that it is appropriate to consider capacity-focused DSM as a resource option in the next IRP, and expect that in its IRP application BC Hydro will provide details of its evaluation activities not available for inclusion in Section 4.2 of Appendix M of the current Application. In addition to BC Hydro's submissions in its IRP application, the Panel also expects BC Hydro to provide evidence in its F2023 RRA to support any proposed spending on capacity-focused DSM spending in the fiscal period beyond F2022.

The Panel notes that BC Hydro provides no retrospective evaluation in the Application of the effectiveness of its DSM spending. Despite the moderated level of DSM spending, the Panel still considers it worthwhile for the BCUC to examine whether BC Hydro's DSM spending has achieved its forecast objectives, including energy and capacity savings, to evaluate the actual impact of DSM spending on rates compared with that forecast. While this one-year RRA proceeding has been streamlined, BC Hydro's F2023 RRA filing is expected to be examined in depth. **The Panel directs BC Hydro to include in its F2023 RRA BC Hydro's most recent evaluation of its DSM effectiveness**.

4.6.2.2 British Columbia's Energy Objectives

Section 44.2 (5.1)(a) of the UCA requires the BCUC to consider B.C.'s energy objectives in determining whether to accept an expenditure schedule filed by BC Hydro.

BC Hydro summarizes in the table below how its traditional DSM expenditures support the energy objectives in the CEA.

Table 23: DSM Plan Alignment with BC Energy Objectives[381]

Energy Objective	DSM Plan
To achieve electricity self-sufficiency	The DSM Plan's energy and capacity savings have contributed to BC Hydro achieving and maintaining electricity self-sufficiency and will continue to do so going forward.
To take demand-side measures and to conserve energy	Fiscal 2022 expenditures will continue the objective of taking demand-side measures and conserving energy at a similar level to the Previous Application.
To use and foster the development of innovative technologies that support energy conservation	Both DSM programs and the Codes and Standards initiatives will use and foster the development of innovative technologies supporting energy conservation. Refer to Appendix M for more detail.
To ensure that BC Hydro's rates remain among the most competitive	The moderation strategy reduces rates relative to the DSM investment level for fiscal 2022 that was contemplated in the 2013 Integrated Resource Plan.
To reduce B.C. GHG emissions	The Non Integrated Areas Program is expected to reduce GHG emissions by reducing diesel generation.

[380] Exhibit B-2, p. 10-12.
[381] Exhibit B-2, Table 10-8, pp. 10-16 to 10-17.

To encourage communities to reduce GHG emissions and use energy efficiently	BC Hydro's Codes and Standards initiatives provide support to communities (including Indigenous communities) to incorporate electricity efficiency into community energy planning and implement energy efficiency policies and projects.
To encourage economic development and the creation and retention of jobs	BC Hydro's DSM efforts create significant economic activity and jobs within the province. Analysis undertaken for the Previous Application estimated the impact at 11,600 person years of employment over the ten years from fiscal 2020 to fiscal 2029.

Positions of Parties

BC Hydro submits that the proposed DSM expenditures continue to support B.C.'s Energy Objectives including taking demand-side measures to conserve energy.[382]

BCSEA submits that BC Hydro's DSM expenditure schedule supports the B.C. Energy Objective to take demand side measures and to conserve energy.[383]

Panel Determination

The Panel finds, pursuant to section 44.2(5.1)(a) of the UCA, that the proposed DSM expenditure schedule is consistent with and supports the relevant energy objectives set out in the CEA. In general, the Panel agrees with BC Hydro's assessment of the alignment of its proposed DSM expenditure schedule with B.C.'s Energy Objectives set out in Table 10-8 of the Application.

The Panel expresses in Section 4.6.2.1 above its concern that increased levels of DSM spending could reduce affordability of BC Hydro's rates, which would be in conflict with the Energy Objective to "ensure the authority's rates remain among the most competitive of rates charged by public utilities in North America." We agree that moderating expenditure may improve affordability compared to the level of expenditure contemplated in the 2013 IRP. However, as described above, even the moderated level of spending may contribute to reducing the affordability of rates. The Panel expects BC Hydro's proposed levels of DSM spending in the next IRP to consider its effect on affordability.

4.6.2.3 Most Recent Long-Term Resource Plan

Under section 44.2 (5.1)(b) of the UCA, the BCUC must consider the most recent of the following documents:

> (i) an integrated resource plan approved under section 4 of the Clean Energy Act before the repeal of that section;
>
> (ii) a long-term resource plan filed by the authority under section 44.1 of this Act.

The 2013 IRP approved by the Government of B.C. under Section 4 of the CEA (now repealed)[384] is the most recent BC Hydro resource plan. That IRP was not subject to BCUC review or approval but is nonetheless the most

[382] BC Hydro Final Argument, p. 61.

[383] BCSEA Final Argument, p. 19.

[384] Clean Energy Act S3-5 repealed 2019-24-2; Clean Energy Act, SBC 2010, c 22, retrieved on 2020-08-12 from <http://canlii.ca/t/53hhq>

recent IRP which the Panel must consider pursuant to section 44.2(5.1)(b)(i) of the UCA. BC Hydro's next IRP is to be filed with the BCUC for review and approval under Section 44.1 of the UCA by December 31, 2021.[385]

BC Hydro notes that the selected level of DSM expenditures continues a moderation approach, as was recommended in the 2013 IRP for F2014 to F2016. This moderation approach was subsequently continued for F2017 to F2019, and for F2020 to F2021, in response to an extended energy surplus and to limit forecast rate increases. The BCUC has accepted BC Hydro's past expenditure schedules reflecting the moderation approach.[386] For F2022, BC Hydro has continued with the same approach, consistent with the Previous RRA.[387]

In accordance with Directive 46 of the Previous RRA Decision, BC Hydro's next IRP will examine different levels of DSM.[388]

BC Hydro notes that the NIA is not included in the next IRP, and that resource planning in these areas has different requirements than in the integrated system. BC Hydro is working with several communities on resource plans to support specific supply-side diesel reduction projects and expects to provide a project plan outline in the F2023 RRA.[389]

Until BC Hydro submits its next IRP to the BCUC for review and approval under section 44.1 of the UCA, its DSM Plan does not need to show that BC Hydro intends to pursue adequate, cost-effective demand side measures as required by section 44.1(8)(c). However, BC Hydro provides a table showing how the DSM programs align with the adequacy requirement set out in the DSM Regulation for long-term resource plans.[390]

Positions of Parties

BC Hydro submits that it agrees with the BCUC's decision in the Previous RRA that alignment between the DSM expenditure schedule and the 2013 IRP is moot given the passage of time. Nevertheless, BC Hydro submits the proposed DSM expenditure schedule continues the moderation approach first recommended in the 2013 IRP and continued since then.[391]

BCSEA submits that BC Hydro's DSM expenditure schedule is consistent with the moderation approach in BC Hydro's 2013 IRP.[392]

Panel Discussion

Section 44.2(5.1)(b)(i) of the UCA does not require us to find consistency between BC Hydro's 2013 IRP and its current DSM expenditure schedule. It simply requires us to consider that IRP. As eight years have now elapsed since the 2013 IRP (which was not reviewed by the BCUC) and BC Hydro is in the process of developing its next IRP for submission to the BCUC in 2021, we have considered BC Hydro's 2013 IRP and find alignment between it and the DSM expenditure schedule continues to be moot.

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[385] Section 44.1 (2.1) of the UCA has been updated to state that "The authority need not file a long-term resource plan before February 28, 2021." *Utilities Commission Act*, RSBC 1996, c 473, retrieved on 2020-08-12 from <http://canlii.ca/t/53lxk> ; Order G-28-21.
[386] Exhibit B-2, p. 10-17.
[387] BC Hydro Final Argument, p. 58.
[388] Exhibit B-2, p. 10-17; BC Hydro Final Argument, pp. 60 to 61.
[389] Exhibit B-5, Zone II RPG, IR 1.16.2.
[390] Exhibit B-2, Table 10-9, pp. 10-18 to 10-19; BC Hydro Final Argument, pp. 61 to 62.
[391] BC Hydro Final Argument, p. 61.
[392] BCSEA Final Argument, p. 19.

4.6.2.4 Cost-effectiveness as defined by the DSM Regulation

BC Hydro submits that its proposed DSM expenditure schedule meets the adequacy and cost-effectiveness requirements set out in the regulation.[393]

Section 4 of the DSM Regulation[394] sets out the process for determining cost-effectiveness for the purposes of section 44.2(5.1)(d) of the UCA, including the specific application of the Total Resource Cost (TRC) and a modified TRC (mTRC) test to represent societal and non-energy benefits for DSM programs.

The Utility Cost Test and TRC tests are standard cost tests used in the DSM industry to assess cost-effectiveness. A ratio of 1.0 or more indicates that benefits exceed the costs and that the DSM program or portfolio is cost-effective under that particular test.[395] The TRC is the ratio that results when the value of the benefits of DSM activity, as measured by avoided energy and capacity costs as applicable, is divided by the sum of the utility and customer costs for that DSM activity. The Utility Cost Test is used to assess the impact of a DSM investment on BC Hydro's revenue requirement. Consistent with previous applications, BC Hydro is using the export market price to value the energy savings resulting from activities in the Test Period. A positive Utility Cost Test result using BC Hydro's market price forecast would provide assurance that even surplus energy resulting from DSM would have a positive impact on BC Hydro's revenue requirements.[396]

The TRC is the test required by the DSM Regulation, and requires that a long-run marginal cost (LRMC) of acquiring electricity from clean or renewable resources in B.C. be used as an input. BC Hydro has used an avoided cost of $54 per MWh in this Application, based on the low end of the preliminary range of the cost of new wind resources presented in the Previous RRA.[397]

The following table presents the benefit cost ratios for the various DSM programs and overall portfolio in the Test Period:[398]

Table 24: Benefit-Cost Ratios and Net Levelized Costs ($/MWh)

	Benefit-Cost Ratios		Net Levelized Costs ($/MWh)	
	Utility Cost Test (Market Price at $33 per MWh)	Modified Total Resource Cost Test (LRMC at $54 per MWh)	Utility Cost ($)	Total Resource Cost ($)
Rate Structures	34.6	1.8	(11)	26
Programs	2.1	2.4	1	(18)
Total Portfolio[253]	1.4	1.6	19	14

Positions of Parties

BC Hydro submits that its proposed DSM initiatives are cost effective in accordance with the requirements of the DSM Regulation, adding that the net levelized utility cost of $19 per MWh is lower than the market price of

[393] Exhibit B-2, pp. 10-19 to 10-21.
[394] B.C. Reg. 117/2017.
[395] Exhibit B-2, p. 10-19.
[396] Exhibit B-2, pp. 10-19 to 10-20.
[397] Exhibit B-2, p. 10-20.
[398] Exhibit B-2, Table 10-10, p. 10-21.

energy of $33 per MWh, and that BC Hydro's proposed DSM initiatives have a total resource cost of $14 per MWh, which is lower than the low end of the preliminary range of new wind resources ($54 per MWh).[399]

BCSEA submits that BC Hydro's DSM expenditure schedule is cost-effective within the meaning of the DSM regulation.[400]

CEABC submits that using the ratepayer impact measure test (RIM Test), which accounts for the lost billing revenues due to energy savings, the costs borne by BC Hydro for its DSM measures exceed the value of the savings by a factor of roughly 2.5 to 3.0.[401]

BC Hydro submits that section 4(6) of the DSM Regulation does not allow the BCUC to use the RIM Test to find that DSM expenditures are not cost-effective. BC Hydro adds that CEABC's analysis is misleading because it "incorrectly includes reduced revenue as a cost in its analysis," whereas BC Hydro uses the Utilities Cost Test which results in a reduction to its revenue requirement. BC Hydro acknowledges that this may lead to an increase in rates, not because BC Hydro is incurring more cost but because it is recovering lower costs over fewer units of sales. Therefore, BC Hydro submits that the BCUC should not consider the RIM Test or CEABC's interpretation of it, as it is potentially misleading.[402]

Panel Determination

The Panel finds, pursuant to section 44.2(5.1)(d) of the UCA and regulation 3(4), that the proposed DSM expenditure schedule is cost-effective within the meaning prescribed by regulation.

We agree with BC Hydro that the proposed DSM programs are cost-effective using the Total Resource Cost test, having a portfolio benefit-to-cost ratio exceeding 1.0, as set out in Table 10-10 of the Application. We also agree with BC Hydro that Demand-Side Measures Regulation section 4(6) prevents the BCUC from considering a ratepayer impact measure test when assessing the cost-effectiveness of DSM measures, which the CEABC submits assesses the impact of DSM measures on rates, which the TRC does not.

4.6.3 Implementation of DSM in the NIA

Zone II RPG submits it is concerned with continuing delays to BC Hydro's implementation of DSM in the NIA and notes that BC Hydro's diesel reduction strategy will be informed by Phase 2 of the provincial government's review of BC Hydro, which in turn appears to have been delayed by the COVID-19 pandemic and the provincial election.

Panel Discussion

The Panel is concerned that achievable cost-effective opportunities for BC Hydro to reduce the use of diesel in NIA are being overlooked in a search for a perfect strategy. The Panel encourages BC Hydro to consider implementing such DSM activities on their own merits, including those suggested by Zone II RPG, without waiting for either the Phase 2 Review or BC Hydro's own diesel reduction strategy. The Panel notes that the absence of an electrification plan is not preventing BC Hydro progressing with its LCE activities.[403]

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399 BC Hydro Final Argument, p. 62.
400 BCSEA Final Argument, p. 19.
401 CEABC Final Argument, pp. 5 to 7.
402 BC Hydro Reply Argument, pp. 41 to 42.
403 BC Hydro Final Argument, p. 66.

4.7 Low Carbon Electrification

In addition to the traditional DSM activities described in the previous section of this Decision, which are aimed at reducing energy use, BC Hydro is forecasting expenditures of $15.5 million on LCE undertakings in F2022 that is expected to add 148 GWh/year in new incremental load growth and 29 MW of new incremental associated capacity.[404]

4.7.1 Legislative Framework for Low Carbon Electrification Expenditures

Section 4 of the GGRR sets out the criteria for electrification infrastructure projects and electrification programs to be considered prescribed undertakings for the purposes of section 18 of the CEA.

Section 4(3) of the GGRR provides:

> Subject to subsection (4), a public utility's undertaking that is in a class defined in one of the following paragraphs is a prescribed undertaking for the purposes of section 18 of the Act:
>
> (a) a program to encourage the public utility's customers, or persons who may become customers of the public utility, to use electricity, instead of other sources of energy that produce more greenhouse gas emissions, by
>
> (i) educating or training those customers respecting energy use and greenhouse gas emissions, carrying out public awareness campaigns respecting those matters, or providing energy management and audit services, or
>
> (ii) providing funds to those persons to assist in the acquisition, installation or use of equipment that uses or affects the use of electricity;
>
> (b) a program to encourage the public utility's customers, or persons who may become customers of the public utility, to use electricity instead of other sources of energy that produce more greenhouse gas emissions, by
>
> (i) educating, training, providing energy management and audit services to, or carrying out awareness campaigns respecting energy use and greenhouse gas emissions for, or
>
> (ii) providing funds to
>
> persons who
>
> (iii) design, manufacture, sell, install or, in the course of operating a business, provide advice respecting equipment that uses or affects the use of electricity,
>
> (iv) design, construct, manage or, in the course of operating a business, provide advice respecting energy systems in buildings or facilities, or

[404] BC Hydro Final Argument, p. 62.

(v) design, construct or manage district energy systems;

(c) a project, program, contract or expenditure for research and development of technology, or for conducting a pilot project respecting technology, that may enable the public utility's customers to use electricity instead of other sources of energy that produce more greenhouse gas emissions;

(d) a project, program, contract or expenditure supporting a standards-making body in its development of standards respecting

(i) technologies that use electricity instead of other sources of energy that produce more greenhouse gas emissions, or

(ii) technologies that affect the use of electricity by other technologies that use electricity instead of other sources of energy that produce more greenhouse gas emissions;

(e) a project for the construction, acquisition or extension of a plant or system, that the public utility reasonably expects is necessary to meet the public utility's incremental load-serving obligations arising as a result of an undertaking defined in paragraph (a), (b), (c) or (d), if the public utility reasonably expects any one such project to cost no more than $20 million.

Section 4(4) of the GGRR provides:

> An undertaking is within a class of undertakings defined in paragraph (a) or (b) of subsection (3) only if, at the time the public utility decides to carry out the undertaking, the public utility reasonably expects the undertaking to be cost- effective.

By Order in Council 100/2017, direction was provided to the BCUC with respect to certain undertaking costs incurred by BC Hydro.

Section 3 of the Direction to the BCUC Respecting Undertaking Costs provides:[405]

> The commission must allow the authority to defer to the DSM regulatory account amounts equal to the undertaking costs.

Section 1 of the Direction to the BCUC Respecting Undertaking Costs defines undertaking costs as:

> all costs incurred by the authority to implement an undertaking within a class defined in section 4 (3) (a), (b), (c) or (d) of the Greenhouse Gas Reduction (Clean Energy) Regulation.

4.7.2 Low Carbon Electrification Expenditures

BC Hydro plans a total of $15.5 million in LCE expenditures in F2022, with 148 GWh/year in new incremental load growth and 29 MW of new incremental associated capacity.[406] BC Hydro's LCE expenditures continue the

[405] Direction to the BCUC Respecting Undertaking Costs (B.C. Reg. 77/2017), OIC 100/2017.
[406] BC Hydro Final Argument, p. 62.

activities that BC Hydro described in the Previous RRA and that the BCUC accepted as prescribed undertakings. BC Hydro submits the LCE expenditures should be recovered through the DSM Regulatory Account, pursuant to the Direction to the BCUC Respecting Undertaking Costs,[407] which requires the BCUC to allow BC Hydro to defer the costs incurred for prescribed undertakings as defined under section 4 (3) (a), (b), (c) or (d) of the GGRR to the DSM Regulatory Account.[408]

BC Hydro states that $6 million of the $15.5 million LCE expenditures forecast for F2022 relates to completing its initial projects started in previous fiscal years:[409]

Table 25: Expenditures and New Incremental Load and Capacity Growth for Initial LCE Projects

Initial LCE Projects	2022 Plan			
GGRR Regulation Subsection	Project	Expenditures ($ million)	New Incremental Load Growth (GWh/yr)	New Incremental Associated Capacity Growth (MW)
4(3)(a)	Project 1	6.00	119.1	16.0

The remaining $9.5 million of the $15.5 million LCE expenditures forecast for F2022 relates to new activities:[410]

Table 26: BC Hydro LCE Program Expenditures

BC Hydro LCE Program		F2022 Plan		
GGRR Regulation Subsection	Program Component	Expenditures ($ million)	New Incremental Load Growth (GWh/yr)	New Incremental Associated Capacity Growth (MW)
4(3)(a), 4(3)(b)	Energy Management Studies and Incentives[4]	8.61	29.2	10.1
4(3)(d)	Standards Enabler	0.91	n/a	n/a
Program Total		**9.52**	**29.2**	**10.1**

BC Hydro states that expenditures are higher in F2022 compared to F2021 due to the timing of larger projects in the natural gas and transportation sector, which are planned to be implemented in F2022.[411]

BC Hydro submits that its LCE expenditures incurred under sections 4(3)(a) or 4(3)(b) of the GGRR are cost effective as they have a positive net present value.[412] BC Hydro provides the calculation of the cost effectiveness of its LCE expenditures in the following table:[413]

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407 Direction to the BCUC Respecting Undertaking Costs (B.C. Reg. 77/2017), OIC 100/2017.

408 Exhibit B-2, p. 2-11; p. 10-23; BC Hydro Final Argument, pp. 56, 64.

409 Exhibit B-2-2, Appendix N, Table N-1, p. 6.

410 Exhibit B-2-2, Appendix N, Table N-3, p. 8.

411 Exhibit B-2, p. 10-14.

412 Exhibit B-2-2, Appendix N, pp. 8 to 9.

413 Exhibit B-2-2, Appendix N, Table N-4, p. 10.

Table 27: Cost Effectiveness

A	B	C	D	E		F		G	
GGRR	Project/ Program/ Contract/ Expenditure	Expenditure ($ million)	Cost Effectiveness (F18 $million)	Additional Energy Consumption (MWh/year)		Additional Demand (MW)		Estimated GHG Emission Reductions (tonnes CO2e/year)	
		Total	GGRR NPV to 2030 (F2031)	Incremental	Cumulative	Incremental	Cumulative	Incremental	Cumulative
4(3)(a)	Project 1	16.20	64.32	268,056	268,056	36.0	36.0	160,274	160,274
4(3)(a)	Project 2[5]	13.50	110.20	223,380	491,436	30.0	66.0	133,562	293,836
4(3)(a)	Project 3[5]	0.28	110.47	2,737	494,173	0.0	66.0	562	294,398
4(3)(a) or (b)	BC Hydro LCE Program[6]	15.60	118.77	65,824	559,996	14.9	80.9	36,301	330,699
	Total	**45.58**	**118.77**	**559,996**	**559,996**	**80.9**	**80.9**	**330,699**	**330,699**

Electrification Plan

BC Hydro is working on a broader electrification plan[414] which BC Hydro intends to present as part of the F2023 RRA.[415] It will cover existing electrification efforts from across the company (infrastructure projects addressed under the Capital Plan, and the LCE programs included with DSM)[416] as well as plans for additional actions to drive increased electrification, including all efforts to connect and attract new customers.[417] Current engagement efforts are structured around the three sectors of industry, transportation and buildings – pulling together activities which are already occurring into one place, and building on from there. Electrification benefits BC Hydro due to increased load, keeping rates down, while the fuel switching elements assist the CleanBC GHG reduction target.[418]

The electrification plan is a 5-year plan describing efforts in different sectors and will include metrics and targets to measure success, and the resources required, and will be included in the F2023 RRA.[419] The upcoming IRP is looking at different load scenarios, including different amounts of electrification, with a long-term focus.

Positions of Parties

The CEC supports the identified intended benefits of the electrification activities broadly, and the development of the electrification plan. The CEC also submits that the BCUC should have BC Hydro include in its F2023 RRA the electrification plan and metrics.[420] BC Hydro submits that the CEC's request is "unclear and unnecessary," and that its electrification plan and associated performance metrics will be filed in its F2023 RRA.[421]

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[414] Exhibit B-2, p. 10-2.

[415] Exhibit B-2, Application, p. 10-2; Exhibit B-5, BCSEA IR 1.12.5 and CEC IR 1.61.1, Transcript Vol. 1, pp. 15, 39.

[416] BC Hydro Final Argument, p. 65.

[417] Transcript Vol. 1, pp. 39, 49 to 50; BC Hydro Final Argument, p. 65; Transcript Vol. 1, pp. 49 to 50.

[418] Transcript Vol. 1, p. 50.

[419] Transcript Vol. 1, pp. 208 to 212.

[420] CEC Final Argument, pp. 36 to 37.

[421] BC Hydro Reply Argument, p. 46.

The CEC submits that establishing a separate review of the electrification plan could be an appropriate measure and ensure adequate time and attention is provided to this important and impactful plan.[422] BC Hydro submits that the electrification plan, *per se*, is not subject to BCUC approval, and as such a separate review is unnecessary and its purpose would be unclear. The electrification plan should be reviewed in the context of an RRA, which includes the capital projects and LCE expenditures that are included in the plan.[423]

BCSEA supports BC Hydro's LCE Projects and Programs for F2022 and submits that BC Hydro should substantially increase its LCE spending and results in order to help reduce B.C.'s GHG emissions and meet B.C.'s ambitious GHG reduction targets. BCSEA submits that the LCE projects and programs for F2022 are prescribed undertakings under section 18(2) of the CEA and section 4(3)(a) to (d) of the GGRR.[424]

BCSEA strongly supports BC Hydro's development of a five-year Electrification Plan,[425] and recognizes that one of the potential benefits of an electrification plan is the opportunity to identify metrics, set targets and report on achievements across all of BC Hydro's electrification activities.[426] BCSEA sees the inclusion of the plan in the F2023 RRA as a reasonable timeframe, given that the F2023 RRA is scheduled to be filed in August 2021.

CEABC encourages BC Hydro to pursue cost-effective electrification as broadly and rapidly as possible but recommends the BCUC change its decision to exclude the electrification plan from BC Hydro's next IRP.[427] BC Hydro submits that the electrification plan properly belongs in the F2023 RRA as it is linked to financial commitments.[428]

CM&E submits the LCE program that BC Hydro has implemented is welcomed, and encourages further electrification, particularly for mid size industrial customers.[429]

RCIA does not dispute the importance of DSM and LCE activities.[430]

Panel Determination

The Panel agrees with BC Hydro that the appropriate time for the BCUC to review the electrification plan is in the F2023 RRA, as the plan contains capital and operating expenditures that are subject to BCUC approval.

BC Hydro seeks no approval for its forecast LCE expenditures, stating that its LCE activities are prescribed undertakings under the GGRR.[431] The Panel agrees that BC Hydro's current LCE activities are prescribed undertakings, and the BCUC must, under section 18(2) of the CEA, set rates to allow BC Hydro "to collect sufficient revenue in each fiscal year to enable it to recover its costs incurred with respect to the prescribed undertaking." For this reason, the Panel accepts that the F2022 LCE expenditures of $15.5 million will be added

[422] CEC Final Argument, p. 37.
[423] BC Hydro Reply Argument, p. 47.
[424] BCSEA Final Argument, pp. 19 to 20.
[425] BCSEA Final Argument, p. 20.
[426] BCSEA Final Argument, p. 21.
[427] CEABC Final Argument, p. 9, 16.
[428] BC Hydro Reply Argument, p. 47
[429] CM&E Final Argument, pp. 3 to 4
[430] RCIA Final Argument, p. 23
[431] Exhibit B-2, p. 10-13.

to the DSM Regulatory Account pursuant to the Direction to the BCUC Respecting Undertaking Costs wherein the BCUC must allow BC Hydro to defer to the DSM regulatory account amounts equal to the undertaking costs.

However, the Panel notes that neither the CEA nor the Direction to the BCUC Respecting Undertaking Costs make any direction as to from whom the costs of these prescribed undertaking must be recovered, and at present the expenditures in the DSM Regulatory Account are recovered from all ratepayers. The Panel is of the view that the principle of cost causation requires the expenditures associated with prescribed LCE undertakings to be recovered only from the customers who receive the benefits of these prescribed undertakings. **The Panel directs BC Hydro to provide in its F2023 RRA a discussion of whether LCE expenditures deferred to the DSM Regulatory Account should be recovered only from the beneficiaries of these expenditures, and if so by what methods this could be accomplished.**

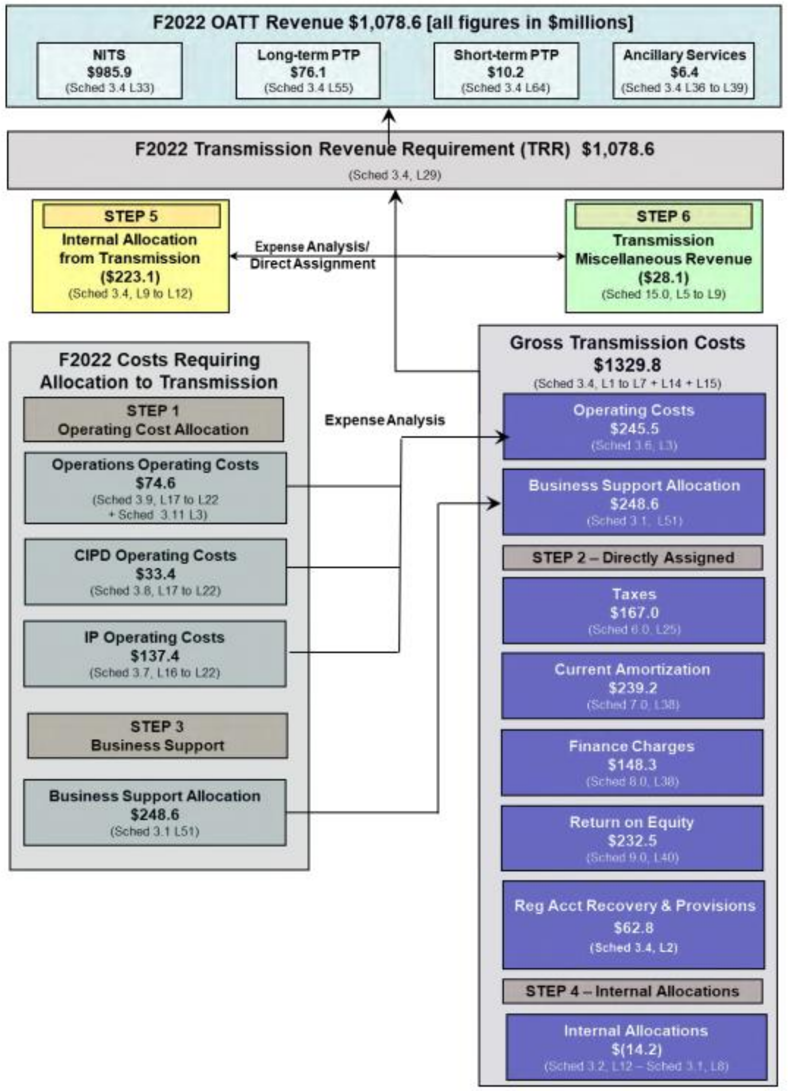
4.8 Transmission Revenue Requirement and Open Access Transmission Tariff

BC Hydro's Open Access Transmission Tariff (OATT) provides BCUC-approved terms through which customers may access BC Hydro's transmission system "on a comparable basis to that of electric utilities throughout the Western Interconnection." The OATT rates apply to all usage of BC Hydro's transmission system, including usage by BC Hydro itself and by external OATT customers. The OATT considers only transmission capacity and not the sale of energy except for some ancillary services.[432]

The Transmission Revenue Requirement (TRR) is comprised of the current costs associated with BC Hydro's transmission lines and high-voltage equipment used to provide transmission service pursuant to the OATT, which excludes both generation-related transmission assets and substation distribution assets. The allocations and direct assignments involved in calculating the TRR are set out in BC Hydro's figure below:[433]

[432] Exhibit B-2, p. 9-1.
[433] Exhibit B-2, Figure 9-1, p. 9-3.

Figure 11: F2022 Transmission Revenue Requirement Components ($ million) with References to Appendix A Financial Schedules



Where possible, BC Hydro directly assigns costs to the TRR. Where direct assignment is not possible, costs are allocated using one or more of the following parameters:[434]

i. Planned expenditures for maintenance and/or capital programs that are representative of the work a KBU [Key Business Unit] expects to undertake during the Test Period;
ii. Historical expenditures for work performed by a KBU;
iii. Work performed by Full-Time Equivalents (FTEs) within a KBU;
iv. Manager and financial analyst interviews; and
v. Direct allocation of certain specific activity costs.

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[434] Exhibit B-2, p. 9-7.

As a result of the above analysis, BC Hydro allocates to the TRR the following operating costs from other business functions:[435]

- 39 per cent of the Integrated Planning Business Group operating costs;
- 28 per cent of the Capital Infrastructure Project Delivery Business Group operating costs;
- 30 per cent of the Operations Business Group operating costs;
- 25 per cent of the Materials Management operating costs; and
- 30 per cent of the Fleet Services operating costs.

BC Hydro directly assigns to gross transmission costs certain costs such as provisions, taxes, amortization, finance charges, return on equity, and business support costs.[436]

To calculate the TRR from gross transmission costs, BC Hydro directly assigns miscellaneous revenues from external OATT customers and FortisBC, and certain other revenues.[437]

The cost components which make up the TRR in F2022 are set out in BC Hydro's table below:[438]

Table 28: Transmission Revenue Requirement

		F2020 RRA ($ million)	F2020 Actual ($ million)	F2021 RRA ($ million)	F2021 Forecast ($ million)	F2022 Plan ($ million)
		1	2	3	4	5
1	Operating Cost	219.4	206.4	220.5	226.2	245.5
2	Provisions and Other	33.8	48.7	37.3	37.8	62.8
3	Taxes	157.6	158.4	163.7	163.1	167.0
4	Amortization	233.5	234.4	236.1	233.9	239.2
5	Finance Charges	243.9	243.0	227.6	226.8	148.3
6	Allowed Net Income	236.1	232.8	232.9	225.2	232.5
7	Business Support Cost	203.3	207.2	210.0	207.0	248.6
8	Internal Allocations to Transmission					
9	Generation Ancillary Services	2.8	2.1	2.8	2.8	2.5
10	Transmission Capitalized Overhead	(16.1)	(16.1)	(16.3)	(15.6)	(16.6)
11	Gross Transmission Costs	1,314.4	13116.8	1,314.7	1,307.2	1,329.8
12	Less Internal Allocations from Transmission					
13	Generation Related Transmission Assets	(43.3)	(43.3)	(43.3)	(43.3)	(43.3)
14	Generation Real Time Dispatch	(2.4)	(2.4)	(2.4)	(2.4)	(3.1)
15	Distribution Real Time Dispatch	(20.6)	(20.8)	(21.0)	(20.9)	(26.3)
16	Substation Distribution Assets	(125.6)	(127.0)	(127.4)	(145.8)	(150.4)
17	Less Miscellaneous Revenues					
18	FortisBC Inc. General Wheeling Agreement	(5.2)	(5.2)	(5.3)	(5.3)	(5.3)
19	Secondary Revenues	(6.0)	(7.1)	(6.2)	(6.9)	(7.1)
20	Interconnections	(2.2)	(6.4)	(2.2)	(4.6)	(2.3)
21	Amortization of Contributions	(14.6)	(14.6)	(15.0)	(14.8)	(11.0)
22	NTL Supplemental Charges	(2.3)	(2.3)	(2.3)	(2.4)	(2.4)
23	Subtotal	(222.1)	(229.1)	(225.0)	(246.2)	(251.2)
24	Transmission Revenue Requirement	1,092.3	1,087.7	1,089.6	1,061.0	1,078.6

4.8.1 Open Access Transmission Tariff

BC Hydro's TRR is recovered through the OATT, which sets out the rates for the following services:[439]

[435] Exhibit B-2, p. 9-9.

[436] Exhibit B-2, pp. 9-9 to 9-12.

[437] Exhibit B-2, pp. 9-15 to 9-17.

[438] Exhibit B-2, Table 9-1, p. 9-5.

[439] Exhibit B-2, pp. 9-1 to 9-2.

1. Network Integrated Transmission Service (NITS);
2. Point-to-point (PTP) Transmission Service; and
3. Ancillary Services.

As the main users of BC Hydro's transmission system, BC Hydro and Powerex account for approximately 99 percent of the revenue (forecast $1,067.5 million for F2022) collected through the OATT, while external transmission customers account for approximately 1 percent of the revenue (forecast $11.1 million for F2022).[440]

Once the TRR is known, the OATT rates are calculated using the following steps:[441]

- The revenue from Ancillary Services under the OATT is forecast based on forecast volumes of NITS and PTP transmission service;
- The PTP transmission service rate is calculated based on the TRR minus the Ancillary Service revenue divided by the Maximum Supply Capacity;
- The PTP revenue forecast is calculated based on the PTP rate and forecast volumes of PTP transmission service; and
- The monthly NITS rate is calculated based on the TRR minus Ancillary Services and PTP revenue, divided by 12 months.

The derivation of the ancillary services is shown in BC Hydro's table below:[442]

Table 29: Calculation of Scheduling, System Control and Dispatch Rate

		Schedule Reference	F2020 RRA	F2020 Actual	F2021 RRA	F2021 Forecast	F2022 Plan
			1	2	3	4	5
1	**PTP Volumes (MWh)**						
2	Long-Term PTP	Schedule 3.4 L52	9,881,280	10,120,632	9,881,280	9,286,728	8,453,400
3	Short Term PTP	Schedule 3.4 L61	9,939,991	4,017,483	10,324,607	4,347,966	4,087,966
4	**Total PTP Volumes**		19,821,271	14,138,115	20,205,887	13,634,694	12,541,366
5	NITS and Secondary Transmission		9,566,902	12,954,763	9,566,902	12,954,763	12,954,763
6	**Total Volumes**	**Schedule 3.4 L48**	29,388,173	27,092,878	29,772,789	26,589,457	25,496,129
7	**Scheduling, Control and Dispatch Cost ($ million)**	Schedule 3.4 L47	4.1	3.6	4.1	4.0	4.0
8	**Scheduling Fee**[233] **($/MWh)**	**(L47/L48) =Schedule 3.4 L49**	0.138	0.133	0.139	0.152	0.155

The PTP rates are calculated as follows:[443]

[440] Exhibit B-2, p. 9-1.
[441] Exhibit B-2, p. 9-18.
[442] Exhibit B-2, Table 9-5, p. 9-20.
[443] Exhibit B-2, Table 9-6, p. 9-23.

Table 30: Calculation of the PTP Transmission Service Rate

		Reference	F2020 RRA ($ million)	F2020 Actual ($ million)	F2021 RRA ($ million)	F2021 Forecast ($ million)	F2022 Plan ($ million)
			1	2	3	4	5
1	TRR	Schedule 3.4 L29	1,092.3	1,087.7	1,089.6	1,061.0	1,078.6
2	Less Ancillary Services	Schedule 3.4 L36 to L39	(6.9)	(5.7)	(7.0)	(6.9)	(6.4)
3	Net TRR	Schedule 3.4 L40	1,085.4	1,082.0	1,082.7	1,054.1	1,072.2
4	Maximum Capacity Supply (MW)	Schedule 3.4 L.41	13,279	13,279	13,279	13,279	13,596
5	Annual Billing Determinants (MW month)	L4 x 12 months	159,348	159,348	159,348	159,348	163,152
6	PTP Rate ($/MW Month)	L3 X 1,000,000/L5 = Schedule 3.4 L43	6,811.71	6,540.80	6,794.28	6,615.27	6,571.79

The NITS rate is calculated as follows:[444]

Table 31: Calculation of Monthly NITS Charge

		Reference	F2020 RRA ($ million)	F2020 Actuals ($ million)	F2021 RRA ($ million)	F2021 Forecast ($ million)	F2022 Plan ($ million)
			1	2	3	4	5
1	**TRR**	Schedule 3.4 L29	1,092.3	1087.7	1,089.6	1,061.0	1,078.6
2	**Less PTP and Ancillary Services Revenue:**						
3	PTP Revenue	Schedule 3.4 L70	(117.0)	(102.2)	(117.8)	(95.0)	(86.3)
4	Ancillary Service	Schedule 3.4 L36 to L39	(6.9)	(5.7)	(7.0)	(6.9)	(6.4)
5	**Total PTP and Ancillary Services Revenue**	L3+L4	(123.9)	(107.9)	(124.8)	(101.9)	(92.7)
6	**NITS Revenue Requirement**	Schedule 3.4 L33	968.4	928.2	964.8	959.1	985.9
7	**Monthly NITS Charge**	Schedule 3.4 L34	80.7	77.4	80.4	79.9	82.2

BC Hydro does not support the initiation of a proceeding to review the OATT rate design that was recommended by the BCUC in the Previous RRA Decision. However, BC Hydro plans to file an OATT application with regard to the Federal Energy Regulatory Commission Order No. 845/842 (generator interconnection) in 2021, at which time the BCUC could further explore or review the OATT.[445]

Positions of Parties

BC Hydro submits it has determined the OATT rates for F2022 in the same way as the OATT rates which have been approved by the BCUC in prior proceedings, and that its proposed OATT rates are just and reasonable and should be approved.[446]

No intervener opposes BC Hydro's proposed TRR or OATT rates.

Panel Determination

The Panel finds that the proposed OATT rates are just and reasonable and approves the OATT rates as applied for, subject to any adjustments resulting from the determinations and directives contained in this Decision.

The Panel is satisfied that, in general, BC Hydro has calculated the TRR based on allocations and direct assignment of costs consistent with prior BCUC decisions and approved rate designs.

444 Exhibit B-2, Table 9-8, p. 9-27.
445 Exhibit B-2, pp. 9-28 to 9-30.
446 BC Hydro Final Argument, p. 55.

4.8.2 Interconnection Revenues Forecast

During the proceeding, BCOAPO raised a concern with BC Hydro's interconnection revenues forecast.

Interconnection revenues is a component of the TRR and consist of payments for engineering studies done by BC Hydro for generator and load interconnection customers connecting to the transmission system. Under the OATT, BC Hydro conducts engineering studies, which are paid for by the customers requesting service.[447]

The forecast and actual interconnection revenues from F2020 to F2022 are as follows:[448]

- F2022 planned of $2.3 million,
- F2021 forecast of $4.6 million and RRA approved of $2.2 million, and
- F2020 actual of $6.4 million and RRA approved of $2.2 million.

BC Hydro forecasts interconnections revenue based on active studies and anticipated studies. These studies are based on discussions with customers who have indicated that they will be requesting a study in the upcoming fiscal year. BC Hydro submits that its forecasting approach is appropriate because the volume, cost and revenue of studies completed in the previous fiscal year(s) are not an indicator of the volume, cost and revenue of future study requests. BC Hydro also notes that in the past, changes in commodity or market conditions have caused the volume of requests to increase or decrease significantly.[449]

Positions of Parties

BCOAPO requests that the BCUC direct BC Hydro to report back on the pros and cons of using a regulatory account to capture the variances between actual and forecast interconnection revenue. Interconnection revenue is difficult to forecast and, being based on customer requests and requirements, is beyond the control of BC Hydro.[450]

In reply, BC Hydro submits that in addition to interconnection revenues it also incurs additional costs, which are also non-deferable, in order to generate the revenues in question. However, BC Hydro adds that it can report back to the BCUC in the F2023 RRA if the BCUC would consider it helpful.[451]

Panel Determination

The Panel notes that in F2020 BC Hydro forecasted interconnection revenue of $2.2 million and actually received $6.4 million, and in F2021 forecasted $2.2 million and currently forecasts receiving $4.6 million. This appears to indicate that BC Hydro has been under-estimating the interconnections revenue. The Panel is not persuaded that BC Hydro's forecasting methodology would not continue to under-estimate the interconnection revenue for F2022. The Panel does not have confidence in BC Hydro's forecast of $2.3 million for F2022. **Therefore, the Panel directs BC Hydro to amend its forecast for interconnection revenue in F2022 to $4.6 million, the same figure as BC Hydro's most recent forecast for F2021, and to make any corresponding adjustments to forecast costs required to generate this level of interconnection revenue.** The Panel expects BC Hydro to justify in its F2023 RRA any estimate of interconnection revenue not consistent with recent historical trends.

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[447] Exhibit B-2, p. 9-16.

[448] Exhibit B-2, Table 9-1, p. 9-5.

[449] Exhibit B-4, BCUC IR 65.5.

[450] BCOAPO Final Argument, p. 57.

[451] BC Hydro Reply Argument, p. 39.

The Panel declines BCOAPO's request to direct BC Hydro to consider the benefits of a regulatory account to capture variances between actual and forecast interconnection revenue. While acknowledging that these revenues are difficult to forecast, the Panel notes that BC Hydro forecasts the F2022 interconnection revenues to be $2.3 million, and interconnection revenues have been at most $6.4 million since F2020. The Panel does not consider that the size of the variances in these revenues justifies the cost of a regulatory account.

4.9 Other Items

4.9.1 Depreciation Rates for the Burrard Facility and Infrastructure Rights

In the Application, BC Hydro is requesting approval of the depreciation rates for:

- Certain property, plant and equipment at the Burrard synchronous condense facility for F2022;
- Infrastructure rights; and
- EV charging stations.

The depreciation rates for BC Hydro's EV charging stations are discussed in Section 4.9.2.2 of this Decision.

Burrard Facility

BC Hydro is requesting approval of the depreciation rates of certain property, plant and equipment at the Burrard synchronous condense facility for the F2022 test period as provided in Table 8-2 of the Application. The methodology used to determine the depreciation rates is consistent with that used to determine the prior years' depreciation rates that the BCUC previously approved. The depreciation rates for a given fiscal year are applied against the net book value of the assets at the beginning of that fiscal year to calculate the depreciation expense. BC Hydro expects these assets to have remaining useful lives of 4 years and reach the end of their useful lives at the end of F2025.[452]

Infrastructure Rights

BC Hydro is requesting approval to continue to depreciate the assets within the infrastructure rights asset class over a 35-year period in F2022, which is consistent with the treatment approved for F2020 and F2021.[453]

In the Previous RRA Decision, the BCUC approved the requested depreciation rates for the infrastructure rights asset class for the F2020 to F2021 test period only. The BCUC also directed BC Hydro to review the expected useful life of infrastructure rights in its depreciation study and to identify any differences from the requested 35-year useful life in the RRA immediately following the completion of the depreciation study.[454]

BC Hydro is seeking approval to continue depreciating these assets over 35-years for F2022 because the depreciation study will be completed and filed as part of its F2023 RRA.[455]

[452] Exhibit B-2, p. 8-5.
[453] Exhibit B-2, p. 8-5.
[454] BC Hydro F2020 to F2021 RRA, Decision, Directive 57.
[455] Exhibit B-2, p. 8-5.

Positions of Parties

Interveners either support or do not take a position on these requests.[456]

Panel Determination

The Panel is generally satisfied that the depreciation rates requested by BC Hydro continue to match the estimated life of the underlying assets and it recognizes the depreciation study is underway and will be filed with the BCUC as part of BC Hydro's F2023 RRA. **Therefore, the Panel approves the depreciation rates for the Burrard synchronous condense facility and infrastructure rights assets as requested by BC Hydro for F2022.**

4.9.2 EV Charging Stations

The GGRR was amended on June 22, 2020 to include EV charging stations as prescribed undertakings. Section 5(2) of the GGRR sets out the criteria that qualify an EV charging station as a prescribed undertaking for the purposes of section 18 of the CEA. Section 18(2) requires the BCUC to set rates that allow public utilities, such as BC Hydro, to collect sufficient revenue to recover the costs incurred for implementing prescribed undertakings.

Section 5(2) of the GGRR states:

> (2) A public utility's undertaking that is in a class defined as follows is a prescribed undertaking for the purposes of section 18 of the Act:
>
> (a) the public utility constructs and operates, or purchases and operates, an eligible charging station;
>
> (b) the public utility reasonably expects, on the date the public utility decides to construct or purchase an eligible charging station, that
>
> > (i) the station will come into operation by December 31, 2025, and
> >
> > (ii) if the station will be located in a limited municipality, the number of eligible charging sites in the municipality on the date the station will come into operation will not exceed the site limit for the municipality on that date;
>
> (c) if an eligible charging station comes into operation on or after January 1, 2022, the station uses or is configured to use the Open Charge Point Protocol.

Section 5(1) of the GGRR defines the terms used in section 5(2) of the GGRR. It provides that an "eligible charging station" is a fast charging station (i.e., a fixed device capable of charging an electric vehicle using a direct current) that:

> (a) Is available for use 24-hours a day by any member of the public;
>
> (b) Does not require users to be members of a charging network; and
>
> (c) Is capable of charging electric vehicles of more than one make.

[456] BCOAPO Final Argument, p. 49.

A "limited municipality" is defined as a municipality with a population of 9,000 or more, and "site limit," in relation to a limited municipality, is the number calculated by dividing the population of the municipality by 9,000 and, if applicable, rounding the quotient up to the nearest whole number. Further, an "eligible charging site" is a site where one or more eligible charging stations are located.

By the end of F2022, BC Hydro expects to have a total of 155 EV charging stations that qualify as prescribed undertakings, which include 98 stations that came into operation prior to F2022, including a station that will be modified so that the public can use it 24-hours a day in F2022.[457] BC Hydro forecasts $2.7 million of costs in F2022 related to its stations that qualify as prescribed undertakings in the revenue requirement for recovery from ratepayers.[458]

BC Hydro acknowledges that there are some stations listed as coming into operation in F2022 that may not come into operation until F2023. However, it does not expect this to significantly impact the forecast costs in the Application and only variances between forecast and actual operating costs do not currently have deferral treatment. It notes that since these are new stations, the maintenance and repair costs forecast for F2022 should not be significant.[459]

BC Hydro submits that if a station was to cease to meet the requirements of a prescribed undertaking, then it would no longer be considered a prescribed undertaking and the costs would not be recoverable under section 18 of the CEA. The recoverability of the costs would be subject to BCUC approval.[460]

BC Hydro has not included any forecast revenue with respect to its EV charging stations in its revenue requirement as it did not have a BCUC approved rate for providing EV charging service at the time the Application was filed.[461] However, subsequent to filing the Application, BC Hydro filed an application for approval of rates for its public EV fast charging service that is currently before the BCUC.

The following subsections address parties' requests and issues related to BC Hydro's EV charging stations. Specifically, the following subsections address: (i) the establishment of an Electric Vehicle Costs Regulatory Account, (ii) depreciation rates for EV charging stations, and (iii) the transfer value of BC Hydro's low carbon fuel credits.

4.9.2.1 Electric Vehicle Costs Regulatory Account

BC Hydro is requesting to establish an Electric Vehicle Costs Regulatory Account to defer any actual operating costs, amortization, and cost of energy amounts related to its EV charging stations that meet the definition of a prescribed undertaking under the GGRR for F2020 and F2021. BC Hydro is also requesting to apply interest to the balance of the account based on its current weighted average cost of debt, recover from the account each year the forecast interest charged to the account each year, and, starting in F2022, recover the forecast balance at the end of a test period over the next test period, until such time that the actual amounts deferred to the account for F2020 and F2021 are recovered in rates.[462]

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457 Exhibit B-2, pp. 2-16, 2-21, Appendix C; BC Hydro Final Argument, pp. 67 to 68.
458 Exhibit B-4, BCUC IR 1.3.
459 Exhibit B-4, BCUC IR 3.7; Transcript Vol. 1, p. 236, line 16 to p. 277, line 7 (Layton).
460 Exhibit B-4, BCUC IR 5.6.4.
461 Exhibit B-4, BCUC IR 3.6.1.
462 Exhibit B-2, pp. 7-13 to 7-14.

In the Previous RRA Decision, issued prior to the GGRR amendment, the BCUC disallowed the recovery of costs related to BC Hydro's EV charging stations. However, the BCUC encouraged BC Hydro to apply to the BCUC if it wishes to have any of its prior, current or future EV capital expenditures considered as possible prescribed undertakings.[463] Accordingly, BC Hydro removed the capital additions related to EV charging stations from its rate base and the associated depreciation, operating costs and cost of energy from its F2020 to F2021 revenue requirements.

BC Hydro anticipates it will incur $4.8 million in total costs over F2020 and F2021 with respect to its EV charging stations that are considered prescribed undertakings.[464] However, it notes that the proposed regulatory account defers the actual costs incurred and BC Hydro is requesting, consistent with its other cash variance accounts, the forecast balance at the end of the test period to be recovered over the next test period. As a result, there may be a difference between forecast and actual amounts that will need to be amortized into rates over the subsequent test period. BC Hydro plans to propose to close this account once the balance is fully recovered and the account is no longer required. BC Hydro submits that this approach ensures that ratepayers pay the actual costs related to its EV charging stations that meet the definition of a prescribed undertaking under the GGRR for F2020 and F2021.[465]

Positions of Parties

The CEC, BCSEA and MoveUP agree with BC Hydro that its EV charging stations are prescribed undertakings, including those that came into operation prior to the GGRR amendment (i.e. June 22, 2020), and recommends that the BCUC approve the recovery of the stations' costs as requested.[466]

BCOAPO, however, opposes the recovery of costs incurred prior to June 22, 2020 (i.e. F2020 costs and F2021 Q1 costs) even though it agrees that these stations are prescribed undertakings. BCOAPO opposes because it may set a precedent "that might allow utilities to recover costs associated with past activities in their going forward rates." BCOAPO also submits that the balances in the proposed EV costs regulatory account should not attract interest because finance costs were already included in rates for F2020 and F2021.[467]

In reply, BC Hydro submits that BCOAPO has not provided evidence or rationale for its position, "which is incorrect in law and must be rejected." BC Hydro notes that section 18 of the CEA requires the recovery of costs incurred on prescribed undertakings, which would include costs incurred in F2020 and F2021. Furthermore, there is nothing in the CEA or the GGRR that would exclude the recovery of BC Hydro's past costs. BC Hydro also notes that in the Previous RRA Decision, the BCUC had encouraged it to apply for recovery of prior expenditures and, as such, the recovery of past costs was always contemplated.[468]

With respect to the application of interest, BC Hydro submits that interest should be applied to the EV Costs Regulatory Account because these are costs incurred by BC Hydro that have not been collected from ratepayers. BC Hydro explains that these interest charges are distinct from any finance costs incurred in F2020 and F2021 in

[463] BC Hydro F2020-F2021 RRA Decision, p. 94.
[464] Exhibit B-2, p. 7-13; Exhibit B-4, BCUC IR 1.1.
[465] Exhibit B-4, BCUC IR 1.2.
[466] CEC Final Argument, pp. 37 to 38, BCSEA Final Argument, pp. 22 to23, MoveUP Final Argument, pp. 3 to 4.
[467] BCOAPO Final Argument, pp. 11 to 13.
[468] BC Hydro Reply Argument, pp. 47 to 48.

relation to the EV charging assets. Also, there is no risk of double-counting of finance costs, as interest applied to regulatory accounts reduces the amount of interest recovered through finance charges.[469]

CEABC submits that BC Hydro's EV Station Program, as a whole, should be set up as a profit-making entity and all costs and benefits, including revenues, should flow into that entity, so that a profit or loss can be determined for the business as a whole (and, preferably, for each charging station within the entity). Further, revenues should be forecast to ensure that the entity makes a profit for ratepayers. Any variance from the revenue forecast should not flow through a regulatory account but, rather, should go directly to net income. In CEABC's view, this would improve management accountability for the overall success or failure of the program. CEABC also suggests that the assets be depreciated based on usage rather than time, as further discussed in Section 4.9.2.2 of this Decision.[470]

In reply to CEABC, BC Hydro submits that the BCUC "does not have jurisdiction to direct BC Hydro to set up a separate entity and operate its EV station program as a 'profit making entity'" as this is a management function. Also, BC Hydro notes that it can track its costs and revenues from EV stations without setting up a profit-making entity. BC Hydro further submits that its EV customers are BC Hydro electricity customers and should not be treated as a "profit making" entity any more than any other group of customers should be.[471]

Panel Determination

The Panel does not entirely agree with BC Hydro that the BCUC does not have the jurisdiction to direct BC Hydro to set up a separate entity to operate its EV station program. Generally, the BCUC does have this jurisdiction and, in the past, the BCUC had directed public utilities to provide utility services through a separate corporate entity. For example, the BCUC had previously directed FEI to provide thermal energy services through a separate corporate entity.[472] However, whether the BCUC should direct the creation of a separate entity was not sufficiently examined in this proceeding and thus, the Panel makes no findings or directions on this.

In this Application, BC Hydro is requesting approval to establish an Electric Vehicle Costs Regulatory Account to defer its actual costs incurred in F2020 and F2021 related to its EV charging stations that meet the definition of a prescribed undertaking under the GGRR. The Panel agrees with BC Hydro that section 18(2) of the CEA requires the recovery of costs incurred on prescribed undertakings. Therefore, the Panel is not persuaded by BCOAPO's argument that costs incurred prior to June 22, 2020 should not be recoverable. The Panel is also not persuaded that interest should not be applied to the proposed regulatory account. The Panel agrees with BC Hydro that these interest charges are distinct from the finance costs incurred in F2020 and F2021 in relation to the EV charging stations.

The Panel finds that BC Hydro's EV fast charging stations meet the criteria in section 5 of the GGRR to be considered prescribed undertakings. However, the Panel notes that BC Hydro currently has an application before the BCUC for public EV fast charging rates, which could examine the revenue and costs related to BC Hydro's EV fast charging stations in a holistic manner. That proceeding could address issues that may impact the

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[469] BC Hydro Reply Argument, p. 48.
[470] CEABC Final Argument, pp. 11 to 12.
[471] BCH Reply Argument, p. 49.
[472] BCUC Decision dated March 9, 2012 in the matter of FEI CPCN for Approval of Contracts and Rate for Public Utility Service to Provide Thermal Energy Service to Delta School District Number 37, p. 96.

cost recovery of EV station costs from BC Hydro's non-EV fast charging customers and, as such, it is prudent to defer the recovery of these costs until that proceeding is concluded. **Therefore, the Panel approves the establishment of the Electric Vehicle Costs Regulatory Account to defer any actual operating costs, depreciation, and cost of energy amounts related to BC Hydro's EV charging stations that meet the definition of a prescribed undertaking under the GGRR for F2020 and F2021. The Panel also approves BC Hydro's request to apply interest to the balance of the account based on BC Hydro's current weighted average cost of debt. However, the Panel denies BC Hydro's request to recover from the account each year the forecast interest charged to the account each year. Further, the Panel also denies BC Hydro's request to, starting in F2022, recover the forecast account balance at the end of a test period over the next test period. BC Hydro is directed to apply for a recovery mechanism for the account in its F2023 RRA. The Panel also directs BC Hydro to remove from its revenue requirement all F2022 costs related to its EV charging stations that meet the definition of a prescribed undertaking under the GGRR and defer these costs to the Electric Vehicle Costs Regulatory Account.**

The Panel acknowledges the requirements of section 18(2) of the CEA, which requires the BCUC to "set rates that allow the public utility to collect sufficient revenue in each fiscal year to enable it to recover its costs incurred with respect to the prescribed undertaking." The Panel finds that the above directives meet the requirements of section 18(2) of the CEA because, although these amounts are deferred to a regulatory account, the Panel is allowing BC Hydro to recover its costs incurred with respect to its EV charging stations that meet the definition of a prescribed undertaking pending the conclusion of the proceeding to review BC Hydro's public EV fast charging rate.

4.9.2.2 Depreciation Rates for Electric Vehicle Charging Stations

BC Hydro is requesting approval of the following depreciation rates for its EV charging stations:

- 10 percent based on a 10-year useful life for the majority of its EV charging stations;
- 20 percent based on a 5-year useful life or 14 percent based on a 7-year useful life for its remaining EV charging stations.

BC Hydro explains that the majority of its EV charging stations are depreciated over 10-years, which is consistent with the manufacturers' recommended life. However, it depreciates its remaining EV charging stations over either 5-years or 7-years because of poor reliability experienced for charging stations supplied by one manufacturer.[473] The following table provides the opening and closing net book value of the EV charging stations broken down by asset category:[474]

[473] Exhibit B-9, Undertaking No. 19, p. 3.
[474] Exhibit B-9, Undertaking No. 19, p. 3.

Table 32: Net Book Value of EV Charging Stations

($ million)	Fiscal 2022 Opening	Fiscal 2022 Closing
Electric Vehicle Charging Stations in-service (10 years amortization)	3.3	3.6
Electric Vehicle Charging Stations in-service (5-7 years amortization)	0.5	0.5
Electric Vehicle Charging Stations (fully amortized)	0.5	0.5
Subtotal Electric Vehicle Charging Stations	**4.3**	**4.6**
Other Distribution Assets in-service	0.7	0.8
Total Capital Assets in-service	**5.0**	**5.4**
Accumulated amortization	(0.7)	(1.2)
Total Net Book Value of Capital Assets in-service	**4.3**	**4.2**

BC Hydro clarifies that "Other Distribution Assets in-service" do not require further BCUC approval of the depreciation rates because these are assets, such as transformers, cables, duct banks, that are depreciated using existing asset classes.

BC Hydro submits that the useful life of its EV charging stations will be assessed as part of its depreciation study. BC Hydro plans to file its depreciation study in its F2023 RRA, at which time, it will request approval for an ongoing depreciation rate for its EV charging stations based on the rate (or useful life) recommended in the depreciation study. BC Hydro notes that in the Application, it has requested to defer any variances resulting from the depreciation study in F2022. This means that, if approved, any differences in useful life determined in the depreciation study for its EV charging stations from what BC Hydro has requested in the Application, will be deferred to a regulatory account, resulting in ratepayers only paying the costs associated with the depreciation rate determined in the study.[475]

Positions of Parties

BCOAPO[476] and BCSEA do not oppose the request. Although supporting BC Hydro's approach to request approval of depreciation rates based on the recommendations of the depreciation study, BCSEA submits that a 10-year life may be optimistic.[477]

As mentioned in Section 4.9.2.1 of this Decision, CEABC submits that BC Hydro's EV Station Program should be operated as "a transparent profit-making entity" and suggests, in part, that the depreciation rates for the charging stations should "to the extent possible, be set on the basis of usage rather than time." CEABC explains that this would result in increasing depreciation expense as the business grows and avoids excessively large depreciation in the early years when the business is in its growth and development stage.[478]

In reply, BC Hydro submits that it will be treating its EV station costs and revenues like all other costs and revenues and forecasting them into future RRAs.[479]

[475] Exhibit B-9, Undertaking No. 19, pp. 2 to 3.
[476] BCOAPO Final Argument, p. 49.
[477] BCSEA Final Argument, p. 25.
[478] CEABC Final Argument, pp. 11 to 12.
[479] BC Hydro Reply Argument, p. 49.

Panel Determination

Given that this revenue requirement was reviewed in a streamlined manner and BC Hydro did not request approval of its depreciation rates for EV charging stations until after the Review Session, the appropriateness of the proposed depreciation rates and any alternatives could not be sufficiently examined. The Panel is particularly concerned with the impact of potential advances in EV technology on the useful life of BC Hydro's charging stations. The Panel is not persuaded that depreciation rates based on manufacturer recommendations take technological obsolescence into consideration and therefore may be optimistic. The Panel notes that BC Hydro currently has an application before the BCUC for public EV fast charging rates. That proceeding could potentially examine the useful life of the EV stations as part of the process of determining appropriate rates for public EV fast charging. **Therefore, the Panel denies the depreciation rates for BC Hydro's EV charging stations and recommends the BCUC panel in the BC Hydro Public EV Fast Charging Rate Application proceeding review the depreciation rates.**

With respect to CEABC's suggestion that depreciation rates for EV charging stations be set on the basis of usage rather than time, the Panel is not persuaded that the depreciation method for EV charging stations should be different than the method applied to BC Hydro's other capital assets, which is based on time.

4.9.2.3 Low Carbon Fuel Credits

The *Greenhouse Gas Reduction (Renewable and Low Carbon Fuel Requirements) Act* and the Renewable and Low Carbon Fuel Requirements Regulation (collectively, Low Carbon Fuel Standard or LCFS) sets carbon intensity targets that decline each year. Fuel suppliers generate credits for supplying fuels with a carbon intensity below the targets and receive debits for supplying fuels with a carbon intensity above the targets. The debits and credits are proportional to the emissions a fuel generates over its full life cycle. The credits can be banked for future use or traded between fuel suppliers to offset debits. Suppliers that have a debit balance at the end of a compliance period are subject to non-compliance penalties.[480]

BC Hydro, as a supplier of low carbon fuels, receives low carbon fuel credits. BC Hydro's approach has been to use the revenue from these credits to reduce the overall revenue requirement for the benefit of all ratepayers.BC Hydro submits that this approach recognizes that investments in clean energy infrastructure have been funded by all ratepayers.[481]

BC Hydro received 137 low carbon fuel credits related to the ownership and operation of its EV charging stations for the 2018 calendar year. BC Hydro has transferred these carbon credits to Powerex to monetize.[482] The monetized credits were included in Powerex's F2020 net income, which is flowed back to BC Hydro's ratepayers via Trade Income and the Trade Income Deferral Account. BC Hydro submits that the transfer was made at zero cost, pursuant to an agreement between the parties, because it would not make a difference from a ratepayer's perspective. This is because Powerex's net income is included in BC Hydro's revenue requirement as Trade Income.[483] BC Hydro is working with the Government of B.C. on the allocation of the calendar 2019 and 2020 credits.[484]

[480] Exhibit B-9, Undertaking No. 24, pp. 2 to 3.
[481] Exhibit B-9, Undertaking No. 24, p. 2.
[482] Exhibit B-5, BCOAPO IR 67.1, 67.1.3.
[483] Exhibit B-9, Undertaking No. 24, p. 2; Transcript Vol. 2, p. 273, line 13 to 18 (Layton).
[484] Exhibit B-5, BCOAPO IR 67.1.

Positions of Parties

CEABC is concerned that BC Hydro's current approach makes it difficult to track the value of the credits. Therefore, CEABC recommends that the 2020 TPA between BC Hydro and Powerex be amended to include the sale of "Credits, RECs or similar products (Products)" and the amendments should include a mechanism for tracking the value of the Products sold. Alternatively, CEABC suggests that all transfers of Products from BC Hydro to Powerex be recorded by separate agreements that include a mechanism for tracking the value of the Products sold.[485]

In reply, BC Hydro notes that Direction no. 8 to the BCUC has been amended so that sections 71(1)(b) and (3) of the UCA do not apply to the 2020 TPA. Further, BC Hydro clarifies that the low carbon fuel credits transferred to Powerex are under an agreement separate from the 2020 TPA. BC Hydro also notes that the Ministry of Energy, Mines and Low Carbon Innovation is currently considering changes to the low carbon fuel standard. Therefore, as the market evolves, BC Hydro and Powerex will determine what changes to the transfer credits need to be made and will consider CEABC's recommendations at that time.[486]

Panel Determination

The Panel acknowledges that there would likely be minimal impact to BC Hydro's rates from assigning a value to the carbon credits that are transferred to other parties, whether that be Powerex, as it was for the 2018 credits, or to any other party. However, since the cost to generate these credits are included in BC Hydro's cost of service calculation, to arrive at an accurate net cost of service, it is necessary to include the value of these credits as revenue. Having the value of the credits embedded in Powerex's net income does not provide an accurate net cost of the BC Hydro activity that generated the credits. Further, including the value of the credits in Powerex's net income does not ensure that their value flows back to BC Hydro's ratepayers. For example, Powerex losses on other activities could, potentially, reduce Powerex's net income to zero or below, in which case none of the value of the credits would flow back to BC Hydro's ratepayers via Trade Income and the Trade Income Deferral Account.

The Panel acknowledges that it cannot compel Powerex to provide the monetized amount of the credits that Powerex sells after it has received them at no cost from BC Hydro. The Panel also recognizes that the amount received by Powerex would not be the same as the amount that BC Hydro would have received had it sold the credits directly. However, BC Hydro can provide the BCUC with the quantity of credits that it has transferred or plans to transfer to Powerex or other parties and a value can be estimated based on the market value of the credits. **Therefore, the Panel directs BC Hydro to increase its F2022 forecast revenue by the estimated value of the low carbon fuel credits that it plans to transfer to other parties, if any, during F2022. The Panel also directs BC Hydro to record in all future RRAs, the forecast revenue based on an estimate of the value of the low carbon fuel credits that it plans to transfer to other parties.**

Further, the Panel directs BC Hydro to track all of its revenues and costs related to its EV charging stations that are deemed prescribed undertakings under the GGRR and to provide this information broken down by year and by revenue and cost categories in all future RRAs. The revenues related to BC Hydro's EV charging stations should include the transfer value of the low carbon fuel credits based on the estimated value of the credits that are related to the EV charging stations.

[485] CEABC Final Argument, pp. 13 to 14.
[486] BC Hydro Reply Argument, p. 50.

4.9.1 Debt Management Strategy

In AMPC's final argument, it reiterates the concerns it made in the Previous RRA proceeding regarding BC Hydro's debt management strategy emphasizing cost certainty rather than minimizing the cost of debt. AMPC submits that BC Hydro has not made reasonable steps since the previous proceeding to hedge its debt at a lower cost and as a result has caused harm to ratepayers.[487]

AMPC submits that BC Hydro's hedging strategy prioritizes cost certainty and it is not in the best interests of ratepayers because it has not led to least-cost service and competitive prices. To support its submission, AMPC cites evidence from the proceeding that shows that BC Hydro decided to stop hedging while bond yields were in a "persistent state of decline." AMPC also submits that if BC Hydro had prioritized cost reduction in its debt management strategy, it would have timed its borrowings with drops in the market. Further, AMPC submits that BC Hydro should be constantly re-evaluating its hedging strategy rather than evaluating it annually if the debt management strategy was focused on cost reductions as well as cost certainty.[488]

AMPC also notes that BC Hydro's $5.025 billion of outstanding hedges will result in significant costs to ratepayers over the next few years as these hedges are settled if interest rates do not increase enough.[489] AMPC submits that in the appropriate future proceeding, these hedging losses should be closely scrutinized for prudence if and when the losses crystallize.[490]

In reply, BC Hydro submits that its hedging strategy is intended to mitigate exposure to interest rate volatility and it is achieving its intended purpose. BC Hydro explains that its hedging program is a risk mitigation strategy that provides increased cost certainty and protection to ratepayers from interest rate volatility by locking in interest rates related to BC Hydro's forecast future borrowing requirements. Its approach is not premised on betting on short-term market fluctuations, rather the goal is to lock in interest rates related to long-term borrowings and provide cost certainty over the long term.[491]

BC Hydro submits that similar to resiliency investments (e.g. cybersecurity) that are made to mitigate risk for the utility and its customers, there may not be an immediate pay-off in terms of cost-savings, higher reliability or new revenues from investments. Another example is insurance premiums that are paid to mitigate the risk of losses.[492]

Panel Discussion

The Panel notes that the BCUC had discussed BC Hydro's hedging strategy in the Previous RRA Decision and stated:[493]

> Since BC Hydro is exempt from section 50(1) of the UCA, the BCUC cannot disallow BC Hydro from entering into future debt hedges and it cannot direct BC Hydro to alter its debt management strategy. It is not in the BCUC's jurisdiction to determine if the debt management

[487] AMPC Final Argument, p. 12.
[488] AMPC Final Argument, pp. 14 to 15.
[489] AMPC Final Argument, p. 14.
[490] AMPC Final Argument, p. 15.
[491] BC Hydro Reply Argument, p. 37.
[492] BC Hydro Reply Argument, pp. 37 to 38.
[493] BC Hydro F2020 to F2021 RRA, Decision, p. 170.

strategy has been successful and therefore the Panel makes no such finding. However, the BCUC does have the jurisdiction to determine if the costs resulting from BC Hydro's hedging activities were prudently incurred and reasonable to recover from ratepayers. As such, the Panel sees value in BC Hydro providing additional information regarding its hedging activities and the resulting rate impact in its future RRAs.

The Panel also notes that AMPC is not opposing the cost recovery of BC Hydro's hedging strategy in this RRA and it is simply flagging a potential issue for future consideration. As such, the Panel makes no findings or directions with respect to BC Hydro's debt management strategy. AMPC can pursue this issue further through IRs in the appropriate future proceeding.

5.0 Summary of Directives

This summary is provided for the convenience of readers. In the event of any difference between the Directions in this Summary and those in the body of the Decision, the wording in the Decision shall prevail.

	Directive	Page No.
1.	Therefore, the Panel approves the requested rates, subject to the adjustments resulting from the determinations and directives contained in this Decision. BC Hydro is directed to re-calculate its revenue requirements based on the Panel's determinations in this Decision, in a compliance filing within 30 days of this Decision (Compliance Filing). BC Hydro is directed to include in its Compliance Filing, a revised Appendix A to the Application and updated rate schedules, reflecting the BCUC's Decision and accompanying Order. The Panel further directs BC Hydro to file a copy of this Compliance Filing and any responses to BCUC staff questions related to the Compliance Filing in the proceeding to review BC Hydro's F2023 RRA, either as an appendix to the RRA or as a separate exhibit.	7
2.	For this reason, BC Hydro is directed to back-test and compare whether developing uncertainty bands around the distribution load only and using discrete high and low cases for transmission load versus the previous methodology improved the accuracy of its large industrial load forecast. BC Hydro is further directed to provide the results of the back-test run over the five previous load forecasts to the BCUC by December 31, 2021.	13
3.	The Panel appreciates the breakout of the EV energy forecast. However, it would be helpful if there was some historical context provided. Therefore, BC Hydro is directed to provide the historical actuals or estimated actuals related to EV energy consumption over the five previous load forecasts (i.e. F2017 to F2021) in the F2023 RRA.	13

	Directive	Page No.
4.	Therefore, BC Hydro is directed to provide, in its F2023 RRA, an update on the timeline referenced in Table 11, herein, and explain any changes to the timeline.	23
5.	[W]e direct that in the F2023 RRA, BC Hydro report on the historic actual system imports/exports divided into flexible and non-flexible (i.e. according to the format in the 2020 TPA).	24
6.	BC Hydro is also directed to identify the cost of market purchases of electricity to meet domestic requirements based on the 2020 TPA pricing methodology and provide this information based on the actual outcomes in the F2023 RRA.	24
7.	The Panel directs BC Hydro to include the actual cost of energy information for F2021 in the F2023 RRA.	24
8.	Therefore, the Panel, directs BC Hydro to undertake a Cyber Risk Assessment of all of its cyber assets and to notify the BCUC of any action that has been or needs to be taken on any immediate or time-sensitive concerns. BC Hydro is directed to file a Cyber Risk Assessment Report to the BCUC confidentially within 3 months of the issuance of this Decision.	33
9.	Since BC Hydro's information technology platforms interface with at least some of its subsidiaries, BC Hydro is directed to develop a company-wide, comprehensive Cyber Security Plan that encompasses BC Hydro and its subsidiaries and third-parties with whom it interfaces. BC Hydro is directed to develop the Cyber Security Plan informed by the Cyber Risk Assessment Report, and to file the plan to the BCUC confidentially within 1 year of issuance of this Decision.	33
10.	Given the importance of a new long-term vegetation management plan which will inform future RRAs, BC Hydro is directed to file with the BCUC, the new Vegetation Management Strategy in the F2023 RRA and any revisions to it thereafter.	42

	Directive	Page No.
11.	In addition, to assist with monitoring the vegetation management budget, the Panel directs BC Hydro to provide in future RRAs a breakdown of the vegetation management budget in a format similar to that provided in Table 5-11 of the Application and expanded to include historical costs for the most recent five years.	42
12.	[T]he Panel directs BC Hydro to file its dam safety vulnerability index for all dams and its aggregate dam safety vulnerability index in the F2023 RRA. Further, the Panel directs BC Hydro to file a long-term capital plan for ensuring the sustainable safety of all its dams by December 31, 2021.	58
13.	The Panel directs BC Hydro to provide updated figures for the customer satisfaction index on reliability in the F2023 RRA.	58
14.	Therefore, the Panel approves the recovery of the balances in the Cost of Energy Variance Accounts through the proposed DARR table mechanism for F2022 only. Using this approach, the DARR percentage is set at 0 percent as of April 1, 2021 for F2022.	67
15.	Therefore, the Panel directs BC Hydro to establish a new regulatory account to capture the variances arising in F2022 as a result of any changes to the depreciation expense determined in the depreciation study, with interest charges being on the same basis as previously approved for the Amortization of Capital Additions Regulatory Account. The Panel further directs BC Hydro to propose a recovery mechanism for this new regulatory account in its F2023 RRA.	68–69
16.	The Panel approves the following requests with respect to BC Hydro's regulatory accounts: • To continue to defer any variances between forecast and actual dismantling costs in F2022 to the Dismantling Cost Regulatory Account; continue to apply interest to the balance of the account each year based on BC Hydro's current weighted average cost of debt; continue to recover the forecast interest charged to the account each year from the account each year; and, continue to recover the forecast account balance at the end of a test period over the next test period. • To recover amounts deferred to the Project Write-off Costs Regulatory Account in respect of completed fiscal years over the next test period, starting in F2022 and on an ongoing basis, subject to BCUC review and approval of the recovery of	70–71

	Directive	Page No.
	these amounts; apply interest to the balance of the account based on BC Hydro's current weighted average cost of debt; and, recover actual interest charged to the account for amounts related to any completed fiscal years over the next test period.	
17.	The Panel approves the closure of the Rock Bay Remediation Regulatory Account at the end of F2022, or a subsequent fiscal year, when the account balance is zero.	71
18.	The Panel finds that BC Hydro's proposed "traditional" DSM expenditure schedule for the Test Period is in the public interest, and accepts the DSM expenditure schedule of $82.2 million in F2021 under section 44.2 of the UCA.	76
19.	The Panel directs BC Hydro to include in its F2023 RRA BC Hydro's most recent evaluation of its DSM effectiveness.	81
20.	The Panel directs BC Hydro to provide in its F2023 RRA a discussion of whether LCE expenditures deferred to the DSM Regulatory Account should be recovered only from the beneficiaries of these expenditures, and if so by what methods this could be accomplished.	91
21.	The Panel finds that the proposed OATT rates are just and reasonable and approves the OATT rates as applied for, subject to any adjustments resulting from the determinations and directives contained in this Decision.	95
22.	Therefore, the Panel directs BC Hydro to amend its forecast for interconnection revenue in F2022 to $4.6 million, the same figure as BC Hydro's most recent forecast for F2021, and to make any corresponding adjustments to forecast costs required to generate this level of interconnection revenue.	96
23.	Therefore, the Panel approves the depreciation rates for the Burrard synchronous condense facility and infrastructure rights assets as requested by BC Hydro for F2022.	98

	Directive	Page No.
24.	Therefore, the Panel approves the establishment of the Electric Vehicle Costs Regulatory Account to defer any actual operating costs, depreciation, and cost of energy amounts related to BC Hydro's EV charging stations that meet the definition of a prescribed undertaking under the GGRR for F2020 and F2021. The Panel also approves BC Hydro's request to apply interest to the balance of the account based on BC Hydro's current weighted average cost of debt. However, the Panel denies BC Hydro's request to recover from the account each year the forecast interest charged to the account each year. Further, the Panel also denies BC Hydro's request to, starting in F2022, recover the forecast account balance at the end of a test period over the next test period. BC Hydro is directed to apply for a recovery mechanism for the account in its F2023 RRA. The Panel also directs BC Hydro to remove from its revenue requirement all F2022 costs related to its EV charging stations that meet the definition of a prescribed undertaking under the GGRR and defer these costs to the Electric Vehicle Costs Regulatory Account.	102
25.	Therefore, the Panel denies the depreciation rates for BC Hydro's EV charging stations and recommends the BCUC panel in the BC Hydro Public EV Fast Charging Rate Application proceeding review the depreciation rates.	104
26.	Therefore, the Panel directs BC Hydro to increase its F2022 forecast revenue by the estimated value of the low carbon fuel credits that it plans to transfer to other parties, if any, during F2022. The Panel also directs BC Hydro to record in all future RRAs, the forecast revenue based on an estimate of the value of the low carbon fuel credits that it plans to transfer to other parties.	105
27.	Further, the Panel directs BC Hydro to track all of its revenues and costs related to its EV charging stations that are deemed prescribed undertakings under the GGRR and to provide this information broken down by year and by revenue and cost categories in all future RRAs.	105

DATED at the City of Vancouver, in the Province of British Columbia, this 17th day of June 2021.

Original signed by:

D.M. Morton
Panel Chair / Commissioner

Original signed by:

T. A. Loski
Commissioner

Original signed by:

R. I. Mason
Commissioner

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ORDER NUMBER
G-187-21

IN THE MATTER OF
the *Utilities Commission Act*, RSBC 1996, Chapter 473

and

British Columbia Hydro and Power Authority
Fiscal 2022 Revenue Requirements Application

BEFORE:
D. M. Morton, Panel Chair
T. A. Loski, Commissioner
R. I. Mason, Commissioner

on June 17, 2021

ORDER

WHEREAS:

A. On December 22, 2020, British Columbia Hydro and Power Authority (BC Hydro) filed its Fiscal 2022 Revenue Requirements Application (Application) with the British Columbia Utilities Commission (BCUC) pursuant to sections 58 to 61 and 89 of the *Utilities Commission Act* (UCA), requesting, among other things:

(I) Approval of an increase in rates by 1.16 percent, effective April 1, 2021; and

(II) Approval of the Fiscal 2022 Open Access Transmission Tariff (OATT) rates as set out in Table 9-4 of the Application, effective April 1, 2021;

B. BC Hydro requested that these rate changes be set on an interim basis, pending a final BCUC decision on the Application;

C. By Order G-345-20, the BCUC established the regulatory timetable for the review of the Application, which included one round of BCUC and intervener information requests and a review session, followed by a written argument phase;

D. By Order G-1-21, the BCUC approved, on an interim basis, the requested rate increase of 1.16 percent and the requested Fiscal 2022 OATT rates, effective April 1, 2021; and

E. The BCUC has considered the Application and the evidence and submissions filed in the proceeding and makes the following determinations.

NOW THEREFORE pursuant to sections 44.2, 56, and 58 to 61 of the UCA, and for the reasons outlined in the decision issued concurrently with this order, the BCUC orders as follows:

1. BC Hydro is approved to increase rates by 1.16 percent, effective April 1, 2021, subject to the adjustments resulting from the determinations and directives contained in the decision issued concurrently with this order.

2. The following changes to BC Hydro's deferral and regulatory accounts are approved as follows:

    a. Cost of Energy Variance Accounts

    BC Hydro is approved to recover the balances in the Cost of Energy Variance Accounts through the Deferral Account Rate Rider (DARR) using the DARR table mechanism as described in Chapter 7, Section 7.2.1 of the Application for fiscal 2022 only. Specifically, in fiscal 2022, the DARR percentage effective April 1, 2021 is set based on the percentage in the DARR table mechanism corresponding to the forecast net balance of the Cost of Energy Variance Accounts at the end of the preceding fiscal year.

    b. Amortization of Capital Additions Regulatory Account

    BC Hydro is denied deferral of the variances arising in fiscal 2022 as a result of any changes determined in the depreciation study to the Amortization of Capital Additions Regulatory Account. BC Hydro is directed to establish a new regulatory account to capture the variances arising in fiscal 2022 as a result of any changes to the depreciation expense determined in the depreciation study, with interest charges being on the same basis as previously approved for the Amortization of Capital Additions Regulatory Account.

    c. Dismantling Cost Regulatory Account

    BC Hydro is approved to continue to defer any variances between forecast and actual dismantling costs in fiscal 2022 to the Dismantling Cost Regulatory Account. BC Hydro is to apply interest to the balance of the account each year based on BC Hydro's current weighted average cost of debt, and to recover from the account each year the forecast interest charged to the account each year. BC Hydro is to recover the forecast account balance at the end of a test period over the next test period.

    d. Project Write-Off Costs Regulatory Account

    BC Hydro is approved to recover the amounts deferred to the Project Write-off Costs Regulatory Account in respect of completed fiscal years over the next test period, starting in fiscal 2022, and on an ongoing basis thereafter, subject to BCUC review and approval of the recovery of these amounts. BC Hydro is to apply interest to the balance of the account based on BC Hydro's current weighted average cost of debt. BC Hydro is to recover the actual interest charged to the account for amounts related to any completed fiscal years over the next test period.

    e. Electric Vehicle Costs Regulatory Account

    BC Hydro is approved to establish an Electric Vehicle Costs Regulatory Account to defer actual operating costs, depreciation, and cost of energy amounts related to electric vehicle charging stations that meet the definition of a prescribed undertaking under the Greenhouse Gas Reduction

(Clean Energy) Regulation for fiscal 2020 and fiscal 2021. BC Hydro is to apply interest to the balance of the account based on BC Hydro's current weighted average cost of debt. BC Hydro is denied to recover from the account each year the forecast interest charged to the account each year. Further, BC Hydro is denied, starting in fiscal 2022, to recover the forecast account balance at the end of a test period over the next test period.

f. Rock Bay Remediation Regulatory Account

BC Hydro is approved to close the Rock Bay Remediation Regulatory Account at the end of fiscal 2022, or a subsequent fiscal year, when the account balance is zero.

3. BC Hydro is approved to depreciate certain property, plant and equipment at the Burrard synchronous condense facility for fiscal 2022, as set out in Table 8-2 of the Application, at the rates requested in the Application.

4. The requested depreciation rates for electric vehicle charging stations, as set out in Undertaking No. 19, are denied.

5. BC Hydro is approved to amortize the assets within the infrastructure rights asset class over a 35-year useful life as set out in Section 8.2.2 of the Application for fiscal 2022.

6. BC Hydro is approved to set OATT rates for fiscal 2022 as set out in Table 9-4 of the Application effective April 1, 2021, subject to the adjustments resulting from the determinations and directives contained in the decision issued concurrently with this order.

7. The BCUC accepts BC Hydro's demand-side management expenditure schedule of $82.2 million for fiscal 2022.

8. BC Hydro is directed to re-calculate its revenue requirements based on the determinations and directives contained in the decision issued concurrently with this order.

9. BC Hydro is directed to file within 30 days of this order a revised Appendix A to the Application and updated rate schedules, reflecting the terms of this order and the determinations and directives contained in the decision issued concurrently with this order.

10. BC Hydro is directed to comply with all other directives contained in the decision issued concurrently with this order.

DATED at the City of Vancouver, in the Province of British Columbia, this 17th day of June 2021.

BY ORDER

Original signed by:

D. M. Morton
Commissioner

Glossary of Terms

Acronym	Description
AMPC	Association of Major Power Customers of British Columbia
Application	BC Hydro Fiscal 2022 Revenue Requirements Application
B.C.	British Columbia
BC Hydro, Authority	British Columbia Hydro and Power Authority
BCOAPO	British Columbia Old Age Pensioners' Organization, Disability Alliance BC, Council of Senior Citizens' Organizations of BC, and the Tenant Resource and Advisory Centre (BCOAPO et al.)
BCSEA	BC Sustainable Energy Association
BCUC	British Columbia Utilities Commission
BES	Bulk Electric System
Bonneville	Bonneville Power Administration
Bryenton	Roger Bryenton
CEA	*Clean Energy Ac*t
CEABC	Clean Energy Association of B.C.
CEC	Commercial Energy Consumers Association of British Columbia
CIP	Critical Infrastructure Protection
CM&E	Canadian Manufacturers and Exporters
Compliance Filing	BC Hydro compliance filing due within 30 days of this Decision
CPCN	Certificate of Public Convenience and Necessity
CVI	Compliance Violation Investigation
DARR	Deferral Account Rate Rider
Direction No. 8	Direction No. 8 to the British Columbia Utilities Commission, OIC 051/2019
DSM	Demand-Side Management
DSM Regulation	Demand-Side Measures Regulation, BC Reg. 326/2008
EPA	electricity purchase agreement
EV	electric vehicle
Evidentiary Update	Evidentiary update to the Previous RRA dated August 22, 2019 and revised January 21, 2020
FortisBC	FortisBC Energy Inc. and FortisBC Inc.

FTE	full-time equivalents
GHG	greenhouse gas
GGRR	Greenhouse Gas Reduction Regulation
Hadland	Randal Hadland
IFRS	International Financial Reporting Standards
IPP	Independent Power Producer
IR	information request
IRP	integrated resource plan
KBU	Key Business Unit
LCE	low carbon electrification
LCFS	low carbon fuel standard
LiDAR	Light Detection and Ranging
LRMC	long-run marginal cost
McCandless	Richard McCandless
MoveUP	Movement of United Professionals
MRS	Mandatory Reliability Standards
mTRC	Modified TRC
Next RRA	F2023 RRA
NIA	Non-Integrated Area
NITS	Network Integrated Transmission Service
OAG	Office of the Auditor General
OATT	Open Access Transmission Tariff
OIC	Order in Council
Powerex	Powerex Corp.
Previous RRA	BC Hydro F2020 to F2021 RRA
PTP	Point-to-point (PTP) Transmission Service
[redacted]	[redacted]
RCIA	Residential Customer Intervener Association
RIM Test	rate payer impact measure test
RRA	Revenue Requirements Application
SAE	Statistically Adjusted End Use

SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
Test Period	F2022 test period
TPA	Transfer Pricing Agreement
TRC	Total Resource Cost
TRR	Transmission Revenue Requirement
UCA	*Utilities Commission Act*
VMS	Vegetation Management Strategy
WECC	Western Coordinating Council
ZEV Act	*Zero-Emission Vehicles Act*
Zone II RPG	Kwadacha Nation and Tsay Keh Dene Nation, together the Zone II Ratepayers Group

IN THE MATTER OF
the *Utilities Commission Act*, RSBC 1996, Chapter 473

and

British Columbia Hydro and Power Authority
Fiscal 2022 Revenue Requirements Application
EXHIBIT LIST

Exhibit No.	Description

COMMISSION DOCUMENTS

A-1	Letter dated December 16, 2020 – Appointing the Panel for the review of BC Hydro Fiscal 2022 Revenue Requirements Application
A-2	Letter dated December 18, 2020 – BCUC Order G-345-20 establishing the regulatory timetable
A-3	Letter dated January 5, 2021 – BCUC Order G-1-21 approving interim rates
A-4	Letter dated January 21, 2021 – BCUC Information Request No. 1
A-5	**CONFIDENTIAL** - Letter dated January 21, 2021 – BCUC Confidential Information Request No. 1
A-6	Letter dated March 23, 2021 – BCUC Order G-91-21 amending the regulatory timetable

COMMISSION STAFF DOCUMENTS

A2-1	**CONFIDENTIAL** - Letter dated January 21, 2021 – Confidential document dated December 18, 2020
A2-2	**CONFIDENTIAL** - Letter dated January 21, 2021 – Confidential document dated February 18, 2020

A2-3	Letter dated January 21, 2021 – Document dated September 9, 2019
A2-4	**CONFIDENTIAL** - Letter dated January 21, 2021 – Confidential document dated June 19, 2020
A2-5	**CONFIDENTIAL** - Letter dated January 21, 2021 – Confidential document dated January 20, 2021
A2-6	**CONFIDENTIAL** - Letter dated January 21, 2021 – Confidential document dated January 18, 2021
A2-7	**CONFIDENTIAL** – Letter dated February March 2, 2021 – Confidential document dated February 10, 2021
A2-8	**CONFIDENTIAL –** Letter dated March 1, 2021 – Confidential document dated March 1, 2021

Applicant Documents

B-1	**British Columbia Hydro and Power Authority (BC Hydro)** - Fiscal 2022 Revenue Requirements Application (F2022 RRA) Proposed Regulatory Process dated December 9, 2020
B-2	Letter dated December 22, 2020 – BC Hydro submitting F2022 Application
B-2-1	**CONFIDENTIAL** - Letter dated December 22, 2020 – BC Hydro submitting F2022 Application Confidential Chapter 6
B-2-2	Letter dated December 22, 2020 – BC Hydro submitting F2022 Application Appendices
B-2-3	**CONFIDENTIAL** - Letter dated December 22, 2020 – BC Hydro submitting F2022 Application Confidential Appendices I and N
B-2-4	**CONFIDENTIAL** - Letter dated December 22, 2020 – BC Hydro submitting F2022 Application Confidential Appendix Z
B-2-5	Letter dated February 23, 2021 – BC Hydro submitting Errata to the Application
B-2-6	Letter dated March 3, 2021 – BC Hydro submitting Errata No. 2 to the Application – Revision to Chapter 5
B-2-7	Letter dated March 18, 2021 – BC Hydro submitting Revision No. 1 to the Application – Appendix B

B-3	Letter dated January 14, 2021 – BC Hydro submitting Compliance with Order G-345-20, Directives 3, 4, 5 and 6
B-4	Letter dated February 23, 2021 – BC Hydro submitting response to BCUC Information Request No. 1
B-4-1	**CONFIDENTIAL -** Letter dated February 23, 2021 – BC Hydro submitting confidential responses to BCUC Information Request No. 1
B-4-2	Letter dated March 3, 2021 – BC Hydro submitting response Revisions to BCUC Information Request No. 1.22.1.3
B-5	Letter dated February 23, 2021 – BC Hydro submitting response to Interveners Information Request No. 1
B-5-1	**CONFIDENTIAL -** Letter dated February 23, 2021 – BC Hydro submitting confidential responses to Interveners Information Request No. 1
B-5-2	Letter dated March 3, 2021 – BC Hydro submitting response Revisions to BCOAPO Information Request No. 1.36.2 and CEC Information Request No. 1.24.1
B-6	**CONFIDENTIAL -** Letter dated February 23, 2021 – BC Hydro submitting confidential responses to Confidential BCUC Information Request No. 1
B-7	Letter dated February 25, 2021 – BC Hydro submitting Agenda and Review Session Information
B-8	Letter dated March 3, 2021 – BC Hydro submitting presentation for Review Session
B-9	Letter dated March 18, 2021 – BC Hydro submitting responses to Review Session Undertakings
B-9-1	**CONFIDENTIAL –** Letter dated March 18, 2021 – BC Hydro submitting responses to Review Session Undertakings
B-10	**CONFIDENTIAL** – Letter dated March 18, 2021 – BC Hydro submitting responses to Review Session In Camera Undertakings
B-11	Letter dated March 29, 2021 – BC Hydro submission regarding amendment to Directive 8 by Order in Council No. 172

Intervener Documents

C1-1	**BC Sustainable Energy Association (BCSEA)** – Letter dated December 23, 2020 Request to intervene by William Andrews
C1-2	Letter dated January 26, 2021 – BCSEA submitting Information Request No. 1 to BC Hydro
C2-1	**Movement of United Professionals (MoveUP) -** Letter dated January 8, 2021 Request to Intervene by James Quail, Allevato Quail & Roy
C2-2	Letter dated January 26, 2021 – MoveUP submitting Information Request No. 1 to BC Hydro
C3-1	**Kwadacha Nation and Tsay Keh Dene Nation, together the Zone II Ratepayers Group (Zone II RPG) –** Letter dated January 11, 2021 submitting request to intervene by Jana Mclean, Iris Legal Law Corporation
C3-2	Letter dated January 26, 2021 – ZoneII RPG submitting Information Request No. 1 to BC Hydro
C4-1	**FortisBC Energy Inc. and FortisBC Inc. (FortisBC)** – Submission dated January 12, 2020 Request for Intervener Status by Diane Roy
C4-2	Letter dated January 26, 2021 – FortisBC submitting Information Request No. 1 to BC Hydro
C5-1	**Hadland, R. (Hadland) -** Letter dated December 26, 2020 submitting request to intervene
C6-1	**Bryenton, R. (Bryenton) -** Letter dated December 26, 2020 submitting request to intervene
C6-2	Letter dated January 26, 2021 – Bryenton submitting Information Request No. 1 to BC Hydro
C7-1	**McCandless, R. (McCandless) -** Letter dated January 8, 2021 submitting request to intervene
C7-2	Letter dated January 25, 2021 – McCandless submitting Information Request No. 1 to BC Hydro
C8-1	**Residential Customer Intervener Group (RCIG) -** Letter dated January 14, 2021 submitting request to intervene by Peter Helland
C8-2	Letter dated January 26, 2021 – RCIG submitting Information Request No. 1 to BC Hydro

C9-1	**Commercial Energy Consumers Association of British Columbia (CEC) -** Letter dated January 15, 2021 Request to Intervene by Christopher Weafer
C9-2	Letter dated January 26, 2021 – CEC submitting Information Request No. 1 to BC Hydro
C9-3	Letter dated March 23, 2021 – CEC submitting extension request to file Final Argument
C10-1	**Clean Energy Association of B.C. (CEABC) -** Letter dated January 15, 2021 Request to Intervene by Laureen Whyte
C10-2	Letter dated January 26, 2021 – CEABC submitting Information Request No. 1 to BC Hydro
C11-1	**Association of Major Power Customers of British Columbia (AMPC) -** Letter dated January 15, 2021 Request to Intervene by Matthew Keen
C11-2	Letter dated January 26, 2021 – AMPC submitting Information Request No. 1 to BC Hydro
C11-3	Letter dated March 4, 2021 – AMPC submitting Aid presented at Review Session
C12-1	**British Columbia Old Age Pensioners' Organization et al (BCOAPO) –** Letter dated January 15, 2021 – Request for Intervener Status by Leigha Worth and Irina Mis
C12-2	Letter dated January 26, 2021 – BCOAPO submitting Information Request No. 1 to BC Hydro
C13-1	**Canadian Manufacturers and Exporters (CME) –** Letter dated January 20, 2021 – Request for Intervener Status by Paul Willis

INTERESTED PARTY DOCUMENTS

D-1	**PAGAN, C. (PAGAN)** – Submission dated February 26, 2021 Request for Interested Party Status
D-1-1	Pagan – Letter of Comment dated February 24, 2021

LETTERS OF COMMENT

E-1	Warman, J. – Letter of Comment dated January 23, 2021
E-2	Jacques, J. – Letter of Comment dated February 8, 2021

E-3	Harvey, M. – Letter of Comment dated February 19, 2021
E-4	Ma, J. – Letter of Comment dated March 4, 2021
E-5	Fortier Sr., R. – Letter of Comment dated March 22, 2021
E-6	Young, R. – Letter of Comment dated April 10, 2021