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British Columbia Hydro and Power Authority

F2020 to F2021 Revenue Requirements Application

Decision
and Order G-246-20

October 2, 2020

Before:
D. M. Morton, Panel Chair
A. K. Fung, QC, Commissioner
E. B. Lockhart, Commissioner
R. I. Mason, Commissioner

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Executive Summary

In British Columbia Hydro and Power Authority's (BC Hydro or Authority) Revenue Requirements Application (RRA) for the fiscal 2020 to fiscal 2021 test period (Test Period), BC Hydro requests approval for, among other things:

- an interim and permanent general rate increase of 6.85 percent on April 1, 2019 (for fiscal 2020) and 0.72 per cent on April 1, 2020 (for fiscal 2021);
- a reduction of the Deferral Account Rate Rider from 5 percent to 0 percent effective April 1, 2019; and
- the fiscal 2020 to fiscal 2021 Open Access Transmission Tariff (OATT) rates effective April 1, 2019 and April 1, 2020, respectively.

The British Columbia Utilities Commission (BCUC) reviewed BC Hydro's RRA through a written and oral hearing process involving fifteen registered interveners and ten letters of comment from members of the public. The regulatory review process included four rounds of BCUC and intervener IRs and two rounds of Panel IRs to BC Hydro; Intervener Evidence and IRs on that evidence; rebuttal evidence from BC Hydro; an oral hearing, followed by written final and reply arguments from all parties; an oral phase of argument with BC Hydro, written submissions from all parties and a written reply submission from BC Hydro.

Following our review of the Application, we direct adjustments in the following areas of the revenue requirement:

- Trade Income;
- Storm restoration costs;
- Gain from elimination of MSP premiums;
- Real property sales gains;
- Project write-off costs;
- Reduction in the load forecast; and
- Costs related to EV charging infrastructure

In an evidentiary update to the RRA dated August 22, 2019 and revised January 21, 2020 (Evidentiary Update), BC Hydro changed the requested fiscal 2021 rate to a decrease of 1.01 percent from an increase of 0.72 percent. BC Hydro requested that all rate impacts resulting from the Evidentiary Update be reflected in the fiscal 2021 rates to avoid adjustments to fiscal 2020 bills.[1] The Evidentiary Update included adjustments to some of the forecasts for the Test Period based on the actuals that were known by the date the Evidentiary Update was prepared.

However, in the Evidentiary Update, the Test Period forecasts for storm restoration costs and Trade Income were not updated even though the 2019 actuals were available to BC Hydro. Therefore, the Panel directed BC Hydro to adjust these forecasts. Some Interveners argued that rates should also be adjusted for known changes in finance costs, although the Panel disagreed and declined to do so.

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[1] Exhibit B-11-2, p. 1.

Overall, based on the Panel's key adjustments to BC Hydro's requested revenue requirements, we estimate that the fiscal year 2021 rate change will be a decrease of 1.14 percent. We recognize this figure does not include other adjustments, such as the costs related to the EV charging infrastructure, as directed in this Decision and therefore the final rate impact is subject to BC Hydro's confirmation in its Compliance Filing to the BCUC:

Table 1: BCUC Estimated Fiscal 2021 Rate

Adjustment	Impact to FY 2021 Rate
BC Hydro's proposed rate decrease	-1.01%
Trade Income	-2.12%
Storm restoration costs	+0.16%
Gain from elimination of MSP premiums	-0.20%
Real property sales gains	+0.38%
Project write-off costs	-0.38%
Reduction in load forecast	+2.03%
BCUC estimated rate decrease	**-1.14%**

The Panel finds BC Hydro's forecast revenue requirement for the Test Period to be reasonable, with the exception of certain components of the revenue requirement as identified and discussed in the Decision. **Therefore, the Panel approves the requested rates, subject to the adjustments resulting from the determinations and directives contained in the Decision.**

The Panel also approves BC Hydro's request to reduce the DARR from 5 percent to 0 percent, effective April 1, 2019, and the OATT rates for fiscal 2020 and fiscal 2021, as applied for by BC Hydro, subject to any adjustments resulting from the determinations and directives contained in the Decision.

We commend BC Hydro on its general responsiveness in both the written and oral hearing phases of the proceeding. This is the first RRA in many years where the BCUC has had a relatively unfettered opportunity to review, for the entire Test Period, BC Hydro's revenue requirement, including its operations, capital plans, deferral accounts and cost of energy.

We use the term "relatively unfettered" because Direction No. 8 continues to prescribe the cost of equity BC Hydro's ratepayers must pay, and it also directs that the BCUC must not disallow for any reason the recovery in rates of the balance of the authority's regulatory accounts as at March 31, 2019 and the costs incurred by the authority with respect to the following:[2]

a) the construction of extensions to the authority's plant or system that came into service before April 1, 2016;

b) energy supply contracts entered into before April 1, 2016; and

c) debt servicing costs on amounts borrowed in relation to the rate smoothing regulatory account.

In the course of this proceeding, InterGroup Consultants Ltd. (InterGroup), on behalf of AMPC, advocated that the BCUC identify the costs of legislated policies even if the BCUC cannot direct associated changes. InterGroup submits that BCUC should consider and test the prudence and "least cost nature" of all costs that continue to be included in the revenue requirement, including costs associated with government directions.[3] In response, BC Hydro argues that the BCUC is a creature of statute and derives its mandate from the existing legislation and must operate within that framework.[4]

[2] Direction No. 8, section 3 and section 4.
[3] Exhibit C11-11, InterGroup Evidence, Recommendations 9 and 10.
[4] BC Hydro Final Argument, p. 6.

While we understand that at times, it may be necessary for BC Hydro to implement Government policy, we too are concerned about both the lack of transparency of these actions and of the costs borne by ratepayers. In the proceeding we focussed on that subset of such activities that are the subject of projects that are explicitly exempt from BCUC oversight – such as prescribed undertakings under the Greenhouse Gas Reduction (Clean Energy) Regulation. In light of this concern, we encourage BC Hydro to follow the practice of other utilities in BC and file applications to allow the BCUC to determine whether a project is exempt from the UCA before incurring expenditures on it.

The review of this Application spanned more than 19 months which, as outlined above, included various rounds of IRs, an oral hearing lasting almost 11 days and various submissions on specific topics. One Intervener submits that "the time required for the review of the current RRA has been excessive in relation to the value of the rate change requested, or for the policy implications involved in BC Hydro's planned expenditures." They go on to say that "[w]hile there was some suggestion that the current RRA would receive more scrutiny because the government has restored more of the regulator's discretion in setting BC Hydro rates, the prolonged process cannot be justified on this basis."[5]

We do not agree with this view. Given the lengthy hiatus in full regulation, it is important for both the BCUC and Interveners to conduct as thorough a review as possible. BC Hydro is a large and complex organization, one of Canada's largest utilities and therefore a thorough review is necessarily time consuming. Further, just because the rate increase applied for may be relatively small, it doesn't necessarily mean that a small increase is warranted – it is entirely possible that the facts could support a rate decrease. Rates must be looked at in concert with the revenue requirement.

This review, however, is somewhat compromised by the timing of the Application, which resulted in the Decision being unavoidably issued halfway through the second fiscal year of the two year test period. This provides very little opportunity for BC Hydro to implement any directives concerning costs without the risk of a significant rate impact. Given the time required for the preparation of the RRA process, it appears that unless steps are taken to avoid it, the next RRA review will likely suffer from the same shortcoming — it appears unlikely that a multi-year RRA application can be completed in sufficient time to complete a review by the start of the 2022 fiscal year.

As a result, after going out for submissions from parties, we direct BC Hydro to file what we describe as a "gap year" revenue requirement for fiscal 2022 by December 2020, for expedited review. This will allow for a better alignment of the next multi-year RRA timing.

We acknowledge BC Hydro's comprehensive approach to developing its load forecast and appreciates that such an approach takes time. However, we are concerned that the length of time required to produce its load forecasts may mean that BC Hydro is not able to react quickly enough to changes, including keeping stakeholders and the BCUC informed of changes to its load forecast.

The biggest component of the revenue requirement is the cost of energy. The cost of energy consists of three separate "buckets" – Heritage energy, Non-Heritage energy and Market sales and purchases. To both forecast the cost of energy and also to make operational decisions concerning the mix of energy with respect to each bucket, BC Hydro utilizes a suite of modelling tools it refers to as "Energy Studies" and the modelling process known as the "Energy Studies Process."

[5] Exhibit C4-3, pp. 1–2.

The modelling process is intended to support BC Hydro's system optimization objective of meeting domestic load requirements and maximizing consolidated net revenue. We have concerns about the various different ways this objective is stated in the evidence and also concerns that it lacks explicit acknowledgement of potential ratepayer risk.

We also review a recent audit report of BC Hydro's monthly Energy Studies Process and we express concerns about the lack of testing and benchmarking identified in the audit report, in addition to the age, documentation and performance of some of the models. As a result, we are unable to determine whether either the forecast is reasonable or whether on an operational basis, ratepayers' risk is mitigated and energy costs are as low as can be. However, in the absence of any better forecast or forecast methodology for the Test Period, we accept the updated forecast in the Evidentiary Update.

Non-Heritage energy includes electricity purchased from IPPs. Approximately 74 percent of the total forecast cost of energy over the Test Period of $3,663.5 million is driven by the cost of IPPs and long-term commitments totalling $2,705.5 million.[6]

Interveners expressed concerns about how BC Hydro manages IPP costs, including the EPA renewal process, particularly due to the significant volume of take-or-pay energy that BC Hydro holds during and following the Test Period. While IPP costs are the major driver of the forecast cost of energy, the Panel is limited by legislation, which requires the majority of these costs to be recovered from ratepayers:

- cost recovery of EPAs entered into prior to April 1, 2016, is legislated as per Direction No. 8; and
- six of eight EPAs set to expire during the Test Period qualify under the Biomass Energy Program, for which cost recovery from ratepayers is required under Order in Council (OIC) 158/2019.[7]

We therefore recommend BC Hydro examines all provisions in its EPA contracts if it appears there is significant decreased demand due to the COVID-19 pandemic. We also note an issue that recently arose in another proceeding regarding forbearance agreements that may limit BC Hydro's rights to terminate certain EPAs.

Further, BC Hydro's "cost of energy" is not the actual cost incurred by ratepayers to generate or otherwise obtain electricity needed to meet domestic load. Heritage energy costs, for example, do not include operating or capital related costs for the reservoir and dam system; and the cost of Non-Heritage energy is not an "apple to apples" comparison to the cost of Heritage energy, in part, because IPP costs do effectively include operating and capital related costs. However, BC Hydro's cost of energy presentation does represent the portion of energy acquisition costs that are subject to variance account treatment.

Direction No. 8 rescinded the inclusion of Trade Income in BC Hydro's revenue requirement. Trade income had been defined as the greater of Powerex net income and $0. BC Hydro proposes to continue the practice of including Trade income in the revenue requirement. We disagree with this approach because it puts the ratepayer at risk of having income that accrues from sales of energy generated by ratepayer assets eroded by losses from other Powerex transactions that do not involve BC Hydro electricity.

In light of our concern, we direct that only the proceeds, less associated overhead costs, for transactions involving BC Hydro electricity and associated with the acquisition of natural gas for BC Hydro be captured in the Trade Income Deferral Account. For further clarity, we allow the continuance of the Trade Income Deferral Account to capture variances between forecast and actual gains and losses on transactions involving BC Hydro electricity and associated with the acquisition of natural gas for BC Hydro and between forecast and actual gains

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[6] Exhibit B-11-2, Appendix A, Schedule 4.0, lines 29 and 39; Total of IPPs and Long-Term Commitments = ($1,294.7M + $1,410.8M) = $2,705.5M; Total Cost of Energy = ($1,928.9M + $1,734.6M) = $3,663.5M. ($2,705.5M/$3,663.5M) = 73.9%
[7] Section 4 of OIC 158, dated April 1, 2019; https://www.bclaws.ca/civix/document/id/oic/oic_cur/0158_2019

and losses of other Powerex transactions that do not involve BC Hydro electricity or natural gas, subject to BCUC approval.

There is no regulatory impediment to the inclusion of positive income from other Powerex transactions that do not involve BC Hydro electricity, and we have no objections to their inclusion in BC Hydro's Trade Income Deferral Account.

We determine that BC Hydro's capital expenditures in EV charging infrastructure are not recoverable from ratepayers at this time and direct BC Hydro to remove all capital expenditures for EV charging infrastructure from rate base. This is not because we take any position on societal goals to increase EV adoption, but because these assets are not used and useful to deliver electricity to ratepayers – in many cases they are "behind the meter" and used for a specific purpose. The BCUC EV Charging Inquiry recommended that the Government provide direction if it wished ratepayers to subsidize EV charging and it did so on June 22, 2020 for certain EV charging infrastructure.

BC Hydro has been increasingly focused on its mandate to keep costs down and rates low. In fact, BC Hydro's executive compensation pay is linked to keeping rates low. This is a reasonable objective for any utility, and we applaud this attention to cost reduction. However, our mandate is to ensure not that rates are kept low or affordable, but that rates are just, reasonable and not unduly discriminatory or unduly preferential. In doing so, we must be satisfied that the utility is able to recover sufficient funds to enable it to continue to provide safe and reliable service and to provide a return to shareholders. Further, given the principles of cost causation and intergenerational equity, these costs must be recovered from customers that benefit from them and not deferred to recovery in a future period.

We are concerned that a singular focus on keeping rates low, while salutary, may encourage any utility to cut corners and focus on cutting costs in areas that may have detrimental effects. These effects could be in the Test Period but could also manifest in a future test period(s).

Mr. O'Riley stated in the Oral Hearing, "BC Hydro's ability to absorb costs is being challenged and tested by the increasing complexity in the business, in areas particularly such as critical infrastructure protection, mandatory reliability standards, cyber security, increasing service expectations, societal expectations, and diverse regulatory requirements." [8] He describes vegetation management, cyber security and employee training as areas that are critical to BC Hydro's ability to operate effectively and provide safe and reliable service in the future.[9]

In this Decision, we express concerns about a number of areas where cost cutting may have been too aggressive or that needed increases have been put on hold:

1. Employee Training
2. Energy Studies
3. Vegetation management
4. Cybersecurity
5. Safety

Increased spending in these areas and others may be required in upcoming test periods. This will provide upward pressure on rates and there may not be any further cuts that can be made in other areas to mitigate these upward pressures.

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[8] Transcript Volume 5, p. 337.

In addition, while we are satisfied with BC Hydro's sustainment capital budget for this Test Period, we encourage BC Hydro to continue to maintain appropriate spending levels in this area. Reducing sustainment spending can be a false economy, leading to increased maintenance costs in future. For this reason, we direct BC Hydro to report in its fiscal 2023 RRA on any additional maintenance spending it identifies has incurred as a result of the reduced sustainment capital spending during the Test Period.

During the proceeding, interveners brought up the issue of affordability and the competitiveness of BC Hydro's rates. As discussed above, the BCUC has no legislative mandate to make rates affordable, either for all customers or for specific groups of customers. While we are satisfied that most of BC Hydro's costs are reasonable, there are areas, such as vegetation management and cyber-security, where BC Hydro should be increasing its spending to improve reliability and to reduce risk of future expenditures.

In the Decision, we also make the following directives concerning other issues that arose in the proceeding:

Table 2: Directives Concerning Other Issues

Issue	Determination
The continued usage of the BCUC's Uniform System of Accounts and whether a more appropriate framework can be adopted by BC Hydro	We approve BC Hydro's request to rescind the requirement to file information that follows the BCUC's Uniform System of Accounts, and hereby rescinds Directive 57 of the BCUC's Decision on BC Hydro's fiscal 2009 to fiscal 2010 RRA. We direct BC Hydro to maintain its records in such a way that it can produce financial information that follows the Federal Energy Regulatory Commission's Uniform System of Accounts.
Issues relating to the Covid-19 pandemic	We direct BC Hydro to report in all future RRAs, until directed otherwise, on the impact of the COVID-19 pandemic with respect to its operations and how it plans to handle the resulting impact on its revenue requirement, rates and regulatory accounts
BC Hydro's debt management strategy	We direct BC Hydro to provide in all future RRAs an updated Debt Management Regulatory Account Annual Status Report as provided in its Annual Report to the BCUC.
Rate design	We direct BC Hydro to include a discussion of its progress in developing

Issue	Determination
	its next RDA for commercial and industrial customers, as well as for customers in the NIA, in its report regarding the development of its next residential RDA. The report should also include results of the most recent fully allocated COS study, and a discussion on whether BC Hydro's COS methodology should be adjusted and if not, its rationale for not doing so.
Other BC Hydro subsidiaries	1. We direct BC Hydro to provide confirmation in its Compliance Filing that only the net income of Powerex and Powertech are included in its revenue requirement. 2. We direct BC Hydro to file any existing transfer pricing agreement between BC Hydro and Powertech in its compliance filing. 3. BC Hydro is required to file annually as part of its annual report to the BCUC, in confidence if necessary, a summary of Powertech's net income in sufficient detail to enable the BCUC to determine whether the inclusion of Powertech's net income is appropriate. 4. BC Hydro is directed, as part of its compliance filing, to further clarify the nature of the operations of BCHPA Captive Insurance Company Ltd., Columbia Hydro Constructors Ltd. and Tongass Power and Light Company and whether they are part of BC Hydro's regulated businesses or operate as separate regulated or unregulated businesses. BC Hydro is also directed to file any transfer pricing agreements with these three subsidiaries along with their most recent financial statements as part of its compliance filing. 5. As part of its compliance filing, the Panel also directs BC Hydro to provide the net income for its 11 remaining subsidiaries that "either serve as nominee holding companies …or are considered to be inactive/dormant." Any existing transfer pricing agreements between BC Hydro and these 11 subsidiaries must also be filed as part of its compliance filing.

Issue	Determination
Depreciation Rates for the Burrard facility; and new asset classes	We are generally satisfied that the depreciation rates requested by BC Hydro match the estimated life of the underlying assets and therefore, the Panel finds the requested depreciation rates for the Burrard synchronous condense facility, new water rights and LED street lights asset classes and three new asset classes for agreements recognized as leases under IFRS 16, to be reasonable and approves them. We approve the requested depreciation rates for the infrastructure rights asset class for the Test Period only and directs BC Hydro to review the expected useful life of infrastructure rights in its upcoming depreciation study and to identify any differences from the requested 35 year useful life in the RRA immediately following the completion of the depreciation study.

In light of concerns about the possible guarantee of recovery of all actual expenditures, we requested submissions during the deliberation period on the interpretation of section 3 of Direction No. 8. We agree with BC Hydro that section 3 of Direction No. 8 does not mean that ratepayers must pay, in the subsequent test period, for any deficiency in the actual return on equity earned in the Test Period, and this approach is the same as for any other utility. We find that under section 3 of Direction No. 8, BC Hydro's opportunity to earn $712 million is the same as the opportunity for any other utility to earn a fair return.

During the course of this proceeding, the BCUC established a separate process to review the Performance Based Regulation Report that was included in the RRA.

1.0 Introduction

1.1 The Application

On February 25, 2019, 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 test period from fiscal 2020 to fiscal 2021 (Test Period) (Application). The Application contains several requests, including:

- a request for approval of a reduction of the Deferral Account Rate Rider (DARR) from 5 percent to 0 percent effective April 1, 2019;
- approval of an increase in rates of 6.85 percent effective April 1, 2019; and
- approval of an increase in rates of 0.72 percent effective April 1, 2020.[10]

These requests would result in a net bill increase of 1.76 percent on April 1, 2019 and 0.72 percent on April 1, 2020.[11]

BC Hydro also requests approval for the fiscal 2020 and fiscal 2021 Open Access Transmission Tariff (OATT) rates, effective April 1, 2019 and April 1, 2020, respectively.[12]

In an evidentiary update to the Application dated August 22, 2019 and revised January 21, 2020 (Evidentiary Update),[13] BC Hydro adjusted its fiscal 2021 rate request from a 0.72 percent rate increase to a 1.01 percent decrease, effective April 1, 2020.

1.2 The Applicant

BC Hydro is a Crown corporation established under the *Hydro and Power Authority Act*. BC Hydro provides electricity to 95 percent of British Columbia's (BC) population with a service area that covers most of the province. The company has approximately 2 million customer accounts and provides service to approximately 4 million people and businesses.[14]

BC Hydro's vertically integrated electricity system includes 30 hydroelectric generating facilities, two natural gas-fired generating facilities, 134 contracts with Independent Power Producers (IPPs) and approximately 86,000 kilometers of transmission and distribution lines.[15]

1.3 Approvals Sought

BC Hydro outlined its approvals sought in Section 1.6 of the Application, which it subsequently amended in the Evidentiary Update.[16] 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:

[10] Exhibit B-1, p. 1-1.
[11] Exhibit B-1, p. 1-1.
[12] Exhibit B-11-2, Appendix E, Table E-2, p. 4.
[13] Exhibit B-11; Exhibit B-11-2.
[14] Exhibit B-1-1, p. 1-1.
[15] Exhibit B-1-1, p. 1-1.
[16] Exhibit B-11; Exhibit B-11-2.

Approval Sought	Location in this Decision
Reduce the Deferral Account Rate Rider (DARR) from 5 percent to 0 percent on April 1, 2019, as set out in Section 1.6 of the Application.	Section 4.5.4
Approve a permanent general rate increase of 6.85 percent on April 1, 2019 (for fiscal 2020) and permanent general rate decrease 1.01 percent on April 1, 2020 (for fiscal 2021), as set out in Section 1.6 of the Application and amended in the Evidentiary Update.	Section 3.0
Refund the forecast fiscal 2019 net closing balance and the forecast fiscal 2020 and fiscal 2021 net additions and net interest applied to the cost of energy variance accounts, over the Test Period, as described in Chapter 7, Section 7.7 of the Application and the Evidentiary Update.	Section 4.5.4
Defer any variances related to the accounting for electricity purchase agreements (EPA) determined to be leases under International Financial Reporting Standards (IFRS) 16, which are not eligible for deferral treatment under existing BCUC orders, to the Non-Heritage Deferral Account (NHDA), as described in Chapter 7, Section 7.7 of the Application.	Section 4.5.5
Defer any variances between forecast and actual amounts related to the Biomass Energy Program, which are not eligible for deferral treatment under existing BCUC orders, to the NHDA, as described in Chapter 7, Section 7.7 of the Application.	Section 4.5.1
Continue to defer, on an annual and ongoing basis, any variances between forecast and actual dismantling costs to the Dismantling Cost Regulatory Account, continue to apply interest to the balance of the account and recover the forecast interest charged to the account each year, and continue to recover the forecast account balance at the end of the Test Period over the next test period, as described in Chapter 7, Section 7.7 of the Application.	Section 4.5.2
Defer low-carbon electrification expenditures to the Demand-Side Management (DSM) Regulatory Account, consistent with the Government Direction to the BCUC Respecting Undertaking Costs.	Section 4.6.5
Remove the reference to the “Prescribed Standards” from the scope of what may be deferred to the Site C Regulatory Account, as BC Hydro has fully adopted IFRS, as described in Chapter 7, Section 7.7 of the Application.	Section 4.5.5
Close the Capital Project Investigation Costs Regulatory Account at the end of fiscal 2021 as its balance will be fully amortized into rates at that time, as described in Chapter 7, Section 7.7 of the Application.	Section 4.5.5
Close the Rate Smoothing Regulatory Account in fiscal 2020, as described in Chapter 7, Section 7.7 of the Application, as this account has a zero balance and BC Hydro is not proposing to smooth rates over the Test Period.	Section 4.5.5

Approval Sought	Location in this Decision
Close the Arrow Water Systems Provision Regulatory Account and the related Arrow Water Systems Regulatory Account in fiscal 2020, as the balance in the Arrow Water Systems Provision Regulatory Account has been written-off.	Section 4.5.5
Establish new depreciation rates for the Burrard synchronous condense facility, as described in Chapter 8, Section 8.2 of the Application, for new Water Rights, Infrastructure Rights and LED Streetlights asset classes and for three new asset classes for agreements recognized as leases under IFRS 16, *Leases*.	Section 5.3
Establish Open Access Transmission Tariff (OATT) rates, as set out in Chapter 9, Table 9-8 of the Application and as updated in Appendix E, Table E-2 of the Evidentiary Update.	Section 4.7
Accept a traditional DSM expenditure schedule of $90.8 million for fiscal 2020 and $89.1 million for fiscal 2021, as described in Chapter 10 of the Application and as updated in the Evidentiary Update.	Section 4.6
Reconsider and vary Directive No. 3 of the BCUC's Decision on BC Hydro's Fiscal 2017 to Fiscal 2019 Revenue Requirements Application which, among other things, directs BC Hydro to file a Certificate of Public Convenience and Necessity (CPCN) application for the Northwest Substation Upgrade project.	Section 4.4.4
Reconsider and rescind Directive No. 61 of the BCUC's Decision on BC Hydro's Fiscal 2005 to Fiscal 2006 RRA which directs that a prorated amount of costs from DSM portfolio-level initiatives be added to the cost of each DSM program to assess cost effectiveness, as described in Chapter 10, section 10.5.4 of the Application.	Section 4.6.6
Reconsider and rescind Directive 57 of the BCUC's Decision on BC Hydro's Fiscal 2009 to Fiscal 2010 RRA which directs that BC Hydro RRAs filed after January 1, 2011 contain financial information that follows the BCUC's Uniform System of Accounts.	Section 5.4

1.4 Regulatory Process and Participants

On March 1, 2019, the BCUC established a regulatory timetable for the review of the Application, which included a BC Hydro workshop, intervener registration, one round of information requests (IR), a procedural conference and community input sessions with further process to be determined.[17] On March 15, 2019, BC Hydro held its public workshop to introduce and present the Application. Subsequent to the BCUC's approval of BC Hydro's interim rate increase of 6.85 percent and a reduction of the DARR from 5 percent to 0 percent, effective April 1, 2019,[18] the Panel scheduled several Community Input Sessions throughout the province to promote public understanding of the scope of review for this Application. The Panel held sessions in Vancouver and Kamloops; however, due to low attendance and registration, additional sessions in Prince George, Fort St. John and Victoria were cancelled.

[17] Exhibit A-2, BCUC Order G-45-19.
[18] Exhibit A-2.

The intent of the Community Input Sessions was to inform the public on how to participate in the BCUC's regulatory processes, to explain the scope of the Application and to provide the public an opportunity to give their feedback to the Panel.[19]

The BCUC also held two Procedural Conferences on June 24, 2019 and November 22, 2019, and invited comments from interveners on a number of scope and procedural matters.

Subsequent to the June 24, 2019 Procedural Conference, the BCUC further established the regulatory timetable to include a written and oral hearing process.[20] The oral hearing commenced on January 20, 2020 and concluded on March 4, 2020.

There were fifteen registered interveners and three interested parties to this proceeding. The registered interveners were:

- Movement of United Professionals (MoveUP);
- Catalyst Paper Corporation (Catalyst);
- FortisBC Energy Inc. and FortisBC Inc. (FortisBC);
- Richard McCandless (McCandless);
- Kwadacha Nation and Tsay Keh Dene Nation, together the Zone II Ratepayers Group (Zone II RPG);
- British Columbia Old Age Pensioners' Organization et al. (BCOAPO);
- Paul Willis (Willis);
- BC Sustainable Energy Association (BCSEA);
- Commercial Energy Consumers Association of British Columbia (CEC);
- Clean Energy Association of B.C. (CEABC);
- Association of Major Power Customers of British Columbia (AMPC);
- David Ince (Ince);
- Steve Davis & Associates Consulting Ltd. (Davis-Associates);
- Edlira Gjoshe (Gjoshe); and
- BC Non-Profit Housing Association (BCNPHA).

The BCUC also received 10 letters of comment from members of the public.

The BCUC's regulatory review process for this Application included four rounds of BCUC and intervener IRs and two rounds of Panel IRs to BC Hydro; Intervener Evidence and IRs on that evidence; rebuttal evidence from BC Hydro; an oral hearing, followed by written final and reply arguments from all parties; an oral phase of argument with BC Hydro, written submissions from all parties and a written reply submission from BC Hydro.

[19] Exhibit A-6.
[20] Exhibit A-8, Order G-146-19.

On July 6 and 15, 2020, the Panel sought further legal submissions from BC Hydro and registered interveners on certain matters.[21] These items are addressed in Section 5.11 and 5.12 of this Decision.

During the course of this proceeding, the BCUC determined that the Performance Based Regulation Report would not be reviewed as part of this proceeding and established a separate review process.[22]

2.0 Legal and Legislative Framework

The *Utilities Commission Act* (UCA), in particular sections 59 to 61, provides the regulatory framework for BCUC's review of BC Hydro's revenue requirements. These sections, generally speaking, reflect what is commonly known as the "Regulatory Compact" which provides for a utility to recover its prudently incurred costs and be given the opportunity to earn a fair return on its invested capital, in return for providing safe and reliable service at rates that are not unreasonable, not unjust and not unduly discriminatory or unduly preferential. In addition to these rate setting sections of the UCA, the BCUC also reviews BC Hydro's capital projects and expenditures under section 44.2 for the acceptance of a capital expenditure and / or section 45 of the UCA to determine whether the project requires a CPCN.

Notwithstanding this legal framework, the BCUC's oversight of BC Hydro has evolved to reflect various legislative changes by the BC Government Directions No. 3, 6 and 7 to the BCUC have been repealed, thus restoring the review of most matters in this Application to BCUC oversight. Subsequently, the Government issued Direction No. 8 to the BCUC, which continues its direction to the BCUC in specific areas previously covered by Direction No. 7.[23]

The Government also repealed part of the Government Organization Accounting Standards Regulation[24] under the *Budget Transparency and Accountability Act*. In response, BC Hydro subsequently adopted IFRS as of its fiscal 2019 year-end financial statements.

BC Hydro submits that although the BCUC's discretion is much broader now, cost recovery is still mandated for certain matters, as follows:[25]

a) the balance of BC Hydro's regulatory accounts as of March 31, 2019;

b) the costs incurred by BC Hydro with respect to the construction of extensions to BC Hydro's plant or system that came into service before April 1, 2016;

c) the costs that BC Hydro incurs with respect to energy supply contracts entered into before April 1, 2016;

d) debt servicing costs on amounts borrowed in relation to the rate smoothing regulatory account; and

e) the costs associated with "prescribed undertakings" under the Greenhouse Gas Reduction (Clean Energy) Regulation (GGRR), which includes the Peace Region Electricity Supply ("PRES") project.

In addition, BC Hydro quotes from Direction No. 8 that the BCUC "must ensure that those rates allow the authority to collect sufficient revenue in each fiscal year to enable the authority to achieve an annual rate of return on deemed equity that would yield a distributable surplus of $712 million" for each of fiscal 2020 and fiscal 2021.[26]

[21] Exhibit A-37; Exhibit A-38.
[22] Exhibit A-18, Order G-244-19.
[23] Exhibit B-1, p. 2-2.
[24] B.C. Reg. 257/2010.
[25] BC Hydro Final Argument, p. 5.
[26] Section 3, Direction No. 8.

Details of these changes to directions to the BCUC are outlined in BC Hydro's Application in Table 2-1.[27]
On February 14, 2019, the Government of BC released a report on Phase One of its Comprehensive Review of BC Hydro (Phase One Review). BC Hydro states that this has resulted in changes that have enhanced the BCUC's oversight of BC Hydro and includes a number of actions by the Government and BC Hydro to keep rates affordable.[28]

In addition to the above legislative and policy directions, the BCUC is also guided by the details and the limitations set out in the *Hydro and Power Authority Act*, the *Clean Energy Act* and the UCA.

Notwithstanding BC Hydro's submission that the BCUC now has enhanced regulatory oversight of its operations, BC Hydro also outlines the other regulations issued under the UCA that continue to affect various aspects of its revenue requirements, and hence limit the BCUC's review and oversight. These include:

- the requirements for a DSM portfolio to be considered adequate and for the demand side measures within that portfolio to be considered cost-effective (DSM Regulation);[29]
- the regulation designed to encourage operators of cruise ships docked at Canada Place wharf in Vancouver to use port electricity (Shore Power Regulation);[30]
- the electrical efficiency of mills that use thermo-mechanical pulping processes (TMP Program Direction);[31]
- the Mining Customer Payment Program[32] to help mines remain in operation when prices for the commodities they produce are low;
- the direction relating to legacy meters or radio-off meters;[33]
- the supply of electricity to the City of Seattle (Skagit Agreement Direction);[34]
- an exemption for the Iskut Extension project from the BCUC's requirement for a CPCN;[35]
- an exemption for BC Hydro from Part 3 of the UCA with regards to certain transmission upgrades;[36]
- a direction which removes a previous provision that prevented Liquified Natural Gas (LNG) customers from receiving service under BC Hydro's transmission rate schedules;[37]
- a direction which prevents the BCUC from requiring BC Hydro to provide storage services;[38] and
- a direction which requires the BCUC to consider the objective for BC Hydro to achieve electricity self-sufficiency when considering CPCN applications and energy supply contracts.[39]

3.0 Overall Determination on Rates

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

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27 BC Hydro Final Argument, p. 5.
28 Exhibit B-1, pp. 1-8 and 1-9.
29 B.C. Reg. 326/2008.
30 B.C. Reg. 291/2008.
31 B.C. Reg. 139/2015.
32 B.C. Reg. 47/2016.
33 B.C. Reg. 203/2013.
34 B.C. Reg. 390/85.
35 B.C. Reg. 137/2013 and B.C. Reg. 24/2019.
36 B.C. Reg. 140/2013 and B.C. Reg. 160/2018.
37 B.C. Reg. 197/2018.
38 B.C. Reg. 157/2005.
39 B.C. Reg. 245/2007.

- an interim and permanent general rate increase of 6.85 percent on April 1, 2019 (for fiscal 2020) and 0.72 per cent on April 1, 2020 (for fiscal 2021);
- a reduction of the Deferral Account Rate Rider from 5 percent to 0 percent effective April 1, 2019; and
- the fiscal 2020 to fiscal 2021 Open Access Transmission Tariff (OATT) rates effective April 1, 2019 and April 1, 2020, respectively.

Following our review of the Application, we direct adjustments in the following areas of the revenue requirement:

- Trade Income;
- Storm restoration costs;
- Gain from elimination of MSP premiums;
- Real property sales gains;
- Project write-off costs;
- Reduction in the load forecast; and
- Costs related to EV charging infrastructure

In an evidentiary update to the RRA dated August 22, 2019 and revised January 21, 2020 (Evidentiary Update), BC Hydro changed the requested fiscal 2021 rate to a decrease of 1.01 percent from an increase of 0.72 percent.[40] BC Hydro requested that all rate impacts resulting from the Evidentiary Update be reflected in the fiscal 2021 rates to avoid adjustments to fiscal 2020 bills. The Evidentiary Update included adjustments to some of the forecasts for the Test Period based on the actuals that were known by the date the Evidentiary Update was prepared.

However, in the Evidentiary Update the Test Period forecasts for storm restoration and Trade Income were not updated even though the 2019 actuals were available to BC Hydro. Therefore, the Panel directed them to adjust these forecasts. Some Interveners argued that rates should also be adjusted for known changes in finance costs, although the Panel disagreed and declined to do so.

Overall, based on the Panel's key adjustments to BC Hydro's requested revenue requirements, we estimate that the fiscal year 2021 rate change will be a decrease of 1.14 percent. We recognize this figure does not include other adjustments, such as the costs related to the EV charging infrastructure, as directed in this Decision and therefore the final rate impact is subject to BC Hydro's confirmation in its Compliance Filing to the BCUC:

Table 3-1: BCUC Estimated Fiscal 2021 Rate

Adjustment	Impact to FY 2021 Rate
BC Hydro's proposed rate decrease	-1.01%
Trade Income	-2.12%
Storm restoration costs	+0.16%
Gain from elimination of MSP premiums	-0.20%
Real property sales gains	+0.38%
Project write-off costs	-0.38%
Reduction in load forecast	+2.03%
BCUC estimated rate decrease	**-1.14%**

[40] Exhibit B-11-2, p. 1.

For the reasons laid out in Sections 4.0 and 5.0 of this Decision, the Panel finds BC Hydro's forecast revenue requirement for the 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 60 days of this Decision. 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.

As discussed in Section 4.5.5 of the Decision, the Panel approves BC Hydro's request to reduce the DARR from 5 percent to 0 percent, effective April 1, 2019. Further, as discussed in Section 4.7 of the Decision, the Panel approves BC Hydro's OATT rates as requested and shown in the table below, subject to any adjustments resulting from the determinations and directives contained in this Decision:[41]

Table 3-2: BC Hydro's Proposed OATT Rates for Fiscal 2020 to Fiscal 2021

				F2020			F2021		
	Rate Schedule	Rate Class	Ref	Plan	Evidentiary Update	Diff	Plan	Evidentiary Update	Diff
				1	2	3	4	5	6
1	Attachment H	NITS Revenue Requirement ($)	Schedule 3.4 L32	928,236,000	967,788,000	39,552,000	926,484,000	~~965,040,000~~ 964,788,000	~~38,556,000~~ 38,304,000
2	RS 00	NITS Monthly Rate ($)	Schedule 3.4 L33	77,353,000	80,649,000	3,296,000	77,207,000	~~80,420,000~~ 80,399,000	~~3,213,000~~ 3,192,000
3	RS 01	Long Term Firm Point-to-Point							
4		Yearly - $/MW of Reserved Capacity per year	Schedule 3.4 L41	78,433	81,695	3,262	78,375	~~81,546~~ 81,527	~~3,171~~ 3,152
5		Short Term Firm and Non-Firm Maximum Price for Delivery							
6		Monthly - $/MW of Reserved Capacity per month	Schedule 3.4 L42	6,536.12	6,807.92	271.80	6,531.23	~~6,795.47~~ 6,793.92	~~264.24~~ 262.69
7		Weekly - $/MW of Reserved Capacity per week	Schedule 3.4 L43	1,508.34	1,571.06	62.72	1,507.21	~~1,568.19~~ 1,567.83	~~60.98~~ 60.62
8		Daily - $/MW of Reserved Capacity per day	Schedule 3.4 L44	214.89	223.82	8.93	214.73	~~223.41~~ 223.36	~~8.68~~ 8.63
9		Hourly - $/MW of Reserved Capacity per hour	Schedule 3.4 L45	8.95	9.33	0.38	8.95	9.31	0.36
10	RS 03	Scheduling, System Control & Dispatch Service ($)							
11		per MW of Reserved Capacity per hour	Schedule 3.4 L48	0.133	0.137	0.004	0.136	0.140	0.004

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 BC 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.

[41] Exhibit B-11-2, Appendix E, Table E-2.

The requested rates reflect a total revenue requirements of $5,223.9 million and $5,197.4 million for fiscal 2020 and fiscal 2021, respectively.[42] BC Hydro submits the Test Period revenue requirement forecast is appropriate and reflects "a pervasive culture of restraint and cost containment in the face of external cost pressures and an increasingly complex operating environment."[43]

4.1 Load Forecast

BC Hydro's October 2018 load forecast (October 2018 Load Forecast) is used in calculating its revenue forecast for fiscal 2020 and fiscal 2021. BC Hydro updated its Test Period revenue requirements as filed in the Evidentiary Update using actual financial results for April 2019 and May 2019 and the October 2018 Load Forecast for the remainder of fiscal 2020 and all of fiscal 2021.[44] The October 2018 Load Forecast is also one of the inputs to BC Hydro's Energy Studies models which are used to forecast its cost of energy across a five-fiscal-year time horizon. The modeling horizon and load forecast inputs extend beyond the Test Period because system conditions beyond the Test Period can have impacts on optimal operations during the Test Period, which in turn impact BC Hydro's cost of energy.[45]

BC Hydro's Non-Heritage Deferral account (NHDA) captures, among other things, the variances between revenues received for actual vs planned customer load, referred to as the Domestic Revenue Variance.[46] BC Hydro recovers the balances in the NHDA using the Deferral Account Rate Rider (DARR).

4.1.1 2019 Load Forecast

In addition to the October 2018 Load Forecast, BC Hydro also filed a 20-year load forecast, updated in June 2019, covering fiscal 2020 to fiscal 2039 (June 2019 Load Forecast), in response to a commitment made at the March 15, 2019 Workshop, information requests received, and in accordance with BCUC Order G-218-19.[47] The June 2019 Load Forecast[48] includes both an energy forecast and a peak demand forecast over a 20-year horizon.

BC Hydro states that the June 2019 Load Forecast is primarily an extension of the October 2018 Load Forecast because, with the exception of the EV forecast, the methodology is the same and only selected inputs were changed.[49] BC Hydro further states that fiscal 2022 to fiscal 2039 are outside of the Test Period covered by the Application and are provided for information purposes only. The June 2019 Load Forecast was prepared as an interim step to inform BC Hydro's future capital planning cycle and the February 2020 Service Plan.[50] BC Hydro is currently preparing a comprehensive system-level energy and peak load forecast for its 2021 Integrated Resource Plan (IRP), which will reflect more current information and assumptions. As of the time of filing of the Application, BC Hydro expected that the forecast would be ready for review and approval by BC Hydro's Executive Team by early 2020.[51]

Panel Discussion

The Panel considers it more appropriate to address the June 2019 Load Forecast that covers the period beyond the Test Period in BC Hydro's upcoming Integrated Resource Plan proceeding, and therefore makes no determination on the load forecast beyond the Test Period.

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[42] Exhibit B-11-2, Appendix A, Schedule 1.0, Line 33.
[43] BC Hydro Final Argument, p. 1.
[44] Exhibit B-15, p. 5.
[45] Exhibit B-5, BCUC IR 4.2.1.
[46] Exhibit B-1, p. 4-19.
[47] Exhibit B-15, cover letter, p. 1.
[48] Exhibit B-15.
[49] Exhibit B-23, BCSEA IR 4.86.1.
[50] Exhibit B-15, p. 1.
[51] Exhibit B-22, BCUC IR 318.4.

4.1.2 Past Issues with Load Forecast

The BCUC identified a number of issues with BC Hydro's load forecast in the fiscal 2017 to fiscal 2019 RRA and in the BCUC Inquiry Respecting Site C Final Reporting to the Government of British Columbia (Site C Report). The issues identified are the price elasticity assumption used, the appropriateness of using the same forecast methodology for the short-term and the long-term forecasts, the source of economic forecasts and the lack of probability assessment for LNG load. Each of these issues has been addressed by BC Hydro in the Application and a number of them are elaborated in the subsections below.

4.1.2.1 Price Elasticity

The load forecast uses price elasticity, which is a measure of customer response to electricity rate increases, to estimate rate impacts.[52] BC Hydro defines price elasticity of demand to be the measure of the responsiveness of quantity demand to a change in price and is expressed as the percent change in quantity to a one percent change in price.[53] BC Hydro explains that utilities use price elasticity to help determine whether and to what extent customers may reduce their electricity demand in response to a price increase.[54] In other words, a larger negative value for price elasticity means, assuming the same price increase, customers would have a larger reduction in electricity demand in response to the price increase. The need to review and update the price elasticity assumption was a finding from the Load Forecasting Audit[55], the fiscal 2017 to fiscal 2019 RRA's proceeding as well as the Site C Inquiry.[56] BC Hydro engaged DNV GL consulting (DNV GL) to review price elasticity, which includes a literature review of price elasticity estimates, methodology and application in 18 utilities in Canada and in the US, as well as BC Hydro's past review of price elasticity.[57] BC Hydro states that DNV GL prepared a comprehensive report filed as Appendix Q to the Application and recommended increasing elasticity values from -0.05 to -0.1 and applying price elasticity across all customer sectors. DNV GL explains:

- the literature indicates -0.1 to be the most common elasticity;
- BC Hydro's data indicates values (-0.08 to -0.14[58]) that surround -0.1;
- BC Hydro's consumption weighted tier-one and tier-two price elasticity is roughly -0.09; and
- the previous assessment of elasticity by BC Hydro expert Dr. Orans submits -0.1 to be suitable for BC Hydro.

However, DNV GL submits that a value of -0.1 for BC Hydro is reasonable.[59]

BC Hydro has more than 45 rate schedules and 70 rates across a number of rate structures[60] and notes that different customer groups will have different distributions of end-uses and will also have different consumption

[52] Exhibit B-6, Ince IR 8.29.
[53] Exhibit B-1, Appendix Q, p. 1.
[54] Exhibit B-1, p. 1-13.
[55] BC Hydro's Corporate Affairs Business Group completed an internal load forecast audit in Q1 2018 with input from GDS Associates Inc. The Load Forecast Audit report is filed as Appendix P to the Application.
[56] Exhibit B-1, p. 3-15.
[57] Documents reviewed by DNV GL include: Direct testimony of Ren Orans in support of the 2008 Long-run Acquisition Plan; Electric Load. Forecast Fiscal 2013 to 2033; Evaluation of the Large and Medium General Service Conservation Rates: F2014; The jurisdictional review included in the 2015 Rate Design Application; The load forecast section of the Fiscal 2017 to Fiscal 2019 Revenue Requirements Application; The statistically adjusted end-use (SAE) model description referenced in the load forecast section; and Evaluation of the Residential Inclining Block Rate, Fiscal 2013 to 2017; Exhibit B-1, Appendix Q, p. 2.
[58] BC Hydro's evaluation of the Residential Inclining Block Rate through regression analysis of consumption data from fiscal 2005 to fiscal 2017 identified price elasticities of -0.14 for the lower-priced tier and -0.08 for the higher-priced tier. (Exhibit B-5, BCUC IR 1.8.5.1).
[59] Exhibit B-1, Appendix Q, p. 16.
[60] BC Hydro's rate structures include: tiered energy (unit price varies by usage level), flat energy (unit price does not vary by usage level), floating energy (unit price floats with a market index), tiered demand, flat demand, fixed basic (set price for period of time), and other fixed (set price based on customer equipment).

patterns, both of which can affect overall price elasticities.[61] However, BC Hydro submits that, with regards to load forecasting, it is not aware of other electric utilities that apply distinct price elasticity values to each rate.[62] BC Hydro further states that it is generally accepted that price elasticity of demand for electricity is sensitive to the absolute price level and is not linear. However, because the expected rate increases over the Test Period are small, BC Hydro has applied the same price elasticity estimate for each year of the October 2018 Load Forecast to the applicable loads.[63] BC Hydro presents the following table showing that changing the price elasticity assumption has a minimal impact on the overall load forecast.[64]

Table 4-1: Load Forecast Based on a Range of Elasticity Assumptions

	Load Forecast For F2020				Load Forecast For F2021		
	A	B	C		D	E	F
	Elasticity	Elasticity	Elasticity		Elasticity	Elasticity	Elasticity
	-0.05	-0.1	-0.15		-0.05	-0.1	-0.15
	GWh	GWh	GWh		GWh	GWh	GWh
Residential	18,266	18,258	18,251		18,343	18,330	18,317
Light Industrial and Commercial	18,980	18,973	18,965		19,043	19,030	19,017
Large Industrial	14,708	14,702	14,696		14,253	14,243	14,233
Irrigation	79	79	79		79	79	79
Street Lighting	232	232	232		232	232	232
New Westminster & Tongass	470	471	470		473	472	471
Fortis	542	542	542		555	555	555
Seattle City Light	310	310	310		310	310	310
Total	53,587	53,567	53,545		53,290	53,253	53,215

Rate Increase Assumption

BC Hydro developed the rate impacts for the October 2018 Load Forecast "using the past five years of the 2013 10-Year Rates Plan. However, the rates within that rate plan are not the same as the rates BC Hydro is seeking within this Application."[65] BC Hydro explains that the rates it is seeking approval for in this Application were not used as an input to estimate the rate impacts and price elasticity because BC Hydro had not finalized its updated five-year rates forecast at the time the October 2018 Load Forecast was developed.[66] BC Hydro presents the following table comparing the rate increase used in the October 2018 Load Forecast versus the rate increase requested in the Evidentiary Update, as well as the impact on the fiscal 2020 and fiscal 2021 load forecast.[67]

61 Exhibit B-1, Appendix Q, p. 1.
62 Exhibit B-5, BCUC IR 8.3.
63 Exhibit B-6, Ince IR 8.29.
64 Exhibit B-5, BCUC IR 8.1.
65 Exhibit B-5, BCCU IR 5.3.1.
66 Exhibit B-12, BCUC IR 211.1.
67 Exhibit B-12, BCUC IR 211.2.

Table 4-2: Test Period Load Forecast under Various Rate Increase Assumptions

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

Positions of Parties

Ince submits with respect to elasticity, BC Hydro's doubling from -0.05 to -0.10 is a directional improvement, but is still at a level at the low end of the literature range. Ince agrees with BC Hydro[68] that price elasticity assumption has a minimal impact on the load forecast during the Test Period. Ince further states that elasticity is an underappreciated 'sleeper' issue in which erroneous starting assumptions compound and could create significant long-term load forecast errors and adverse consequences in planning processes. Towards the final resolution of this issue, BC Hydro needs to continue work on its stock turnover model. Due to the complexity of the issue, the scarcity of necessary expert resources and the long lead time required for a solution, the initiation of work should not wait for the review of BC Hydro's Integrated Resource Plan. The results of this work should be ready in time for the first phases of the IRP review. [69]

BCOAPO submits that the BCUC should direct BC Hydro, to the extent possible, to align the rate increase assumptions used for purposes of determining price elasticity impacts on its load forecast with the proposed rate increases. However, BCOAPO also recognizes that the load forecast is an input to the determination of the Test Period revenue requirements and resulting proposed rate increases and, as such, total alignment may not be possible.[70]

In reply, BC Hydro argues Ince's submission implies that BC Hydro should derive its elasticity estimates from the stock and flow model, which was not a topic that was examined during the course of the proceeding, and is an approach with which BC Hydro does not agree. BC Hydro notes that the DNV GL electricity price elasticity study does not describe this practice.[71]

In reply to BCOAPO's submission, BC Hydro submits that BCOAPO's recommendation is impractical and would have adverse implications.[72] The effect of using BCOAPO's approach would be to delay the filing of a RRA because the rate assumptions would be required to feed into the load forecast.[73] Further, BC Hydro submits that the effect of using the proposed rates would be a negligible change from the October 2018 Load Forecast (0.1% higher forecast load for fiscal 2020 and 0.5% higher forecast load in fiscal 2021).[74] BC Hydro further states that

[68] BC Hydro Final Argument, p 20.
[69] Ince Final Argument, p. 23.
[70] BCOAPO Final Argument, p. 12.
[71] BC Hydro Reply Argument (May 27, 2020), p. 26.
[72] BC Hydro Reply Argument (May 27, 2020), p. 23.
[73] BC Hydro Reply Argument (May 27, 2020), p. 24.
[74] BC Hydro Reply Argument (May 27, 2020), p. 24.

the BCUC should reject a direction in the nature sought by BCOAPO as there is no basis upon which to conclude that this is an item for which significant effort is currently required.[75]

Panel Determination

The Panel considers the adjustment to the elasticity assumption from -0.05 to -0.1 to be supported by literature, consistent with what is commonly reported among other surveyed utilities and is aligned with BC Hydro's past review of price elasticity. As shown in Table 4-1 above, the overall load forecast is very similar under an elasticity assumption of -0.05, -0.1 and -0.15, respectively. Therefore, the Panel finds BC Hydro's elasticity assumption of -0.1 to be reasonable for the purpose of setting rates within the RRA.

BC Hydro describes price elasticity as a measure of customer response to electricity rate increases and acknowledges that it is generally accepted that price elasticity of demand for electricity is sensitive to the absolute price level and is not linear.[76] As discussed above, given the rate adjustment in fiscal 2020 and fiscal 2021 is small and the load forecast is very similar under various elasticity assumptions, the Panel concurs with BC Hydro that a single price elasticity assumption is appropriate for this RRA. However, the Panel notes customers may respond differently to nominal versus real changes in price. In addition, considering BC Hydro has requested a price decrease in fiscal 2021, customers' responsiveness to a price increase versus a price decrease may also differ. **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.** The Panel further encourages BC Hydro to continue to monitor the appropriateness of its elasticity assumption in preparing future load forecasts.

With regards to BCOAPO's suggestion to "align the rate increase assumptions used for purposes of determining price elasticity impacts on its load forecast with the proposed rate increases," the Panel observes this would in principle better reflect reality in the Test Period. However, as the load forecast is an input to determine the proposed rate increase in the RRA, the Panel concurs with BCOAPO and BC Hydro that perfect alignment may not be possible or practical. The Panel notes that the rate change assumption used by BC Hydro reflects information available at the time the load forecast was prepared, and as presented in Table 4-2 above, the difference in rate increase assumption does not materially impact the load forecast. Therefore, the Panel finds the rate increase assumption used by BC Hydro for purposes of determining price elasticity impacts on its load forecast to be reasonable.

4.1.2.2 Short Term Load Forecast Methodology Used by Other Utilities

The BCUC commented in its decision on BC Hydro's fiscal 2017 to fiscal 2019 RRA, "other utilities such as Pacific Northern Gas Ltd., FortisBC Energy Inc., and FortisBC Inc. use a different load forecast methodology for their short term forecast for setting rates as compared to its long term forecast for resource planning."[77] In response to this comment, BC Hydro undertook a review of FortisBC Electric's (FBC) short-term load forecast methodology and showed a comparison between BC Hydro's and FBC's methodology for the residential, commercial and large industrial sector in Table 3-2 of the Application. BC Hydro also generated a load forecast from fiscal 2016 through fiscal 2018 using FBC's short-term forecast methodology and found that the variance between actual and forecast is smaller using BC Hydro's existing methodology for that period. Specifically, BC Hydro averaged a billed sales variance of -0.3 percent (residential sector) and -0.4 percent (commercial sector) for fiscal 2016 to fiscal 2018 using its load forecasting methodology. The average billed sales variance using FBC's methodology was 2.4 percent (residential sector) and 0.8 percent (commercial sector) for the same time period.[78] Therefore, BC Hydro submits that its load forecast methodology should be maintained.

[75] BC Hydro Reply Argument (May 27, 2020), p. 24.
[76] Exhibit B-6, Ince IR 8.29.
[77] Decision accompanying Order G-47-18, Appendix B, p. 11.
[78] Exhibit B-1, p. 3-36.

Panel Determination

BC Hydro's back-testing analysis shows that its existing load forecasting methodology results in a smaller variance between actual and forecast for short term load than does the short term load forecasting methodology used by FBC. Since the BCUC has previously approved FBC's load forecast, the Panel finds it reasonable for BC Hydro to maintain its existing load forecast methodology for the purpose of preparing its fiscal 2020 to fiscal 2021 revenue requirement.

4.1.2.3 Economic Forecast and Consideration of Possible Recession

Economic forecasts such as retail sales, housing starts, housing stock and population are one of many inputs that go into the models BC Hydro uses to develop the residential and commercial load forecasts.[79] In the Site C Report, the BCUC found, "the GDP and disposable income used by BC Hydro are higher than similar Conference Board of Canada estimates."[80]

Following BC Hydro's normal competitive procurement practices and using a merit-based evaluation, the Conference Board of Canada (CBoC) was selected by BC Hydro as the preferred proponent among two request for proposal respondents. BC Hydro notes that its previous economic forecast service provider, Robert Fairholm Economic Consultant, did not respond to the Request for Proposal.[81] The residential and commercial load forecasts are developed on a regional basis using economic forecasts from the CBoC. The load forecast for the "other" sub-sector, which is part of the light industrial sector, is developed at the provincial level using the BC Ministry of Finance GDP forecast for the first five years and CBoC GDP forecast for years beyond 5 years. BC Hydro notes the large industrial load forecast was developed on an account by account basis and does not use BC's GDP as a direct input.[82] BC Hydro explains that to maintain consistency with the source of other financial assumptions used within the Company, BC Hydro prefers to use the BC Ministry of Finance's economic forecasts, where applicable. However, these economic forecasts are produced only at the provincial level and only for a five-year forecast horizon.

BC Hydro shows the following the table comparing the total provincial GDP Growth forecast in 2019 and 2020 by CBoC and by the BC Ministry of Finance:[83]

Table 4-3: Total Provincial BC GDP Growth (%)

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

<u>Consideration of Possible Recession</u>

BC Hydro explains that its load forecast over the entire short-term period does not reflect any specific period of economic recession or recovery. However, a recession scenario would likely fall within the total domestic system

[79] Exhibit B-5, BCUC IR 6.1.1.
[80] BCUC Inquiry Respecting Site C Final Reporting to the Government of British Columbia dated November 1, 2017, p. 78.
[81] Exhibit B-5, BCUC IR 6.2.
[82] Exhibit B-12, BCUC IR 210.2.1.
[83] Exhibit B-12, BCUC IR 210.1; heading to second column revised to read "B.C. Ministry of Finance BC Budget February 2019" rather than "B.C. Ministry of Finance BC Budget February 20191."

high and low forecast uncertainty band.[84] The band is created around the mid forecast, and represents a range in future demands for electricity before savings from DSM and demonstrates some of the range of uncertainty.[85] The Monte Carlo simulation's perturbation process used the CBoC's GDP growth forecast as the base. That base was then perturbed randomly using a normal distribution with a mean of zero and standard deviation of 1.7 that was itself derived from the actual, annual values for GDP growth for BC over the past twenty years in order to incorporate variability.[86] BC Hydro explains that the use of a perturbation process for GDP based on 20 years of actuals that contained a recession (BC's annual GDP growth was -2.4 percent in fiscal 2009), means the Monte Carlo modelling itself then contains simulations with recessions.[87]

Positions of Parties

The CEC submits that, notwithstanding the extremeness of the current economic situation, recessions typically occur with some level of predictable frequency and should be planned for in load forecasting. This is of increased concern when there are circumstances signalling the imminence of a recession, particularly in an RRA with such a short timeframe. The CEC recommends that the BCUC requests BC Hydro to develop potential practices that would enable it to include a probability of recessions and provide these to the BCUC for review prior to the next IRP.[88]

In reply, BC Hydro submits that given its load forecast already includes the probability of recessions, the CEC's request that BC Hydro do so would serve no purpose.[89]

Panel Discussion

The economic forecast is an important input into the load forecast for multiple customer classes, and a failure to consider a recession, or an inaccurate anticipation of a future recession would likely have a material impact on forecasting load and revenues. However, the Panel also notes the difficulty in predicting the timing and duration of a future recession. As such, BC Hydro's consideration of a possible recession using its existing Monte Carlo simulation process appears reasonable. The Panel finds the economic forecast to be reasonable for the purpose of preparing the Test Period load forecast. The Panel also accepts BC Hydro's rationale for changing the economic forecast service provider.

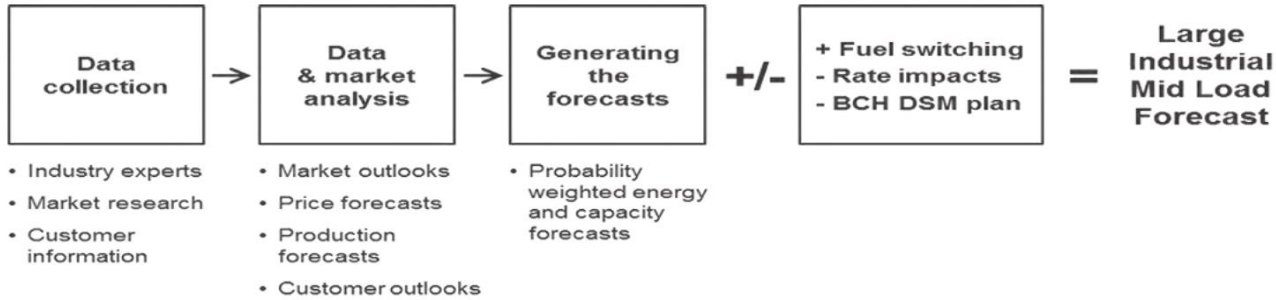
4.1.2.4 Large Industrial Load Forecast

The large industrial sector of the load forecast makes up approximately 27 percent of BC Hydro's total load forecast,[90] and is estimated based on an aggregation of individual forecasts for approximately 190 customers. The individual customers are organized into four main sub-sectors: mining, forestry, oil and gas (including LNG), and other large industrial customers. BC Hydro explains that most of its large industrial customers are involved in extracting, processing and manufacturing resource based commodities, which are largely exported outside BC. Export volumes can vary significantly from year to year in response to market forces and consequently, electricity sales to this sector can also vary.[91]

The large industrial load forecast methodology is summarized in the following figure[92]:

[84] Exhibit B-5, BCUC IR 7.1, 7.2.
[85] Exhibit B-1, Appendix O, p. 2.
[86] Exhibit B-5, BCUC IR 7.2.
[87] Exhibit B-5, BCUC IR 7.2.1.
[88] CEC Final Argument, p. 16.
[89] BC Hydro Reply Argument (May 27, 2020), p. 28.
[90] 14592/53296 (27.4%) in fiscal 2020, 14243/53253 (26.7%) in fiscal 2021 (Exhibit B-12-1, Appendix A, Tab 14).
[91] Exhibit B-1, Appendix O, p. 61.
[92] Exhibit B-1, Appendix O, Figure 7-1, p. 61.

Figure 4-1: Large Industrial Load Forecast Process



<u>Changes to Large Industrial Load Forecast Methodology</u>

BC Hydro's review of its fiscal 2018 load forecast variance showed significant variances for several industrial sub-sectors, notably forestry (positive variances) and oil and gas (negative variances). These variances were determined to be attributed to risk adjustments (i.e., probability weightings) on specific customers that were significantly driven by closure risk considerations (for some existing customers) or start-up likelihood consideration (for new customers).[93] Previously, a customer's load was adjusted by the probability weighting BC Hydro assigned to it over the forecast period. For example, a customer with a 25 percent probability of closure would have its anticipated load included in a load forecast at 75 percent.

In response to significant variances in the large industrial load forecast, BC Hydro revised its load forecast methodology to use a binary approach for the first three years of the forecast which resulted in a discrete projection of load and revenues. Load with high probability of materializing is included in the forecast at 100 percent weighting, whereas load with low probability of materializing is included in the forecast at 0 percent weighting. BC Hydro explains that operationally, the net effect of facility closures or start-ups is that a facility will either be fully operational (i.e., on) or not operating at all (i.e., off).[94] BC Hydro states that on an aggregate sector total basis, this binary approach may or may not improve load forecast accuracy over the Test Period since positive variances in one sub-sector may offset negative variances in another. However, BC Hydro believes this approach will improve load forecast accuracy for specific segments since it addresses why the most recent variances occurred. Over the long term, BC Hydro believes a probabilistic based approach continues to be the best method for developing the large industrial sector forecast on an aggregate basis.[95]

<u>LNG Load Forecast</u>

In the Site C Report, the BCUC stated, "[it] agrees with several parties who express concern with the fact that BC Hydro has not made a probabilistic assessment of the likelihood of the LNG load materializing."[96] In response, BC Hydro updated its load forecast methodology to forecast sales to LNG customers in a manner consistent with other large industrial customers using the probabilistic assessment approach as described in the section above.[97] In terms of presentation, LNG load is now reported as part of the large industrial load estimate and not as a separate line item because in October 2018, the Government of BC removed a provision[98] that prevented LNG customers from receiving service under BC Hydro's transmission rate schedules.[99] Revenue from LNG customers is now recorded as general rate revenue and not as a separate line item.[100] BC Hydro notes it is not expecting

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[93] Exhibit B-1, p. 3-28.
[94] Exhibit B-1, p. 3-28.
[95] Exhibit B-1, p. 3-29.
[96] BCUC Inquiry Respecting Site C Final Reporting to the Government of British Columbia dated November 1, 2017, p. 78.
[97] Exhibit B-1, p. 3-28.
[98] Direction Respecting Liquified Natural Gas Customers (B.C. Regs 197/2018).
[99] Rate Schedules 1823, 1825, 1827 and 1852.
[100] Exhibit B-5, BCUC IR 1.10.2.1.

electricity sales to LNG customers over the Test Period beyond sales to the FortisBC Tilbury plant, which is in operation.[101]

Possible Bias in Self-Reported Customer Data

A forecast for each large industrial customer is derived by considering the amount of energy it needs to conduct its operations multiplied by an assessment of how likely it is to sustain those operations (i.e., a probability). In order to determine how much energy customers need, BC Hydro typically perform a bottom-up analysis for their various operations.[102] This analysis assesses the historical (or requested) energy usage and compares it to the volume of product a customer produces to determine load or intensity factors.[103]

Since the large industrial load forecast relies, in part, on customer self-reported data, there is a potential for bias. BC Hydro explains that the potential for bias is mitigated in several ways. First, for customer requests, the interconnection process has a built-in incentive for the customer to avoid overstating its load requirements. This is because the customer will likely trigger major system upgrades if it requests a greater load than what it truly needs, and for which it will be financially responsible. Second, the Transmission Voltage Customer Interconnection Data Form requires applicants to itemize plant equipment with horsepower – information that can be used to reconfirm load requirements.[104] Third, each month BC Hydro conducts a forecast review process where each large industrial customer's forecast is compared against the actual load. This review is a cross departmental process involving the Customer Service, Finance and Load Forecast departments. Material biases resulting in over-stated loads would result in obvious large variances that would be identified and addressed in subsequent forecasts.[105]

Positions of Parties

The CEC agrees that for the first three years of the load forecast, the binary approach is appropriate since significant drops in output can result in the failure of the business as a whole.[106]

BCSEA submits that although the ongoing challenges in the forestry sub-sector have been at the forefront of public attention, upside potential also exists from electrification. BCSEA also refers to BC Hydro indicating that the CleanBC Plan represents incremental load potential and that BC Hydro's load forecast reflects an appropriate amount of this upside potential, having regard to the early state of development of the CleanBC Plan and the available information.[107]

Ince raises uncertainty regarding LNG and upstream natural gas projects and encourages the BCUC to require BC Hydro to provide as soon as is practical, a high-level update on the load forecasts specific to the LNG, oil and natural gas sectors, reflecting current information.[108]

In BC Hydro's reply argument, BC Hydro submits that any update on load forecast should be rejected for the following reasons: there is a strong need to bring this proceeding to a close; BC Hydro anticipates returning to an annual load forecasting cycle and BC Hydro will provide a 20-year load forecast in the upcoming IRP; BC Hydro's load forecast includes an uncertainty band given the inevitability that actual results will vary from forecasts; and

[101] Exhibit B-1, p. 3-46.
[102] Please refer to Exhibit B-5, BCUC IR 9.2 for details on which subsector relies on the bottom-up, top-down, or the combination of both approaches in each subsector's forecast methodology.
[103] Exhibit B-5, BCUC IR 9.2.
[104] Exhibit B-5, BCUC IR 9.1.1.
[105] Exhibit B-5, BCUC IR 9.1.1.
[106] CEC Final Argument, p. 19.
[107] BCSEA Final Argument, p. 29.
[108] Ince Final Argument, p. 4.

lastly, variances in the cost of energy associated with load are included in the revenue requirements for the next test period, such that customers pay the actual cost of energy.[109]

Panel Determination

The Panel is satisfied that BC Hydro has updated its load forecast methodology for the Test Period to forecast sales to LNG customers using the probabilistic assessment approach, consistent with other large industrial customers. The Panel recognizes the inherent uncertainty in the large industrial load forecast and acknowledges BC Hydro's efforts to refine the short-term load forecast methodology for this customer class. While the binary approach to consider the probability of load materializing appears reasonable, the Panel concurs with BC Hydro's comment that this binary approach may or may not improve load forecast accuracy over the Test Period since positive variances in one sub-sector may offset negative variances in another. **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.**

4.1.3 Other Issues Arising

4.1.3.1 Electric Vehicle Load Forecast

The EV load forecast is split "between the residential sector and commercial sectors" based on Insurance Corporation of British Columbia (ICBC) data on the number of light duty EVs that are for personal and business use. As a result, 85 percent of the total EV load forecast is allotted to the residential sector and 15 percent is allotted to the commercial sector.[110] The forecast of the annual total number of EVs is determined by the product of the EV market share and the total vehicle purchase forecast.[111]

BC Hydro projects about 100 GWh from EVs for each of the two test years. BC Hydro states that relative to other drivers, EV load impacts are not a major contributor to projected sales. [112] BC Hydro prepared a mid and high EV forecast, but did not prepare an EV low load forecast.[113] BC Hydro explains it believes there is an asymmetrical risk (i.e., there is more upside potential than downside) for future EV stock and load, and attributes its beliefs to the following factors that have occurred since the development of the October 2018 EV forecast, including:

- the CleanBC Plan announced in December 2018 and its potential impacts;
- The federal government's introduction of a new EV incentive program that provides up to a maximum of $5,000 purchase incentive;[114]
- The Government of BC's commitment of an additional $41.5 million toward a rebate program for the purchase of eligible EVs (the CEVforBC rebate program) for fiscal 2020 and the lowering of the maximum price eligibility threshold to $55,000; [115]
- The Government of BC's passage of Zero-Emission Vehicle (ZEV) legislation as part of its CleanBC Plan, which will require all new vehicles sold in BC to be electric by 2040; and [116]
- higher gasoline prices relative to those reflected in the October 2018 Load Forecast.[117]

[109] BC Hydro Reply Argument (May 27, 2020), pp. 22–23.
[110] Exhibit B-1. Appendix O, p. 106.
[111] Exhibit B-1, Appendix O, p. 107.
[112] Exhibit B-5, BCUC IR 5.3.1.
[113] Exhibit B-1, Appendix O, p. 109; Exhibit B-6, CEC IR 12.1.
[114] Exhibit B-13, CEC IR 95.1.
[115] Exhibit B-13, CEC IR 95.1.
[116] Exhibit B-13, CEC IR 95.1.
[117] Exhibit B-5, BCUC IR 5.3.1.

Positions of Parties

BCSEA is satisfied with BC Hydro's statement that "[a]s part of development efforts for future load forecasts, we intend to place more focus on our EV modelling, given the emphasis that the CleanBC plan places on the electrification of transportation."[118]

The CEC agrees with this approach as it relies on actual information rather than expected information. The CEC expects that this may be a benefit under the current global crisis which is seeing many environmental regulations being rolled back in an effort to stabilize the economy.[119] The CEC accepts BC Hydro's reasoning that there is an asymmetrical risk regarding the EV load forecast, but states, "BC Hydro has not adequately considered the potential for conservation and efficiency in the electric vehicle forecast and the potential role DSM can and should play in reducing load and load impacts."[120]

In reply, BC Hydro explains the basis for its belief is that there is an asymmetrical risk and that these upside factors would pull in the opposite direction to the conservation and efficiency considerations noted by the CEC.[121] BC Hydro further submits it has recognized that the actual EV load growth may be higher or lower than the EV uncertainty bands in the June 2019 Load Forecast. BC Hydro notes that the EV contribution to BC Hydro's overall forecast during the Test Period is small, and that it continues to monitor EV market development and actual sales growth. It will be incorporating that information as part of future load forecast updates.[122]

Panel Discussion

The EV projections within the Test Period are small, and therefore any underlying uncertainty with regards to the EV load forecast likely has a small impact on the overall Test Period load forecast. The Panel acknowledges that several government policies and incentives relating to the EV market were released shortly after BC Hydro prepared its October 2018 Load Forecast. However, government policy implemented since the development of the October 2018 Load Forecast regarding EVs will likely have a greater impact on the load forecast beyond the Test Period. The Panel finds the EV load forecast for the Test Period to be reasonable. The Panel encourages 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.

4.1.3.2 Accuracy of Recent Load Forecasts

The load forecast for the fiscal 2017 to 2019 RRA was developed in May 2016 (May 2016 Load Forecast). BC Hydro states that actual results have tracked within 0.1 percent to 0.5 percent against the May 2016 Load Forecast for fiscal 2017 and fiscal 2018.[123] The actual domestic energy sales in fiscal 2019 were 0.5 percent lower than fiscal 2019 RRA Plan.[124]

With regards to the performance of the Test Period load forecast, the year-to-date fiscal 2020 (i.e., April 1, 2019 to December 31, 2019) actual sales are 1,009 GWh or 2.6 percent below forecast, and are shown in more detail in the table below: [125]

[118] BCSEA Final Argument, p. 12.
[119] CEC Final Argument, p. 19.
[120] CEC Final argument, p. 20.
[121] BC Hydro Reply Argument (May 27, 2020), p. 30.
[122] BC Hydro Reply Argument (May 27, 2020), p. 30.
[123] Exhibit B-1, p. 3-4.
[124] Exhibit B-11, p. 2.
[125] Exhibit B-41, p. 2.

Table 4-4: Fiscal 2020 Year-to-Date up to December 2019

(GWh)	Fiscal 2020 Year-To-Date up to December 2019			
	EU	Actual	Diff	% Diff
	1	2	3 = 2 - 1	4 = 3 / 1
Residential	12,480	12,204	(276)	-2.2%
Light Industrial and Commercial	13,945	13,741	(204)	-1.5%
Large Industrial	10,858	10,064	(794)	-7.3%
Other	1,049	1,314	265	25.2%
Total	38,332	37,323	(1,009)	-2.6%

Positions of Parties

The CEC has reviewed the various rate sector forecasts and submits that the general methodologies were reasonably suitable at the time of the forecast.[126] The CEC accepts BC Hydro's load forecast as provided but expects that the actual load will likely be significantly lower than currently forecast and that the load forecast could be appropriately adjusted to a lower level.[127] In the CEC's view, it would be appropriate for BC Hydro to review its forecast in light of the current COVID-19 pandemic and at least identify load reduction changes consistent with past evidence of the flattening of the load expectations over time.[128] With respect to the current situation, the CEC expects that in particular the commercial and industrial load will likely be lower than forecast, while the residential load may be higher. The CEC recommends that the BCUC request BC Hydro to lower its load forecast for the 2020 period and/or request that BC Hydro revisit its load forecast in light of the current economic conditions and other factors highlighted in the evidence to make a suitable adjustment for this RRA.[129]

In BCSEA's view, the October 2018 Load Forecast was reasonable at the time it was made and was not materially contradicted by actual experience up to the closing of the evidentiary record in the proceeding on March 4, 2020.[130]

MoveUP states BC Hydro's load forecasting and its most recent forecasts were the subject of extensive prehearing process and oral hearing time. No one has demonstrated that the load forecast is the product of flawed methodology and BC Hydro's evidence withstood close scrutiny.[131] MoveUP submits that the BCUC should accept BC Hydro's October 2018 Load Forecast for the purposes of setting its rates in the current Test Period, despite the fact that it will be proven inaccurate.[132]

BCOAPO submits it is content to let the load forecast as submitted with the Evidentiary Update stand as reasonable for the purposes of determining BC Hydro's fiscal 2020 and fiscal 2021 electricity rates. In coming to this position, BCOAPO has taken into consideration not only the possible impacts of COVID-19, but the fact that the variances that may occur between the forecast and actual domestic revenues are eligible for deferral to BC Hydro's regulatory accounts.[133]

In reply, BC Hydro submits that the BCUC should find that the load forecast and revenue forecast for the Test Period reflected in the Evidentiary Update are reasonable. Intervener comments and observations do not call

[126] CEC Final Argument, p. 16.
[127] CEC Final Argument, p. 20.
[128] CEC Final Argument, p. 16.
[129] CEC Final Argument, p. 1.
[130] BCSEA Final Argument, p. 11.
[131] MoveUP Final Argument, p. 6.
[132] MoveUP Final Argument, p. 7.
[133] BCOAPO Final Argument, p. 15.

this into question.[134] Reporting on the impacts of COVID-19 should occur in the next RRA when more information is available.[135]

Panel Determination

The load forecast between April 1, 2019 to December 31, 2019 was over-forecast by 2.6 percent, with the large industrial sector having the largest variance of 794 GWh or 7.3 percent. The Panel is concerned by the performance of the load forecast for the first nine months of fiscal 2020, and notes that the actual sales for the Test Period may turn out to be even lower than forecast under the impact of the COVID-19 pandemic. **Accordingly, the Panel directs BC Hydro to adjust its load forecast for the entire Test Period by the percentage variance experienced between April 1, 2019 and December 31, 2019 for each customer class, respectively. 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 extent of any variance that is attributable to and independent from the COVID-19 pandemic, respectively.** The Panel also encourages BC Hydro to continue to examine ways to improve the accuracy of its load forecast.

4.1.3.3 Load Forecasting Process

BC Hydro explains it normally makes changes to its load forecast in three ways, and each with different frequency. BC Hydro changes its load forecast by either building a comprehensive system level energy and peak load forecast (referred to as a "comprehensive load forecast"), by developing partial updates to a comprehensive load forecast (referred to as a "load forecast update"), or by adjusting a version of a comprehensive load forecast or a load forecast update within a fiscal year for financial forecasting purposes.[136] BC Hydro's comprehensive load forecast and load forecast update processes are further elaborated below.

<u>Comprehensive Load Forecast</u>

A comprehensive load forecast encompasses updates to key inputs and model calibration periods. BC Hydro normally completes a comprehensive load forecast once per year as part of its Service Plan schedule. The most current Service Plan load forecast, referred to as the October 2018 Load Forecast, is also used in the cost of energy study that supports the same Service Plan. The comprehensive load forecast is also the starting point for other products and forecasts used within BC Hydro (e.g., the distribution substation peak forecast). [137]
BC Hydro explains that both energy and peak forecast processes begin at the start of the fiscal year once the previous fiscal year's sales and peak demand data have been compiled. The energy portion of the forecast is scheduled to be completed every October as part of the Service Plan schedule and the system peak portion of the forecast is normally finalized one to two months later. Both the Service Plan and system peak forecasts are multi-year projections, including the current fiscal year. BC Hydro explains that the time gap between the last comprehensive load forecast in May 2016 and the October 2018 Load Forecast was the result of two back-to-back regulatory proceedings (i.e., the fiscal 2017 to 2019 RRA and the Site C Inquiry), which required an extensive time commitment from the load forecast team and necessitated altering the comprehensive load forecast schedule from its annual cycle. [138]

BC Hydro's monthly Energy Studies uses the latest approved load forecast. The latest approved load forecast is the October 2018 Load Forecast and it will be used in the Energy Studies until the next Service Plan load forecast is available[139]

[134] BC Hydro Reply Argument (May 27, 2020), p. 32.
[135] BC Hydro Reply Argument (May 27, 2020), p. 22.
[136] Exhibit B-12, BCUC IR 209.1.
[137] Exhibit B-12, BCUC IR 209.1.
[138] Exhibit B-12, BCUC IR 209.1.
[139] Exhibit B-12, BCUC IR 208.1.

BC Hydro is currently preparing a comprehensive system-level energy and peak load forecast for the 2021 Integrated Resource Plan. As of the filing of the Application, BC Hydro expected that the forecast would be ready for review and approval by BC Hydro's Executive Team by early 2020. This schedule is not expected to impact subsequent annual load forecast updates.[140] BC Hydro further states that given the significance of the IRP, it believes a comprehensive forecast is warranted.[141]

BC Hydro submits in the Load Forecast Audit, "[b]ased on interviews with various user groups and review of relevant documentation, the subject matter expert believes that providing the long-term forecast once a year is sufficient for long-term planning. The needed outputs are provided to users in sufficient detail and are generally delivered on time."[142]

Load Forecast Updates

BC Hydro develops partial updates to the comprehensive load forecast, referred to as load forecast updates, that use the most recent comprehensive load forecast and refresh selected elements of that forecast. Load forecast updates are developed when specific business, planning and regulatory processes require current load forecast information but do not allow for the necessary amount of time needed to develop a comprehensive load forecast. [143]

Subject to timing and resource availability constraints, partial updates to the comprehensive load forecast have typically been limited to updates to specific light and large industrial accounts based on information provided directly to BC Hydro from existing customers or customers requesting service; specific new loads for emerging sectors such as cannabis and crypto-currency that are included in distribution peak guideline updates that inform the annual distribution substation forecast; and other elements depending on their relevance to a specific application (e.g., a regulatory submission). For example, BC Hydro states that the updated May 2016 Load Forecast, filed as part of the Electricity Purchase Agreement Renewals for Sechelt Creek Hydro, Brown Lake Hydro and Walden North Hydro, only included updates to LNG assumptions, DSM and rate impacts associated with BC Hydro's updated price elasticity assumption. [144]

Panel Determination

We acknowledge BC Hydro's comprehensive approach to developing its load forecast and we appreciate that such an approach takes time. We also agree that, under normal circumstances, developing a comprehensive load forecast once a year is appropriate. The comprehensive forecast provides a baseline to make "adjustments" or "partial updates" to deal with stochastic events, at least in the short term.

While we do not have any direct evidence on this issue, we infer that a comprehensive forecast takes roughly nine months. It appears that the process for a comprehensive load forecast begins in April-May (once the previous fiscal years' data is compiled), the energy forecast is completed in October and the system peak forecast would be completed in December (1-2 months from October). We are unable to determine how long "adjustments" or "partial updates" take, although we assume that they would depend on the specific nature of the adjustment or update.

That said, we acknowledge the effects of COVID-19 on business in general and this creates particular challenges for utilities, including BC Hydro, in forecasting demand in both the near and the longer term. Changes to electricity demand caused by the pandemic may be significant and may be long term. However, unfortunately, planning decisions that rely on a load forecast may not be easily postponed to allow for the development of a

[140] Exhibit B-22, BCUC IR 318.4.
[141] Exhibit B-22, BCUC IR 318.4.2.1.
[142] Exhibit B-1, Appendix P, p. 17.
[143] Exhibit B-12, BCUC IR 209.1.
[144] Exhibit B-12, BCUC IR 209.1.

new comprehensive load forecast. We are concerned that BC Hydro is not able to react quickly enough, including keeping stakeholders and the BCUC informed of changes to its load forecast.

A second area of concern to the Panel is the impact of the length of time required to develop a load forecast on the overall time required to develop an IRP. The timeline of the 2021 IRP filing is the subject of another proceeding before the BCUC, and that is an appropriate place to consider this matter. However, it is not only the filing date of the 2021 IRP that may be impacted but the length of time required for BC Hydro to react to and produce the results of a load forecast with new inputs and updated information.

Given the rapid changes experienced in the electricity sector and the expectation that change will continue, Long Term Resource Plans should not necessarily be updated every five, seven or ten years, but should be updated sooner as and when circumstances require them to be updated. Accordingly, BC Hydro's modeling process should be flexible enough to take into account these changing inputs. Granted, the load forecast is only half of the puzzle and we comment in the following section on the other half – the process to model BC Hydro's long term electricity supply. Here, however, we focus our concern on the load forecasting process.

To address the Panel's concerns discussed above, BC Hydro is directed to, as part of its compliance filing:

1. **Provide the BCUC with general time estimates to prepare: a comprehensive load forecast, "partial updates" and "adjustments";**
2. **Provide information on benchmarking studies regarding the time required to prepare BC Hydro's load forecast models compared to Manitoba Hydro, Quebec Hydro, Bonneville Power – or any other comparable utility; and**
3. **Provide suggestions on ways to streamline its load forecasting methodology without a material loss of accuracy.**

4.2 Cost of Energy

In this section, we review BC Hydro's energy costs to determine whether its forecast cost of energy is reasonable for the purpose of setting rates in the Test Period. BC Hydro explains that it uses its forecast cost of energy in determining its total revenue requirements for this Application. However, the use of regulatory accounts ensures that customers ultimately only pay the actual cost of energy.[145]

Cost of energy represents 35 percent or $3,663.5 million of BC Hydro's total revenue requirement of $10,421.3 million over the Test Period. It is the largest single component of BC Hydro's expenses. BC Hydro has broken down its cost of energy into three categories: Heritage energy, Non-Heritage energy and Market energy below:[146]

Table 4-5: Cost of Energy Forecast (Integrated System and Non-Integrated Areas)

Cost of Energy ($millions)	Schedule Reference	F2020 Plan	F2020 EU	Diff	F2021 Plan	F2021 EU	Diff
		1	2	3=2-1	4	5	6=5-4
Heritage Energy	4.0L28	350.9	351.2	0.3	350.8	317.7	(33.1)
Non-Heritage Energy	4.0L33	1,576.3	1,332.4	(243.9)	1,641.1	1,447.2	(193.9)
Market Energy	4.0L38	(40.2)	245.3	285.5	(71.7)	(30.3)	41.4
Total	4.0L39	1,887.0	1,928.9	41.9	1,920.2	1,734.6	(185.6)

The allocations of energy in the three categories is a consequence of the outputs of the Energy Studies process – which uses a suite of 85 models. In its Application, BC Hydro explains "the role of our monthly Energy Studies in

[145] Exhibit B-1, p. 4-1.
[146] Exhibit B-19, Appendix C, Table C-1, p. 1.

optimizing our operational management of all sources of energy supply on BC Hydro's integrated system, including the heritage assets". In the evidence this "optimization of operational management" is given different labels and described in different ways. To avoid confusion, we refer to it as BC Hydro's "system optimization objective."

In order to determine whether the forecast or actual costs incurred in each of these categories is reasonable the Panel must be satisfied that BC Hydro's system optimization objective, and the Energy Studies – and any other forecasting or planning tool that relies on them or that is used to develop input data for them – are appropriately designed, built, tested and verified. Therefore, we begin our determinations on the cost of energy by considering the system optimization objective. Then we consider the Energy Studies Process. We then review the cost of energy by category: Heritage, Non-Heritage and Market.

A variance account related to the cost of energy is the Trade Income Deferral Account that captures variances between forecast and actual Powerex net income. We discuss this account further as we examine the income that flows into the Trade Income Deferral Account from the activities of Powerex related to Market energy transactions and other business activities, in section 4.2.7.

4.2.1 BC Hydro's System Optimization Objective

BC Hydro states, "[i]n the operational (i.e., up to three years) time horizon, BC Hydro operates the system to meet load first and then makes decisions to dispatch resources and to undertake Electricity Purchases or Surplus Sales to maximize the expected value of its energy supply portfolio within a range of outcomes. This objective is in the best interests of ratepayers."[147]

However, in the Oral Hearing, Ms. Matthews stated, "the objective function of the model is set up to maximize consolidated net revenue while satisfying domestic integrated systems requirements and contractual obligations."[148]

Mr. Ahmed explained:[149]

> [A] starting point is, to describe what is going on, or to change the definitions a little better, or clarify them. What the question seems to be asking is, is how can BC Hydro and Powerex simultaneously optimize BC Hydro's surplus sales and trading using residual system capability, respectively.
>
> And first, as a point of clarification, trading utilizing residual system capability is only a portion of Powerex's trade activity that ends up as trade income. Within the context of the RRA, trading utilizing residual system activity gets labeled as "net purchases" or "(Sales)" from Powerex.
>
> Now second, a key point is that the two activities need to be optimized together, not individually to yield the highest consolidated net revenue, and hence the lowest cost of energy for BC Hydro's customers.

He then went on to say, "there are two things that are being maximized, but they are being maximized on a consolidated basis to have the highest -- the best overall cost of energy for BC Hydro's customers at the end of the day."[150]

[147] BC Hydro Final Argument, p. 42.
[148] Transcript Volume 10, pp. 1741–1742.
[149] Transcript Volume 16, pp. 2924–2925.
[150] Transcript Volume 16, p. 2929.

Mr. Ahmed was asked whether BC Hydro's use of the term income also included expenditures: [151]

> THE CHAIRPERSON: So does income also include expenditures? Like, is it net income that's being maximized or is it just the income? People use that term in different ways. Accountants, as I understand it, when they say "income" they usually mean "net income" but not everybody does mean that. So can you also clarify whether when you are maximizing that portion of income that relates to Hydro's energy sales, whether you're talking about maximizing the revenue portion? Or maximizing the net income?
>
> MR. AHMED: Is your question with respect to Powerex's net income? Or BC Hydro's cost of energy as a whole?
>
> THE CHAIRPERSON: It's the Powerex portion. It's the [sic] while maximizing Powerex's trade income. So you're saying it's not actually Powerex's trade income that is being maximized, it's something else, it is a portion of it. So I am further asking you to clarify whether you're talking -- now that that has been redefined, is that redefined as revenue or net income of that portion?
>
> MR. AHMED: I think the concept is there are two things that are being maximized, but they are being maximized on a consolidated basis to have the highest -- the best overall cost of energy for BC Hydro's customers at the end of the day. I'm not sure if I captured what you were asking though, sir.
>
> THE CHAIRPERSON: Well, I could maximize revenue and take a loss.
>
> MR. AHMED: Yeah, I see. It's on a net basis.
>
> THE CHAIRPERSON: But that wouldn't be that helpful, right?
>
> MR. AHMED: Yes.
>
> THE CHAIRPERSON: So it's on a net basis?
>
> MR. AHMED: That's correct, it's on a net consolidated basis.
>
> THE CHAIRPERSON: Thank you.

BC Hydro states that its two objectives of meeting domestic load and maximizing consolidated net revenue are not in conflict. Rather, meeting load requirements is the first objective, and then how to meet those requirements determines how consolidated net revenue is maximized.[152]

Positions of Parties

BCSEA accepts "meeting domestic load and maximizing the expected value for ratepayers [are] complementary, rather than conflicting, objectives."[153] BCSEA also accepts that BC Hydro makes all of the decisions related to system operations and has the ability to put constraints on Powerex's activities.[154]

BCSEA agrees with BC Hydro's explanation and understands that the optimization, or maximization, is applied to net revenue for both BC Hydro and Powerex, after BC Hydro meets its load-serving requirements.[155]

[151] Transcript Volume 16, pp. 2928–2929.
[152] Transcript Volume 10, p. 1746.
[153] BCSEA Final Argument, p. 17.
[154] BCSEA Final Argument, p. 17.
[155] BCSEA comment on BCH Submissions dated June 16, 2020, p. 2.

MoveUP submits that BC Hydro's description that maximizing surplus sales and trading activities "need to be optimized together, not individually to yield the highest consolidated net revenue" is an accurate and adequate response.[156]

Willis submits that BC Hydro does prioritize the need to meet domestic load requirements, while Powerex meets its responsibility to maximize export sales revenue.[157]

BCOAPO is of the view that maximizing the expected value of BC Hydro's energy supply portfolio is an appropriate objective for system operations.[158] BCOAPO views that the valuation of optimal operations with respect to net deposits or withdrawals from storage is a key output of the monthly Energy Study.[159]

CEABC agrees with the core concept of system management, where BC Hydro states:[160]

> [S]o our objective that we operate the system to is to maximize the consolidated operation net revenue, and I know that's sort of our mantra that we say all the time, and what it means when I say consolidated is that it's the BC Hydro domestic buying and selling -- or selling our surplus and buying for our deficit and the Powerex trade.

CEABC adds that BC Hydro should be open and transparent about the risks it takes to achieve this objective, and views that this objective can be more easily achieved with far less risk if BC Hydro sells more electricity domestically by setting sales objectives and incenting its workforce accordingly.[161]

CEABC also submits that the principal purpose of BC Hydro's energy modelling is to optimize the net revenues from BC Hydro's trading activities (including Powerex) into and out of British Columbia.[162] In CEABC's view, there is far too much reliance being put on taking more import/export risk, as a means of increasing revenue and minimizing rate increases.[163]

In reply, BC Hydro submits that CEABC's view of BC Hydro's energy modelling is unduly narrow. BC Hydro asserts that the Energy Studies do not optimize trading activities to the detriment of domestic needs, but instead optimize consolidated net revenues. BC Hydro also submits that CEABC's view overlooks the use of the Energy Studies for informing operational dispatch decisions, monitoring risks, and forecasting BC Hydro's cost of energy for financial reporting. Further, BC Hydro states that the Energy Studies do not set targets to meet domestic load, but rather are used to determine how to meet domestic load.[164]

CEABC further submits that BC Hydro did not directly respond to the Panel's question, instead recasting the question in terms of "residual system capability" which includes energy and capacity. In CEABC's view, the time horizon for determining residual system capability for capacity is much shorter than for energy and consequently there is less risk of error.[165]

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[156] MoveUP comment on BCH Submissions dated June 16, 2020, p. 3.
[157] Willis comment on additional BCH Submission dated June 16, 2020, p. 1.
[158] BCOAPO Final Argument, p. 17.
[159] BCOAPO Final Argument, p. 18.
[160] Transcript Volume 9, pp. 1426–1427.
[161] CEABC Final Argument, p. 51.
[162] CEABC Final Argument, p. 9.
[163] CEABC Final Argument, p. 51.
[164] BC Hydro Reply Argument (May 27, 2020), pp. 35–36.
[165] CEABC comments on BCH submission dated June 18, 2020, p. 1.

CEABC also sought to clarify the "netting" of revenues in the context of Energy Studies optimizing BC Hydro's consolidated net revenue from operations.[166] BC Hydro confirmed that the "netting" of revenues is "revenues from sales from the system (for both Surplus Sales and sales to Powerex), less expenditures for purchases to the system (for both Market Energy Purchases and purchases from Powerex). Operating expenses are not deducted in this calculation."[167]

Panel Discussion

The Panel has the following concerns regarding BC Hydro's system optimization objective:

1. It is not clearly stated. There are different versions of the objective;
2. The distinction between net revenue and net income isn't clear; and
3. Risk to ratepayers is not recognized in the statement of the system optimization objective.

Different Versions of the System Optimization Objective

BC Hydro's system optimization objective has been characterized in a number of different ways during this proceeding. For example, one characterization is to "maximize consolidated net revenue while satisfying domestic integrated systems requirements and contractual obligations."[168] Another is to "meet load first and then makes decisions to dispatch resources and to undertake Electricity Purchases or Surplus Sales to maximize the expected value of its energy supply portfolio within a range of outcomes."[169] Other expressions include[170] "simultaneously optimize BC Hydro's surplus sales and trading using residual system capability, respectively." The fiscal 2019 Energy Studies Process Audit, which we will discuss further in the following section, describes BC Hydro's "objective for system coordination" as "to maximize risk neutral long-term net revenue from operations."[171]

Further the Application describes consolidated net revenue from operations as "domestic revenue from accrued sales plus revenue from surplus (domestic) sales plus revenue from Columbia River Treaty related agreements less cost of IPPs and long-term commitments less cost of market electricity (domestic) purchases less cost of water rentals less cost of natural gas for thermal generation less cost of net purchases (sales) from Powerex."[172] In our view, consolidated net revenue means revenue of a parent and its subsidiaries determined on a consolidated basis in accordance with GAAP. It appears that the definition provided in the Application differs from this.

Given these different description of BC Hydro's system optimization objective, it is not possible for the Panel to be satisfied that ratepayer interests are adequately provided for. **The Panel directs BC Hydro, in its compliance filing, to clarify what its system optimization objective is. This filing should include clarification of the basis of consolidation for net revenue.**

166 CEABC comments on BCH submission dated June 18, 2020, p. 2.
167 BC Hydro Reply to Interveners on Oral Phase of Argument (June 22, 2020), p. 2.
168 Transcript Volume 10, pp. 1745–1746.
169 BC Hydro Final Argument, pp. 35–36.
170 Transcript Volume 16, p. 2924.
171 Exhibit B-1, Exhibit DD, p. 7 of 15.
172 Exhibit B-1. p. 4-16.

The Distinction between Net Revenue and Net Income

There also appears to be conflicting evidence concerning the distinction made between net revenue and net income. In our view, revenue means sales, so net revenues are the same as net sales. Net income means profits, the amount left over from sales, after accounting for all costs. BC Hydro's definition of net income, as expressed in its Final Argument, appears to be consistent with our view when it claims that operating expenses are not deducted in the calculation of net revenues.

However, Mr. Ahmed appears to contradict this, at least with respect to the portion of consolidated net revenues that come from Powerex Trade Income, when he confirms that they are on a "net consolidated basis".

The definition of consolidated net revenue from operations, as provided in BC Hydro's reply to interveners during the oral phase of argument, deviates from the definition provided in the Application. In that reply, BC Hydro "confirms" that the net amount is: "revenues from sales from the system (for both Surplus Sales and sales to Powerex), less expenditures for purchases to the system (for both Market Electricity Purchases and purchases from Powerex). Operating expenses are not deducted in this calculation. However, Powerex's Net Income or Trade Income as used in the calculation of rates is based on the full audited net income as consolidated by BC Hydro, such that it does account for operating expenses as well."[173]

The difference between maximizing net revenues and maximizing net income, given the definitions described by the Panel above, is significant. Ratepayer interests may be better served if net income is maximized rather than net revenue. If BC Hydro's system optimization objective is defined in terms of maximizing net revenue, the Panel cannot be satisfied that ratepayer interests are adequately provided for. **The Panel directs BC Hydro, in its compliance filing, to clarify whether its system optimization objective is to maximize net revenue or net income.**

Ratepayer Risk

Here, our concern is the distinction between – and here we paraphrase two of BC Hydro's various statements of its system optimization – the statement that domestic load is met first then net revenue (or income) is maximized, and the statement that net revenue is maximized while satisfying domestic needs. While this may appear to be a distinction without a difference, there is at least one scenario where that may not be so - it depends upon how domestic load is met first.

Consider two very different possible meanings of these different statements of BC Hydro's system optimization objective. One, concerning meeting load first, is that energy from BC Hydro's heritage assets, supplemented by energy from IPP take or pay commitments, is relied upon to meet most or all of its domestic needs. There may be surpluses from time to time which are then used by Powerex to earn, and maximize, trade income. This approach substantially reduces supply risk for ratepayers because they are assured of being first in line for Heritage and Non-Heritage energy.

In the second possible meaning, maximizing net revenue while satisfying domestic needs, there is no setting aside of any Heritage or Non-Heritage energy. Domestic needs are simply included in the objective function to be maximized. If, for example, Heritage energy can be sold now for a higher price than it can be purchased for at a later date, then domestic needs at that later date can still be satisfied by selling the energy now and repurchasing it later from the market. This strategy may produce higher consolidated net income. However, it exposes ratepayers to the inherent unpredictability of market prices, thereby putting them at additional risk that the price of the repurchase later might be higher, not lower (price risk). In an extreme case it is possible that the energy isn't actually available later for repurchase (availability risk).

[173] BC Hydro Reply to Interveners during the Oral Phase of Argument dated June 22, 2020, pp. 2–3.

Therefore, the system optimization objective of maximizing consolidated net revenue should also include any appropriate constraints to ensure the maximization is subject to adequately managing ratepayer risk. **The Panel directs BC Hydro to address, in its compliance filing, how price risk and availability risk are recognized in the system optimization objective.**

In summary, BC Hydro must do the following in its compliance filing to the BCUC:

1. Clarify what its system optimization objective is (e.g. to maximize net revenue or net income). This clarification should include an explanation of the basis of consolidation for net revenue.
2. Address how price risk and availability risk are recognized in the system optimization objective.

4.2.2 Energy Studies and System Operations

BC Hydro states that the primary objectives of the Energy Study are to forecast:

1. The marginal value of water in BC Hydro's two largest reservoirs (Williston and Kinbasket) that is used to inform operational dispatch decisions; and
2. The Cost of Energy for financial reporting.

It further explains that "the forecast monthly marginal value of water provides BC Hydro with a relative measure that guides the operation of these reservoirs in the context of market and system conditions (i.e., when domestic energy resources should be dispatched versus purchases made from Powerex or when additional domestic resources should be dispatched to facilitate sales to Powerex. This output of the monthly Energy Study allows us to manage our integrated system to maximize the value for ratepayers."[174]

BC Hydro states that it produces an Energy Study every month, the primary objective of which is to forecast, over a five year horizon, an optimal set of reservoir and generating station operations and market transactions under current forecasts of market, inflow, and weather conditions. It states "[t]he Energy Study process consists of numerous proprietary models which are developed and maintained by a specialized team in Generation System Operations. Some key models have been reviewed externally over the last 20 years as part of continuous improvement efforts." [175]

BC Hydro submits that the monthly Energy Studies support the objective of maximizing consolidated net revenue from operations, where: [176]

- "consolidated" refers to the combined activity of both BC Hydro (domestic) and Powerex (trade); and
- "net revenue from operations" is "domestic revenue from accrued sales plus revenue from surplus (domestic) sales plus revenue from Columbia River Treaty related agreements less cost of IPPs and long-term commitments less cost of market electricity (domestic) purchases less cost of water rentals less cost of natural gas for thermal generation less cost of net purchases (sales) from Powerex."

A key component of the Energy Studies involves optimizing the Kinbasket and Williston reservoirs, which account for approximately 90 percent of the total storage in BC Hydro's system and are the primary source of seasonal and multi-year operational flexibility.[177] BC Hydro describes a cyclical pattern to these reservoirs, where they are drafted across fall and winter to meet load, and normally reach a minimum level in April, at which point snow melt refills the reservoirs and peak levels are normally reached "somewhere between July and September."[178]

[174] Exhibit B-1, pp. 4-13 to 4-14.
[175] Exhibit B-1, Appendix DD, p. 3.
[176] Exhibit B-1. p. 4-16.
[177] Exhibit B-1, p. 4-17.
[178] Transcript Volume 9, p. 1424.

According to BC Hydro, many dependencies between models exist within the Energy Studies process, and most models take inputs in ensemble form to produce an ensemble of results. This ensures that the variability in inflows, prices, loads, and resources due to the impacts of weather is well represented, and produces a range of possible outcomes, which capture dry and wet periods and accurately represent the historic geographic correlation in weather between the regions included in the modelling. This range is large enough that the average of the resulting forecast is considered to be an unbiased estimator of the drivers, and therefore a reasonable representation of how the system will be operated.[179]

Although the Energy Studies provide price signals to operate the system in an economic way, BC Hydro states that it evaluates the "tails", or outliers, in the distribution of probable reservoir levels, and intervenes in cases where reservoir levels are low, or there is potential for spill.[180] BC Hydro submits that "checking our tails", so to speak, is how it balances operational risks of high or low System Storage levels against financial gains.[181] During the Oral Hearing, BC Hydro provided an example of how financial gains from sales of surplus energy in the summer of 2018 more than offset a number of operational risks in the months that followed, including cold weather, low water conditions and the Enbridge pipeline explosion. However, BC Hydro submits that even with hindsight, the sales of surplus energy were the correct actions to take because choosing the alternative would have created less value for ratepayers.[182]

In fiscal 2019, BC Hydro undertook an internal audit of the monthly Energy Studies process[183] to evaluate whether it reliably supports operations, financial and strategic planning (Energy Study Audit).[184] The Energy Study Audit focused primarily on governance, the Energy Studies process, the timeliness of reporting and the review and approval process and was supplemented by two external subject matter experts from SINTEF Energy Research (SINTEF), one of Europe's largest independent research with over 40 years of experience in developing models for planning and operation of hydrothermal power systems.[185]

The overall findings of the Energy Study Audit stated that "BC Hydro has a well-established Energy Studies process in place. Governance is effective with appropriate level of oversight, and responsibilities and accountabilities are well understood across the team. Key models developed are appropriate and the methodologies applied are in line with leading industry practices. The Energy Studies process can be further automated to reduce cycle time and free up resources."[186]

The Energy Study Audit found that "Energy Study reports are prepared on time and contain an appropriate level of detail; however, they do not serve short-term operational planning needs."[187] This contrasts with the statement in the Application that "monthly Energy Studies optimize our operational management of all sources of energy supply on BC Hydro's integrated system."[188] When asked about this through IRs, BC Hydro responded that "the Energy Studies are not designed for in-month operations and are not intended to accommodate within month changes" – instead "[o]ther tools such as spreadsheets, database applications and proprietary software" are used to manage its system during rapidly changing conditions.[189]

BC Hydro clarified how the Energy Studies are used in short-term operational planning: [190]

[179] Exhibit B-5, BCUC IR 1.31.1.
[180] Transcript Volume 9, pp. 1454–1455.
[181] Transcript Volume 10, pp. 1760–1761.
[182] Transcript Volume 9, pp. 1482 to 1486; Transcript Volume 10, pp. 1780–1781.
[183] Exhibit B-1, p. 4-14.
[184] Exhibit B-1, Appendix DD, p. 8.
[185] Exhibit B-1, Appendix DD, p. 8; https://www.sintef.no/en/this-is-sintef/
[186] Exhibit B-1, Appendix DD, p. 9.
[187] Exhibit B-1, Appendix DD, p. 9
[188] Exhibit B-1, p. 4-8.
[189] Exhibit B-31, IR 2.5.1; Exhibit B-5, BCUC IR 1.28.1.
[190] Exhibit B-5, BCUC IR 1.28.1.

> The Energy Study does not serve short-term operational planning needs because it does not recommend a day-to-week ahead operation based on short-term variation in inflows, loads and market prices. Furthermore, Energy Study models simulate and optimize operation at plant level, not a generating unit level, in order to be able to run over multi-year time periods. Other tools such as spreadsheets, database applications and proprietary software are used to manage individual units, projects and the system as a whole to be responsive to rapidly changing conditions (e.g., storms, cold snaps, forced outages). In the month-to-year ahead time horizon, the Energy Study provides an appropriate level of guidance in terms of pricing, given that the large storage reservoirs fill and draft on a seasonal time scale. In other words, short-term impacts can be absorbed by the larger system and there would be little benefit from increasing the frequency of the monthly Energy Study.

In the Oral Hearing, Ms. Matthews elaborated:[191]

> And a lot of those within the month tools that we have are spreadsheet based. So they're doing the same sort of calculations but they're doing it in a more simple way. So they're not optimizing it, it's just okay, we're getting this much more water in, what does that mean for how short we are if our load goes up? So it's more simple calculations.
>
> But one of those spreadsheet tools can -- it essentially takes the energy studies' outputs and can manipulate or change it, I guess you could say. So if the energy studies are showing something with an assumed inflow and now our inflow drops by a bit, it's almost like just adding and subtracting to the base that's there in the energy study without redoing the optimization. So they tend to be these spreadsheet models that then can take that data and change them based on the current imports or forecasts that we have.

BC Hydro provided an example of how the Energy Studies were used as the basis for BC Hydro's forecast short position over the winter of 2019. During that time, estimates were updated weekly to inform import requirements, and the weather impact on load was updated every few days.[192]

Ms. Matthews explained how the Energy Studies model allocates imports and exports after the fact:[193]

> THE CHAIRPERSON: …So regarding the trades that are for trade purposes, the ones not for operational reasons, and so those are the ones that presumably Powerex is initiating. And they are the ones that we discussed a little earlier this afternoon I think. And as you just characterized it, they may be buying low now to sell high later, or they may be arbitraging or for whatever reason they see an economic opportunity…Presumably you logically store that in your reservoir too, especially if they need it to sell back later, that electricity has to be somewhere. Would you agree? Am I right?
>
> MS. MATTHEWS: Right, yeah, so I would agree that -- I talked about the trade account, and the trade account is an accounting construct…But if the trade account is positive, let's say, it has 500 gigawatt in it, then assumingly our system storage… [h]as that 500 more in it, yes.
>
> THE CHAIRPERSON: So, my question then is …[W]hen your model is going through its optimizing, it also has all those, I'll call them speculative Powerex transactions in there are also reflected in the model too because they are reflected in the reservoir levels?
>
> MS. MATTHEWS: Yeah, so when we do the energy studies modelling, we do it -- we model it as consolidated, so it is based on the current conditions, and what we think the most economic

[191] Transcript Volume 10, p. 1753.
[192] Exhibit B-31, Panel IR 2.5.1.
[193] Transcript Volume 10, pp. 1811–1812.

> output is. And then after the fact, this other model does the allocation. So, for example, if let's say the trade account was really high, it would then be -- and let's say the surplus actually wasn't. Like it would probably be putting more of that allocation onto the trade account, because we would be expecting it to be sold out. So, the allocation, like the economic optimization is done just on the system, and then this other model is used afterwards to do the allocation.

Ms. Matthews also stated, "it's actually Powerex who is deciding when we import or export in almost all situations."[194] However, she also said:

> I and my team have full ability to put constraints on what they do, and we set those constraints on what they can and can't do, because ultimately I'm responsible for operating the system. They like to trade and sometimes there can be discussion back and forth on if they are wanting to do something and we're saying no. ….if there's leftover capability, then Powerex can use, but we decide how we use our resources.[195]

When asked if these activities increased risk for BC Hydro ratepayers, Ms. Matthews answered:

> No. And, again, it's -- I guess it's what I had said before in terms of -- I mean, one, we have to meet our load first, that's our obligation and we plan the system to meet our load. And then we use the system to then generate the operational net revenue, which is what's the best way to operate that system to meet our load and create value for ratepayers?[196]

BC Hydro also described certain constraints currently in place. When asked what kind of internal oversight and reporting processes there are leading up to executing a decision to import and export, BC Hydro replied: [197]

> So, there is threshold limits of what I can change when changing a threshold price. So when I say management decisions versus what's coming out of the energy studies, like the energy studies is a model, so it always informs. And then we look at it to see what else has changed, and if there is something changed, should we move it up or down or not? But the sign off authority is that I can change threshold sale prices up to four dollars, and beyond that it goes to the EVP, executive vice president… at the moment it's David Wong is signing off on energy studies.

Ms. Matthews also states that the purposes of BC Hydro and Powerex are different: [198]

> So BC Hydro wants to import or export from the system when we have a surplus, and we also want to import to meet our load, whereas what Powerex does is that they import for the purpose of reselling later to make trade revenue. So the purposes of what the two companies do are quite different. They are trying to trade income, we're trying to maximize the surplus when we have it, and sell it to Powerex to sell into the market, and then we're also buying when we need it to meet our domestic needs, which could be for a number of reasons.

BC Hydro elaborates on this point by stating that the Energy Studies model the economics of the system at a consolidated level and that, once a threshold price is set, imports and exports are allocated to each of Powerex and BC Hydro after the fact.[199]

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[194] Transcript Volume 10, p. 1806.
[195] Transcript Volume 7, pp. 1447–1448.
[196] Transcript Volume 10, p. 1778.
[197] Transcript Volume 10, p. 1791.
[198] Transcript Volume 9, p. 1480.
[199] Transcript Volume 9, p. 1481.

With respect to "within month" tools, the Energy Study Audit referenced an "Ultralight Model," which can be executed within one day to provide updated water values, but is not as sophisticated as the Energy Studies models (which take three weeks to run) and relies on the results of the Energy Studies as a starting point. The Energy Study Audit recommended BC Hydro consider replacing the "Ultralight Model" with a more robust model that is formally coupled with the Energy Studies models. However, BC Hydro has given this a lower priority.[200]

The Energy Study Audit also found that no regular back testing is performed in the current process, and that back-testing could be easier to perform if the process is further automated.[201]

Other findings of the Energy Study Audit included:

- "The Energy Study cycle time could be improved as it currently takes approximately three weeks to complete. Presently, there are many manual components and synchronizing points which slow down the process. Further automation would provide more frequent basin price updates and free up labour resources."[202]
- "Key models are developed using standard development tools and programming languages. Source codes are tracked and retained in a version control system. While most key models can accommodate changes in the system, the Peace model is less flexible as it is based on legacy software codes. Management is working on a replacement solution."[203]
- "The Market Model was last reviewed externally in 2005. The basic methodology behind the model has been more or less unchanged for many years, but model code was rewritten as part of the Comet Improvement Project implemented in 2016."[204]

BC Hydro states it aims to have a plan to review the recommendations on back-testing and benchmarking, as well as a determination of priority items, completed by June 2020. BC Hydro further states that at least five years would be required in order to implement all recommendations.[205]

Matthews testified that "we do take the audit recommendations seriously and want to respond to them but then I also have to balance what the other competing interests are. Like I've said, we've been working on the TPA [Transfer Pricing Agreement] and also against other competing needs because this is just the energy studies, we also have a whole lot of other models so we have to prioritize…". As an example, she stated "currently we do the optimization of the Peace and the Columbia separately and then bring them together. If we can improve the techniques we might actually be able to do that together and as one and then that would save us time, but that's a really long-term goal to do." Ms. Matthews described as academic a report recommendation that "ultimately [it] might lead to" achieving that goal.[206]

Positions of Parties

In BCSEA's view, the Energy Studies involve an assessment of uncertainty and risk around domestic requirements. [207] BCSEA agrees with BC Hydro that the Energy Studies methodology produces a sound price signal that enables BC Hydro to achieve its operating objective to meet load first while maximizing value within a range of outcomes.[208]

[200] Exhibit B-31, Panel IR 2.5.1.
[201] Exhibit B-1, Appendix DD, p. 13.
[202]Exhibit B-1, Appendix DD, p. 11.
[203] Exhibit B-1, Appendix DD, p. 4.
[204] Exhibit B-1, Appendix DD, p. 11.
[205] Transcript Volume 10, pp. 1793–1794.
[206] Transcript Volume 10, pp. 1794–1795.
[207] BCSEA Final Argument, p. 18.
[208] BCSEA Final Argument, p. 19.

BCSEA also submits that BC Hydro's monthly Energy Studies process received a favourable review by SINTEF and BC Hydro's Internal Audit group.[209]

The CEC submits that it is important for BC Hydro to have an established plan with specified timelines for conducting appropriate testing for the monthly Energy Studies, as recommended in the Energy Study Audit.[210] As such, the CEC recommends that the BCUC request BC Hydro to: i) complete and deliver a plan for back-testing and benchmarking, including timeframes and anticipated costs, ii) report on the results of back-testing and benchmarking once such activities have been completed, and iii) do a complete review of the model improvements required and provide a plan for full updating of the models.[211]

BC Hydro responds to the CEC's recommendations that formal back-testing and benchmarking, which are done prior to any model being brought into production, are a time consuming process, and instead it prioritizes understanding changes in key input drivers that have the largest impact on the outcomes, and analyzing for bias.[212]

Panel Determination

We acknowledge the overall findings of the Energy Study Audit that describe BC Hydro's Energy Studies process as being well-established, with appropriate levels of oversight, and that key models are appropriate and are consistent with leading industry practices. However, the auditors expressed concerns in, generally speaking, three areas:

- The age of, potential for lack of support for, and the lack of documentation of some legacy models, gives rise to a need to replace them;
- The lack of back-testing and benchmarking for some models; and
- The models do not serve short-term operational planning needs.

We have a number of concerns related to these findings of the Energy Study Audit. As we pointed out above, the cost of energy is the biggest single component of BC Hydro's revenue requirement. The Energy Studies are the basis for planning and operational decisions that affect the cost of Heritage, Non-Heritage and Market energy. The BCUC must be able to rely on BC Hydro's Energy Studies and other tools that are used to support these planning and operational decisions in order to assess the reasonableness of its cost of energy expenditures.

BC Hydro indicates that a plan to review the recommendations and priorities on back-testing and benchmarking was expected to be completed in June 2020. We appreciate the concerns raised by Ms. Matthews that while there is more modelling work to do, resources currently available are allocated based on priority, but we are concerned about the lack of transparency regarding how these decisions are prioritized. As a result, below the Panel directs a number of compliance filings that are intended to improve transparency. The Panel recommends the BCUC review the compliance filings and consider whether further improvement measures are warranted.

Earlier in this Decision, we comment on BC Hydro's culture of cost cutting. The Panel is concerned that not following some of the audit recommendations is an example of cost-cutting measures that may be "penny wise and pound foolish." While we appreciate this focus on cost savings, the Energy Studies support decisions regarding billions of dollars in expenditures. We are of the view that it is prudent to ensure that the models are functioning properly.

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[209] BCSEA Final Argument, p. 19.
[210] CEC Final Argument, p. 24.
[211] CEC Final Argument, p. 25.
[212] BC Hydro Reply Argument (May 27, 2020), p. 38.

Age and state of some models

The Market Model is described in the Audit Report as "an econometric (regression) model that provides forecasts for future electricity spot prices for the electricity market in the US that BC Hydro can sell to or buy from as function of important drivers".[213]It was last reviewed externally in 2005, but was rewritten in 2016. We are concerned about the lack of another external review of this model over the past 15 years, particularly in light of the 2016 revisions.

The Energy Study Audit reported that "[t]he Energy Study cycle time could be improved as it currently takes approximately three weeks to complete. Presently, there are many manual components and synchronizing points which slow down the process. Further automation would provide more frequent basin price updates and free up labour resources."[214]

In our view, these are potential examples of cost trade-offs that need to be fully understood. Investments made in upgrading the Energy Studies models can provide long term cost savings and potential planning and operational efficiencies owing to faster modelling turn-around times.

While upgrading the Energy Study Models can be time consuming, it is a one-off exercise that should be assessed against the ongoing operational efficiencies gained. In particular, we are concerned that the time it takes to complete medium and long-term modelling runs may contribute to an inflexibility in BC Hydro's ability to do long term planning that is required not only in order to provide internal decision support, but also to prepare Integrated Resource Plans for BCUC review. This becomes even more important when external circumstances rapidly change and evolve due to events such as a pandemic, changing resource mixes driving changing demand patterns throughout the region and potential government policy changes due to electrification, carbon reduction and self-sufficiency.

Further, the Panel is concerned that the amount of time it takes the models to run may hamper any determination of surplus capability in the timeframe it is required. Therefore, the Panel is not persuaded that this element of ratepayer risk is being adequately contained and mitigated.

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

Backtesting and Benchmarking

The Energy Study Audit report states that "[n]o regular back-testing is performed in the current process."[215] BC Hydro argues that it focuses on understanding key model input drivers and analyzing for bias. We agree that understanding key model input drivers is important, as is analyzing for bias. However, neither is a substitute for back-testing and benchmarking. Benchmarking can provide an understanding of how a given model performs against other models and back-testing provides a key understanding of the predictive power of a model. A model that has limited power to predict outcomes that occurred in the past cannot be relied upon to predict outcomes in the future.

[213] Exhibit B-1, Appendix DD, p. 11 of 15.
[214] Exhibit B-1, Appendix DD, p. 11.
[215] Exhibit B-1, Appendix DD, p. 13 of 15.

BC Hydro's argument that formal back-testing and benchmarking are a "time consuming process" is not a good reason not to do them. That said, there may be cost effective steps that BC Hydro could take to reduce the complexity and cost of back-testing. The Energy Study Audit report noted that "[b]ack-testing could be easier to perform if the process is further automated."[216] This would require updating the model portfolio as discussed above.

Therefore, the Panel agrees with the CEC's recommendations for BC Hydro to complete and deliver a plan for back-testing and benchmarking, including timeframes and anticipated costs.

Accordingly, 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.

BC Hydro is further directed to provide a report on the results of back testing and benchmarking once the testing activities have been completed.

<u>Operational Needs</u>

The evidence in this proceeding suggests that the Monthly Energy Studies provide BC Hydro with a point in time value optimized over a 3 to 5 year time period. This serves as a starting point from which BC Hydro make in-month operational decisions. For these operational decision BC Hydro relies on "[o]ther tools such as spreadsheets, database applications and proprietary software …. to manage individual units, projects and the system as a whole to be responsive to rapidly changing conditions (e.g., storms, cold snaps, forced outages)."[217]

The objective of the Energy Study Audit was to "evaluate whether the monthly Energy Studies process reliably supports <u>operations</u>, financial and strategic planning at BC Hydro" [emphasis added].[218] A key finding of the Audit Report is that the Monthly Energy Studies Process does not serve short-term operational planning needs. It goes on to say:

> The Operations Planning group often relies on a less sophisticated model to aid with short term system planning as information provided from the Energy Studies may not represent the current state of the system due to outdated inputs.[219]

It does not appear that the Audit conducted any further investigation of the in-month planning tools used by BC Hydro. Further, there is no evidence before us concerning testing, benchmarking or verification of these tools. Given this lack of evidence it is not possible for the Panel to assess their effectiveness in providing accurate forecasts.

We also note Ms. Matthew's testimony that "in operations we have the system as it is and it's my group's job to operate it and we're just focussed on operating the system to maximize value… the time horizon for which I'm accountable is the operating horizon, which we define as three years, being the current fiscal year and the following two." [220] Further, BC Hydro appears to use the terms "in month planning" and "short term operational requirements" interchangeably. It is not clear to the Panel exactly what time horizon is implied by the term "operational requirements" as used in the Energy Study Audit. **BC Hydro is directed in its compliance filing, to clarify the use of these terms.**

[216] Exhibit B-1, Appendix DD, p. 13.
[217] Exhibit B-5, BCUC IR 1.28.1.
[218] Exhibit B-1, Appendix DD, pp. 2-3 of 15.
[219] Exhibit B-1, Appendix DD, p. 4.
[220] Transcript Volume 9, pp. 1446–1447.

Therefore, as part of its compliance filing, BC Hydro is directed to:

1. **Clarify the use of the terms "in-month planning" and "short term operational requirements", including the time horizon implied by the term "operational requirements";**
2. **Describe how the short-term planning models/tools interface work and how they interface with the Energy Studies models;**
3. **Explain whether the Energy Study models were originally designed to serve short term operational planning needs and whether upgrades recommended in the Energy Study Audit would allow the Energy Studies to do so;**
4. **Explain whether tools used for within-month planning, such as spreadsheets, database applications and propriety software, meet all of BC Hydro's short term operational planning requirements;**
5. **Provide a brief description for each of the within-month planning tools used, which includes:**
   a. **the age of each tool;**
   b. **how frequently each tool is reviewed and updated;**
   c. **whether source code or documentation exists that supports each tool; and**
   d. **the process used to validate/verify/benchmark each tool; and**
6. **Provide the most recent audit report that identifies the scope and results of the review of the within-month planning tools.**

In addition to the concerns raised in the Energy Study Audit, the Panel is concerned about how ratepayer risk is modelled. BC Hydro should have risk management policies to guide the actions of those doing the modelling, for example, when the Energy Studies produce a distribution of outcomes. More transparency on how these issues are considered is needed.

We have concerns with regard to Ms. Matthews' statement that, "it's actually Powerex who is deciding when we import or export in almost all situations," and her assertion that "I and my team have full ability to put constraints on what they do." [221] How such constraints are determined or applied is not clear to the Panel, and the evidence suggests the process is somewhat ad hoc.

As BC Hydro points out, "the purposes of what the two companies do are quite different. They are trying to [earn] trade income, we're trying to maximize the surplus when we have it". As we have previously pointed out, a focus on market activities has the potential to expose the ratepayer to supply risk. Because of this possible risk, appropriate controls should be in place. Other tools and processes are in place for in-month operational decisions and they have not been audited, nor is there sufficient evidence for the Panel to find that they adequately manage ratepayer risk.

While we acknowledge Ms. Matthews' statement that constraints are in place, we remain concerned, especially in light of apparently contradictory statements such as: "we decide how we use our resources" [222] and "it's actually Powerex who is deciding when we import or export in almost all situations."[223] A clearer methodology and approach to its application would increase confidence that prudent risk management is in place. **The Panel directs BC Hydro to explain, in its compliance filing, the existing controls on Powerex's ability to use the system to support import and export activities and whether they are sufficient.**

[221] Transcript Volume 10, p. 1806.
[222] Transcript Volume 10, p. 1806.
[223] Transcript Volume 10, p. 1806.

4.2.3 Heritage Energy

BC Hydro states that Heritage energy costs are the energy costs related to the operation of Heritage assets listed in the *Clean Energy Act* and include the following:[224]

- Water Rental Fees;
- Natural Gas for Thermal Generation;
- Domestic Transmission – Other: this relates to transmission costs within BC associated with obligations under the Skagit River Valley Treaty;
- Columbia River Treaty Related Agreements: this includes costs or recoveries associated with the Non-Treaty Storage Agreement and a short-term coordination agreement related to the Libby Coordination Agreement;
- Remissions and Other: this relates to remissions available to be applied against the cost of water rental fees, as specified by the *Water Sustainability Act; and*
- Exchange Net: this relates to BC Hydro's entitlement obligations under the Canal Plant Agreement and the Keenleyside Entitlement Agreement.

The forecast cost of Heritage energy, as stated in the Evidentiary Update, is estimated at $351.2 million and $317.7 million for each of the fiscal 2020 and fiscal 2021 test years respectively, an increase of $0.3 million in fiscal 2020 and decrease of $33.1 million in fiscal 2021, compared to the Application.[225] Of this amount, the cost of water rental fees paid by BC Hydro totals $652.5 million, or 97.5 percent, of the total cost of Heritage energy over the Test Period.[226]

BC Hydro must pay water rental fees when water is used for generation in accordance with the *Water Sustainability Act.*[227] Water rental fees consist of a variable stepped-rate generation component and a fixed capacity component. Each of these components is based on prior year rates and multiplied by the B.C. Consumer Price Index annual percentage change.[228]

As water rental fees are forecast based on actual generation volumes from the prior calendar year multiplied by the current year water rental rates, the decreased forecast cost of Heritage energy over the Test Period is largely due to lower generation from Heritage assets in each of fiscal 2019 and fiscal 2020 resulting from lower actual inflows in fiscal 2019, and lower forecast inflows in fiscal 2020.[229]

BC Hydro states that while Heritage energy volumes in the Evidentiary Update contribute 67 percent and 76 percent towards the total sources of supply in fiscal 2020 and fiscal 2021 respectively, costs associated with these volumes account for approximately 18 percent of the forecast total gross cost of energy in each test year, respectively.[230]

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[224] Exhibit B-1, pp. 4-4–4-5.
[225] Exhibit B-11-2, Appendix A, Schedule 4.0, line 28; Total cost of Heritage energy = ($351.2M + $317.7M) = $668.9M.
[226] Exhibit B-11-2, Appendix A, Schedule 4.0, line 23; Total of water rentals over the Test Period = ($329.3M + $323.2M) = $652.5M. ($652.5M/$668.9M) = 97.5%.
[227] Exhibit B-6, CEC IR 1.18.1.
[228] Exhibit B-1, pp. 4-21–4-22.
[229] Exhibit B-19, Appendix C, p. 2.
[230] Volumes: Exhibit B-11-2, Appendix A, Schedule 4.0, lines 4 and 12; (39,075 GWh/58,630 GWh) = 67% and (44,467 GWh/58,806 GWh) = 76% in each of fiscal 2020 and fiscal 2021, respectively;
Costs: Exhibit B-11-2, Appendix A, Schedule 4.0, lines 28 and 39; ($351.2M/$1,928.9M) = 18% and ($317.7M/$1,734.6M) = 18% in each of fiscal 2020 and fiscal 2021, respectively.

Panel Discussion

The cost of water rentals comprises approximately 97 percent of the almost $670 million cost of Heritage energy. Water rentals are paid to the provincial government at a prescribed rate and are forecast based on prior year actual volumes. We find the forecast methodology to be sound and, in any event, will be trued up to actuals. However, given our concerns raised in the previous sections concerning the Energy Studies, we cannot determine whether BC Hydro is actually generating the optimal amount of Heritage energy. Therefore, we are concerned whether the actual amount that will be generated is the optimal amount. It may either be higher or lower than it should be.

As BC Hydro points out, "[v]ariances between planned and actual costs of energy [as that term is defined by BC Hydro] are deferred to either the Heritage Deferral Account or the Non-Heritage Deferral Account.[231] While this statement is true, we have concerns about how the actual amount of Heritage energy is determined, as we discuss in the previous section. We will return to this issue in section 4.2.6.

With regard to the remaining 3 percent of Heritage energy expenditures, we have no evidence that it is not a reasonable forecast, and, like the water rentals, it will be trued up to actuals.

4.2.4 Non-Heritage Energy

BC Hydro defines Non-Heritage energy as energy costs not categorized as Heritage energy costs or Market energy costs and includes the following:[232]

- IPPs and Long-Term Commitments: This includes EPAs with IPPs connected to BC Hydro's integrated system.
- Non-Integrated Areas: This includes diesel costs and IPP costs associated with serving non-integrated communities.
- Gas and Other Transportation: This includes costs related to upstream gas transportation contracts entered into by BC Hydro and external electricity transmission charges incurred to serve domestic load in the Fort Nelson, Goodlow (Boundary Lake), Rogers Pass, and Duck Lake areas.
- Water Rentals: Water rental fees related to the 2017 Waneta transaction between BC Hydro and Teck Resources.

In addition, BC Hydro submits that "[t]he Non-Heritage Deferral account also captures the variances between planned and actual domestic customer load, referred to as the Domestic Revenue Variance. The balances in these accounts are amortized into rates in subsequent years in a manner approved by the BCUC." [233]

Approximately 74 percent of the total forecast cost of energy over the Test Period of $3,663.5 million is driven by the cost of IPPs and long-term commitments of $2,705.5 million.[234] Commitments relate to the projects that comprise the Impact Benefit Agreements. Otherwise, IPPs and long-term commitments relate to all EPAs.[235]

For the fiscal 2020 and fiscal 2021 test years, the cost of IPPs and long-term commitments per the Evidentiary Update is estimated at $1,294.7 million and $1,410.8 million, respectively, and amounts to a decrease of $243.8

[231] Exhibit B-1, pp. 4-19–4-20.
[232] Exhibit B-1, pp. 4-5–4-6.
[233] Exhibit B-1, pp. 4-19–4-20.
[234] Exhibit B-11-2, Appendix A, Schedule 4.0, lines 29 and 39; Total of IPPs and Long-Term Commitments = ($1,294.7M + $1,410.8M) = $2,705.5M; Total Cost of Energy = ($1,928.9M + $1,734.6M) = $3,663.5M. ($2,705.5M/$3,663.5M) = 73.9%.
[235] Exhibit B-5, BCUC IR 1.14.2.

million in fiscal 2020 and a decrease of $190.3 million in fiscal 2021, compared to the Application.[236] The following table indicates the current breakdown of IPP purchase volumes by resource type. [237]

Table 4-6: IPP Volumes by Resource Type

Resource Type	F2019 Actual (GWh)	F2020 (GWh)	F2021 (GWh)
Non-Storage Hydro	6,122	6,239	6,696
Biomass	2,400	2,773	2,735
Storage Hydro	2,713	1,260	2,636
Wind	1,574	1,626	1,660
Biogas	94	94	98
Gas Fired Thermal	959	1,543	994
Solar	2	2	3
Other	385	411	417
Total	14,248	13,948	15,238

While total Non-Heritage volumes in the Evidentiary Update are forecast to contribute 24 percent and 26 percent towards the total source of supply over each of the respective fiscal 2020 and fiscal 2021 test years, costs associated with these volumes account for approximately 69 percent and 83 percent of the forecast total gross cost of energy in each of the test years, respectively.[238]

Direction No. 8 provides that the BCUC must not disallow for any reason the costs incurred by BC Hydro with respect to EPAs entered into before April 1, 2016. As a result, the recovery of the increase in IPP costs under most existing EPAs has been mandated by Government.[239]

During the Oral Hearing, for those EPA contracts entered into before April 1, 2016 BC Hydro confirmed the average cost of "Exempt" versus "Non-Exempt" EPA contracts, [240] as reflected in the table below:

Table 4-7: EPAs entered into before April 1, 2016[241]

	Exempt	Non-Exempt
2020		
Cost ($mil)	776	413
Volume (GWh)	8,312	4,837
Ave Price ($/MWh)	**$ 93.36**	**$ 85.38**
2021		
Cost ($mil)	807	467
Volume (GWh)	7,839	5,908
Ave Price ($/MWh)	**$102.95**	**$79.05**

BC Hydro states that energy costs from IPPs are managed, among other ways, by reducing the volume of IPP energy where there are cost savings to BC Hydro and pursuing the renewal of some existing IPP contracts to

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236 Exhibit B-11-2, Appendix A, Schedule 4.0, lines 29 and 39.
237 Exhibit B-20, BCUC IR 3.3.3.
238 Exhibit B-11-2, Appendix A, Schedule 4.0, lines 7 and 12; Volumes: (14,067 GWh/58,630 GWh) = 24% and (15,358 GWh/58,806 GWh) = 26% in each of fiscal 2020 and fiscal 2021, respectively; Exhibit B-11-2, Appendix A, Schedule 4.0, lines 33 and 39; Costs: ($1,332.4M/$1,928.9M) = 69% and ($1,447.2M/$1,734.6M) = 83% in each of fiscal 2020 and fiscal 2021, respectively.
239 BC Hydro Final Argument, p. 38.
240 Transcript Volume 9, p. 1389.
241 Exhibit C1-7. "Exempt" refers to EPAs where the BCUC did not perform a review, while "Non-Exempt" refers to EPAs reviewed by the BCUC pursuant to s71 of the UCA.

meet future long-term energy needs.[242] Current initiatives taken by BC Hydro and the Government of BC to manage the volume and cost of energy purchased from IPPs are described below.

Government of BC Phase One Review

The Phase One Review introduced the Biomass Energy Program as a transitionary measure to allow time for the forestry sector to become more competitive while also providing optionality should BC Hydro require additional supply resources in the future. Under the Biomass Energy Program, BC Hydro will potentially renew up to 80 percent of the historical aggregate energy deliveries from biomass IPPs whose EPAs are expiring in the next three years. The Biomass Energy Program requires costs associated with the program to be recovered from ratepayers,[243] albeit the renewal price, while lower than the existing per unit cost, will exceed market prices.[244]

In February 2019, the Government of BC issued a regulation allowing BC Hydro to indefinitely suspend the Standing Offer Program. Apart from five First Nations' clean energy projects that are part of the Impact Benefit Agreements between First Nations and BC Hydro and/or mature projects that have significant First Nations involvement, BC Hydro will not be executing any other Standing Offer Program EPAs.[245]

EPA Renewals

BC Hydro's approach to EPA renewals is to renew contracts at lower prices than their original contracts.[246] Since fiscal 2016, the BCUC accepted six EPAs (five run-of-river hydro EPAs and one storage hydro EPA).[247] More recently, the BCUC accepted two of these six EPA renewals by Order G-39-20 dated March 4, 2020.[248]

During the Test Period, eight EPAs are due to expire, including six that qualify under the Biomass Energy Program, and two run-of-river EPAs for facilities that represent a total of less than 4MW in capacity. Evaluation of the run-of-river EPAs will be based on a recently adopted approach – the "interim market" approach – of using the market price as a conservative interim assumption for evaluating the cost-effectiveness of EPAs on the integrated system.[249] This approach is consistent with the Decision to Order G-278-19, where the BCUC found the interim market approach to be the more appropriate method to value EPA renewals than BC Hydro's opportunity cost, as the interim market approach provides a more recent comparison of opportunity costs relative to the long-run marginal cost (LRMC).[250] BC Hydro states it will continue to use the interim market approach until it updates its LRMCs in the next IRP.[251]

Management of Existing EPAs

BC Hydro states that while the majority of EPAs are considered to be take-or-pay contracts,[252] it does not have unilateral rights to terminate existing EPAs (i.e. terminate without cause), but instead monitors EPA agreements

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[242] Exhibit B-1, p. 4-7
[243] Exhibit B-1, pp. 4-11–4-12; Section 4 of OIC 158, dated April 1, 2019; https://www.bclaws.ca/civix/document/id/oic/oic_cur/0158_2019
[244] BCOAPO Final Argument, p. 22
[245] Exhibit B-1, p. 4-9
[246] Exhibit B-1, p. 4-10
[247] Exhibit B-1, p. 4-11
[248] Order G-39-20
[249] Exhibit B-5, BCUC IR 1.15.2.1.
[250] Order G-278-19 with Reasons for Decision, Appendix A, p. 14.
[251] BC Hydro Electricity Purchase Agreement Renewals for Sechelt Creek Hydro, Brown Lake Hydro and Walden North Hydro Proceeding; Exhibit B-12, BCUC IR 2.2.2.
[252] Exhibit B-6, Ince IR 1.7.2.

to consider exercising termination rights when such rights arise. Further, BC Hydro states that rights within certain existing agreements can be exercised in order to reduce cost of energy.[253]

Positions of Parties

In BCSEA's view, BC Hydro is managing energy costs from IPPs to the extent possible within the parameters of its contractual obligations under EPAs.[254]

The CEC agrees with BC Hydro's practices to manage IPP costs.[255] However, the CEC also views that the overall increase in cost of energy between fiscal 2018 and fiscal 2020 is driven by forecast increases in IPP energy costs. The CEC submits that such costs should be managed with caution and considers that it may be worthwhile for BC Hydro to annually report on its cost of energy in order to better understand the source of the consistent over-estimation.[256]

The CEC also points out that BC Hydro does not examine all the EPAs as a group when considering renewals, but instead conducts negotiations as the EPAs expire. Recognizing that the EPAs expire at different times, the CEC submits that it could be worthwhile for BC Hydro to examine all the EPA options and preferentially select only those for negotiation or renegotiation that appear to offer the most cost-effective option relative to the others.[257]

BCOAPO views that while the lower IPP costs in the Evidentiary Update provide some relief in terms of the fiscal 2020 and fiscal 2021 revenue requirements, this relief is to some extent only temporary and IPPs costs will be higher in the future when weather and water flows return to more normal conditions.[258] In BCOAPO's view, BC Hydro should provide a full accounting of its efforts to proactively manage IPP costs and should specifically address those circumstances where BC Hydro explicitly choses to refrain from exercising its right to terminate an EPA.[259]

BC Hydro responds to recommendations from BCOAPO and the CEC that appropriate oversight of IPP costs and cost of energy is already occurring and that the revenue requirements applications provide a regular opportunity to review BC Hydro's cost of energy. BC Hydro also submits that strategies for EPA renewals and its EPA renewal approach beyond the Test Period will be revisited as part of the process for the next IRP.[260]

MoveUP views that "BC Hydro will continue to hold a significant glut of energy well beyond the test period, pursuant to the host of take-or-pay energy purchase agreements under IPPs."[261] As a method of managing the cost of IPPs, MoveUP submits that the BCUC should direct BC Hydro to examine the *force majeure* provisions in its EPAs and provide a report regarding the potential to mitigate energy costs and energy surplus in the context of the COVID-19 pandemic.[262]

BC Hydro submits that the BCUC should refrain from directing BC Hydro to examine *force majeure* provisions in its EPAs. BC Hydro views that the assessment of its legal rights under these agreements is both legally privileged and commercially sensitive. The actions BC Hydro has taken with regards to managing IPP contracts generally

[253] Exhibit B-5, BCUC IR 1.18.1.
[254] BCSEA Final Argument, p. 16.
[255] CEC Final Argument, pp. 27–28.
[256] CEC Final Argument, p. 23.
[257] CEC Final Argument, p. 29.
[258] BCOAPO Final Argument, p. 20.
[259] BCOAPO Final Argument, pp. 22 to 23.
[260] BC Hydro Reply Argument (May 27, 2020), pp. 34 to 35.
[261] MoveUP Final Argument, p. 3.
[262] MoveUP Final Argument, p. 8.

are best addressed in the context of future revenue requirements proceedings (as they were in the current proceeding), and in a manner that respects considerations of privilege and commercial sensitivity.[263]

Panel Determination

Interveners expressed concerns about how BC Hydro manages IPP costs, including the EPA renewal process, particularly due to the significant volume of take-or-pay energy that BC Hydro holds during and following the Test Period. While the Panel recognizes that IPP costs are the major driver of the forecast cost of energy, the Panel is limited by legislation, which requires the majority of these costs to be recovered from ratepayers:

- Cost recovery of EPAs entered into prior to April 1, 2016, is legislated as per Direction No. 8; and
- Six of eight EPAs set to expire during the Test Period qualify under the Biomass Energy Program, for which cost recovery from ratepayers is also required under Order in Council (OIC) 158/2019.[264]

According to BC Hydro's testimony, it does not have unilateral rights to change the take or pay IPP contracts. However, MoveUP suggests that BC Hydro "examine the force majeure provisions in its EPAs and provide a report regarding the potential to mitigate energy costs and energy surplus in the context of the COVID-19 pandemic." We agree with the recommendation of MoveUP that this would be a prudent step to take**.** We therefore recommend BC Hydro examines all provisions in its EPA contracts if it appears there is significant decreased demand due to the COVID-19 pandemic.

BC Hydro seeks to lower the cost of its expiring IPP contracts by renewing them at reduced prices, substituting the market price of energy for the originally agreed price. We recommend the BCUC review BC Hydro's EPA renewal approach beyond the Test Period in the next IRP.

Another approach that could be used to manage IPP contracts is not to renew take or pay contracts when energy is not needed. However, in some cases, BC Hydro may have already negotiated away its ability to do so through forbearance agreements. This issue arose in a recent proceeding for a renewal of the "Walden North EPA". The original Walden North EPA had a 20-year term, along with an evergreen provision allowing the contract to continue on a year-to-year basis unless terminated by either party by providing six-months' notice. However, BC Hydro subsequently agreed to a forbearance agreement which amended the Walden North EPA (Forbearance Agreement). In the reasons for decision stemming from the proceeding in which the BCUC considered the Walden North EPA, the BCUC stated: "As it acknowledges, BC Hydro would be in breach of the Forbearance Agreement if it attempted to exercise its original termination rights under the Original EPA during the period covered by the Forbearance Agreement."[265]

The BCUC directed BC Hydro to file the Forbearance Agreement as an amendment to an energy supply contract under Section 71 of the UCA. If, as a result of the review of that application, the BCUC finds the Forbearance Agreement is not in the public interest, the costs of the Walden North EPA may change. In this circumstance, the actual costs incurred in the Test Period could be affected.

The BCUC also ordered BC Hydro to file with the BCUC all existing, but unfiled agreements entered into from October 1, 2001, that are associated with and materially affect existing EPAs, by July 10, 2020.[266] The Panel is concerned that some of these forbearance agreements that BC Hydro may be directed to file may, like the Walden North EPA Forbearance Agreement, have the potential to affect the actual cost of Non-Heritage energy in the Test Period. **Therefore, in its Compliance Filing, BC Hydro is directed to report on any EPA renewing during the Test Period that has an associated forbearance agreement.**

[263] BC Hydro Reply Argument (May 27, 2020), p. 35.
[264] Section 4 of OIC 158, dated April 1, 2019; https://www.bclaws.ca/civix/document/id/oic/oic_cur/0158_2019.
[265] Order G-148-20, Appendix A, p. 6.
[266] Order G-148-20.

With regard to the Non-Heritage Deferral Account capturing the variances between planned and actual domestic customer load, referred to as the Domestic Revenue Variance, the Panel has concerns. Combining variances of energy cost with variances of income due to load results is an unacceptable lack of transparency. **Therefore the Panel directs the establishment of a load forecast variance account and directs BC Hydro to move all balances related to load forecast variance from the Non Heritage Deferral Account to the load forecast variance account. BC Hydro is directed to use the load forecast variance account to capture the variances between planned and actual domestic customer load. The Panel directs that the load forecast variance account be categorized as one of BC Hydro's cost of energy variance accounts and that BC Hydro apply the same mechanisms for interest charges and recovery that are applicable to the Non-Heritage Deferral Account.**

4.2.5 Market Energy

Market energy is defined by BC Hydro as costs related to electricity purchased from or sold to Powerex through transfer pricing arrangements between Powerex and BC Hydro.

The forecast cost of Market energy per the Evidentiary Update is estimated at $245.3 million for fiscal 2020, an increase of $285.5 million compared to the Application, which forecast a negative cost of $40.2 million. For fiscal 2021, BC Hydro forecasts a negative cost from Market energy of $30.3 million, a decrease of $41.4 million compared to the Application, which forecast revenues of $71.7 million.[267]

BC Hydro attributes the continuation of dry weather conditions from the winter of fiscal 2019 to fiscal 2020 as driving the need for increased market electricity purchases and decreased surplus sales and domestic transmission costs over the Test Period. BC Hydro states:[268]

> One of the drivers of the change in BC Hydro's Cost of Energy forecast is the continuing dry conditions from fiscal 2019 through to fiscal 2020, with low reservoir levels recorded at the end of fiscal 2019 and a reduction in the water supply forecast for fiscal 2020. These dry conditions impact hydro facilities owned by Independent Power Producers (IPPs), as well as facilities owned by BC Hydro. This results in higher cost of Market Energy, with market electricity purchases forecast to increase and surplus sales forecast to decrease. The forecast increase in cost of Market Energy is mitigated by a decrease in costs for IPPs and Long-Term commitments and Water Rentals.

BC Hydro describes Market Electricity purchases as "the amount of electricity purchases allocated to BC Hydro to serve domestic load in a given year, and vary depending on reservoir inflows, market prices, and customer demand." It goes on to say that "[t]hese purchases are performed exclusively with Powerex, and the energy is provided to BC Hydro in accordance with the applicable transfer price."[269]

BC Hydro expects the following transfer prices in the Test Period:[270]

Table 4-8: Expected Transfer Prices

Period	Expected Transfer Price Associated with Market Electricity Purchases (C$/MWh)	Expected Transfer Price Associated with Surplus Sales (C$/MWh)
Fiscal 2020	41.5	32.9

[267] Exhibit B-19, Appendix C, p. 3.
[268] Exhibit B-19, p. 2.
[269] Exhibit B-1, p. 4-36.
[270] Exhibit B-11-2, Appendix A, Schedule 4.0, lines 20 and 21.

Fiscal 2021	5.0	47.0

The costs or revenues associated with these transactions are allocated to the following categories:[271]

Table 4-9: Transaction Categories

Transactions for Domestic Purposes	Transactions for trade related activities
Market Electricity Purchases: These represent market purchases of energy from Powerex by BC Hydro to meet domestic load requirements. Surplus Sales: These represent sales of electricity from BC Hydro to Powerex in excess of domestic load requirements. Domestic Transmission – Export: These represent transmission costs within BC related to exports categorized as Surplus Sales.	Net Purchases (Sales) from Powerex: These represent transactions where Powerex purchases from and sells to BC Hydro for the purpose of trade related activities, provided that the BC Hydro system has the ability to accommodate these transactions. These are not purchases (sales) for domestic purposes.

On April 1, 2020, the 2003 TPA was replaced with a new TPA (2020 TPA).[272] Under the 2020 TPA, import and export transactions between BC Hydro and Powerex are no longer allocated between trade and domestic purposes, and all electricity and gas purchased from or sold to Powerex is classified in the following categories:

- System Exports – represent sales of electricity (flexible exports and non-flexible exports) to Powerex by BC Hydro.
- System Imports – represent purchases of electricity and thermal generation (flexible imports and non-flexible imports) from Powerex by BC Hydro.[273]

Prior to April 1, 2020, the 2003 TPA was in effect and import and export transactions allocated to Powerex are tracked separately as Ms. Matthews described:

> There is something called a trade account, so the trade account both has a gigawatt hours assigned to it -- and a dollar value as imports come in and out. So if it's a trade import, the trade account will be going up. And if it's an export, it is coming out of that…It is a physical account, yes, but it is an account, it's not a physical storage in our system. But it does all match our system.[274]

BC Hydro states that a threshold purchase price is set to allocate imports to BC Hydro's system between BC Hydro and Powerex, with a similar threshold sales price set to allocate exports from BC Hydro's system between

[271] Exhibit B-1, pp. 4-6–4-7.
[272] Transcript Volume 10, p. 1750.
[273] 2020 TPA Application, Appendix F, p. 2.
[274] Transcript Volume 10, p. 1767.

BC Hydro and Powerex. In explaining these mechanics, BC Hydro states its role in setting threshold prices is to either sell surplus energy or buy market energy when needed to meet domestic requirements and distinguishes this from the role of Powerex which is to use imports and exports to arbitrage price differences in the market.[275]

The 2003 TPA defines "Threshold Purchase Price" as "…the maximum Electricity Purchase Price at which BC Hydro will purchase electricity from Powerex in any period to service Domestic Load, as established by BC Hydro from time to time…". It also defines "Threshold Sale Price" as "…the minimum Electricity Transfer Price at which BC Hydro will sell Surplus Hydro Electricity to Powerex, as established by BC Hydro from time to time…".[276]

The Trade Account is defined in the 2003 TPA as "…the account to which electricity sold or deemed to be sold by Powerex to BC Hydro [for trade activity] is credited and to which electricity sold or deemed to be sold by BC Hydro to Powerex [for trade activity] is debited…".[277]

This difference between a trade made by Powerex on behalf of BC Hydro for operational needs and a trade initiated by Powerex (i.e., for trade related activities) that involves BC Hydro electricity was explored in the Oral Hearing when Commissioner Mason asked Ms. Matthews: [278]

> the transactions that you do on BC Hydro's own behalf, if they eventually, through whatever reason, make less money than you'd anticipated, the ratepayers do pay for that difference …. [w]hereas if Powerex had executed exactly those same trades on its behalf, and that had cause a loss, that ultimately isn't the risk to BC Hydro ratepayers, because at least at a total annual level there's a floor at which the losses don't get passed onto ratepayers, yes?

Ms. Matthews responded that:

> all of their transactions that aren't related to our system might affect their trade income. And it's that whole trade income part, if it goes negative that goes to the shareholder not the ratepayer.[279]

With respect to exports:[280]

> So let's just say that …the Mid-C price is $50 and our threshold [price] is $40, so that's above ours. That means that any exports from the system in that hour will be allocated to domestic [Surplus Sales]. Now, let's say that the Mid-C price was $37 and there was still exports from the system, those would be allocated to trade to Powerex [Net Purchases (Sales) from Powerex]. And so BC Hydro sets the threshold sale price to be able to sell to Powerex our surplus energy because it's surplus to our load need so we have to get rid of it from the system. And likewise we set a threshold purchase price to bring energy into the system when we have deficits, and that's the signal that we use in terms of the -- it becomes an after-the-fact allocation based on what the Mid-C price was and what our threshold sale price was.

With respect to imports:[281]

> Now, to the example I just gave, it's very similar but the opposite view on if we're importing. So if we have an import threshold price of, let's say, $20 and the market price is $15 and there's imports into the system that hour, they would be allocated to domestic [Market Purchases]. Whereas if they [imports]

[275] Transcript Volume 10, pp. 1762–1765.
[276] Exhibit B-13, AMPC IR 2.46.3, Attachment 1, pp. 6, 7.
[277] Exhibit B-13, AMPC IR 2.46.3, Attachment 1, p. 7.
[278] Transcript Volume 10, p. 1808.
[279] Transcript Volume 10, p. 1809.
[280] Transcript Volume 10, pp. 1763–1764.
[281] Transcript Volume 10. p. 1764.

> were at $21, then that's above our threshold purchase price so they wouldn't be allocated to domestic, they'd be allocated to Powerex [Net Purchases (Sales) from Powerex].

BC Hydro submits that a strategy to limit the use of imports or exports to/from the BC Hydro system in the operational timeframe would inhibit the economic operation of the BC Hydro system and result in higher rates for BC Hydro's ratepayers. In BC Hydro's view, it is unclear how shifting from an import/export focus to a domestic sales focus could be achieved, considering that the Energy Studies are not used to set targets to meet domestic load, but rather are used to determine how to meet domestic load.[282]

Panel Discussion

We consider the following issues regarding Market energy:

1. Whether it is appropriate to include transactions for both domestic purposes and for trade income purposes in BC Hydro's revenue requirement.
2. Whether the costs and transaction volumes of Market energy included in the cost of energy forecast are appropriate.

<u>Inclusion of all "Market" Transactions in the Cost of Energy</u>

Should the costs and proceeds from market transactions – including those characterized by BC Hydro as being for "trade" purposes accrue to the ratepayer, or should some other principle apply – such as, for example, should ratepayers be entitled to only recover their costs and any " profits" or "losses" with respect to those costs accrue to the shareholder? We examine a simplified example of market transactions of sales of electricity surplus to an electric utility's requirements.

Given the variability of demand and the lumpiness of capital investments in generation assets, it is not uncommon for electric utilities to find themselves long on electricity supply in the short or even medium term. Consider the case of a utility building a dam and power station that is intended to not be fully utilized for 20 years, even though the costs associated with the infrastructure are recovered from ratepayers in that 20 year period. There may be significant surplus electricity available for sale until demand catches up with the new supply. Often, that electricity can be sold at a surplus to its fully embedded cost which is paid by the utility's ratepayers.

In determining how these sales of electricity should be treated, we consider the reverse situation when the utility is short supply, for whatever reason, and electricity is purchased. In cases of short supply, it is not expected that the shareholder would, absent a finding of imprudence, pay anything toward the acquisition of electricity to meet ratepayer demand. The same logic applies in reverse; if the utility has surplus energy, it is not expected that the ratepayer would be expected to share any earnings from the surplus with anyone else. We therefore find that unless the shareholder paid for a generation asset, it is not entitled to the proceeds from sales of any electricity generated by that asset.

This is consistent with the approvals granted to BC Hydro in the 2017 Waneta Transaction decision.[283] There, the BCUC approved the inclusion in BC Hydro's revenue requirement of the income flowing from unregulated revenues associated with the Waneta dam, which is a rate base asset. In particular, the BCUC stated: "One may question why BC Hydro's ratepayers should bear the risks of a transaction that does not serve ratepayer needs or interests. However, that question fails to take into account certain benefits to the ratepayer, the most obvious one being the guaranteed Lease payments."[284]

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[282] BC Hydro Reply Argument (May 27, 2020), pp. 35–37.
[283] Waneta 2017 Transaction and Application - Decision and Order G-130-18, dated July 18, 2018, p. 95.
[284] Ibid, p. 92.

For these reasons, we find it appropriate that all proceeds from sales of BC Hydro electricity are on the account of the ratepayer.

Are the Forecast Market Energy Costs and Amounts Reasonable?

Both the forecast and the operational decisions that determine the actual market energy amounts – and therefore costs – are based on BC Hydro's Energy Studies and we have raised issues concerning the currency and the adequacy of those models.

Further, the evidence suggests that the Transfer Price is generally based on the Mid C price. While this may be a "fair" price, some of these transactions can come with a degree of risk for ratepayers that arise from increased exposure to the market. Therefore, simply ensuring "fair" compensation may not mitigate or properly price this risk.

Until BC Hydro is able to confirm that these models are fully tested, we are unable to determine that the forecast amount of Market Energy is reasonable.

Further, the net Market energy costs only include that portion of the transaction proceeds and costs that are crystallized upon delivery to or from Powerex. The balance, if any, of the full market value of the transactions remains in Powerex's net income. This is because transfers between BC Hydro and Powerex takes place at the agreed upon transfer price, which may differ from what Powerex actually realizes on any sale or purchase. Therefore, a portion of the full economic value of these transactions is captured in BC Hydro's unconsolidated net income and a portion in Powerex net income. This makes it more difficult to determine whether these forecast net costs, which represent only a portion of the full net costs, are reasonable.

We note that in fiscal 2020, the forecast cost of Market Energy is $245 million, almost $300 million greater than originally forecast in the Application (where a negative cost of $40.2 million was forecast). While we acknowledge BC Hydro's explanation – dry weather conditions from the winter of fiscal 2019 to fiscal 2020, we have no evidence to confirm that a forecast surplus in FY 2021 continues to be reasonable.

4.2.6 Overall Determination on the Inclusion of the Cost of Energy in Rates

BC Hydro's Evidentiary Update replaced the October 2018 Energy Study forecast in the Application with the June 2019 Energy Study forecast, which includes actual costs for April and May 2019.[285] As a result of the Evidentiary Update, the forecast cost of energy is estimated to increase $41.9 million in fiscal 2020 from $1,887.0 million to $1,928.9 million, and decrease by $185.6 million in fiscal 2021 from $1,920.2 million to $1,734.6 million, with the net decrease in the total forecast cost of energy of $143.7 million over the Test Period. The net decrease in forecast cost of energy over the Test Period is primarily attributable to drier than normal conditions and lower water inflows, which decrease the volume of hydroelectricity generated from Heritage assets, purchases from IPPs and long-term commitments, and surplus sales, offset by an increase in market electricity purchases.[286]

BC Hydro's forecast cost of energy comprises approximately 35 percent of the total revenue requirements over the Test Period.[287] Table C-1 from the Evidentiary Update, reproduced below, summarizes the components of the cost of energy over the Test Period, respectively:[288]

[285] Exhibit B-19, p. 2.
[286] Exhibit B-19, pp. 7–8.
[287] Per Evidentiary Update: fiscal 2020 cost of energy of $1,928.9M + fiscal 2021 cost of energy of $1,734.6M period = $3,663.5M; fiscal 2020 RRA of $5,223.9M + fiscal 2021 RRA of $5,198.4M = $10,422.3M; cost of energy as percent of total RRA over the Test Period = $3,663.5M / $10,422.3M ≈ 35%.
[288] Exhibit B-19, Appendix C, Table C-1, p. 1.

Table 4-10: Cost of Energy Components

Cost of Energy ($millions)	Schedule Reference	F2020 Plan	F2020 EU	Diff	F2021 Plan	F2021 EU	Diff
		1	2	3=2-1	4	5	6=5-4
Heritage Energy	4.0L28	350.9	351.2	0.3	350.8	317.7	(33.1)
Non-Heritage Energy	4.0L33	1,576.3	1,332.4	(243.9)	1,641.1	1,447.2	(193.9)
Market Energy	4.0L38	(40.2)	245.3	285.5	(71.7)	(30.3)	41.4
Total	4.0L39	1,887.0	1,928.9	41.9	1,920.2	1,734.6	(185.6)

Approximately 97.7 percent of the total forecast cost of energy of $3,663.5 million over the Test Period is driven by the cost of IPPs and long-term commitments ($2,705.5 million), the cost of water rental fees ($652.5 million) and market activity ($215.1 million). The remaining $90.4 million relates to various other items, including the cost of natural gas for thermal generation, diesel fuel to supply Non-Integrated Areas, and Gas & Other Transportation Costs. [289]

BC Hydro submits that the forecast cost of energy, as updated in the Evidentiary Update, is based on a sound methodology and appropriate assumptions.[290] BC Hydro also states that the forecast cost of energy is influenced by many factors, including the available Heritage resources, reservoir levels, pricing and delivered volumes under existing IPP contracts, market prices, and load.[291] However, customers ultimately only pay the actual cost of energy through the use of regulatory accounts.[292]

The 2020 TPA Application also clarifies the treatment of certain items for the purposes of the RRA in fiscal 2020:

> RRA Plan amounts for Fiscal 2021 included in the Fiscal 2020 to Fiscal 2021 Revenue Requirements Application were prepared under the 2003 TPA. As a result, for Fiscal 2021, the first fiscal year transacted under the 2020 TPA, the RRA Plan amounts for System Exports and System Imports are zero. This means that the entire difference between zero and the Fiscal 2021 actual amounts for System Exports and System Imports will be deferred to the Non-Heritage Deferral Account. Similarly, for Fiscal 2021, as BC Hydro is no longer transacting under the 2003 TPA, the actual Surplus Sales and Market Electricity Purchases amounts will be zero and the entire difference between the RRA Plan amounts of Surplus Sales and Market Electricity Purchases and zero in Fiscal 2021 will be deferred to the Heritage Deferral Account. In combination with deferring variances between plan and actual Trade Income to the Trade Income Deferral Account, this approach ensures that ratepayers receive the benefit of all transactions related to System Imports and System Exports, including those maximizing the value of the Residual System Capability, as was the case under the 2003 TPA.[293]
>
> Deferral of variances to the Heritage Deferral Account, Non-Heritage Deferral Account, and Trade Income Deferral account will occur under the 2020 TPA under existing orders, which accept that deferral of these non-controllable variances is appropriate, so that ratepayers pay for, and receive, only the actual amounts, of the associated costs and revenues. The names used to describe and classify the transactions have been revised to reflect the 2020 TPA; however, the nature of the transactions has not changed.[294]

The treatment of domestic transmission also changes under the new TPA. The 2020 TPA Application states: [295]

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[289] Exhibit B-11-2, Appendix A, Schedule 4.0; cost of IPPs and long-term commitments (Line 29) = $1,294.7M + $1,1410.8M = $2,705.5M; cost of water rental fees (Line 23) = $329.3M + $323.2M = $652.5M.
[290] BC Hydro Final Argument, p. 57.
[291] BC Hydro Final Argument, p. 35.
[292] Exhibit B-1, p. 4-1.
[293] 2020 TPA Application, Appendix F, p. 4.
[294] 2020 TPA Application, Appendix F, p. 4.
[295] 2020 TPA Application, Appendix B, p. 24 of 59.

> As with the 2003 TPA, BC Hydro acquires and pays for all necessary wholesale transmission services on the Transmission System for electricity transactions under the 2020 TPA. Powerex pays BC Hydro for a reasonable allocation of the point-to-point transmission costs incurred by BC Hydro in respect of Powerex's trading activities, as determined by BC Hydro and Powerex.
>
> The allocation serves to incent economically efficient decision-making by Powerex and BC Hydro but its precise calculation has no effect on BC Hydro's revenue requirements.

In the Oral Hearing, BC Hydro testified that the new TPA "doesn't change what BC Hydro does, and it doesn't change what Powerex does. It will change how the financials all look later on, and it changes how we are doing the allocation between two companies. So, it is a change, but fundamentally what we do doesn't change."[296]

Positions of Parties

No intervener submits that either the forecast cost of Heritage or Market energy is unreasonable. Instead submissions are concerned more with how BC Hydro manages IPP costs, as well as how BC Hydro operates its system to maximize consolidated net revenue.

BCSEA supports BC Hydro's request that forecast cost of energy for the Test Period is reasonable, being based on a sound methodology and appropriate assumptions.[297]

Overall, BCOAPO has no issues with either the proposed cost of Heritage energy or the cost of Market energy and does not expect any cost savings during the Test Period from EPA renewals.[298]

Panel Determination

While we find no evidence that the forecast cost of energy is unreasonable, we are not able to say that BC Hydro has minimized these costs.

As BC Hydro points out in its Application, "BC Hydro's revenue requirements are based on a forecast Cost of Energy but customers only pay the actual costs."[299] That is factually correct. However, in order to be satisfied that inaccuracies in the forecast amount are properly reconciled to actuals, we must be persuaded that the actual energy costs are reasonable. We have concerns with both the forecast and the actual cost of energy.

As we have discussed, BC Hydro manages its system with the objective of maximizing consolidated net income while meeting ratepayer load. Forecasts are generated in each of the three categories by BC Hydro's Energy Studies to meet this system optimization objective. These forecasts may differ from the actual energy used in each category. However, the Energy Studies model are also used as a basis for "[i]n month" operational decisions concerning energy generation and acquisition. The evidence also shows the same models are used for operational decisions over the entire operational horizon of up to three years.

In Section 4.2.1, we identified a number of issues concerning the use of models that are not fully tested. In addition, day-to-day operational decisions appear to be made at least somewhat heuristically and accordingly it is difficult to determine whether such decisions result in an integrated system, the operation of which is optimized for ratepayers. These issues affect both the forecast and actual amounts flowing into the cost of energy account.

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[296] Transcript Volume 10, pp. 1750–1751.
[297] BCSEA Final Argument, p. 21.
[298] BCOAPO Final Argument, pp. 19, 22, 24.
[299] Exhibit B-1, p. 4-19.

It would be easier to accept a less rigorous forecast amount if it was trued up with actuals in which we have confidence. However, in this case, we are not persuaded that the actuals represent an optimal mix of energy from the three sources (Heritage, Non-Heritage and Market).

However, in the absence of any better evidence concerning the cost of energy and in the interests of regulatory efficiency, we approve the forecast provided. When BC Hydro has fully tested its suite of models and tools and complied with other directives in this section, going forward the BCUC will be better able to determine the reasonableness of both forecast and actual amounts applied to the cost of energy accounts.

BC Hydro is directed, in its Compliance Filing to clarify its proposed changes to the fiscal 2021 allocations to its deferral accounts as described in the 2020 TPA regarding the following:

- **the difference between the actual System Exports and System Imports and zero;**
- **the difference between the actual Surplus Sales and Market Electricity Purchases amounts and zero; and**
- **the treatment of domestic transmission costs.**

Panel Discussion on the meaning of Cost of Energy

BC Hydro's "cost of energy" is not the actual cost incurred by ratepayers to generate or otherwise obtain electricity needed to meet domestic load. It does not include, for example, the cost of O&M, amortization or shareholder return on any BC Hydro owned generation assets. In particular, with regards to Heritage energy, it could be viewed as including only variable costs, and does not represent the fully allocated cost to produce that energy. In addition, Market energy by BC Hydro's definition includes, among other things, the proceeds from surplus sales. As a result, BC Hydro's cost of energy may not be a useful benchmark when comparing to the cost of energy in other jurisdictions.

For example, BC Hydro asserts that while only 18 percent of the cost of energy is Heritage energy, it supplies approximately 70 percent of BC Hydro's total supply in the Test Period. We caution about drawing any comparative conclusions from this. As we point out above, the component of Heritage energy costs in the cost of energy does not reflect the fully embedded cost to supply that energy. The full cost consists not only of water rental fees, but also includes such costs as dam and powerhouse O&M, amortization and return to shareholder. These costs are included in other portions of the revenue requirement.

In addition, the cost of energy purchased from IPPs is "all in" and includes IPPs' allowance for O&M, depreciation and return. Accordingly, this is not an "apples to apples" comparison to the cost of Heritage energy, as reported in the cost of energy, which includes water rental costs and does not include the cost of O&M or depreciation. In addition, some IPPs are classified as leases under IFRS 16 and categorized as depreciation and finance charges, rather than cost of energy.

However, the significance of BC Hydro's cost of energy presentation is that it represents costs that are subject to variance account treatment. The variance treatment of these costs ensures that ratepayers bear all cost of energy risk. Other components of the fully allocated cost of energy – such as O&M for heritage assets – do not qualify for variance account treatment as they are considered controllable by management.

4.2.7 Powerex Net Income and the Trade Income Deferral Account

Direction No. 7 directed that "[i]n setting rates for the authority, the commission must include the net income of the authority's subsidiaries, assuming that the net income of Powerex Corp. equals trade income." Direction No. 7 defined Trade Income as the greater of zero and "the amount that is equal to the authority's consolidated net income, less the authority's net income, less the net income of the authority's subsidiaries except Powerex

Corp., less the amount that the authority's consolidated net income changes due to foreign currency translation gains and losses on intercompany balances between the authority and Powerex Corp."[300]

Direction No. 7 also directed that the BCUC "must allow the authority to continue to defer to the trade income deferral account the variances between actual and forecast trade income." The Trade Income Deferral Account was established under Order G-96-04 and provides BC Hydro with the ability to include forecast trade income in rates and capture variances between that forecast and actual trade income. BC Hydro forecasts annual trade income for each of the test years as $120.6 million, which it states is "reflective of Powerex's average net income over the last five years."[301]

Although Direction No. 7 was repealed February 14, 2019, BC Hydro states that it

> …continues to include the net income of BC Hydro's subsidiaries in its revenue requirements and continues to define Trade Income on the same basis as previously defined in Direction No. 7. The inclusion of subsidiary net income in BC Hydro's revenue requirements reduces the overall revenue requirements.[302]

As the evidence in this proceeding shows, Powerex provides essential services to BC Hydro, which include the acquisition of needed market energy and the disposition of surplus energy. In addition, Powerex is involved in other transactions, both with BC Hydro electricity and with other commodities. The Panel is concerned that the $0 "floor" on the inclusion of Powerex net income may not adequately shield BC Hydro ratepayers from any losses that arise from unregulated activities undertaken by Powerex and discusses this further in the following sub-sections.

In its application to the BCUC to approve the 2020 TPA application, BC Hydro describes the operations of Powerex as:

> an energy marketing and trading company that operates primarily in the western United States and Alberta. Its activities are focused in three different areas: wholesale electricity, wholesale natural gas, and related environmental products. It operates in highly competitive markets where prices are determined by the interaction of numerous buyers and sellers. It aims to maximize its annual net income.
>
> Powerex was established in 1988, to take advantage of wholesale electricity trade opportunities, for the benefit of British Columbia and BC Hydro ratepayers. Since that time, it has had an exclusive relationship with BC Hydro under which it purchases surplus BC Hydro electricity for export, sells to BC Hydro electricity for import to meet Domestic Requirements, and purchases and sells electricity with BC Hydro to utilize any Residual System Capability.
>
> Powerex independently acquires electricity at a variety of locations, from third-parties, for import into the BC Hydro system, and independently sells electricity that has been exported from the BC Hydro system at a variety of locations, to third-parties. It has full flexibility, vis-à-vis BC Hydro, to decide the locations, parties and prices for its transactions.[303]

Powerex's website states that it has:

> Contractual access to the flexibility of BC Hydro's world-class integrated system of over 17,000 MW of generating capacity – the vast majority of it from hydroelectric and wind resources which are either

[300] OIC 097/2014, dated March 5, 2014; https://www.bclaws.ca/civix/document/id/oic/arc_oic/0097_2014/
[301] Exhibit B-1, p. 8-17.
[302] Ibid, B-1, pp. 8-16–8-17.
[303] 2020 Transfer Pricing Agreement application, Exhibit B-1, p. 4.

owned by BC Hydro or by Independent Power Producers in B.C. with whom BC Hydro has long-term contracts. This system is interconnected with the western U.S. by two 500-kilovolt transmission lines on the West Coast between B.C. and Washington state; one 230-kilovolt line connecting B.C. and Washington on the east side; and a 500-kilovolt line to the east, connecting B.C. with Alberta purchases.

The website further states that Powerex sells a wide range of wholesale electricity products and services, including: [304]

- Standard firm electricity products
- Clean and low-carbon electricity products
- Qualifying renewable electricity products
- Capacity products, including resource adequacy and customized capacity products
- Ancillary Services, including spinning, non-spinning reserves, and balancing reserves
- Frequency Response
- Customized energy solutions, including renewable off-take as well as shaping and moving arrangements

In addition to buying and selling products that involve BC Hydro's reservoir and transmission system, Powerex also engages in other trading activities not related to BC Hydro. For example, it trades natural gas "primarily at Huntingdon/Sumas, Station 2, Kingsgate and AECO, PG&E Citygate, Malin, Stanfield, Rockies, MichCon Citygate and Dawn hubs."[305]

Positions of Parties

CEABC notes that BC Hydro describes the use of BC Hydro's system to back Powerex's energy or capacity sales as being only a portion of trade income. CEABC further states that no breakout of trade income, in terms of the utilization of BC Hydro system resources, is ever given, and therefore, the BCUC and interveners have no idea whatsoever of the risk to reward ratio of using the BC Hydro system to allow Powerex to earn trade income.[306]

CEABC submits that "BC Hydro spends most of its modelling effort trying to optimize these trade revenues."[307] In CEABC's view, there are a lot of risks associated with BC Hydro's current strategy of trying to optimize its reliance on import and export markets, which are inherently volatile and subject to weather uncertainties and price uncertainties. As an alternative, CEABC views that shifting the strategy from an import/export focus to a domestic sales focus would not only enhance revenues, and help meet the Province's climate action goals, but would also greatly reduce the company's business risk exposure.[308] By increasing domestic sales, CEABC views that BC Hydro could mitigate its market risks by reducing its exposure to the volatile export/import market, as well as avoid operational risks associated with drawing its reservoir levels up and down in anticipation of higher and lower market prices.[309]

Panel Determination

The BCUC had no jurisdiction with regard to the inclusion of any Powerex net income or losses in BC Hydro's revenue requirement as long as Direction No. 7 prescribed that all of Powerex's net income (provided it was positive) flowed to ratepayers. However, with Direction No. 7 rescinded, the Panel must consider the regulatory principles that apply to the inclusion of subsidiary income and losses in BC Hydro's rates.

[304] https://powerex.com/our-business/electricity
[305] https://powerex.com/our-business/natural-gas
[306] CEABC comments on BCH Submission dated June 18, 2020, p. 1.
[307] CEABC Final Argument, p. 22.
[308] CEABC Final Argument, pp. 54–55.
[309] CEABC Final Argument, p. 23.

Here, we consider whether it is appropriate for BC Hydro to continue to use the definition of Trade Income from now-repealed Direction No. 7. Doing so provides the appearance of enabling BC Hydro ratepayers to benefit from any positive Powerex net income while being protected from any net losses that may arise.

As noted previously in this Decision, Direction No. 7 directed that all of Powerex's net income, provided it is greater than $0, defined as "Trade Income," be included in BC Hydro's revenue requirements. BC Hydro proposes to continue this practice even though Direction No. 7 is now repealed. The Panel is concerned that BC Hydro's proposed approach introduces unacceptable risk to ratepayers.

We are concerned about various aspects of the inclusion of Trade Income, as defined by BC Hydro. Generally speaking, regulatory principles require that costs and revenues from unregulated activities not be included in a utility's revenue requirements and as such, it is unusual to do so. The Regulatory Compact requires that ratepayers pay only the prudently incurred costs to operate the utility, including a fair return for the utility owners. There is no provision in the Regulatory Compact for a risk/reward trade-off when it comes to activities beyond the utility's own regulated activities.

Typically regulators, including the BCUC, attempt to "ring fence" any non-regulated activities of a utility to protect its ratepayers from risk. However, in this case some of the unregulated activities involve BC Hydro's regulated assets and operations. We have previously discussed the appropriateness of the inclusion of proceeds from transactions involving BC Hydro electricity with Powerex. At that time we observed that a portion of the economic value of these transactions may be captured in Powerex's net income. We now consider that economic value, along with other components of Powerex's net income.

The table below summarizes Powerex's activities. The activities in the first two columns in the table below are based on the taxonomy provided in BC Hydro's definition of Market energy.

Table 4-11: Powerex Activities

Transactions involving BC Hydro electricity for Domestic Purposes	Transactions involving BC Hydro electricity for trade related activities	Transactions of non electricity products for BC Hydro	Other Powerex Transactions
Market Electricity Purchases: These represent market purchases of energy from Powerex by BC Hydro to meet domestic load requirements. Surplus Sales: These represent sales of electricity from BC Hydro to Powerex in excess of domestic load requirements.	Net Purchases (Sales) from Powerex: These represent transactions where Powerex purchases from and sells to BC Hydro for the purpose of trade related activities, provided that the BC Hydro system has the ability to accommodate these transactions. These are not purchases (sales) for domestic purposes.	Acquisition of Natural Gas for BC Hydro	All other Activities

Transactions involving electricity and natural gas between BC Hydro and Powerex take place at the transfer price specified in the agreement in effect at the time of the transaction. We have discussed this aspect of electricity related transactions in the previous section where we expressed our concerns about the ratepayer risk inherent in these transactions. We do not have similar concerns about transactions of non electricity products for BC Hydro.

In many cases, Powerex derives economic value from transactions involving BC Hydro electricity. In doing so, it may simply resell at a price higher than the transfer price or by making offsetting purchases and sales that are timed to take advantage of market prices. This part of the economic value of these transactions contributes to Powerex's net income. The portion of the transactions between Powerex and the market, unlike the portion of the transactions between BC Hydro and Powerex, is unregulated. However, the Panel found in section 4.2.5 that proceeds from sales of BC Hydro electricity are on the account of the ratepayer. Therefore, the portion of Powerex net income that arises from transactions involving BC Hydro electricity should accrue to BC Hydro ratepayers.

Given BC Hydro's proposal to continue with the definition of Trade Income from Direction No. 7, in a circumstance where there is a net loss on all Other Powerex Transactions (as shown in the table above), the benefits ratepayers receive of any positive Powerex net income arising from transactions involving BC Hydro electricity are at risk of erosion.

The Panel finds that BC Hydro ratepayers should assume no risk whatsoever for Other Powerex Transactions. There is no regulatory justification to find otherwise.

There is no regulatory impediment to the inclusion of positive income from Powerex transactions that do not involve BC Hydro electricity, and the Panel has no objections to their inclusion in BC Hydro's Trade Income Deferral Account.

However, in light of the concerns raised above, only the proceeds, less associated overhead costs, for transactions involving BC Hydro electricity and associated with the acquisition of natural gas for BC Hydro should be included in the Trade Income Deferral Account. **Therefore, the Panel directs that no actual Powerex net income be captured in the Trade Income Deferral Account absent further review and approval by the BCUC.**

Therefore, in its next RRA, BC Hydro is required to file, in confidence if necessary, a summary of Powerex's net income, in sufficient detail to enable the BCUC to determine whether any amount of actual Powerex net income is appropriate for inclusion in the Trade Income Deferral Account.

For further clarity, the Panel allows the continuance of the Trade Income Deferral Account to capture variances between forecast and actual income from BC Hydro related transactions and the forecast and actual Other Powerex Transactions, subject to BCUC approval.

The preceding discussion is not intended to be a commentary or criticism of Powerex's activities. We are not suggesting that Powerex takes unnecessary risks or that its activities in regard to BC Hydro's surplus systems capability – or any other activities – are inappropriate. For example, we acknowledge the benefits of Powerex executing a successful arbitrage strategy to purchase cheaper surplus energy, using BC Hydro's reservoir system to effectively store that energy and sell it at a time when the price is higher and the demand is greater.

Such strategies support a system of supply and demand in the Western interconnected energy market and are an appropriate use of BC Hydro's surplus systems capability. Buying "renewable energy from independent power producers and industrial self-generators" and using BC Hydro's reservoir system to deliver "firmed and shaped energy at customers' preferred locations"[310] are also appropriate. These activities can not only benefit BC Hydro ratepayers economically but also contribute in a meaningful way to supporting neighbouring jurisdictions to reduce their dependency on greenhouse gas (GHG) emitting electric generation sources.

[310] https://powerex.com/our-business/environmental-products

4.3 Base Operating Costs[311]

BC Hydro uses the term "base operating costs" to reflect the expenditures incurred in its day-to-day operations. Unlike gross operating costs, base operating costs are net of regulatory account transfers and provisions and do not include costs related to IPP capital leases or ineligible capital overhead under IFRS.[312] BC Hydro submits that base operating costs are the relevant measure for the assessment of its efforts to control operating costs because they exclude costs that, among other things, vary according to changes in accounting rules and the mechanisms in place to recover regulatory account balances.[313] BC Hydro's forecast pertains to base operating costs only.[314]

BC Hydro describes its forecast base operating costs and full time equivalents (FTEs) for the Test Period. Detailed support for BC Hydro's forecast base operating costs, by Business Group, is provided in Chapters 5A through 5G of the Application. BC Hydro submits the planned increases are largely due to uncontrollable factors, such as storm restoration costs, and where possible it offsets non-controllable cost increases with reductions to controllable costs by absorbing controllable cost increases within existing budgets.[315]

BC Hydro contends that the evidentiary record demonstrates the following efforts to contain controllable base operating costs:[316]

1. BC Hydro has provided detailed base operating cost information and benchmarking in response to the BCUC's comments and recommendations;
2. BC Hydro's robust top-down and bottom-up budgeting process yielded a lower budget than would have been possible using zero-based budgeting. BC Hydro monitors performance and makes necessary budget adjustments as circumstances arise;
3. BC Hydro has absorbed controllable cost pressures within existing budgets. Base operating cost increases during the Test Period are generally attributable to uncontrollable factors;
4. BC Hydro has achieved savings, offset uncontrollable cost pressures and absorbed additional work requirements from increased operating complexity through: the Workforce Optimization Program; Accenture repatriation; the consistent approach to vacancy factor savings; re-purposing the unallocated funds budget; lease consolidations; reduced spending on advertising; paperless billing and the Work Smart Program;
5. Operating Full-Time Equivalents have been flat since 2012 and planned increases in the Test Period are associated with work ramping-up on Site C. FTEs added as part of the Workforce Optimization Program and Accenture repatriation have reduced, not increased, BC Hydro's overall costs;
6. BC Hydro has mitigated increases in power system maintenance expenditures in recent years, while still maintaining reliability. It has done so despite a growing power system asset base, aging assets and increased regulatory requirements; and
7. BC Hydro's operating expenses benchmark favourably.

BC Hydro submits that based on the evidentiary record, the BCUC should find the forecast base operating costs in fiscal 2020 and 2021 to be reasonable.[317]

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311 Other items relating to total operating costs, but which BC Hydro does not consider to be 'base' operating costs (such as IFRS Ineligible Capitalized Cost, IPP Capital Leases, gains and losses on capital leases, capital asset write-offs) are examined outside of base operating costs.
312 Exhibit B-1, Section 5.5.1, p. 5-20, Table 5-3.
313 Exhibit B-1, Section 5.5.1, p. 5-19.
314 Exhibit B-1, Section 5.5.2.2, p. 5-22.
315 Exhibit B-1, Section 5.1, p. 5-1; BC Hydro Final Argument, p. 59.
316 BC Hydro Final Argument, pp. 58–59.
317 BC Hydro Final Argument, p. 107.

The Panel must determine whether the forecast base operating costs are reasonable such that they can be recovered in rates. In doing so, the Panel considers the following factors in determining the reasonableness of the base operating costs for the Test Period:

1. BC Hydro's budgeting methodology to forecast base operating costs and its governance process to provide the requisite oversight over operating costs;
2. the reasonableness of any increase of BC Hydro's forecast base operating costs for the Test Period over both the 2019 BCUC approved costs and 2019 actual costs; and
3. the key drivers of the increase in base operating costs as well as the areas in which BC Hydro achieved material offsetting savings and/or absorbed new work or cost pressures.

In addition to the above, we review the following elements of base operating costs which BC Hydro identified as areas within operating costs where it will need to make additional investment in future RRAs: (i) cybersecurity; (ii) vegetation management; and (iii) employee training to ensure BC Hydro meets its evolving safety requirements.[318]

4.3.1 Budgeting Methodology

BC Hydro contends its forecast base operating costs are the product of a robust budgeting process that involves top-down and bottom up elements.[319] As part of the bottom-up perspective, each Key Business Unit (KBU) conducts an in-depth review of its base operating costs, considering current operational and project related needs based on forecast work plans, resourcing, legislative and compliance requirements. Through this process, cost pressures and savings opportunities are identified and consolidated at a Business Group level.[320] From a top-down perspective, BC Hydro's Executive Team then reviews the identified cost pressures and savings opportunities and considers the Mandate Letter from the Government of BC as well as the goals and targets in the Service Plan to inform an overall top-down target.[321] The budgeting process is consistent with the process applied in the 2017-2019 RRA, and, in response to the BCUC's comments during the 2017-2019 RRA, adds enhanced examination and information on the overall starting base operating cost budget in addition to details on changes.[322]

The Finance KBU provides oversight on the base operating cost budget through financial and management reporting throughout the year. Business unit managers receive monthly reporting outlining their monthly and year-to-date results so that KBUs track and compare actual spending to budgeted amounts. On a monthly basis, Executive Team members review these results along with a dashboard of performance metrics for their Business Group with their direct reports. In addition, the Executive Team reviews the consolidated financial results each month.[323] Emerging cost pressures are identified, and if necessary, corrective actions are implemented so that BC Hydro remains on track to achieve its targets.[324]

BC Hydro notes that in the past, where Business Groups could not identify adequate savings to absorb unanticipated cost pressures, it would look to the unallocated funds budget as a possible funding source. The unallocated funds budget was the residual amount between the KBUs/Business Group bottom-up budgeting process and the top-down target set by the Executive Team. However, for the Test Period, BC Hydro has not

[318] Exhibit B-59, p. 2.
[319] Exhibit B-1, Section 5.4, p. 5-14.
[320] Exhibit B-1, Section 5.4.2, p. 5-14.
[321] Exhibit B-1, Section 5.4.2, pp. 5-14–5-15.
[322] Exhibit B-5, BCUC IR 34.1 and 34.2.
[323] Exhibit B-1, Section 5.4, pp. 5-15–5-16.
[324] Exhibit B-1, Section 5.4, p. 5-16.

included an unallocated funds budget within its base operating cost forecast. BC Hydro explains that instead, it has redistributed the unallocated funds budget from 2019[325] to assist with the labour ($7.0 million), maintenance ($7.9 million) and other ($2.0 million) cost pressures in the Test Period. Accordingly, going forward beginning with the Test Period, all funding of unplanned work demands and unanticipated cost pressures will need to come through target adjustments that equal zero on a net basis or will result in a direct impact to the shareholder, all else equal. Without the unallocated funds budget, BC Hydro recognizes it has a significant challenge to manage within the overall base operating budget during the Test Period.[326]

Positions of Parties

Apart from the CEC and BCSEA, interveners do not take a position on BC Hydro's budgeting process. The CEC submits that BC Hydro's project budget to actual costs metric may be valuable in assessing whether BC Hydro capably delivers its costs according to budget; however, the metric does not address whether the budget is reasonable and cost-effective in the first place.[327] Further, the CEC disagrees that coming in "at or under budget" ensures the best and highest use of organizational spend[328] and states that there are "few apparent metrics in use by BC Hydro to ensure that the budgeting process is producing cost effective budgets for activities and projects."[329] The CEC contends, "including additional metrics that address cost / benefit analysis throughout BC Hydro's operations could potentially result in operations with better value per dollar spent, and lower costs over a long-term horizon."[330]

BC Hydro contends the CEC's broad statement about BC Hydro's non-use of cost-benefit analysis is incorrect. It submits that BC Hydro's top-down, bottom-up approach to budget operating costs is an exercise that determines the right balance between rate affordability and carrying out services that benefit ratepayers in some fashion, whether today or in the future.[331]

The CEC agrees with the elimination of the unallocated funds budget. However, it is concerned that maintenance budgets were insufficient in prior years. In the CEC's view, maintenance budgets should be accurate, sufficient and fully reflect the costs required to maintain assets in a manner that permits full recovery of the assets.[332]

BCSEA acknowledges that the elimination of the unallocated fund budget in the Test Period will have an impact on BC Hydro's ability to manage unanticipated costs pressures.[333]

Panel Determination

The Panel accepts BC Hydro's approach to leveraging a top down to bottom up budgeting to forecast its base operating costs for the Test Period, which provides insight into the cost pressures and savings opportunities for BC Hydro. The monitoring processes provide opportunities to adjust as necessary to ensure targets are achieved, as well as to gain insights to develop sound budgets for the future. In addition, the monitoring processes reveal trends that may otherwise go unnoticed.

With regards to the CEC's concern that BC Hydro might defer maintenance issues to avoid increasing its base operating costs, the Panel acknowledges that BC Hydro is aware of this risk and has in part addressed

[325] The amounts re-distributed to address the noted cost pressures include $15.0 million of an unallocated funds budget in 2019, and $1.9 million for trailing costs related to the Accenture repatriation in fiscal 2019. [Exhibit B-1, Section 5G.7.2, p. 5G-12].
[326] Exhibit B-1, Section 5G.7.2, p. 5G-12; Exhibit B-12 BCUC IR 36.3, 63.2, 231.1, 231.7, 231.8.
[327] CEC Final Argument, Section 6.1.2, p. 40, paragraphs 175, 176.
[328] CEC Final Argument, Section 6.1.2, p. 41, paragraph 184.
[329] CEC Argument, Section 6.1.2, p. 41, paragraph 178.
[330] CEC Argument, Section 6.1.2, p. 41, paragraph 181.
[331] BC Hydro Reply (May 27, 2020), p. 17.
[332] CEC Final Argument, Section 6.2, p. 47, paragraphs 230-231.
[333] BCSEA Final Argument, Section F, p. 25, paragraph 98.

maintenance cost pressures through the re-distribution of the 2019 unallocated funds budget. During the Test Period, however, BC Hydro concedes that it will have to fund other unplanned work demands and unanticipated cost pressures through target adjustments. All of this leads to the Panel's concern that there may be cost pressures that cannot be alleviated during the Test Period and which may result in BC Hydro deferring costs into the future.

The Panel agrees with BC Hydro's decision to eliminate the unallocated funds budget. The Panel accepts that BC Hydro will include known cost pressures in the KBUs' cost forecasts for review as part of the revenue requirement approval process. BC Hydro states that without the unallocated funds budget it will have a significant challenge to manage within the overall operating budget during the Test Period.[334] The Panel acknowledges BC Hydro's candor. However, the Panel reminds BC Hydro that this is the reality most businesses face, particularly in the current economic environment. Furthermore, other BCUC-regulated utilities do not have the luxury of including, as part of their operating cost forecasts, an unallocated funds budget with which to manage unanticipated operating cost pressures during any particular test period. While the concept of a contingency reserve may be acceptable for capital project expenditure forecasts, such concept is foreign (if not unheard of) for operating expenditure forecasts for regulated utilities. BC Hydro's operating costs should be based on forecast costs only and should not include a budget for unanticipated costs. Accordingly, the Panel expects BC Hydro will not include in future revenue requirements an unallocated funds budget.

The Panel finds that it would be helpful to review how BC Hydro addresses cost pressures. **Therefore, as part of its fiscal 2023 RRA, the Panel directs that BC Hydro summarize:**

1) **the operating cost pressures it experienced during the Test Period and how it alleviated those costs pressures; and**
2) **where it was unable to alleviate the cost pressure, describe the activities BC Hydro had to forego and the risks resulting from not doing the activity.**

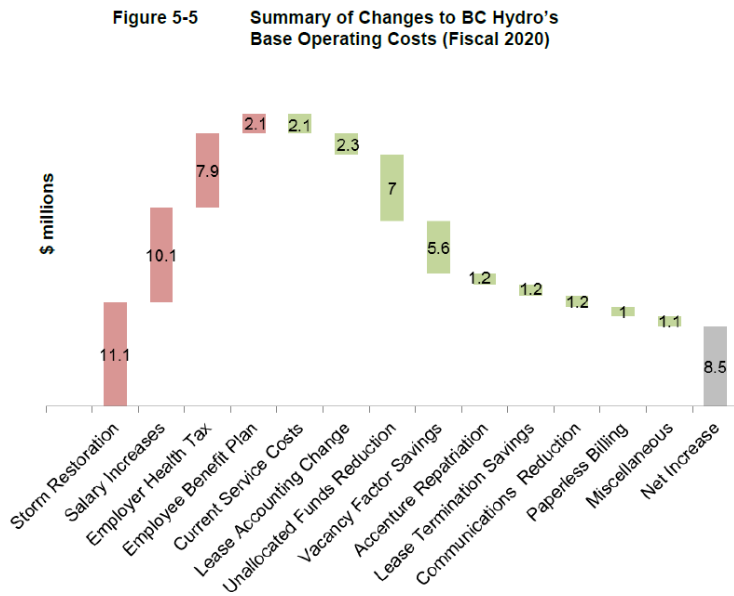
4.3.2 Forecast Increase in Base Operating Costs

BC Hydro states that it is limiting base operating cost increases to below the forecast rate of inflation[335] over the Test Period by partially offsetting non-controllable cost increases with reductions to controllable costs.[336] In the Application, BC Hydro submits that base operating costs are forecast to increase by 1.1 percent in fiscal 2020 and by 1.3 percent in fiscal 2021 for an average increase of 1.2 percent per year compared to fiscal 2019 forecast.[337]

The following figure[338] from the Application provides a visual breakdown of the increases (red bars) and savings (green bars) in base operating costs from fiscal 2019 forecast, as approved in the fiscal 2017 to fiscal 2019 RRA Decision, to fiscal 2020 forecast, prior to the Evidentiary Update and illustrates the overall net increase in base operating costs is $8.5 million.[339]

334 Exhibit B-1, Section 5G.7.2, p. 5G-12; Exhibit B-12 BCUC IR 36.3, 63.2, 231.1, 231.7, 231.8.
335 BC Hydro uses the BC Consumer Price Index measure for the forecast rate of inflation which is 2.3 percent and 2.0 percent in 2020 and Fiscal 2021, respectively [Exhibit B-1, Section 5.5, p. 5-18, footnote 154]. As comparison, Bank of Canada sets its policy interest rate to keep inflation at 2 percent, on average, over the medium term [https://www.bankofcanada.ca/rates/indicators/key-variables/inflation-control-target/].
336 Exhibit B-1, Section 1.8.4, p. 1-48; Section 5.1, p. 5-1.
337 Exhibit B-2, Section 5.5, p. 5-18.
338 Exhibit B-1, Section 5.5.2.1, p. 5-22, Figure 5-5.
339 Exhibit B-19, Section 1.3, Figure 5-5, p. 12.

Figure 4-2: Summary of Changes to BC Hydro's Base Operating Costs (Fiscal 2020)



The Evidentiary Update included adjustments to base operating costs to reflect a change in discount rate used to value BC Hydro's pension costs.[340] After incorporating the adjustments from the Evidentiary Update, the BCUC calculates that base operating costs are forecast to increase by 3.2 percent[341] in fiscal 2020 over the fiscal 2019 forecast and by 1.4 percent[342] in fiscal 2021 over the fiscal 2020 forecast for an average increase of 2.3 percent per year of the Test Period.[343] The notable difference in base operating costs as a result of the Evidentiary Update is the increase in current service pension costs, from a savings of $2.3 million to an increase of $13.8 million (addition of $15.9 million) in fiscal 2020.[344] BC Hydro explains the increase is because the discount rate used to value BC Hydro's pension costs decreased, resulting in a higher present value of BC Hydro's pension liability and increasing its current service pension costs.[345]

The total base operating costs BC Hydro proposes to recover for fiscal 2020 and fiscal 2021 are $793.8 million and $804.9 million, respectively.[346] The BCUC table below summarizes the changes to base operating costs from the fiscal 2019 forecast and over the Test Period:[347]

Table 4-12: Base Operating Costs Changes

($ million)		F2020 Plan	F2021 Plan
Base Operating Costs (Carry Forward) (Schedule 5.0, line 9)	A	769.5	793.8
Test Period Cost Increases			
Storm Restoration		11.1	
Salary Increases		10.1	8.9
Employer Health Tax		7.9	(1.9)
Employee Benefit Plan		2.1	2
Current Service Costs		13.8	2.5
Total Test Period Cost Increases	B	45.0	11.5

340 Exhibit B-19, Section, Section 1.3, p. 12.
341 [(793.8/769.5)-1]*100; Refer to Exhibit B-19, Appendix A, p. 41, Schedule 5.0, line 9 for figures used in calculation.
342 [(804.9/793.8)-1]*100; Refer to Exhibit B-19, Appendix A, p. 41, Schedule 5.0, line 9 for figures used in calculation.
343 Exhibit B-1, Section 5.1, p. 5-1; BCUC staff calculated percentages based on Exhibit B-19, Appendix A, p. 41, Schedule 5.0, line 9.
344 Exhibit B-19, Section 1.3, pp. 12-13, Appendix A, p.41, Schedule 5.0, line 9.
345 Exhibit B-19, Section 1.3, p. 12; BC Hydro Final Argument, p. 59.
346 Exhibit B-19, Appendix A, p.41, Schedule 5.0, line 9.
347 Exhibit B-1, Section 5.5.2.1, p. 5-22, Figure 5-5; Appendix A, Schedule 5.0, Line 9; Exhibit B-19, Appendix A, p.41, Schedule 5.0, line 9.

($ million)		F2020 Plan	F2021 Plan
Test Period Cost Savings			
Lease Accounting Change		(2.3)	
Unallocated Funds Reduction		(7.0)	
Vacancy Factor Savings		(5.6)	
Accenture Repatriation		(1.2)	
Lease Termination Savings		(1.2)	
Communications Reductions		(1.2)	
Paperless Billing		(1.0)	
Miscellaneous		(1.1)	(0.4)
Total Test Period Cost Savings	C	(20.6)	(0.4)
Test Period Net Increase/(Decrease)	D=B+C	24.4	11.1
Base Operating Costs (Current Year) (Schedule 5.0, line 9)*	E=A+D	793.8	804.9
Total Percentage increase (BCUC calculated)	(E-A)/A	3.2%	1.4%

**Totals may not reconcile due to rounding differences.*

As part of the Evidentiary Update, BC Hydro reports actual fiscal 2019 base operating costs of $757.2 million, which are $12.2 million below the fiscal 2019 forecast approved by the BCUC of $769.5 million. A summary of the BCUC approved forecast costs as compared to actual for the period of fiscal 2015 to fiscal 2019 is presented in the BCUC prepared table below[348].

Table 4-13: BCUC Approved Forecast Costs Compared to Actuals

($ millions) Note 1		Fiscal 2015	Fiscal 2016	Fiscal 2017	Fiscal 2018	Fiscal 2019
Forecast in RRA	A	705.7	712.7	756.6	757.5	769.5
Incremental Increase over PY Forecast	(CY/PY)-1	N/A	1.0%	6.2%	0.1%	1.6%
Actual	B	710.1	714.7	763.6	743.1	757.2
Incremental Increase over PY Actual	(CY/PY)-1	N/A	0.6%	6.8%	-2.7%	1.9%
Difference [actual (over) / under forecast]	C=A-B	-4.4	-2.0	-7.0	14.4	12.3

Note 1: N/A is the abbreviation for 'not available' in this table as the 2015 RRA operating costs did not separately disclose base operating costs. CY = Current Year and PY = Prior Year

BC Hydro submits that despite inflation pressures, it has been able to limit increases in its base operating costs below inflation in recent years as a result of prudent management and continuous improvement, noting that its average base operating cost increase over the fiscal 2015 to fiscal 2021 period is 1.50 percent, which is 0.44 percent below the average rate of inflation of 1.94 percent for the same period.[349]

Positions of Parties

The CEC notes that there has been an emphasis on cost reduction in this proceeding.[350] In its view, while it could be worthwhile to limit incremental increases in base operating costs to below inflation in order to manage rates,

[348] Exhibit B-1, Appendix A, Schedule 5.0, Line 9; Exhibit B-19, Appendix A, p.41, Schedule 5.0, line 9.
[349] Exhibit B-1, Appendix C, Comprehensive Review of BC Hydro Phase 1 Final Report, p. 32.
[350] CEC Final Argument, Section 6.2, p. 41, paragraph 187.

"sustainable improvement" also requires an understanding of costs and benefits. Otherwise, according to the CEC, the rate reductions may ultimately be uneconomic, such as certain deferrals of required expenditures.[351]

BCOAPO notes that the general base operating cost percentage increase for fiscal 2020 is in fact greater than BC Hydro reports in its Application, when calculated using the actual 2019 base operating costs included in the Evidentiary Update. BCOAPO submits that when actual costs for the base year are known, the actual cost should be the "starting point" from which to calculate and characterize the cost increases during any RRA's test period. Using the actual 2019 base operating costs reported in the Evidentiary Update, BCOAPO calculates that the 2020 general percentage increase is 2.7 percent, which is more than double that reported by BC Hydro in its Application and its final argument.[352]

BC Hydro does not address BCOAPO's observation in its reply.

Panel Determination

In reviewing BC Hydro's fiscal 2020 forecast of $793.8 million, we note this is an increase of 3.2 percent over the fiscal 2019 budget, which is not an unreasonable increase. For fiscal 2021, the base operating costs forecast is $804.9 million, which is only 1.4 percent higher compared to the fiscal 2020 forecast and is lower than the average inflation rate for the Test Period. Taking these factors into account, the Panel is satisfied that the forecast base operating cost increases for the Test Period are reasonable.

4.3.3 Key Drivers of the Increase

In the following sections the Panel discusses the key drivers of the increase in base operating costs for the Test Period – labour and storm restoration costs, along with vacancy factor savings, where BC Hydro has achieved material offsetting savings. BC Hydro identified the reduction in unallocated funds as another offsetting factor to the increase in base operating costs in Figure 4-2, which we discussed above in Section 4.3.1 (Budgeting Methodology).

4.3.3.1 Labour Costs

Various elements impact BC Hydro's forecast increase in labour costs, including salary increases, which comprise a significant portion of the increased base operating costs. Changes in the number of full-time equivalents (FTEs), alongside the Work Smart program, which is designed to increase employee capacity hours, have contributed to the salary increases. Notwithstanding the fact that salary increases reflect only those FTEs that charge work to operating costs, the number of FTEs encompasses all BC Hydro FTEs, irrespective of where the time is charged (i.e. not only those FTEs whose work is charged to operating costs). We discuss BC Hydro's proposed salary increases and the number of FTEs below.

4.3.3.1.1 Salary Increases

BC Hydro states that changes to the standard labour rates (exclusive of employee benefit plan changes) are forecast to increase labour costs by $10.1 million in fiscal 2020 and by $8.9 million in fiscal 2021.[353] Standard labour rate increases are tied to the bargaining mandate for union staff that the Public Sector Employers Council provides to BC Hydro.[354] BC Hydro's collective agreements expired on March 31, 2019 and the Public Sector

[351] CEC Final Argument, Section 6.2, p. 41, paragraph 192.
[352] BCOAPO Final Argument, Operating Costs, Calculation of Base Operating Cost Increase, pp. 25-27.
[353] Exhibit B-1, Section 5.6.5, pp. 5-46 to 5-47; Section 5.5.2.2, p. 5-23, Table 5-5.
[354] Exhibit B-1, Section 5.5.2.2, p. 5-22.

Employers Council bargaining mandate specifies a three-year term (fiscal 2020 to 2022) with a 2.0 percent general wage increase each year for union employees, which BC Hydro has included in the Test Period.

BC Hydro explains that the cost increase for the Test Period also includes a 2.5 percent general wage increase for management and professional employees. Since 2012, due to the Public Sector Employers Council salary freeze policy, BC Hydro has limited any salary increases for management and professional employees to below the amount provided to unionized employees over the same period.[355] BC Hydro justifies slightly higher management and professional compensation increases as a "catch-up", given how BC Hydro's employee compensation compares to the median market.[356]

A 2017 assessment by Morneau Shepell concluded that, on an average total cash basis, BC Hydro employees earn 11 percent less than median market rates, although after factoring-in the value of pension benefits and time off programs, the compensation package is comparable at two percent below median market rates.[357] BC Hydro explains that the management and professional employee wage increase for the Test Period is higher than the union's 2.0 percent limit due to management and professional increases falling behind union increases in prior years. The Conference Board of Canada anticipates market increases to be 2.6 percent, and in order to keep BC Hydro's rates competitive to attract and retain the employees needed in the management/professional job categories, BC Hydro proposes the 2.5 percent increase such that it remains in a consistent position and does not fall further behind the market.[358]

The executive and director level positions within the management and professional affiliation are eligible to receive incentive pay, which is referred to as salary holdback and the maximum annual award is 10 percent or 20 percent of the employee's salary, depending on position. Awards are based on corporate and individual performance.[359] Corporate performance is based on results achieved on BC Hydro's Service Plan performance measures and individual performance is based on the employee's individual performance objectives established at the start of the year and assessed by the employee's manager or for executive positions, the Board of Directors, at year-end.[360] BC Hydro budgets to pay-out 75 percent of the maximum calculated holdback; this budgeted amount is included in the proposed 2.5 percent salary increase for management and professionals.[361] BC Hydro explains that only one percent of management and professional employees is eligible to receive holdback pay since it is limited to executive and director level positions and notes that in fiscal 2019, actual holdback payments totalled approximately $1.4 million, and no employees received their full holdback amount. If all employees eligible for holdback pay received their full holdback amount in fiscal 2019, the total would have been approximately $1.7 million.[362]

Positions of Parties

BCSEA accepts BC Hydro's budgeted salary increases of 2.0 percent per year for unionized employees and 2.5 percent per year for management and professional salaries as reasonable to keep pace with the market and attract employees, particularly after previous years of restraint. Similarly, BCSEA does not object to the incentive pay component of BC Hydro's total rewards program.[363]

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[355] Exhibit B-1, Section 5.5.2.2, p. 5-23, Table 5-5. During this period union salary increases averaged 1.43 percent as compared to management and professional which averaged 1.0 percent over the same period (Exhibit B-5, BCUC IR 42.5).
[356] Exhibit B-1, Section 5.5.2.2, p. 5-22.
[357] Exhibit B-1, Section 5.6.5.2, p. 5-47; Transcript Volume 8A, p. 1123, lines 8-16.
[358] Transcript Volume 8A, p. 1123, lines 1-16; p. 1125, lines 16-24.
[359] The weighting between components is 60 percent corporate and 40 percent individual for executives and 40 percent corporate and 60 percent individual for director level positions.
[360] Exhibit B-5, BCUC IR 42.10.1
[361] Transcript Volume 8A, p. 1124, 1126–1127.
[362] Exhibit B-37, BC Hydro Undertaking No. 10.
[363] BCSEA Final Argument, Section E, p. 24, Paragraph 94.

MoveUP notes that BC Hydro's employee compensation and benefits are the product of free collective bargaining that operates, from the employer's side of the table, within BC's statutory framework for the broad public sector and submits there is no basis to question their reasonableness.[364] MoveUP does not take a position on the proposed salary increases for management and professional employees or the incentive pay.

The CEC submits that an annual 2.5 percent increase for management and professional employees is likely to be significantly above inflation and notes that BC Hydro's total rewards offer is consistent with median market rates. Further, the CEC draws attention to BC Hydro's voluntary turnover rate of 1.3 percent, which is below the 3.8 percent average for the Power and Utilities industry as reported by the Conference Board of Canada. In anticipation of the impact of the COVID-19 pandemic, the CEC submits it would be prudent for BC Hydro to freeze management and professional wage increases and inappropriate to offer incentive payments to director and executive level positions. The CEC recommends the BCUC not approve revenue requirements for management and professional salary increases.[365]

BC Hydro acknowledges the significant economic harm caused by the COVID-19 pandemic and the resulting financial hardship for many individuals and businesses, and agrees with the importance of keeping rates low. It submits, however, that measures which provide direct relief to customers in financial need are more effective and appropriate than optic-based cost disallowances as suggested by the CEC. BC Hydro contends that the BCUC's determination about whether forecast increases are reasonable should be based on consideration of the long-term interests of customers in attracting and maintaining qualified employees.[366]

Gjoshe submits that BC Hydro's corporate performance has progressively deteriorated in the areas of leadership, financial performance and rate competitiveness, and therefore objects to permitting the recovery of holdback (incentive) pay in rates. Gjoshe submits that leadership has been complacent at worst and on the receiving end of provincial policy at best with little room for leadership on the part of BC Hydro's executives and directors. Further, that BC Hydro's corporate performance has not kept pace when compared against domestic load growth: that it now takes three times as many resources (in the form of assets, debt and regulatory account balances) to supply the same level of domestic load as 1.5 to two decades ago. Gjoshe expresses concern that BC Hydro has lost ground on its rate competitiveness as compared to the other jurisdictions that it benchmarks itself against by raising rates at almost twice the average. Finally, Gjoshe submits that the top quartile performance in the Hydro Québec survey is at least partly due to the $1.1 billion write-off of BC Hydro's rate smoothing regulatory account.[367]

BC Hydro submits that Gjoshe's claims are without merit and the forecast holdback pay for the Test Period is an appropriate element of providing safe, reliable, cost effective service to customers and should be reflected in rates. BC Hydro contends that the evidence shows the Executive Team has overseen significant advancements including developing Service Plan targets that reflect continuous improvements and containing costs in light of pressures associated with an increasingly complex operating environment. BC Hydro notes that Gjoshe's claim that the increase in assets, debt and regulatory account balances as compared to domestic load as an indication of overall efficiency is incorrect and by applying this measure, BC Hydro could demonstrate improved efficiency by recovering regulatory balances more quickly through higher rates. With respect to rate competitiveness, BC Hydro states the potential impact of the Rate Smoothing Regulatory Account on the results of the Hydro Québec survey and the resulting impact on employee holdback pay was minimal to non-existent, noting the largest impact would have been in fiscal 2015 where total holdback pay would have been approximately $7,000 less than that actually paid with no impact in subsequent years.[368]

[364] MoveUP Final Argument, p. 9.
[365] CEC Final Argument, Section 1, p. 2, Section 6.5, pp. 57-58.
[366] BC Hydro Reply Argument (May 27, 2020), Part 6, Section B(a), pp. 43–44, paragraphs 95–96.
[367] Gjoshe Final Argument, Section BC Hydro Performance (Holdback) Pay, pp. 21–26.
[368] BC Hydro Reply Argument (May 27, 2020), Part 6, Section B(b), pp. 44–46, paragraphs 97–102.

Panel Discussion

The Panel finds BC Hydro's proposed salary increases to be reasonable. The Panel accepts that management and professional employees have experienced lower increases in the past as compared to unionized employees. We also accepts that the current total compensation package is on average 2.0 percent below median market rates. Both of these factors offset the fact that the labour rate increases BC Hydro proposes for management and professional staff are higher than the forecast rate of inflation over the same period.

On the other hand, the Panel acknowledges some interveners' concerns that BC Hydro must continue to control labour costs, which form a large portion of its base operating costs. However, we are not persuaded by the CEC's argument that the BCUC should not approve the proposed management and professional salary increases. To be clear, the Panel cannot reject a salary increase, merely deny its recoverability in customer rates. However, the savings to operating costs that would ensue from reducing the proposed management and professional salary increase by 0.5 percent would be minimal. The potential long term negative impact on productivity and employee retention resulting from the disallowance of the proposed management and professional salary increase outweighs the benefits of the resulting rate reduction in the Test Period.

With respect to holdback pay, BC Hydro appears to have a well-established process for evaluating performance against the individual and corporate objectives. Gjoshe raises a good point: the corporate objective related to BC Hydro's ranking in the Hydro Québec survey may be more favourably impacted through the write-off of the rate-smoothing account than excellence in management. Nevertheless, the Hydro Quebec survey has a minimal impact on holdback pay.

4.3.3.1.2 Number of Full Time Equivalents (FTE)

BC Hydro submits that apart from growth in the workforce directly related to increased capital investment, BC Hydro's number of FTEs has remained relatively flat since fiscal 2012 and is forecast to remain flat over the Test Period.[369] BC Hydro notes that FTEs represent the employee workforce that performs operating, capital and deferred work across the organization.[370] A continuity schedule that highlights the changes in total forecast FTEs from the fiscal 2017 to fiscal 2019 RRA is provided in the table below:[371]

Table 4-14: Changes in Total Forecast FTEs

FTE's *(including Regular and Overtime Hours)*	**Total**
F2019 RRA Plan FTEs (Schedule 16, line 52)	**6,365**
Workforce Optimization	536
Accenture Repatriation	423
Site C Project	240
F2019 Customer Metering adjustment	(1)
F2019 Safety - Business Continuity business case	2
Reduction in Apprentices Intakes and Graduations	(107)
Impact of organization changes since F2017-F2019 RRA	-
Miscellaneous changes for overtime FTEs	13
Miscellaneous changes for regular hour FTEs	6
F2020 RRA Plan FTEs (Schedule 16, line 52)	**7,477**
Site C Project	12
Reduction in Apprentice Intakes	(13)

[369] Exhibit B-1, Section 5.6, p. 5-28.
[370] Exhibit B-1, Section 5.6.4, p. 5-45.
[371] Exhibit B-1, Section 5.6.3, p. 5-43.

FTE's *(including Regular and Overtime Hours)*	Total
Miscellaneous changes for overtime FTEs	(5)
F2021 RRA Plan FTEs (Schedule 16, line 52)	**7,471**

The two programs that have the largest impact on the forecast number of FTEs in the Test Period are the Accenture repatriation and the Workforce Optimization.

BC Hydro began outsourcing certain work to Accenture in 2003, based on a 10-year contractual arrangement, which was later renewed for five more years. In 2008, BC Hydro stated it originally estimated it would save approximately $250 million over the 10-year life of the arrangement, and believed at that time it was on track to fully realize the originally anticipated financial benefits of the arrangement.[372] In May 2018, BC Hydro repatriated those services previously performed by Accenture back into BC Hydro.[373] As part of that repatriation, approximately 80 percent of Accenture unionized employees accepted jobs at BC Hydro with a resulting total FTE increase of 423.[374] BC Hydro submits the staffing levels seem appropriate, although it will continue to look for ways to innovate and improve the effectiveness and efficiency of the repatriated services.[375]

The Accenture repatriation restores direct control over key support and customer-facing functions and as a result, increases operating labour costs by $35.3 million from fiscal 2019 RRA plan to the fiscal 2020 forecast.[376] At the same time, overall, this repatriation effort reduces the Accenture Business Service Unit contract (operating) costs to nil and is forecast to save BC Hydro $8.2 million[377] annually in operating costs, starting in fiscal 2020.[378]

BC Hydro explains that the Workforce Optimization Program relates to its initiative to optimize the mix of internal labour and external contractors.[379] BC Hydro initiated this program in fiscal 2016 in response to changing business requirements that, in many instances, made it more cost-effective to hire FTEs rather than continuing to use contractors. The result is an increase of approximately 706 FTEs from fiscal 2016 through to fiscal 2020.[380] The program will close in fiscal 2020 and there are no planned contractor conversions in fiscal 2021.[381]

In the fiscal 2017 to fiscal 2019 RRA Decision, the BCUC observed that although BC Hydro anticipated short-term savings for the Workforce Optimization Program, there did not appear to be an assessment of the long-term effects and costs of hiring contractors as employees.[382] Consequently, in this Application, BC Hydro has assessed both the immediate and ongoing costs (over the term of employment) and future costs (i.e. retirement costs) associated with hiring internal FTEs as compared to continuing to use contractors in each workforce adjustment request.[383] FTE additions through the Workforce Optimization Program are fully funded through an equivalent cost reduction. In most cases, this means a reduction in funding for external contractors; however, in some

[372] BC Hydro 2009-2010 RRA, Exhibit B-20, p. 2.
[373] Exhibit B-1, Section 5.6.2, p. 5-38.
[374] Exhibit B-1, Section 5.6.2.2, p. 5-40; Appendix A, Schedule 5.0.
[375] Exhibit B-5, BCUC IR 49.4.
[376] Exhibit B-6, AMPC IR 3.1.3.
[377] Of the forecast $8.2 million in annual savings $7.0 million in annual savings were achieved prior to the Test Period and the remaining $1.2 million in annual savings will be achieved in fiscal 2020 [Exhibit B-1, Section 5.5.2.3, p. 5-25, Table 5-6].
[378] Exhibit B-1, Section 5.5.2.3, p. 5-25, Table 5-6; Section 5.6 p. 5-28.
[379] Exhibit B-1, Section 5.6.1, p. 5-29; Section 5.6.1.1, p. 5-30; Section 5.6.1.2, p. 5-32.
[380] Exhibit B-1, Section 5.6.1.4, p. 5-35; Exhibit B-5, BCUC IR 47.5.
[381] Exhibit B-12, BCUC IR 224.7.
[382] BC Hydro 2017-2019 RAA Decision, Section 3.2, pp. 34-35.
[383] Exhibit B-5, BCUC IR 46.4.

cases, FTE additions may be funded through reductions to other expenditures or by re-purposing other vacant positions.[384]

Positions of Parties

MoveUP notes that the increase in FTEs is primarily attributable to the Workforce Optimization Program and contends this program will continue to deliver savings as compared to contracting out the work. MoveUP agrees generally with the description of the Workforce Optimization program in BC Hydro's Final Argument. However, MoveUP submits that there is room for further progress at finding ratepayer savings through further labour repatriation efforts.[385]

BCSEA agrees that with respect to the Workforce Optimization Program, BC Hydro has adequately considered the longer term costs of replacing contractors with employees. BCSEA also agrees with BC Hydro to continue managing the business with a focus on total cost rather than FTEs and accepts that apart from growth in the workforce directly related to the increased capital investment and the Accenture repatriation, BC Hydro's FTEs have remained flat since fiscal 2012 and are forecast to remain flat over the Test Period.[386]

BCOAPO contends that excluding the Workforce Optimization Program, Accenture Repatriation, Site C and Smart Metering Infrastructure Project, BC Hydro's FTEs would be lower in fiscal 2020 and fiscal 2021 than they were in fiscal 2016 and as a result, does not consider BC Hydro's forecast increases in FTEs as being an issue.[387]

CEABC submits the underlying increase in operating costs is the size of BC Hydro's labour force and recommends that the BCUC direct BC Hydro to give a full report on the growth of its employee levels and compensation levels, to justify why BC Hydro requires 80 percent more employees today than in fiscal 2006, to deliver the same amount of energy to its domestic customers.[388]

BC Hydro contends that it has already provided in this proceeding extensive information on this topic, which CEABC has not acknowledged. Moreover, BC Hydro contends CEABC has had ample opportunity to assess the evidence and that reporting on this history would be unnecessary and inefficient.[389]

The CEC notes that the Workforce Optimization Program and the Accenture repatriation account for an increase of approximately 900 FTEs, which was partially offset by reduction of 75 apprentice intakes and graduations. The CEC questions whether BC Hydro offset the future cost of the increases to FTEs by reducing the number of apprentices and trainees.[390] The CEC argues that it is not in the long-term interest of ratepayers to be offsetting these large FTE increases with reductions in apprentices and trainees.[391] Further, the CEC also notes that there does not appear to be an assessment of the long term effects and costs of hiring contractors as employees and is uncertain about the extent to which BC Hydro considered human resource requirements and all the softer implications of adding employees.[392] The CEC questions whether the addition of the FTEs from the Workforce Optimization Program and Accenture repatriation could have a deleterious effect on long-term operating costs, and whether a change in economic conditions could make BC Hydro vulnerable to increased costs that may exceed anticipated savings from the Accenture repatriation.[393]

[384] Exhibit B-1, Section 5.6.1.3, p. 5-34, Footnote 161.
[385] MoveUP Final Argument, Operating Costs, p. 11.
[386] BCSEA Final Argument, Section F, p. 24; Section G, p. 26.
[387] BCOAPO Final Argument, Operating Costs, Increases in FTEs versus Operating Costs, p. 28.
[388] CEABC Final Argument, Section B, pp. 14, and 15–16.
[389] BC Hydro Reply Argument (May 27, 2020), Part 6, Section C, p. 46, paragraphs 103–104.
[390] CEC Final Argument, Section 6.3, p. 49, paragraphs 239; p. 50, paragraph 241.
[391] CEC Final Argument, Section 6.3, p. 50, paragraphs 243
[392] CEC Final Argument, Section 6.4, pp. 51–52, paragraphs 250–251 and 253.
[393] CEC Final Argument, Section 6.4.1, p. 53, paragraphs 260–262.

BC Hydro submits that the CEC's claims are not supported. BC Hydro states that the CEC's inference is incorrect: there is no connection between the increase in FTEs through the Workforce Optimization and Accenture repatriation and the reductions in apprentices and trainees. BC Hydro submits the reduction in apprentices and trainees reflects declining attrition in journey people positions and was not prompted by FTE increases resulting from the Workforce Optimization Program or the Accenture repatriation. Further, BC Hydro contends that each workforce adjustment request assessed the duration of BC Hydro's needs. BC Hydro states that it added FTEs only for ongoing and sustainable resourcing needs where the flexibility with contractors was unnecessary and maintains that there are "soft cost" implications with contractors that would also impact customers. Lastly, with reference to vulnerabilities arising due to a change in economic conditions, BC Hydro contends that these types of issues give rise to cost impacts irrespective of whether BC Hydro has repatriated its contract with Accenture.[394]

Panel Discussion

The Panel is satisfied that, as directed by the BCUC, BC Hydro has adequately considered the long-term effects of the Workforce Optimization program. The evidence supports that BC Hydro's process accounted for both the short-term and long-term costs when evaluating whether to hire internal FTEs rather than continuing to use external contractors. While there are "soft cost" implications that BC Hydro may not have considered in the hiring of FTEs in lieu of contractors, we accept BC Hydro's position that there would be similar "soft cost" considerations with hiring or maintaining contractor positions (i.e. procurement processes, contract management, etc.).

The Panel also accepts BC Hydro's explanation that it needs fewer new apprentices and trainees because of lower attrition of journey people. We are not persuaded by the CEC's speculation that BC Hydro reduced the number of apprentices and trainees to offset the increase in FTEs through the Accenture repatriation and Workforce Optimization.

While it may appear counter-intuitive that both the Accenture outsourcing and subsequent repatriation resulted in annual cost savings, the Panel accepts that the Accenture outsourcing may have produced cost efficiencies, which BC Hydro is able to subsequently capitalize on and further improve upon repatriation of services from Accenture. The Panel accepts BC Hydro's decision to repatriate Accenture services on the basis that BC Hydro could further benefit from the process improvement and cost reduction that Accenture achieved.[395]

The Panel denies CEABC's request to direct BC Hydro to provide a report justifying the employee growth since fiscal 2006. In response to IRs, BC Hydro has already provided breakdowns of FTEs from fiscal 2012 through to and including the Test Period and provided rationale for the changes. Therefore, there is limited value in directing BC Hydro to prepare such a report as part of its next RRA.

The Panel acknowledges there will be an increase in the number of FTEs in the Test Period, and that is primarily driven by the Workforce Optimization Program and the Accenture repatriation, and to a lesser but still significant extent, Site C. In consideration of the nature, level of complexity and volume of work performed by BC Hydro, the Panel does not consider the number of FTEs to be unreasonable.

4.3.3.2 Storm Restoration

BC Hydro forecasts storm restoration costs using a five-year average of normal weather years.[396] In recent years, BC Hydro has experienced higher levels of storm related damage, which has caused the five-year average of storm restoration costs to increase by $11.1 million in fiscal 2020, with no further increase in fiscal 2021. The

[394] BC Hydro Reply Argument (May 27, 2020), Part 6, Section D, pp. 47-48, paragraphs 105–109.
[395] BC Hydro Final Argument, Section F(b), p. 79, paragraph 175.
[396] Order G-16-09, Reasons for Decision on the Fiscal 2009/2010 RRA.

Test Period forecast is based on the 5-year average from fiscal 2014 to fiscal 2018 (average $17.8M)[397] and was not updated for fiscal 2019 actual results when the Evidentiary Update was prepared. If BC Hydro had used the five-year average from fiscal 2015 to 2019, the average would increase to $22.0 million, because of a windstorm in December 2018.[398]

BC Hydro evaluated other methodologies including using longer and shorter periods as the basis of the calculation for the average actual storm restoration costs. It found the shorter periods may give too much weight to recent years, and longer terms give too much weight to historical years that may not reflect recent trends.[399] Any variances between planned and actual storm restoration costs are deferred to the Storm Restoration Costs Regulatory Account which means that customers pay the actual storm restoration costs incurred and these variances are recovered over the next test period.[400]

Positions of Parties

Interveners do not dispute the appropriateness of recovering actual storm restoration costs. AMPC and BCOAPO submit that the five-year rolling average forecast for storm restoration costs should be updated to include fiscal 2019 actual results as provided as part the Evidentiary Update.[401] The CEC takes no issue with BC Hydro's use of the five-year average methodology but submits that it may be worthwhile to continue to review this methodology with an eye to moving to a three-year average as storm restoration costs continue to rise.[402]

BC Hydro disagrees that it should revise its storm restoration forecast costs using fiscal 2019 actual costs. BC Hydro explains that the content of the Evidentiary Update focuses on material changes, and not areas in the Application that remain a reasonable basis for setting rates, such as storm restoration costs.[403] BC Hydro emphasizes that significant work would be required to update all inputs in its rates model.[404]

Panel Determination

The Panel is persuaded that BC Hydro's use of a five-year rolling average remains a reasonable basis on which to forecast storm restoration costs, so as to avoid giving too much weight to past years which may no longer be indicative of current trends, or too much weight to more recent years that may be skewed due to a unique/rare storm event(s). The fact that variances in storm restoration costs are recorded in a regulatory account ensures that customers only pay for the actual costs regardless of the forecast amounts.

In the Panel's view, however, the calculation of the rolling five-year average for the storm restoration forecast should incorporate the fiscal 2019 actuals. The Panel acknowledges BC Hydro's perspective that the forecast storm restoration costs as calculated in the Application continued to be a reasonable estimate and accordingly were not updated with the fiscal 2019 actuals as included in the Evidentiary Update. However, the Panel reminds BC Hydro that directive 42 of Order G-16-09 specifies that the storm restoration costs "be calculated as the average of actual costs for the five most recent 'normal weather' years." Upon the filing of the Evidentiary Update, the fiscal 2019 actuals became one of the five most recent 'normal weather' years. Unless justification can be provided that fiscal 2019 is not considered a 'normal weather' year the forecast storm restoration costs should have been updated to include the fiscal 2019 actual. Applying the directive as stated avoids discretion and debate over which historical storm restoration costs are to be applied when forecasting costs as part of an RRA. **Therefore, the Panel directs BC Hydro to update the storm restoration cost forecast in the Test Period by using the fiscal 2015 to fiscal 2019 actual results.**

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397 Exhibit B-1, Section 5.5.2.2, p. 5-23, Table 5-5.
398 Exhibit B-5, BCUC IR 63.11; Exhibit B-12, BCUC IR 232.1.
399 Exhibit B-12, BCUC IR 232.4.1.
400 Exhibit B-12, BCUC IR 232.4.
401 AMPC Final Argument, p. 31, paragraph 106; BCOAPO Final Argument, Operating Costs, Storm Restoration Costs, p. 29.
402 CEC Final Argument, Section 6.6.3, p. 67, paragraph 329.
403 BC Hydro Reply Argument (May 27, 2020), p. 138.
404 BC Hydro Reply Argument (May 27, 2020), Part 12, Section D(a), p. 142, paragraphs 339–341.

4.3.3.3 Vacancy Factor Savings

To offset cost pressures, BC Hydro has identified vacancy factor savings as a method to reduce costs in the Test Period. In previous years, a varied approach was taken amongst the KBUs where some KBUs reduced their labour budgets to recognize positions that would not remain filled 100 percent of the time.[405] Reductions were embedded within labour costs and were not specifically tracked.[406] In contrast, for the Test Period, BC Hydro has taken a consistent approach to assess each KBU and identify any budget reductions associated with unfilled positions. Across all KBUs, labour budgets have been reduced by an additional $5.6 million in total.[407] BC Hydro submits the vacancy factor savings are an estimate applying a judgement-based assessment, that may or may not materialize.[408] If labour costs are lower than planned in the Test Period, the variance would be managed within BC Hydro's overall operating cost budget and may be used to manage unanticipated cost pressures as they arise over the fiscal year.[409]

Positions of Parties

Interveners make no submissions on vacancy factor savings.

Panel Determination

BC Hydro's vacancy factors savings have merit. However, since the Test Period is the first time that BC Hydro is forecasting vacancy factor savings on a consistent organization-wide basis, the Panel sees value in tracking the accuracy of the forecast vacancy factor savings as they reduce the total revenue requirements for the applicable test period. **Accordingly, the Panel directs BC Hydro to begin tracking and measuring the annual actual vacancy factor savings and reporting on these in future RRAs, as well as providing the rationale for any significant differences from the forecast savings.**

4.3.4 Cybersecurity

BC Hydro's Technology Strategy and 5-Year Plan state BC Hydro uses a risk-based approach to cybersecurity and information protection and new investments are made based on compliance requirements, emerging threats, and retaining its risk profile. In order to improve its overall risk profile, BC Hydro intends to apply information technology cybersecurity best practices to its operational technology environments and develop an information protection program to improve security of its systems of record, information sharing and records management platforms.[410]

Independent of BC Hydro's 5-Year Plan the Office of the Auditor General of BC (BC OAG) examined whether BC Hydro was effectively managing cybersecurity risk by detecting, and responding to, security incidents on its industrial control systems operating the electric power infrastructure and released its report in March 2019. Based on these results BC Hydro is currently conducting a risk assessment of the environments identified by the BC OAG and following the results of this assessment, will prioritize investments and efforts that will address the audit recommendations. Although the costs to perform the risk assessment are estimated to be $0.3 million, the expected costs of implementing the remediation activities are not known and are not included in the RRA.[411]

BC Hydro submits it maintains a strong cybersecurity and compliance culture, which is supported by two steering committees: the Mandatory Reliability Standards (MRS) Steering Committee and the Cybersecurity Oversight Committee. The MRS are adopted in BC through an annual assessment process with the BCUC which

[405] Exhibit B-5, BCUC IR 43.1.
[406] Exhibit B-12, BCUC IR 230.4.1.
[407] Exhibit B-1, Section 5.5.2.3, pp. 5-24–5-25, Table 5-6.
[408] Exhibit B-12, BCUC IR 230.8
[409] Exhibit B-12, BCUC IR 230.1.1.2.
[410] Exhibit B-1, Appendix L, p. 15.
[411] Exhibit B-5, BCUC IR 123.1, 123.2.1.

allows BC Hydro to stay aligned with the new and revised versions of the MRS, including the NERC Critical Infrastructure Protection (CIP) standards.[412] The planned operating costs related to MRS compliance are $17.4 million in fiscal 2020 and $14.7 million in fiscal 2021. The decrease in MRS compliance costs from fiscal 2020 to fiscal 2021 is primarily due to the elimination of payments to Peak Reliability for the reliability coordinator fees following BC Hydro's appointment as reliability coordinator for British Columbia in 2019.[413]

BC Hydro recognizes that cybersecurity is one area where it should expect operating cost increases beyond inflation in future test periods.[414] However, it submits it is confident that there are sufficient funds in the proposed budget to meet the base requirements for cybersecurity in the Test Period.[415] BC Hydro notes that cost increases in cybersecurity have been largely driven by NERC compliance requirements as well as protection against an increased number and complexity of cybersecurity threats in the energy sector.[416]

Positions of Parties

Apart from BCSEA, interveners did not make submissions on costs related to cybersecurity. In BCSEA's view, there is no evidence of any deficiency in BC Hydro's approach to cybersecurity in the Test Period or beyond. Further, it agrees that increased costs are being driven by more stringent regulatory requirements in various areas including cybersecurity, and that these are important societal objectives that are part of BC Hydro's corporate responsibilities.[417]

Panel Determination

Cybersecurity risks not only affect BC Hydro, but also have the potential to impact the North America Bulk Electric System. MRS standards mitigate this specific cybersecurity related risk and BC Hydro is required to comply with those standards. It is important to be proactive and have an effective infrastructure that can detect, mitigate damage and quickly respond to incidents.

Since September 2019, the BCUC has issued two Notices of Penalty to BC Hydro for Critical Infrastructure Protection violations. The Notices of Penalty levied administrative penalties totalling approximately $1 million.[418] The Panel is concerned that the violations that gave rise to these penalties are the result of underspending. However, given the confidential nature of the subject matter, we make no further comment. We recommend that BC Hydro address its cybersecurity program funding, on a confidential basis if appropriate, in the next RRA.

In addition to those portions of BC Hydro's operations that are part of the North America Bulk Electric System, there are other areas, such as distribution and head office systems that also provide potential cybersecurity vulnerabilities. The Panel is equally concerned with these areas, as any successful cybersecurity penetration has the potential to significantly affect the reliability of electricity supply and the security of customer's personal information. There are no imposed standards in these areas and there is not enough evidence in this proceeding to make any determinations on the adequacy of BC Hydro's programs in these areas. **However, given the Panel's concerns, we direct that BC Hydro ensure that it also address the adequacy of its cybersecurity programs with respect to its distribution and head office systems in the next RRA.**

We also acknowledge Mr. O'Riley's comments in this proceeding that the next RRA will request increases "beyond inflation" for both cybersecurity and vegetation management, and we encourage BC Hydro to ensure that both of these programs are adequately funded.

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412 Exhibit B-5, BCUC IR 123.7
413 Exhibit B-5, BCUC IR 123.12
414 Transcript Volume 5, pp. 359–360; Exhibit B-59, p. 2.
415 Transcript, Volume 7, p. 981.
416 Exhibit B-1, p. 5E-26.
417 BCSEA Final Argument, Section B, p. 10, paragraph 27; Section J(d), p. 34, paragraph 135.
418 Order R-30-19; Order R-18-20.

4.3.5 Vegetation Management

Vegetation management can have a substantial effect on the extent of major storm damage and thus storm restoration costs. Mr. O'Riley testified that the approach utilities are taking towards vegetation management is changing significantly and attributes this is in part due to:[419]

- Increased prevalence of storms which impacts reliability, particularly in rural areas;
- Increased concern for the electrical utility industry with respect to forest fires; and
- Adherence to the mandatory reliability standards that govern vegetation and the associated penalty costs if a utility is found in violation.

Despite forced outages caused by vegetation steadily increasing on the distribution system from 1,689 in fiscal 2015 to 2,920 in fiscal 2019[420] vegetation management costs have remained relatively stable from fiscal 2015 to fiscal 2019. Over the period from fiscal 2015 to fiscal 2019 the distribution vegetation management program averaged $24.0 million actual costs (and $24.0 million RRA plan costs) and forecast costs for the Test Period remain consistent with past averages ($24.4 million in each of fiscal 2020 and 2021).[421]

Mr. Kumar acknowledges that vegetation management, in particular on the distribution side, is an area of concern that BC Hydro will evaluate.[422] Mr. O'Riley states that BC Hydro will update the vegetation management program for the next test period when it brings forward a plan that demonstrates where work is required and where benefits will be achieved.[423] BC Hydro notes that spending in this area is likely to increase in future test periods to address regulatory standards and growing public aversion to wildfire risk.[424] Mr. Kumar notes, as a complicating factor, that BC Hydro and Telus jointly own a number of power system poles and that BC Hydro must consult with TELUS to increase the distribution vegetation management budget.[425]

Positions of Parties

Interveners take no position on BC Hydro's vegetation management costs.

Panel Determination

We agree with BC Hydro that vegetation management is an area of concern that requires evaluation. In particular, the BCUC recently directed an onsite investigation of BC Hydro regarding FAC-003 vegetation-related events. The purpose of MRS Standard FAC-003 is to maintain a reliable electric transmission system by using a defensive in-depth strategy to manage vegetation located on transmission rights of way and minimize encroachments from vegetation located adjacent to the right of way. Since vegetation growth is constant and always present, unmanaged vegetation poses an increased outage risk, especially when numerous transmission lines are operating at or near their rating. This can present a significant risk of consecutive line failures when lines are experiencing large sags.[426]

In addition to possible vegetation management issues on BC Hydro's transmission system, we are also concerned with whether the appropriate practices are in place on its distribution system. Proper vegetation management is a key way to reduce storm restoration costs, to minimize outages for BC Hydro customers and to protect the integrity of the North American bulk electric system.

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[419] Transcript, Volume 5, p. 505, lines 2-10; 17-21; p. 506, lines 6-12.
[420] Exhibit B-12, BCUC IR 237.9.
[421] Exhibit B-5, BCUC IR 63.15; Exhibit B-12, BCUC IR 237.1.
[422] Transcript Volume 13, p. 2487.
[423] Transcript Volume 5, p. 506, lines 20-26; p. 507 lines 1-4.
[424] BC Hydro Final Submission, p. 101.
[425] Exhibit B-5, BCUC IR 72.3.
[426] https://www.ordersdecisions.bcuc.com/bcuc/orders/en/item/479996/index.do; https://www.ferc.gov/sites/default/files/2020-04/fac-003-4.pdf

However, despite our concern, we are not approving more than what BC Hydro has requested in its budget for vegetation management in the Test Period. This is because BC Hydro would not be able to adequately spend the extra funds on vegetation management in the few months remaining in the Test Period. Further, it is management's responsibility to request the amount that it thinks it needs to carry out a proper vegetation management program.

The Panel supports BC Hydro's commitment to making vegetation management a key priority to be addressed as part of the next RRA and looks forward to receiving BC Hydro's future vegetation management plan that addresses the work required and the benefits to be achieved over the next test period. **However, given the Panel's concerns, we direct that BC Hydro ensure that it also address the adequacy of its vegetation management funding in its next RRA.**

4.3.6 Safety Metrics and Training

Despite a reduction in injuries and fatalities due to electrical worker accidents, BC Hydro has a higher all injury frequency rate and lost time injury rate as compared to those of its industry peers in the Canadian Electricity Association. Accordingly, BC Hydro's focus is to reduce the frequency of incidents leading to injury. Over the Test Period BC Hydro intends to focus on key safety initiatives which include among other things, investing in its Safety and Health Management system, improving incident reporting, building better corrective actions and performing job hazard assessment of the work to improve training and procedures.[427] As noted earlier, Mr. O'Riley expects that BC Hydro's operating costs for employee training necessary to meet evolving safety requirements will exceed inflation in future revenue requirement processes.[428]

BC Hydro's Service Plan includes a lost time injury frequency target. An excerpt of the lost time injury frequency performance measures as presented in the 2018/2019 Service Plan are reproduced in the table below:

Table 4-15: Lost Time Injury Frequency

Performance Measure(s)	2016/17 Actuals	2017/18 Actuals	2018/19 Target	2018/19 Actuals	2019/20 Target	2020/21 Target
4b. Lost Time Injury Frequency [Number of employee injury incidents resulting in lost time (beyond the day of the injury) per 200,000 hours worked]	1.04	0.88	0.85	0.87	0.80	0.80

In order to achieve the fiscal 2020 and fiscal 2021 targets, BC Hydro has implemented the following strategies:[429]

- Maintain zero fatality and permanently disabling injuries by finalizing clarification updates to specific key rules and continuing to analyze near misses and the corrective actions for these incidents that had the potential for a serious incident.
- Improve the lost time injury frequency rate through continued partnership with WorkSafeBC on the Recover at Work Program and by way of enhancements to this program.
- Improve the all injury frequency by expanding BC Hydro's ergonomics program.

[427] Exhibit B-1, Section 5D.2, pp. 5D-2, 5D-5.
[428] Transcript 5, pp. 358-359.
[429] Exhibit B-1, Section 5D.2, pp. 5D-3, footnote 234 and 235; Exhibit B-5, BCUC IR 87.1.
Lost Time Injury Frequency is determined by multiplying the number of Lost Time Injuries incurred, by 200,000 (to represent regular hours worked per employee in a year) and then dividing by the total number of hours worked in that period.
All Injury Frequency is determined by multiplying the number of Lost Time Injuries and Medical Treatment Injuries incurred in a year, by 200,000 (to represent regular hours worked per employee in a year), then dividing by the total number of hours worked in that period.

Mr. O'Riley testified that one of the principles applied in setting these targets is that they should be achievable and set the organization up for success. He stated that BC Hydro's management takes responsibility for the results and as such the targets are set to a level where employees can make improvements while at the same time achieve what management has set out for them.[430]

Forecast operating costs for the Safety Business Group are approximately $56.8 million in fiscal 2020 and approximately $57.5 million in fiscal 2021. The fiscal 2020 forecast represents a $1.9 million and $3.2 million net increase compared to the fiscal 2019 forecast and actual amounts, respectively. The increases in fiscal 2020 and fiscal 2021 are primarily attributable to labour rate increases.[431]

Positions of Parties

Apart from BCSEA and the CEC, interveners did not take a position on safety metrics. BCSEA supports the higher costs that are driven by more stringent regulatory requirements including safety. It views these as important societal objectives and supports BC Hydro in meeting its corporate responsibilities in this regard.[432]

The CEC submits that the safety and well-being of BC Hydro's employees and the public are of the highest importance and it has reviewed the evidence in the Application with regards to the Safety Business Group and has no issues.[433]

Panel Determination

The Panel acknowledges that BC Hydro is implementing strategies to reduce the number of lost time incidents and appreciates the significance that BC Hydro places on safety by way of incorporating these objectives into the Service Plan.

Apart from the labour rate increases the Safety Business Group's forecast operating costs are consistent with prior years, although BC Hydro acknowledges it must increase its spending on employee training to meet evolving safety requirements. The Panel also notes that BC Hydro's investment in safety has achieved a reduction in the lost time injury frequency. In our view, by focusing safety initiatives on those areas identified as being in greatest need for improvement, BC Hydro can better align its safety initiatives with outcomes. **Therefore, the Panel directs BC Hydro, in its fiscal 2023 RRA, to evaluate its safety data to determine whether it could achieve more aggressive lost time injury frequency and lost time injury duration targets, and if so, the additional costs, if any, that achieving such more aggressive targets may entail.**

In our view, considering the danger involved in working with high voltage lines and BC Hydro's lost time injury and duration metrics relative to those of its peer group, the Panel recommends that BC Hydro continue to include safety as a high priority in its Service Plan.

4.3.7 Overall Conclusion on Operating Costs

In evaluating the reasonableness of BC Hydro's forecast base operating costs for the Test Period, the Panel has adopted a three-step approach. First, we examined BC Hydro's governance of its budgeting process; its top-down bottom-up approach appears to provide the requisite oversight of operating costs.

Second, we examined the overall reasonableness of BC Hydro's forecast base operating costs over the fiscal 2019 RRA and actual costs. The BCUC approved the forecast 2019 budget of $769.5 million in the 2017 to 2019 RRA Decision. Actual results presented in the Evidentiary Update of $757.2 million are slightly lower than the approved budget. In reviewing BC Hydro's fiscal 2020 forecast of $793.8 million, we note this is an increase of

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[430] Exhibit B-12, BCUC IR 242.2; Transcript, Volume 6, p. 721.
[431] Exhibit B-1, Section 5D.3, p. 5D-11, Table 5D-3.
[432] BCSEA Final Argument, Section B, p. 10, paragraph 27.
[433] CEC Final Argument, Section 1, p. 2.

3.2 percent over the fiscal 2019 budget, which is not an unreasonable increase. We previously found the increase in operating costs for the Test Period to be reasonable therefore we are satisfied that the forecast base operating costs for the Test Period are reasonable.

Finally, we assessed the key drivers of the increase in base operating costs including those areas where BC Hydro achieved material offsetting savings and/or absorbed new work or cost pressures. These key drivers relate primarily to labour, such as salary increases and number of FTEs. Storm restoration costs represent another key driver, in particular with the Panel's conclusion that BC Hydro should revise the forecast to include 2019 actuals. The Panel acknowledges BC Hydro's efforts to minimize the increase in base operating costs. These efforts include identifying vacancy factor savings and eliminating the unallocated funds budget.

Based on our review and with the exception of the directions discussed in this Decision, the Panel finds BC Hydro's forecast base operating costs for the Test Period 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 two-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.

BC Hydro sets out its proposed capital additions and capital expenditures during the Test Period in Chapter 6 of the Application, and states that it has moderated its forecast capital spending for the period fiscal 2020 to fiscal 2024 since its fiscal 2019 to fiscal 2028 Capital Plan (Previous Capital Plan) because reduced forecast for electricity demand has enabled it to change the timing of some planned investments.[434] BC Hydro submits that its planned level of capital investment from fiscal 2020 to fiscal 2024 reflects an appropriate balance of system performance, risk and affordability, and that further reductions to forecast capital expenditures would degrade asset condition and asset health more than anticipated, with a corresponding negative impact on customer service levels.[435]

BC Hydro submits that the following items demonstrate the reasonableness of its Test Period capital forecasts: [436]

1. BC Hydro has provided a significant amount of evidence in support of the Test Period capital forecasts, consistent with BC Hydro's approved Capital Filing Guidelines.
2. BC Hydro's Test Period capital forecast is the product of a robust capital planning process that incorporates top-down limitations, and risk-based project prioritization to balance affordability, system performance and risk. BC Hydro has developed an ex-plan governance process to respond to evolving needs.
3. BC Hydro has reduced its capital forecast to balance affordability, system performance and risk.
4. BC Hydro delivers capital projects efficiently and effectively, as demonstrated by its ability to deliver it[s] portfolio of projects within 5% of Original Approved Expected Cost.
5. BC Hydro's capital asset management processes have been endorsed by third parties, including the Auditor General and project management organizations.
6. BC Hydro's Amortization of Capital Additions Variance Accounts will ensure that customers only pay actual costs.

[434] Exhibit B-1, Figure 6-5, p. 6-20.
[435] BC Hydro Final Argument, pp. 121–122.
[436] BC Hydro Final Argument, pp. 108–109.

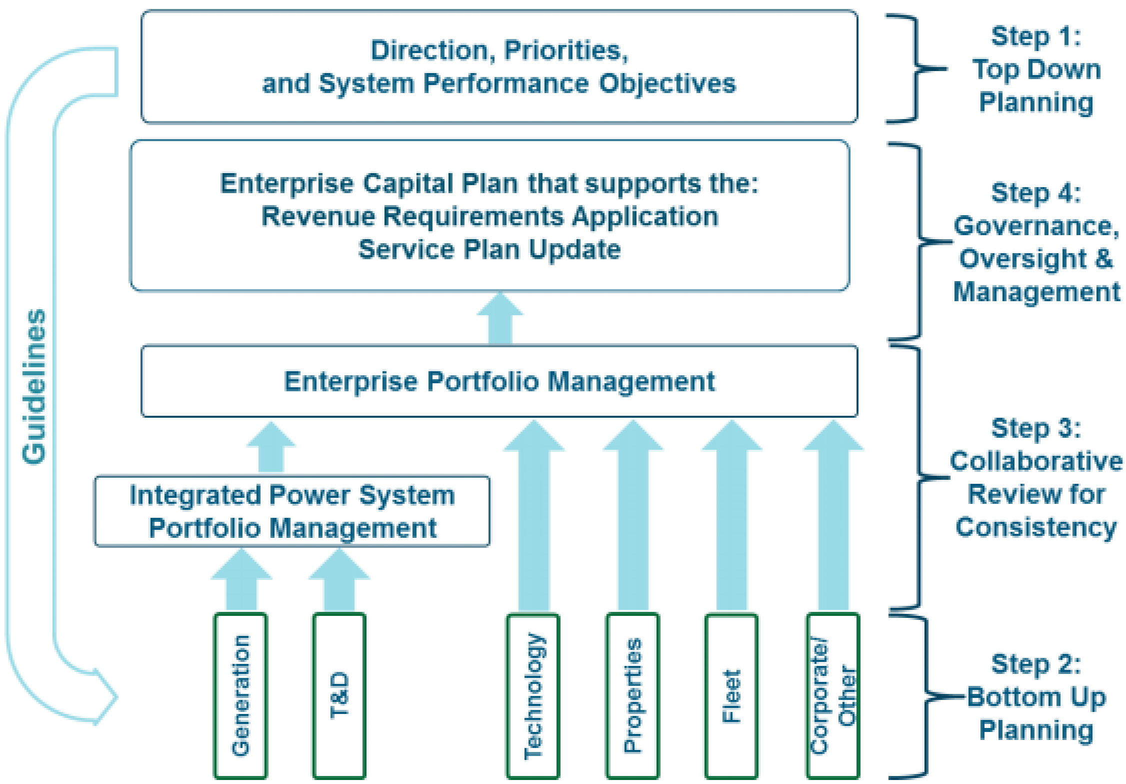
7. BC Hydro has answered specific issues raised in the proceeding relating to planning, project execution and cost recovery.
8. BC Hydro is managing its industrial load interconnection requests well, with study times comparing well against BC Hydro's own business practice timelines and the practices at other utilities. BC Hydro is also continuing to look for opportunities to improve the process.

BC Hydro submits that it has well-developed planning and delivery processes, that it is delivering its projects effectively and efficiently and that the BCUC should find the resulting planned capital additions and expenditures for the Test Period reasonable.[437]

4.4.1 BC Hydro's Capital Planning Process

BC Hydro submits it has "planning and governance processes in place across the organization so that the capital investments required to sustain, expand and operate its assets appropriately balance affordability and system performance".[438] BC Hydro summarizes its capital planning process in the following diagram:[439]

Figure 4-3: Annual Enterprise Capital Planning Process



The capital plan is developed using a top-down and bottom-up approach overseen by the internal Enterprise Capital Planning Management Group.[440] Next, potential investments are scored using a risk matrix and/or a value prioritization, the outcome of which is a rating criterion for each project as either "mandatory", "committed", or "to be prioritized".[441] Then a collaborative peer review takes place, using the prioritization

[437] BC Hydro Final Argument, p. 171.
[438] Exhibit B-1, p. 6-17.
[439] Exhibit B-1, Figure 6-4, p. 6-19.
[440] Exhibit B-1, pp. 6-18–6-19.
[441] Exhibit B-1, pp. 6-29–6-30.

values as an input.[442] The final step is review and approval of the capital plan by the Executive team. An ex-plan governance process considers budget reallocations after the plan is approved.[443]

BC Hydro spoke to the affordability of its capital plan in its testimony at the Oral Hearing:[444]

> Well, I would actually say affordability is captured on three tiers in our capital planning process. The first tier would be in the setting of our strategic objectives and establishing the financial targets for our capital plan. The second would be during bottom-up planning, when we are identifying the specific projects to undertake. And then the third tier would then be in the prioritization phase of the capital planning and ensuring that we are undertaking the projects that are bringing the greatest value within our financial targets.

BC Hydro further testified to BC Hydro's capital project risk and value-based prioritization process, which has been developed as part of ongoing capital planning process improvements over the last 12 years.[445]

BC Hydro submits that its rigorous capital planning processes should provide considerable comfort that the forecast expenditures and additions in the Test Period are reasonable.[446]

Positions of Parties

The CEC does not agree that the cost-effectiveness of BC Hydro's spending can be evaluated against other jurisdictions, as other utilities may have different cost structures and capabilities. The CEC submits that it is necessary for BC Hydro to compare its cost-effectiveness against its own historical performance in order to evaluate whether it is operating as cost-effectively as possible.[447]

The CEC considers that it is "very difficult if not impossible" for the BCUC to assess whether BC Hydro's forecast expenditures are cost-effective because of the limited information submitted and limited follow-up on whether the value of the expenditures has been achieved. The CEC recommends the BCUC to develop its oversight process to assess the cost-effectiveness of BC Hydro's capital expenditures over time.[448]

BC Hydro submits that the Panel should reject the CEC's recommendation. BC Hydro submits that the BCUC recently rejected the CEC's proposal to adjust its capital oversight process to assess cost-effectiveness in the BC Hydro Review of Regulatory Oversight of Capital Expenditures and Projects proceeding (Capital Expenditures Review); the CEC has submitted no evidence or reasoning to explain why the BCUC should reach a different conclusion now. Nevertheless, BC Hydro states it will consider options to improve its evaluation of completed projects as part of its commitment to continuous improvement and will report on any significant changes in its capital management processes in the next RRA.[449]

Ince discusses BC Hydro's risk matrix: [450]

> BC Hydro's risk-based capital prioritization is a valuable tool in assisting with the decisions that allocate [scarce] capital. Nevertheless, this topic within the written and oral hearing phases was frustrating, in that there did not seem to be a clear line of sight between BC Hydro's risk identification, prioritization and mitigation that includes a common basis for the balancing the

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[442] Transcript Volume 12, p. 2304, lines 6-10 (Pinksen).
[443] Exhibit B-1, p. 6-31.
[444] Transcript Volume 11, p. 1850, lines 4-15 (Pinksen).
[445] Transcript Volume 11, p. 1; Transcript Volume 11, p. 1854, line 5 to p. 1855, line 11. (Kumar).
[446] BC Hydro Final Argument, p. 111.
[447] CEC Final Argument, p. 76.
[448] CEC Final Argument, p. 78.
[449] BC Hydro Reply Argument (May 27, 2020), pp. 64–65.
[450] Ince Final Argument, p. 17.

risks being mitigated. There seemed to be no quantification of the value of reliability or safety, challenging but necessary metrics required in making difficult prioritizations.

Ince recommends BC Hydro continue to improve its capital planning process and increase visibility of how the trade-offs between risks are made.[451]

BC Hydro disagrees with Ince's impression of its processes. BC Hydro submits that its enterprise-wide framework for capital prioritization does consider "financial, reliability, safety, environmental and reputational impacts" associated with delaying the investment and making capital prioritization decisions.[452] Further, BC Hydro states that the Auditor General reviewed BC Hydro's capital prioritization process as part of an audit and made no recommendations regarding BC Hydro's capital planning processes.[453]

BCOAPO states, "One issue with BC Hydro's current prioritization process is that while BC Hydro's Corporate Risk Matrix considers a number of 'risks' (e.g., financial, reliability, safety, environmental and reputational), the risk 'score' for purposes of prioritization is based on 'the highest risk that the project is exposing the organization to.'"[454] BCOAPO acknowledges BC Hydro has a "fairly robust capital planning process", but supports efforts to improve the process.[455]

CEABC recommends that BC Hydro revamp its capital expenditure prioritization to give more weight to capital expenditures that have the potential to increase revenues by increasing energy sales. CEABC argues that BC Hydro's capital is all spent on the assumption that ratepayers will pay for it through rate increases, and not on initiatives that would earn money. [456]

BC Hydro submits that the BCUC should reject CEABC's recommendation to change its prioritization of capital expenditures to favour increased energy sales. BC Hydro argues that there is no evidence it has declined to pursue projects which would increase energy sales as a result of its capital prioritization process and provides examples of initiatives such as EV charging stations which will increase energy sales. BC Hydro adds that artificially giving increased weight to projects which increase energy sales would distort its prioritization process and could lead to imprudent decisions and possibly stranded assets.[457]

BC Hydro submits its capital planning process falls within the "exclusive purview of utility management, not the BCUC."[458]

Panel Determination

The Panel finds that BC Hydro's capital planning process is reasonable.

In an RRA proceeding, the Panel's responsibility is to ensure that a utility's rates are not "unjust, unreasonable, unduly discriminatory or unduly preferential", as required by section 59 of the UCA. Capital expenditures are a significant component of BC Hydro's total expenditures, flowing through to ratepayers through amortization and finance costs. For BC Hydro's rates to be just and reasonable, the Panel must find its capital expenditures are the amount required to provide safe and reliable service, and no more.

The Panel agrees with BC Hydro that the BCUC does not manage BC Hydro's capital expenditure prioritization processes. However, the BCUC does have jurisdiction to determine whether BC Hydro's capital expenditures are

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451 Ince Final Argument, p. 17.
452 BC Hydro Reply Argument (May 27, 2020), p. 60.
453 BC Hydro Reply Argument (May 27, 2020), p. 61.
454 BCOAPO Final Argument, p. 32.
455 BCOAPO Final Argument, p. 33.
456 CEABC Final Argument, pp. 21–22.
457 BC Hydro Reply Argument (May 27, 2020), pp. 61–62.
458 BC Hydro Reply Argument (May 27, 2020), p. 59.

recoverable from ratepayers, and the Panel considers it appropriate to review the process by which capital expenditures were selected in making that determination. The BCUC may review any capital expenditure for prudency of execution once the associated asset is in service. However, it is impractical to review every capital project for a utility the size of BC Hydro. Instead, if the Panel is satisfied that capital spending is the result of a sound selection process, prudence reviews can focus on exceptional items.

Sustainment capital expenditures are a good example of this. BC Hydro has concluded, in a top-down analysis, that sustainment capital spending may safely be reduced for the Test Period. If presented with any one proposed sustainment capital project in isolation, the BCUC might find it reasonable. However, it is also appropriate for the BCUC to consider the overall level of sustainment spending for reasonableness, and this overall level of sustainment spending might not be sufficient to allow for some otherwise reasonable individual sustainment projects.

The Panel finds that the CEC's focus on cost effectiveness is both useful and appropriate. In the Capital Expenditures Review, the BCUC did not accept the CEC's specific recommendations with regards to additional BCUC oversight processes. However, in that proceeding, the BCUC made no finding that cost-effectiveness was an inappropriate consideration when reviewing whether BC Hydro's capital expenditures should be recoverable from ratepayers. The CEC recommends that the BCUC should assess the cost-effectiveness of BC Hydro's capital expenditures over time, and the Panel agrees. Each RRA provides the BCUC an opportunity to review BC Hydro's proposed capital spending, and the Panel finds it is appropriate for the BCUC to examine trends in cost-effectiveness, for example with respect to sustainment capital expenditures.

With respect to Ince's recommendations, the Panel agrees with BC Hydro that its capital planning processes do properly consider factors including reliability and safety. While the values of reliability and safety may not be quantified, as Ince observes, that does not mean they are not considered in the prioritization. The Panel is satisfied that the BCUC and interveners have sufficient opportunity to investigate these topics in RRA, CPCN and UCA Section 44.2 applications for proposed capital expenditures and for specific projects.

The CEABC recommends that BC Hydro give more weight in its capital prioritization to expenditures which have the potential to increase energy sales. The Panel rejects this recommendation. The Panel sees no evidence that BC Hydro has failed to make an investment that would have increased energy sales, and shares BC Hydro's concern that imprudent decisions may be made if the prioritization process were to be unduly weighted towards investments with sales potential and other factors such as risk are downplayed.

4.4.1.1 Asset Investment Planning Tool Project

BC Hydro lists the Asset Investment Planning Tool (Planning Tool) project (Planning Tool Project) as a sustaining investment with capital expenditures of $4.2 million in fiscal 2020 and $1.0 million in fiscal 2021.[459] BC Hydro states that the Planning Tool:[460]

> [W]ill develop and implement an enterprise value framework that builds upon BC Hydro's existing enterprise-wide framework for prioritization. The enterprise value framework will enable a more consistent and objective approach to compare the risks, costs and benefits of different investments.

In oral testimony, BC Hydro added:[461]

[459] Exhibit B-1, Appendix I, Attachment 1, p. 9, row 27.
[460] Exhibit B-6, BC Hydro response to CEC IR 4.2, p. 3.
[461] Transcript Volume 11, p. 1850, Line 18-22 (Weafer, Pinksen).

> A project like this is targeted at finding efficiencies and cost effectiveness in terms of that $2 billion spend.

BC Hydro adds that the Planning Tool Project is currently on hold due to the unavailability of subject matter expertise and that the estimate of $5.8 million has changed. BC Hydro considers it prudent "to pause and make sure we can demonstrate benefits to ratepayer of continuing to invest in this type of project."[462]

Positions of Parties

The CEC submits that the Planning Tool is very important in developing long-term cost effectiveness in capital planning and is concerned about the deferral of the Planning Tool Project. The CEC adds that if the Planning Tool truly has the capability to improve the cost-effectiveness of BC Hydro's $2 billion in investments, then the relatively minor cost of $6 million for the Planning Tool Project "may result in a benefit even if the cost were to increase substantially." The CEC submits that the Planning Tool should be prioritised for continuing development rather than being deferred, and recommends that the BCUC request BC Hydro provide a full report on the Project within the next six months. [463]

Ince encourages BC Hydro to resume development of the Planning Tool and submits that the BCUC should "provide guidance and participate in this process."[464]

The BCOAPO submits it supports BC Hydro's cost-effective efforts to improve its capital planning process and "looks forward to the reviewing its conclusions regarding the Asset Investment Planning Tool at the time of its next RRA."[465]

BC Hydro submits that development of projects is a management decision, and the BCUC should not require BC Hydro to provide a report on the Planning Tool project within six months, as suggested by the CEC. BC Hydro states it will update its capital plan and project information in the next RRA, and provide an update on the broader picture of its capital planning.[466]

Panel Discussion

The Panel agrees with BC Hydro that the decision whether to proceed with the Planning Tool Project is a matter for management over which the BCUC has no jurisdiction.

However, the Panel is supportive of the Planning Tool Project as it appears it would enhance BC Hydro's efforts to ensure the cost-effectiveness of its capital expenditures. The Panel is satisfied with BC Hydro's commitment to update the BCUC on its capital planning process in the next RRA, and encourages BC Hydro to pursue the Planning Tool Project if it appears cost-effective.

4.4.2 Forecast Capital Additions

BC Hydro states that capital additions are the capital investments that affect rates during the Test Period, which occur when the capital assets enter service.[467] BC Hydro's actual capital additions for fiscal 2017 and fiscal 2018, its forecast capital additions for fiscal 2019 and its planned capital additions for the Test Period are set out in the following table: [468]

[462] Transcript Volume 11, p. 1845, Line 8-11 (Pinksen).
[463] CEC Final Argument, pp. 80–81.
[464] Ince Final Argument, p. 17.
[465] BCOAPO Final Argument, p. 33.
[466] BC Hydro Reply Argument (May 27, 2020), pp. 73–74.
[467] Exhibit B-1, p. 6-1.
[468] Exhibit B-1, Table 6-2, p. 6-7.

Table 4-16: BC Hydro Actual and Planned Growth and Sustaining Capital Additions Fiscal 2017 to Fiscal 2021

($ millions)	F2017		F2018		F2019	F2019	F2020	F2021
	RRA	Actual	RRA	Actual	RRA	Forecast	Plan	Plan
Generation								
Growth	26.6	24.2	0.9	9.6	0.2	(1.3)	2.7	-
Sustaining	486.4	318.5	386.2	397.6	1,332.1	1,304.7	312.0	297.0
Total Generation (Schedule 13, Line 13)	513.0	342.7	387.1	407.2	1,332.3	1,303.3	314.7	297.0
Site C Project (Schedule 13, Line 17)						-	27.9	189.4
Generation - Waneta 2/3 (Schedule 13, Line 14)						1,219.5	-	-
Transmission								
Growth	237.1	255.8	222.8	176.9	213.8	309.9	97.9	83.3
Sustaining	255.2	227.1	216.9	230.8	245.0	223.5	195.9	146.3
Total Transmission (Schedule 13, Line 15)	492.3	482.9	439.7	407.7	458.8	533.4	293.8	229.6
Distribution								
Growth	189.8	232.7	241.6	232.2	229.0	305.2	306.9	344.2
Sustaining	182.3	188.3	157.7	213.3	184.0	222.3	195.3	196.5
Total Distribution (Schedule 13, Line 16)	372.1	421.0	399.3	445.5	413.0	527.5	502.2	540.7
Business Support								
Technology (Schedule 13, Line 18)	81.6	81.6	91.1	97.2	112.6	67.1	147.6	75.5
Properties (Schedule 13, Line 19)	68.3	54.8	118.2	126.9	25.5	28.7	39.9	55.6
Fleet / Other (Schedule 13, Line 20)	210.3	85.6	54.5	59.4	45.7	69.8	64.9	71.3
Total	1,737.6	1,468.5	1,489.8	1,543.8	2,387.8	3,749.4	1,391.0	1,459.1
Less: Contribution in Aid	(90.1)	(103.6)	(88.0)	(129.5)	(84.6)	(148.5)	(146.1)	(165.8)
TOTAL	1,647.5	1,364.9	1,401.8	1,414.3	2,303.2	3,600.8	1,244.9	1,293.2

BC Hydro provides its actual capital additions for fiscal 2019 in the following table:[469]

Table 4-17: Fiscal 2019 Capital Additions Variances

($ million)	F2019			
	RRA	Actual	Diff	% Diff
	1	2	3=2-1	4=3/1
Generation	1,332.3	1,185.5	(146.8)	-11%
Site C Project	-	-	-	-
Waneta 2/3 Interest Acquisition	-	1,220.3	1,220.3	-
Transmission & Distribution	871.8	977.6	105.8	12%
Business Support				
Technology	112.6	64.1	(48.5)	-43%
Properties	25.5	33.0	7.6	30%
Fleet/Other	45.7	72.5	26.8	59%
Total Gross	**2,387.8**	**3,553.0**	**1,165.1**	**49%**
Less: Contribution in Aid	(84.6)	(135.0)	(50.4)	60%
Total	**2,303.2**	**3,418.0**	**1,114.7**	**48%**

BC Hydro states that its planned capital additions during the Test Period are lower than the prior test period because of the completion of major projects, which are coming into service.[470] BC Hydro submits that the BCUC should find its planned capital additions for the Test Period are reasonable.[471]

Positions of Parties

With the exception of the specific issues raised below, interveners raise no issues with respect to BC Hydro's planned capital additions.

Panel Determination

For the reasons outlined below, the Panel finds BC Hydro's forecast capital additions for the Test Period, with the exception of capital expenditures in EV charging infrastructure, as discussed in section 4.4.2.3 below, are

[469] Exhibit B-11, Appendix G,Table G-6, p. 9.
[470] Exhibit B-1, p. 6-2.
[471] BC Hydro Final Argument, p. 171.

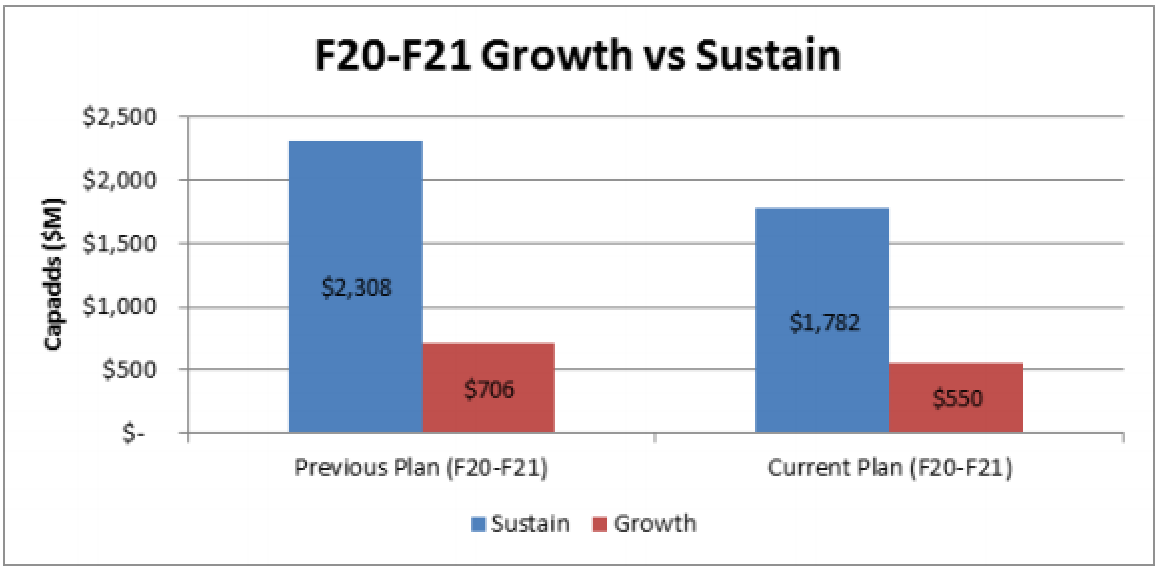
reasonable. In the Panel's view, BC Hydro has provided sufficient evidence to support the reasonableness of its forecast capital additions for the Test Period.

4.4.2.1 Sustainment Capital Spending

BC Hydro plans to moderate its investment in sustainment capital spending compared to previously planned amounts. The Previous Capital Plan had included an increasing level of investment in sustainment capital spending over the next decade, primarily driven by the deteriorating condition of some system assets and the expected rate of replacement required to maintain system performance.[472]

BC Hydro sees an opportunity to moderate total capital spending in the Test Period, reducing both growth and sustainment capital spending, due to strong system performance and slower forecast demand growth.[473] BC Hydro states that the total reduction in capital additions forecast in the Test Period compared to its Previous Capital Plan for the same period is $682 million or 22.3 percent: [474]

Figure 4-4: F20-F21 Growth vs Sustain



BC Hydro explains that $137 million of the reduction is due to decisions to defer investments, after considering their risk score assessment, along with the latest project cost forecast, system performance data and asset information. The remainder of the reduction is due to updates to forecasts for active projects, primarily due to project schedule changes. [475]

With respect to sustainment capital spending, BC Hydro states that a consistently high level of historical system performance provided an opportunity to reconsider the appropriate level of expenditures despite ageing of some system assets.

> To this point in time, this degradation has not resulted in a corresponding decline in overall system performance or customer reliability as measured by two industry-standard metrics. The

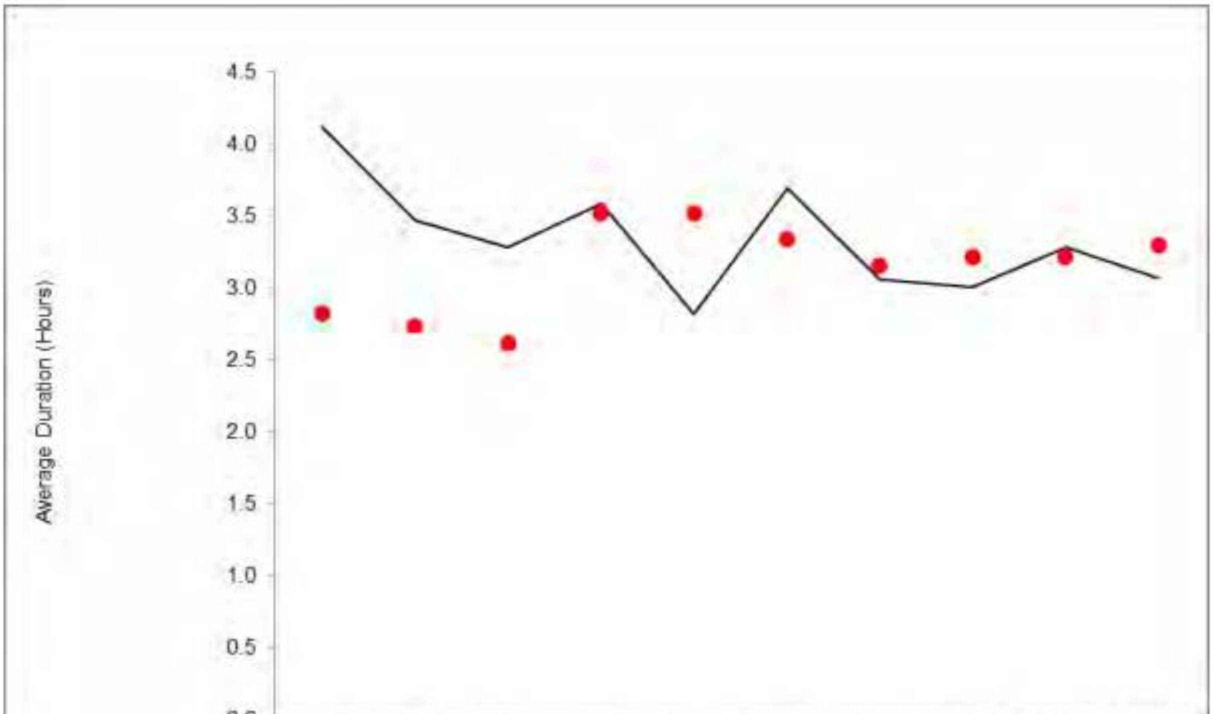
[472] Exhibit B-1, p. 6-20.
[473] BC Hydro Final Argument, p. 117.
[474] BC Hydro Final Argument, pp.119–120.
[475] BC Hydro Final Argument, pp. 119–120.

relatively high level of performance has allowed BC Hydro to moderate the planned investment in sustainment in the interest of mitigating impacts on customers.[476]

BC Hydro system performance is measured by System Average Interruption Duration Index (SAIDI) and the System Average Interruption Frequency Index (SAIFI), among other reliability indices, and this performance is compared regularly with utility industry peers by the Canadian Electricity Association (CEA).[477] BC Hydro also reports annually its performance on reliability indices, as required by Directive 26 of the BCUC's Decision on BC Hydro's fiscal 2005-fiscal 2006 RRA.[478] BC Hydro states its overall SAIDI and SAIFI trends have performed as well as or better than the CEA composite.[479]

The normalized SAIDI results for BC Hydro for the last ten years are presented in the following chart (a lower value on the vertical axis represents a lower average duration for interruptions, which is better):[480]

Figure 4-5: SAIDI (Normalized)

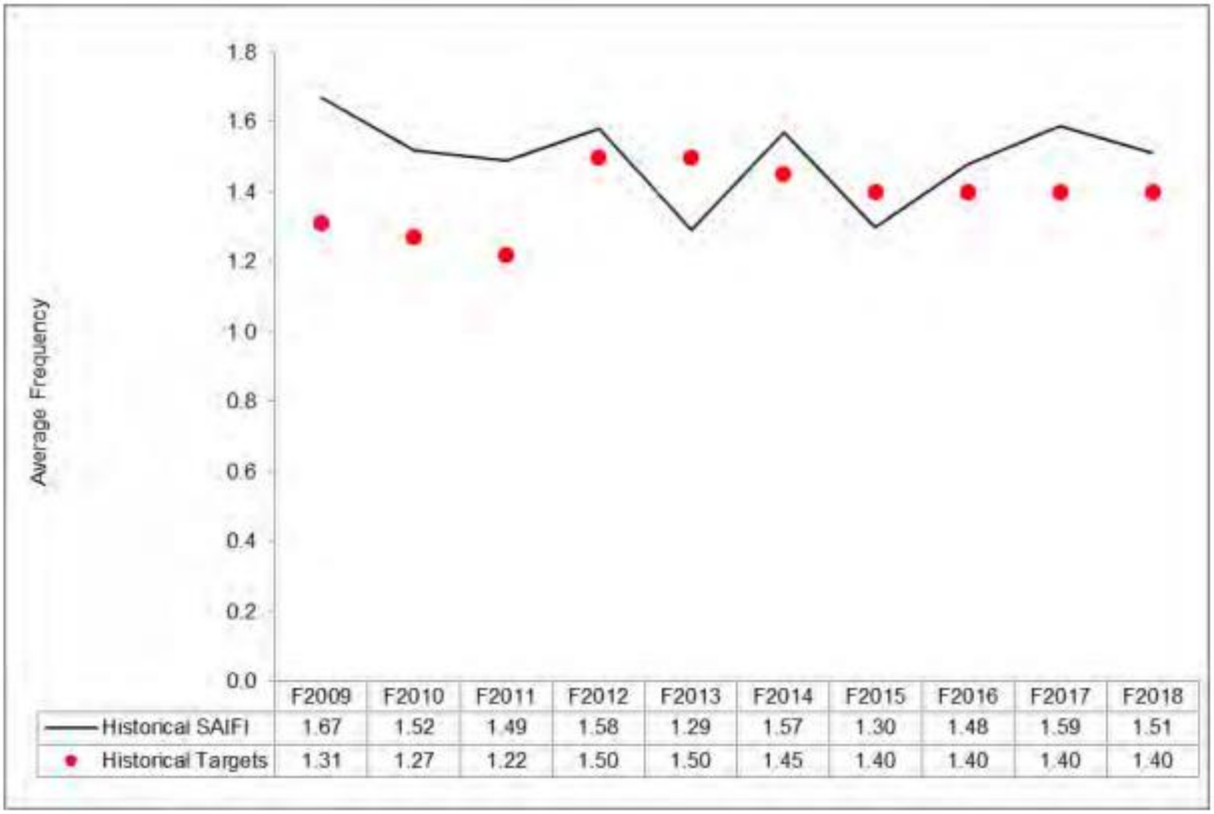


	F2009	F2010	F2011	F2012	F2013	F2014	F2015	F2016	F2017	F2018
Historical SAIDI	4.12	3.47	3.28	3.59	2.82	3.69	3.06	3.01	3.28	3.07
Historical Targets	2.82	2.73	2.62	3.52	3.52	3.34	3.15	3.22	3.22	3.30

The normalized SAIFI results for BC Hydro for the last ten years are presented in the following chart (a lower value on the vertical axis represents a lower average frequency of interruptions, which is better):[481]

[476] Exhibit B-1, p.6-20.
[477] Exhibit B-1, p.6-21.
[478] Exhibit B-1, Appendix W.
[479] Exhibit B-1, pp. 6-21–6-22.
[480] Exhibit B-1, Figure 6-8, p. 6-23.
[481] Exhibit B-1, Figure 6-9, p. 6-24.

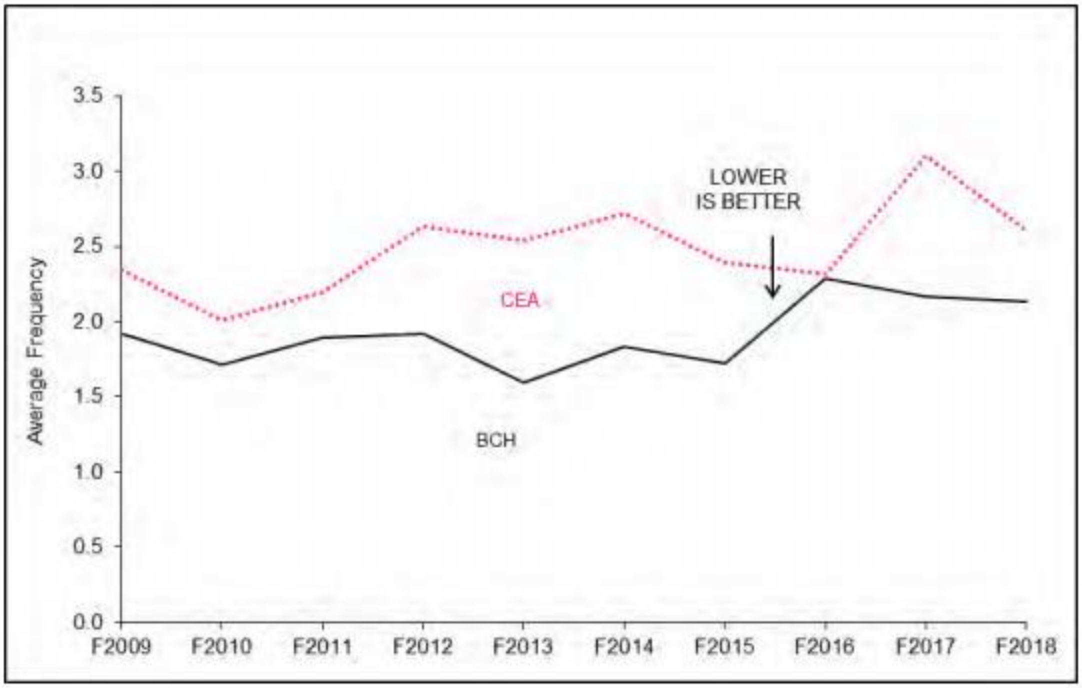
Figure 4-6: SAIFI (Normalized)



The non-normalized SAIFI results compared to the CEA average for the last ten years are presented in the following chart (a lower value on the vertical axis represents a lower average frequency of interruptions, which is better):[482]

[482] Exhibit B-1, Figure 6-7, p. 6-22

Figure 4-7: SAIFI (All Events, Not Normalized) – Average Number of Interruptions per Average Customer



In addition, BC Hydro submits that the overall reliability scores in BC Hydro's Customer Satisfaction Index indicate customers continue to be satisfied with the level of reliability they are receiving:[483]

> Customer satisfaction with reliability is slightly lower in the North Interior and South Interior than in the Lower Mainland and Vancouver Island; however, the regional differences in customer satisfaction with reliability are small. In addition, there are no specific regions in which customers indicated they were dissatisfied with BC Hydro's level of reliability.

BC Hydro adds, however, that its customer satisfaction index does not include results from customers in the Non-Integrated Areas. [484]

BC Hydro states it does not expect any operational impacts or material impacts on customer reliability from the deferral of sustainment projects, due to asset redundancy and the installation of automated devices on the system, although it has accepted the potential for additional maintenance of some assets.[485] BC Hydro adds that it has not reduced dam safety expenditures[486] and that the condition of its most significant generating facilities, those in the "key" and "strategic" categories such as G.M. Shrum, Mica, Bridge River and Cheakamus facilities, is expected to improve due to planned investments.[487] Since changes in system performance and load forecasts are likely to materialize over time, BC Hydro anticipates it will have time to respond to changes if needed.[488]

However, BC Hydro cautions that any further reductions to forecast capital expenditures would degrade asset condition and asset health more than anticipated, with a corresponding negative impact on customer service levels.[489]

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[483] Exhibit B-12, BCUC IR 244.1.
[484] Exhibit B-56, Undertaking 51, p. 1.
[485] BC Hydro Final Argument, p. 121.
[486] BC Hydro Final Argument, p. 119.
[487] BC Hydro Final Argument, p. 120.
[488] BC Hydro Final Argument, p. 121.
[489] BC Hydro Final Argument, pp. 121–122.

BC Hydro recognizes that the planned reduction in sustainment expenditures relative to the previous plan must be accompanied by careful monitoring of asset condition and performance. BC Hydro states: [490]

> If system performance were to decline or if forecast demand were to change, BC Hydro may adjust the level of asset condition driven replacements, update operational or maintenance practices, or bring forward ex-plan projects. Changes in system performance and load forecasts are likely to materialize over time, giving time for BC Hydro to respond to changes if needed.

BC Hydro submits that its planned level of capital investment from fiscal 2020 to fiscal 2024 reflects "an appropriate balance of system performance, risk and affordability."[491]

Positions of Parties

BCSEA agrees that BC Hydro has a "robust capital planning process" and that additional reductions in capital spending would be undesirable.[492]

The CEC notes that BC Hydro's reductions in forecast sustainment capital spending in the Test Period are "very significant" and is concerned that either BC Hydro's original plan may not have been optimized, or the present decision to defer investments may not have been optimized. The CEC is concerned that some cost-effective investments in asset maintenance may be deferred to future periods for short-term gain, at a greater cost overall. In its view, BC Hydro's maintenance budgets should be "accurate, sufficient, and should fully reflect the costs required to maintain the assets of BC Hydro in a manner that will allow the full recovery of the asset value." [493]

Willis recommends that BC Hydro continue to maintain its current system performance level.[494]

Panel Determination

The Panel is satisfied that BC Hydro's capital planning process has balanced the issues of desire for cost containment with the risks to system performance and asset deterioration, and finds that BC Hydro's proposed level of sustainment capital spending in the Test Period is reasonable.

BC Hydro submits that its planned level of spending on sustainment capital represents "an appropriate balance of system performance, risk and affordability". The Panel explains in section 5.13 that the BCUC has no mandate to consider the affordability of utility's rates. When considering BC Hydro's submission in its entirety, we interpret BC Hydro's submission to refer to balancing risks to system performance and asset deterioration while containing costs as far as it deems prudent. Looked at in this light, we agree with BC Hydro's submission.

With respect to BC Hydro's system performance, its current system reliability, as measured by the normalized SAIDI and SAIFI index results, appears stable over the previous ten years and compares favourably to the CEA average. This provides BC Hydro with the opportunity to reduce its sustainment capital spending, but only if the reduction can be done in a manner which does not expose system performance to undue risk and does not allow asset condition to deteriorate to the point where future maintenance costs rise unduly. We now address each of these two considerations.

With respect to system performance, BC Hydro states that the condition of its key and strategic generation facilities is expected to improve as a result of the capital spending that is still forecast to take place in the Test Period, that any changes to system performance would likely happen over time, allowing it to take appropriate

[490] BC Hydro Final Argument, p. 121.
[491] BC Hydro Final Argument, p. 121.
[492] BCSEA Final Argument, p. 30.
[493] CEC Final Argument, pp. 46–47.
[494] Willis Final Argument, p. 2.

corrective action, and that the effects of deteriorating system assets would be mitigated by asset redundancy and automated devices. For these reasons the Panel is satisfied that the proposed reduction in sustainment capital spending poses no imminent danger to BC Hydro's system performance, and that any deterioration of system assets would be identified and allow BC Hydro to take corrective action.

That said, as BC Hydro has acknowledged, the condition of some system assets will deteriorate. The Panel shares the CEC's concern that reduced sustainment spending could be a false economy, leading to significant future increases in maintenance costs. **For this reason, the Panel directs BC Hydro to report in its fiscal 2023 RRA on any additional maintenance spending that has occurred as a result of the reduced sustainment capital spending during the Test Period. Further, the Panel directs BC Hydro to present in its fiscal 2023 RRA a trend analysis of maintenance spending on capital for the ten most recently completed fiscal years.**

Further to this, the Panel considers that the index of customer satisfaction with reliability is a useful indicator of whether the level of sustainment capital spending is appropriate. However, the Panel is concerned about the absence from this index of the results from customers from Non-Integrated Areas, and the resulting lack of transparency. **For these reasons, the Panel directs BC Hydro to provide, as part of its compliance filing, a proposal for including customers from Non-Integrated Areas in the index of customer satisfaction with reliability.**

4.4.2.2 West End Vancouver and East Vancouver Land Purchases

BC Hydro has made two property purchases in Vancouver to advance two substation construction projects, replacements for the existing Dal Grauer and Murrin substations, for which it will file CPCN applications to the BCUC in due course (Property Purchases). Both substation replacements are to support BC Hydro's Downtown Vancouver Electric Supply initiative. [495]

BC Hydro submits that the Dal Grauer and Murrin substations need to be replaced as more than half of their assets are expected to degrade to poor or very poor condition within the next 10 to 20 years. Further, the Murrin substation is on seismically unstable soil and approximately half the switchyard, which serves both substations, is vulnerable to severe earthquake damage. [496]

Direction No. 8 states that rate base includes "the amount listed as property, plant and equipment in service [and intangible assets in service], less accumulated amortization". It also states that rate base must exclude "any amount included in them that is an expenditure incurred by the authority, on or after April 1, 2011, that the commission determines under the Act must not be recovered by the Authority in rates."[497]

BC Hydro submits that customers are well-served by the Property Purchases. [498] BC Hydro submits that the West End Substation land should be in rate base pursuant to Direction No. 8. Specifically, the property is "in service" because it has been acquired "from a revenue requirements accounting perspective", and the acquisition is consistent with the "used and useful" test, one of the "standard regulatory principles employed to determine rate base." [499]

BC Hydro clarified that in its view even though Direction No. 8 defines rate base by using the words "in service," it should be interpreted under the common law "used and useful" concept. BC Hydro submits that Direction No.

[495] BC Hydro Final Argument, p. 155.
[496] Exhibit B-1, Appendix J, Attachment 1, p. 79.
[497] Direction No. 8, Section 1, Rate Base definition: http://www.bclaws.ca/civix/document/id/crbc/crbc/24_2019
[498] BC Hydro Final Argument, p. 155.
[499] Transcript Volume16, pp. 2930–2931.

8 is incorporating the used and useful test by using different words, and that the Direction was not intended to depart from the common law principles with the inclusion of the words "in service."[500]

BC Hydro submits that rate base includes "both assets that are used and assets that are useful," which is a standard regulatory principle used to determine rate base. BC Hydro further explains that the land acquisition is "used and useful" because it supports the delivery of regulated service to customers, even if not in immediate use, as the sole purpose of the acquisition was "to reduce material project risks, ensuring that an option is preserved in areas where land is very limited."[501]

West End Vancouver Land Purchase

BC Hydro intends to build a new underground substation (West End Substation) in the West End of downtown Vancouver to replace the existing Dal Grauer substation. BC Hydro adds that there is a limited supply of suitable properties in the West End of Vancouver that could meet the technical requirements for the West End Substation, and that acquiring the land well in advance of the construction of the new substation provides certainty with respect to location, cost and schedule. Further, the early acquisition of the land enables BC Hydro to prepare designs and estimates for the CPCN application BC Hydro will submit to the BCUC, currently anticipated to be in fiscal 2023.[502] The West End Substation is expected to be in service by calendar 2028.[503]

The two components of the West End Substation property purchase are the purchase of subsurface land at Lord Roberts Annex School, acquired from the Vancouver School Board for $66.8 million, and the acquisition of distribution and transmission statutory rights of way through Nelson Park.[504] The acquisition of the statutory rights of way is ongoing, and expected to be complete by early fiscal 2021. The total cost of the property purchase for the West End Substation is expected to be $80.7 million, which BC Hydro proposes adding to rate base in fiscal 2020.[505]

BC Hydro states: [506]

> The subsurface land and rights-of-way are listed as a capital addition because BC Hydro has acquired an item of property, plant and equipment and intangible assets that meet the IAS 16, Property, Plant and Equipment and IAS 38, Intangible Assets recognition criteria that there are probable future economic benefits from the item. While the subsurface land and rights-of-way are intended to be used in the development of a substation, the [West End] substation development project has not commenced. Therefore, the subsurface land and rights-of-way are not part of a construction project and are not classified as unfinished construction.

BC Hydro adds that once the development project commences, the subsurface land and rights-of-way will be transferred to "unfinished construction" until the development project is in-service. Assets that are part of "unfinished construction" are not included in the rate base.[507]

BC Hydro states: [508]

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[500] Transcript Volume16, pp. 2938–2939.
[501] Transcript Volume16, pp. 2930–2939; BC Hydro Reply to Interveners on Oral Phase of Argument (June 22, 2020), pp. 4–6.
[502] BC Hydro Final Argument p. 156-157.
[503] Transcript Volume 12, p. 2245.
[504] BC Hydro Final Argument, p. 155-156.
[505] Exhibit B-1, Appendix J, Attachment 1, p. 69, Exhibit B-1, Appendix I, Attachment 1, p. 4, line 2.
[506] Exhibit B-12, BCUC IR 249.2.
[507] Exhibit B-12, BCUC IR 249.3.
[508] Exhibit B-12, BCUC IR 249.2.3.

> The carrying costs of subsurface land and rights-of-way are expensed until the substation construction project commences. Once in construction, the carrying costs will be charged to the substation project (i.e., capitalized) until it is placed in-service. When the substation project is placed in-service, depreciation or amortization of the constructed assets will commence based on their expected useful lives.

BC Hydro also notes that the subsurface land and the statutory rights-of-way are not depreciable assets and therefore depreciation expense is not included in the revenue requirement.[509]

East Vancouver Land Purchase

BC Hydro intends to build a new substation (East End Substation) in the Eastside/Strathcona neighbourhood of Downtown Vancouver to replace the Murrin substation.[510]

BC Hydro purchased property for the anticipated East End Substation for $46.6M in fiscal 2017[511]. The fiscal 2017 to fiscal 2019 RRA approved $25.0 million for the purchase; BC Hydro submits that the variance of $21.6 million was because "an acceptable property could not be acquired at the amount included in the Previous Application"[512] due to "the high rate of property appreciation that was occurring in the Vancouver real estate market at the time."[513] The East End Substation is not anticipated to be in service within the timeframe covered by the current 10-year capital plan.[514]

The property acquired for the East End Substation, 303 Vernon Drive, is currently leased to "a credit-worthy commercial tenant" which minimizes BC Hydro's holding costs until the construction of the substation is initiated.[515]

BC Hydro submits, "the purchase of [the East Vancouver] property represented prudent management because the need for a new site is clear, and suitable properties are scarce." Similar to the West End land purchase, BC Hydro submits that "acquiring the land well in advance provides certainty with respect to the site, cost and schedule." [516]

Positions of Parties

AMPC states that "as the properties are intended for future use by specific projects that have not been applied for yet, AMPC would expect the Commission to carefully consider the appropriateness of including them in rate base if and when it has the opportunity. Given the large costs and atypical timing associated with the assets, and BC Hydro's explanation of the proximity of a rate of return proceeding, AMPC is flagging its concern now."[517]

Further, "AMPC's concern is that if and when BC Hydro's rate base has a direct impact on rates, the Commission should consider the treatment of these properties at that time carefully. For example, these properties may be best classed as not in service, or held for future use, and hence subject to a less than full return."[518]

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[509] Exhibit B-12, BCUC IR 249.2.1.
[510] Exhibit B-1, Appendix J, Attachment 1, p. 79.
[511] Exhibit B-16, BCUC IR 291.5.
[512] Exhibit B-16, response to BCUC IR 291.7, Attachment 1.
[513] Exhibit B-13 response to BCOAPO IR 133.2.
[514] Transcript Volume 12, p. 2253, lines 7–10 (Kumar).
[515] Exhibit B-13 response to BCOAPO IR 133.2 p. 2.
[516] BC Hydro Final Argument, p. 159.
[517] AMPC Final Argument, p. 88.
[518] AMPC Comments on BC Hydro additional submissions June 18, 2020, p. 2.

With respect to AMPC's submission, BC Hydro submits that BC Hydro's "accounting treatment in this regard [has] no bearing on matters before the BCUC in this proceeding" as amounts in rate base do not currently impact BC Hydro's net income as Direction No. 8 prescribes BC Hydro's net income to be a fixed amount of $712 million in each of fiscal 2020 and fiscal 2021.[519]

AMPC cites the case of the Terasen Gas CPCN for the Tilbury Property Purchase as an example of utility property not in service being excluded from rate base. AMPC observes that the CPCNs have not yet been filed for either substation and thus, the BCUC does not yet have the necessary information to assess the prudence of the property acquisitions. Thus, in AMPC's view, the BCUC "should wait until the corresponding CPCN applications are filed to decide whether or not to include the Vancouver substation properties in rate base." [520]

In reply to AMPC, BC Hydro submits that the BCUC's Decision in the Tilbury Property Purchase CPCN proceeding supports BC Hydro's position: "properties acquired for future use should, subject to imprudence, be included in rate base and be subject to a full return on equity."[521] BC Hydro concludes: "the application of regulatory principle supports the inclusion of BC Hydro's substation properties in rate base. They are providing value to customers by preserving valuable options. In any event, as AMPC appears to concede, the determination of rate base has no practical impact in this Test Period."[522]

In BCOAPO's view, ratepayers should not be paying for the carrying costs of property until the property is used to provide service to ratepayers. BCOAPO suggests the use of a regulatory account to defer the carrying costs until capitalization following project completion.[523]

In response to BCOAPO, BC Hydro submits that the "carrying costs are not material enough to warrant the establishment of a deferral account for each property." Furthermore, BC Hydro submits that the carrying costs for the property for the new East End Substation are minimized as the property is currently leased to a tenant. BC Hydro submits that the practice of expensing carrying costs has minimal impact on rates or intergenerational equity, is easier to administer, and avoids establishing more deferral accounts. [524]

MoveUP supports BC Hydro's proposal to incorporate the land purchases into rate base and expense the carrying costs in the Test Period.[525] MoveUP states, "An asset need not be in actual current service in order to be included in rate base, so long as it is useful for the purpose of providing service to ratepayers and was prudently acquired."[526] BCSEA also supports BC Hydro's position, but does not speak to carrying costs.[527] Ince "does not disagree" with BC Hydro's proposed accounting treatment of this land acquisition.[528]

Panel Determination

For the following reasons, the Panel finds that the Property Purchases meet the tests set out in the definition of rate base in Direction No. 8, and therefore the Panel approves the purchase of land for the West End Substation as additions into BC Hydro's rate base. As a result, the carrying costs of the land for the West End Substation are recoverable from ratepayers. The Panel notes that the purchase of land for the East End Substation was accepted into rate base in the fiscal 2017 to fiscal 2019 RRA Decision.

[519] BC Hydro Reply Argument (May 27, 2020), p. 70.
[520] AMPC submission June 18, 2020, pp. 1–2.
[521] BC Hydro Reply Argument (June 22, 2020), p. 4.
[522] BC Hydro Reply Argument (June 22, 2020), p. 6.
[523] BCOAPO Final Argument, p. 34.
[524] BC Hydro Reply Argument (May 27, 2020), p. 71.
[525] MoveUP Comments on BC Hydro additional submissions June 18, 2020. pp. 3–4.
[526] MoveUP Comments on BC Hydro additional submissions June 18, 2020, p. 3.
[527] BCSEA Comments on BC Hydro additional submissions June 18, 2020, p. 2.
[528] Ince Comments on BC Hydro additional submissions June 18, 2020, p. 1.

Direction No. 8 includes in its definition of rate base both "property, plant and equipment in service, less accumulated amortization" and "intangible assets in service, less accumulated amortization". The Panel considers that land purchases for the West End Substation and the East End Substation are property, and the statutory rights of way being acquired for the West End Substation are intangible assets. The matter for the Panel is whether the Property Purchases are "in service", given that neither substation is expected to be in operation during the Test Period nor for many years thereafter.

The Panel does not consider that the IAS 16 and IAS 38 recognition criterion for assets as having "probable future economic benefits" is sufficient to determine whether a utility's assets should be included in rate base. Rather, the proper test for whether a utility's assets should be included in rate base is the "Used and Useful" test.

As the BCUC observed in its decision (Waneta Decision) to approve BC Hydro's purchase of a two-thirds interest in the Waneta Dam (Waneta Transaction):[529]

> In determining whether assets should be included in rate base, the BCUC has historically applied the "Used and Useful" test, and will consider this test here. The principle underlying the Used and Useful test requires assets to be <u>physically used and useful in utility service to current ratepayers</u> before those ratepayers can be asked to pay the costs associated with them. Used and Useful is applied in the sense that the asset either directly or indirectly provides service to the customers of the utility. (emphasis added)

In the Waneta Decision, the BCUC identified two exceptions to the Used and Useful principle set out above, namely that assets which are not currently physical used and useful in utility service may still be "Used and Useful", and therefore included in rate base, if they are "expected to be used in the reasonably foreseeable future", or if a portion of the asset is needed now, and the remainder "may not be needed for quite some time."[530]

The West End Substation is expected to come into service by calendar 2028, less than ten years' time. The East End Substation has no planned in-service date, and is not expected to be in operation within the next ten years. However, BC Hydro's Downtown Vancouver Electric Supply initiative clearly identifies the need to address the aging facilities at both the Murrin and Dal Grauer substations within the next ten to twenty years. The Panel is satisfied that the Property Purchases are for planned investments which are expected to come into service in the reasonably foreseeable future.

The Panel also considers that the Property Purchases have value to ratepayers at present because they provide BC Hydro with a valuable option to use suitable land in a constrained area where little exists. However, the Panel makes no determination as to the prudence of either of the Property Purchases.

With respect to BCOAPO's recommendation of establishing a deferral account to capture the carrying costs, the Panel agrees with BC Hydro that the carrying costs are likely not significant enough to warrant deferral treatment, especially since there is currently a tenant on the property for the East End Substation defraying the carrying costs.

4.4.2.3 Electric Vehicle Charging Infrastructure

BC Hydro has been investing in EV charging infrastructure since 2013.[531] Prior to fiscal 2018, BC Hydro classified its capital expenditures for EV charging infrastructure under Technology capital. In fiscal 2018, BC Hydro began

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529 Order G-130-18, p. 71.
530 Order G-130-18, BCUC Decision to the BC Hydro Waneta 2017 Transaction Application, p. 71.
531 BCUC Phase 1 Inquiry into the Regulation of Electric Vehicle Charging Service, Exhibit C1-2, p. 6.

classifying these capital expenditures as "Distribution Sustain – System Expansion and Improvement".[532] From fiscal 2013 to fiscal 2018 BC Hydro incurred $3.5 million in net capital expenditures after contributions in aid, and in fiscal 2019 BC Hydro forecasted an additional $0.4 million in net capital expenditures.[533] In the Test Period, BC Hydro forecasts net capital expenditures of $0.2 million in fiscal 2020 and $2.2 million in fiscal 2021.[534]

BC Hydro states that in fiscal 2019 there were $0.5 million in capital additions for EV charging stations, all of which were leased to other parties.[535] BC Hydro forecasts capital additions of $3.4 million in fiscal 2020 and $2.4 million in fiscal 2021.[536]

Capital expenditures on EV charging stations by BC Hydro include civil and electrical work, charger installation, paving, signage, and lighting. BC Hydro did not incur costs for its land leases, rights-of-way, or land purchases, except for two sites where land purchase costs were "nominal".[537]

BC Hydro states that it intends to apply to the BCUC for approval of a rate design application for BC Hydro owned and operated EV Fast Charging Stations following the completion of the BCUC Inquiry into the Regulation of Electric Vehicle Charging Service, which it expects to be by fall 2019.[538]

BC Hydro submits that capital additions related to EV charging stations should be included in rate base pursuant to Section 1 of Direction No. 8, and that the BCUC cannot direct BC Hydro to exclude these investments from its rate base. BC Hydro adds that such capital additions have no practical effect during the Test Period because its net income is currently prescribed by section 3 of Direction No. 8 to be a fixed amount of $712 million. Further, the BCUC has conducted an inquiry into EV charging infrastructure, and BC Hydro expects the Provincial Government to implement legislation clarifying BC Hydro's role in EV charging.[539]

In addition to capital expenditures, BC Hydro also forecasts operating costs associated with creating and operating EV charging infrastructure. BC Hydro identifies a team of 2 FTEs in the department of the Vice President, Customer Service Department within the Customer Service KBU, who are responsible for EV customer service,[540] and activities by the Distribution Planning Department, which has a budget including labour costs for 38 FTEs, and is responsible for planning "system innovations including electric vehicle charging infrastructure."[541] BC Hydro adds that in fiscal 2019, it incurred labour costs in the Key Account Management Department of the Customer Service KBU to support the negotiation of land lease agreements for 26 EV fast charging stations.[542]

Positions of Parties

BCOAPO submits that the BCUC can determine whether or not EV charging infrastructure costs may be included in rate base, and takes the position that these costs should be excluded. BCOAPO submits that these costs are not required to support the provision of electric service to BC Hydro's customers and that BC Hydro's role in promoting EV charging is still to be determined.[543]

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532 Exhibit B-5, response to BCUC IR 122.1.1.
533 Exhibit B-5, response to BCUC IR 122.2.
534 Exhibit B-5, response to BCUC IR 122.4.
535 Exhibit B-5, response to BCUC IR 122.2.1.
536 Exhibit B-5, response to BCUC IR 122.2.1.
537 Exhibit B-5, BCUC IR 122.4.1; Exhibit B-12, BCUC IR 248.5..
538 Exhibit B-5, response to IR 122.5
539 BC Hydro Final Argument, p. 145.
540 Exhibit B-1, Section 5F.5.1.6, pp. 5F-24, 5F-38.
541 Exhibit B-1, Section 5A.7.2.2, pp. 5A-27–5A-28.
542 Exhibit B-1, Section 5F.5.1.4, pp. 5F-22–5F-23.
543 BCOAPO Final Argument, p. 37-39.

AMPC disagrees with BC Hydro's interpretation of Direction No. 8 and submits that the BCUC may exclude EV charging infrastructure costs from rates. AMPC adds that the BCUC ought to ensure that BC Hydro has demonstrated that its investments are necessary for utility service, reflect the lowest cost alternative that will meet the identified need safely, and will be used and useful, otherwise the investments should not be included in rate base or recovered in rates. [544]

The CEC submits that EV charging infrastructure costs should not be imposed on ratepayers, particularly in this Test Period. The CEC explains that, using the principle of cost causation, these costs should be borne by the customers using the service and not be spread across all ratepayers. The CEC recommends that the BCUC disallow recovery of the EV charging infrastructure costs. [545]

CEABC and Gjoshe both submit that the EV charging infrastructure costs should be separately tracked and excluded from rate base until otherwise directed by the BCUC. [546] Ince recommends that the EV charging infrastructure costs should be excluded from rate base until BC Hydro has developed its EV strategy. [547]

BCSEA concurs with BC Hydro that the capital additions regarding EV charging infrastructure should be included in rate base pursuant to Direction No. 8. BCSEA adds that the question of whether future investments in EV charging infrastructure should be included in rate base should not be considered in the proceeding as the matter is not relevant to the Test Period, and the BC Government is anticipated to issue legislation in response to the BCUC's inquiry into the Regulation of EV Charging Services.[548]

BC Hydro clarifies its position in reply, stating that if the BCUC determines that EV charging infrastructure costs should not be recovered in rates, then by the operation of Direction No. 8 the EV charging infrastructure costs should also be excluded from rate base. BC Hydro reiterates its position that the EV charging infrastructure costs should be recovered in rates, as they are an important aspect of its plans to increase electricity load and reduce GHG emissions in the province, in line with government policy.[549]

Panel Determination

The Panel determines that BC Hydro's capital expenditures in EV charging infrastructure are not recoverable from ratepayers at this time. The Panel directs BC Hydro to remove all capital expenditures for EV charging infrastructure from rate base.

In the Panel's view, Direction No. 8 does not require the BCUC to accept into rate base any expenditure incurred on or after April 1, 2011 if the BCUC determines under the UCA that the expenditure should not be recovered in rates. The Panel considers this to be a plain reading of note 1 to the calculation of rate base included in Direction No. 8. BC Hydro appears to agree with this reading of Direction No. 8 in its clarified position in reply argument.

As BC Hydro explains in its application to have the West End and East Vancouver land purchases added to rate base, capital expenditures must meet the common law test of being "used and useful" before the BCUC allows a utility to recover those expenditures from ratepayers. There is no evidence that the capital expenditures incurred to date by BC Hydro to build EV charging infrastructure are being used or are useful to provide utility service to its customers according to any tariff filed with the BCUC. Therefore, the Panel finds that BC Hydro's capital expenditures on EV charging infrastructure are not used and useful, and may not be recovered from ratepayers.

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[544] AMPC Final Argument, p. 9.
[545] CEC Final Argument, p. 5.
[546] CEABC Final Argument, p. 48; Gjoshe Final Argument, p. 13.
[547] Ince Final Argument, p. 8.
[548] BCSEA Final Argument, pp. 33–34.
[549] BC Hydro Reply Argument (May 27, 2020), p. 58.

The Panel agrees with BC Hydro that by the operation of Direction No. 8, capital expenditures on EV charging infrastructure must be removed from rate base because they are not recoverable from ratepayers. Even in the absence of Direction No. 8, however, the Panel would still direct BC Hydro to remove from rate base its capital expenditures on EV charging infrastructure as these are not used and useful.

Since the close of the evidentiary record in this proceeding, the Provincial Government has amended the GGRR to make certain investments in EV charging stations prescribed undertakings within the meaning of the CEA.[550] This amendment was made on June 22, 2020 and BC Hydro has made no application to the BCUC to have its capital expenditures for EV charging infrastructure treated as prescribed undertakings under this amendment to the GGRR, thus the amendment has no bearing on the current decision. The Panel encourages 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 under the GGRR.

The Panel also encourages BC Hydro to bring forward its proposed rate design application for EV charging stations as soon as possible. Under the UCA, BC Hydro is not able to charge for EV charging services without a rate approved by the BCUC. Even if BC Hydro were to offer EV charging services at no charge to users, BC Hydro would be responsible for reimbursing ratepayers for the cost of any energy given away, since the cost of that energy has been recovered from ratepayers. BC Hydro's application for an EV charging rate should include the associated operating costs and cost of energy as well as capital costs, and should address the matters set out by the BCUC in its decision regarding FBC's application to provide EV charging services.[551]

BC Hydro forecasts some operating costs related to EV charging infrastructure in the Test Period. None of these costs are incurred for the purpose of providing service to ratepayers. **The Panel directs BC Hydro to remove from its revenue requirement all forecast operating costs related to EV charging infrastructure in the Test Period, including those identified in the department of the Vice President, Customer Service Department and the Distribution Planning Department, and also the cost of energy to serve BC Hydro-owned EV charging stations in the Test Period. BC Hydro is further directed to remove from the appropriate cost of energy deferral account the cost of energy incurred prior to the Test Period to serve BC Hydro-owned EV charging stations. BC Hydro is also directed to provide in its compliance filing a report of all the adjustments directed in this section and any supporting calculations.**

The Panel is concerned with BC Hydro's lack of due regard to ensure that its ratebase properly reflects the most accurate accounting records. BC Hydro submits here, and in various other submissions in this proceeding, that capital additions have no bearing on its net income, as that is currently prescribed by section 3 of Direction No. 8. While this may be true in the current Test Period, this explanation does not relieve BC Hydro of its regulatory responsibilities to properly maintain its rate base records.

We note, and BC Hydro itself acknowledges, that Direction No. 8 has time limitations and is only in effect until the end of fiscal 2021. There is a public expectation that the BCUC will be reviewing and approving BC Hydro's return on equity and capital structure after this Test Period. We expect BC Hydro to exercise more diligence now in order to ensure that its accounting records of ratebase can be confidently relied upon, and more easily reviewed and justified, in future regulatory filings.

4.4.3 Planned Capital Expenditures

In this section, the Panel reviews BC Hydro's large planned projects to determine if, in addition to assessing the reasonableness of capital expenditures to the extent such expenditures impact the fiscal 2020 to fiscal 2021 revenue requirement (through capital additions that are reflected in rates), there are potentially significant

[550] Section 5 of the GGRR, added by OIC 339.
[551] Order G-9-18, Decision on the FortisBC Application for Approval of EV DC Fast Charging Service Rates, p. 2.

public interest issues that require further investigation through a separate certificate of CPCN application and review process.

Planned capital expenditures for the Test Period and actual capital expenditures for fiscal 2017 and fiscal 2018 are set out in Table 6-1[552] to the Application, with Table G-5[553] of the Evidentiary Update providing actuals for fiscal 2019.

Table 4-18: BC Hydro Actual and Planned Growth and Sustaining Capital Expenditures Fiscal 2017–Fiscal 2021

($ millions)	F2017		F2018		F2019	F2019	F2020	F2021
	RRA	Actual	RRA	Actual	RRA	Forecast	Plan	Plan
Generation								
Growth (Schedule 13, Line 1)	20.0	21.2	2.4	10.2	0.7	4.0	3.2	-
Sustaining (Schedule 13, Line 3)	530.0	563.6	534.1	533.9	424.3	365.9	341.8	435.5
Total Generation	550.0	584.8	536.5	544.1	425.0	369.9	345.1	435.5
Site C Project (Schedule 13, Line 8)	742.5	662.7	716.5	704.8	829.2	1,186.8	1,530.0	1,535.5
Generation - Waneta 2/3 (Schedule 13, Line 2)						1,219.5		
Transmission								
Growth (Schedule 13, Line 4)	262.0	247.3	222.0	280.5	192.7	223.7	185.0	198.9
Sustaining (Schedule 13, Line 5)	255.5	268.1	326.3	218.3	373.9	209.1	222.6	286.5
Total Transmission	517.5	515.4	548.3	498.8	566.6	432.8	407.6	485.4
Distribution								
Growth (Schedule 13, Line 6)	224.7	226.0	233.4	287.6	209.5	305.7	300.0	284.6
Sustaining (Schedule 13, Line 7)	185.0	224.5	160.1	235.2	187.6	190.9	187.5	176.8
Total Distribution	409.8	450.5	393.4	522.8	397.0	496.6	487.5	461.4
Business Support								
Technology (Schedule 13, Line 9)	83.9	76.5	93.4	71.2	78.8	95.6	95.6	56.0
Properties (Schedule 13, Line 10)	95.7	86.6	75.0	63.5	88.3	43.5	58.9	55.3
Fleet / Other (Schedule 13, Line 11)	204.7	58.9	48.6	59.6	39.6	67.4	63.6	75.1
Total	2,604.0	2,435.4	2,411.9	2,464.8	2,424.6	3,912.2	2,988.3	3,104.1
Less: Contribution in Aid	(86.4)	(138.4)	(100.2)	(156.3)	(106.4)	(146.9)	(157.8)	(148.4)
TOTAL	2,517.6	2,297.0	2,311.7	2,308.5	2,318.2	3,765.3	2,830.5	2,955.7

Table 4-19: Fiscal 2019 Capital Expenditures Variances

($ million)	F2019			
	RRA	**Actual**	**Diff**	**% Diff**
	1	2	3=2-1	4=3/1
Generation	425.0	370.3	(54.7)	-13%
Site C Project	829.2	1,116.7	287.5	35%
Waneta 2/3 Interest Acquisition	-	1,218.8	1,218.8	-
Transmission & Distribution	963.7	920.0	(43.7)	-5%
Business Support				
Technology	78.8	84.3	5.5	7%
Properties	88.3	48.4	(39.9)	-45%
Fleet/Other	39.6	58.2	18.6	47%
Total Gross	**2,424.6**	**3,816.8**	**1,392.2**	**57%**
Less: Contribution in Aid	(106.5)	(185.3)	(78.8)	74%
Total	**2,318.1**	**3,631.5**	**1,313.4**	**57%**

Positions of Parties

With the exceptions discussed in detail below, interveners generally raised no major issues with the capital expenditures during the Test Period.

552 Exhibit B-1, Table 6-1, p. 6-6.
553 Exhibit B-11, Appendix G,Table G-5, p. 9.

The CEC states, "Substantial reductions in growth and sustainment are a remarkable perspective on the state of the BC Hydro system and the capital planning cost-effectiveness. The Commission's oversight is critical with such levels of change and the adequacy of information to assess the result is, in the CEC's view, less than required to properly understand the outcomes."[554] BCOAPO states: "If one excludes the spending on Waneta 2/3 and Site C, the planned spending for each of the two test years is less than the annual spending in F2017-F2019."[555] Zone II RPG states, "BC Hydro has not sought approval for any major capital expenditures in the NIA in the Test Period. Its only plan is to maintain or upgrade current infrastructure."[556]

CEABC states: "…since F2016, rate increases have not been keeping up with the rate of capital expenditures. This is probably because some very large projects, such as Site C, have yet to reach their in-service dates. Once these assets are put into service, all of their associated Capital-Based Charges will stop being capitalized, and will be brought into the Revenue Requirement to be recovered from rates over the life of the assets."[557]

BC Hydro submits that, notwithstanding the intervener arguments, the BCUC should find the forecast capital additions and expenditures to be reasonable.[558]

Panel Determination

Capital spending directly affects finance charges and amortization, and indirectly affects operating costs. As such, capital spending is one of the largest factors affecting BC Hydro's revenue requirement.

The Panel finds that BC Hydro's forecast planned capital expenditures for the Test Period are reasonable. The Panel is satisfied that the forecast is based on a reasonable process, and that BC Hydro has maintained an appropriate balance between cost containment and system performance and reliability.

The Panel reviews large planned projects to identify projects that have potentially significant public interest issues requiring further investigation through separate CPCN review processes. BC Hydro now has an approved set of Capital Filing Guidelines which contains thresholds above which BC Hydro will file UCA Section 44.2 expenditure schedules or CPCNs for BCUC approval. These thresholds provide a balance between regulatory scrutiny and regulatory efficiency and relieve BC Hydro from the obligation in the normal course to file applications for relatively small investments. That said, notwithstanding the thresholds in the Capital Filing Guidelines, the Panel retains the discretion to order BC Hydro to submit CPCN applications for investments below the thresholds if that appears to be in the public interest.

In addition, the UCA provides that utilities are deemed to have a CPCN for all public utility plant operating on September 11, 1980 and further, that utilities are deemed to have a CPCN to construct and operate extensions to the plant or system unless not later than 30 days after construction has begun, the BCUC orders that a CPCN is required.[559] Thus, the Panel has the authority to order a CPCN for any extension where that appears to be in the public interest.

Based on the Panel's review of the capital projects in Appendices I and J of the Application together with BC Hydro's position on these capital projects, and for the reasons set out below, the only planned capital projects the Panel considers require CPCN filings relate to the Bridge River system**.**

[554] CEC Final Argument, p. 74.
[555] BCOAPO Final Argument, p. 30.
[556] Zone II RPG Final Argument, p. 18.
[557] CEABC Final Argument, p. 17.
[558] BC Hydro Reply Argument (May 27, 2020), p. 88.
[559] UCA section 45 (2), (5).

4.4.3.1 Bridge River Projects

The Bridge River System is a multi-facility generating system on the Bridge River located west of Lillooet.[560] The Bridge River System consists of the La Joie generating station, the Bridge River 1 and 2 generating stations, and the Seton generating station, and associated dams and reservoirs.[561] The facilities are capable of generating 550 MW of power but are currently restricted to less than 455 MW, representing about 6 percent of BC Hydro's total generation.[562] BC Hydro has made investments totaling more than $100 million in the Bridge River facility[563] and $35 million in the Seton facility[564] over the last 10 years.

The Bridge River facility is classified as a Key generating facility by BC Hydro. "The Bridge River facility contains 30 percent of all Key facility equipment currently rated as Poor and Unsatisfactory. A number of capital projects are underway [at] Bridge River, including the replacement of two of the eight generating units, which are anticipated to be in service in fiscal 2019. This will result in an improvement of asset condition at Key facilities."[565]

BC Hydro states: [566]

> The Bridge River System lies within the traditional territory of the St'át'imc Nation. BC Hydro and St'át'imc have a set of Agreements (signed in 2011) that settle all past, present and future claims related to the Bridge River facilities and provide legal certainty around continued operations of the Bridge River facilities and inform ongoing relationship development. BC Hydro is engaging the St'át'imc Nation in a manner consistent with our Agreements and continues to work with the St'át'imc to address issues and concerns around this project.

BC Hydro submits that the key issues driving investments are water flow management and operating within water licenses, the deteriorating condition of the generating equipment, and seismic stability of the dams.[567]

BC Hydro lists the following projects with capital expenditures of greater than $20 million in the Test Period in the Bridge River system[568]:

- Bridge River 1 – Mitigate Surge Spill Hazard
- Bridge River 1 Improve Slope Drainage
- Terzaghi – Spillway Chute Access Improvement
- Bridge River 2 – Upgrade Unit 5 and 6
- Bridge River 1 – Strip and Recoat Penstocks 1-4 Interior
- Bridge River 1 – Replace Units 1-4 Generators/Governors
- Bridge River 2 – Strip and Recoat Penstock 2 Interior
- Bridge River 2 – Upgrade Units 7 and 8
- Seton – Upgrade Unit
- Bridge River Transmission Project

560 Exhibit B-1, Appendix K, Attachment 1, p. 7.
561 Transcript Volume 13, pp. 2443–2444; Exhibit B-1, Appendix K, Attachment 1, p. 7.
562 https://www.bchydro.com/energy-in-bc/projects/bridge-river-projects.html
563 Exhibit B-1, Appendix K, Attachment 1, p. 7.
564 Exhibit B-1, Appendix K, Attachment 1, p. 37.
565 Exhibit B-1, Appendix K, pp. 3–4.
566 Exhibit B-1, Appendix J, Attachment 1, p. 51.
567 Exhibit B-1, Appendix K, Attachment 1, p. 7.
568 Exhibit B-1, Appendix J, Attachment 1, pp. i–vii.

The Bridge River 1 - Replace Units 1-4 Generators/Governors Project (BR1 U1-4 Project) will replace the generators, governors, and exciters for units 1-4 in the Bridge River 1 powerhouse. The BR1 U1-4 Project is motivated by the poor condition of the existing equipment and by the Water Use License in place for the facility, and will add 8MW of capacity to the BR1 facility.[569] The facility is currently operating under a variance to its Water Use Plan. BC Hydro states: [570]

> BC Hydro has been, and currently is, operating under a variance to our Water Use Plan order, approved by the Comptroller of Water [Rights] February 16, 2017. With the reduction in generation capacity and the loss of storage due to the drawdown of the Downton Reservoir, effective water management in the system is hindered.

The Bridge River Transmission Project will upgrade the thermal limit to the existing 2L90 transmission line. The driver for the Bridge River Transmission Project is that the transmission system is currently insufficient to accommodate the Bridge River system generation output at all times of the year, causing 2L90 to overload.[571] "The project will be timed to meet the higher generation demands associated with another project, the Bridge River 1 Replace Units 1-4 Generators/Governors."[572] BC Hydro states that a benefit of the Bridge River Transmission Project is to "Increase transmission capacity in the Bridge River area to meet the higher generation demands of the system."[573]

BC Hydro clarified that the need for the Bridge River Transmission Project is driven as much by the increase in capacity from the BR1 U1-4 Project at Bridge River as from the additional IPP generation in the area.[574]

In the fiscal 2017 to fiscal 2019 RRA proceeding, BC Hydro stated that it had not prepared an overall, conceptual level cost estimate for the Bridge River system.[575] BC Hydro confirms that this is still the case.[576] However, BC Hydro explains that the term "conceptual level estimate" has specific connotations for BC Hydro which may have led to its response in the fiscal 2017 to fiscal 2019 RRA proceeding being "misleading". [577] While BC Hydro does not have what it considers a "conceptual level estimate" for the Bridge River System, it does conduct an "area plan" to consider initiatives which are broader than an asset class or a single facility.[578]

BC Hydro submits that there are no projects identified in this proceeding where a joint CPCN would be appropriate. BC Hydro adds that the projects on the Bridge River system are an example of projects which should be managed separately, as the projects "will vary greatly in their nature and combining them would increase risk and uncertainty." [579]

BC Hydro states specifically that the BR1 U1-4 Project and the Bridge River Transmission Project should not be linked. [580]

> While the Bridge River Transmission Project is needed to use the extra 8 MW of capacity resulting from the Bridge River 1 to 4 Project (based on operations within the existing water license), this does not represent a substantial linkage between the projects.

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[569] Exhibit B-1, Appendix J, Attachment 1, pp. 50–51; Transcript Volume 13, p. 2458, line 5 (Darby).
[570] Exhibit B-1, Appendix J, Attachment 1, p. 75.
[571] Exhibit B-1, Appendix J, Attachment 1, p. 75.
[572] Exhibit B-1, Appendix J, Attachment 1, p. 76.
[573] Exhibit B-1, Appendix J, Attachment 1, p. 75.
[574] Transcript Volume 13, p. 2456 (Kumar).
[575] Exhibit C10-24 in this RRA proceeding, or B-15 CEABC IR 2.41.1 in the earlier proceeding.
[576] Transcript Volume 11, p. 1903, Mr. Darby lines 18–21.
[577] Transcript Volume 11, p. 1906, line 10; p. 1907, line 15 (Darby).
[578] Transcript Volume 11, p. 1905, lines 6–7 (Darby).
[579] BC Hydro Final Argument, pp. 153–154.
[580] BC Hydro Final Argument, p. 154.

BC Hydro states that the drivers for each project are independent: the BR1 U1-4 Project is a sustainment project driven by deteriorating asset condition and water passage, and the Bridge River Transmission Project is to support the area as a whole, not just the additional 8MW of capacity added in the BR1 U1-4 project.[581]

BC Hydro confirms it intends to file an application under section 44.2 of the UCA for the BR1 U1-4 Project, and a CPCN for the Bridge River Transmission project if it is over $100 million.[582]

Positions of Parties

BCSEA agrees with BC Hydro that the need for each of the BR1 U1-4 Project and the Bridge River Transmission Project is independent of the other. BCSEA supports BC Hydro's proposed filings on the Bridge River projects, which are in line with the 2018 Capital Filing Guidelines.[583]

BCSEA submits that BC Hydro's planning and project development practices as applied in the Bridge River system are reasonable, and that it would not be accurate to generalize that BC Hydro develops projects without consideration for other projects in the system. BCSEA expects that specific investments in the Bridge River system will come before the BCUC and will be scrutinized at that time "within the broader context". [584]

Panel Determination

The Panel finds that a CPCN for the Bridge River 1 Units 1-4 Generators / Governors Project is warranted. BC Hydro has confirmed its intention to file a Section 44.2 UCA expenditure schedule for this project. However, the Panel wishes to be certain that BC Hydro will seek approval before commencing the project. The UCA does not permit the BCUC to direct the filing of a section 44.2 UCA expenditure schedule. However, as the project meets the definition of an extension because there is a planned increase in capacity of 8 MW at the facility, the Panel relies on section 45 (5) of the UCA to ensure that BC Hydro files for approval. The Panel wishes to ensure that the BCUC evaluates the project alternatives, water licence variance, consultation and other public interest issues.

The Panel finds that a CPCN for the Bridge River Transmission Project is warranted. BC Hydro indicates its intention to file a CPCN for this project "if it is over $100 million". The Bridge River Transmission Project increases the capacity of the transmission line to move more power out of the Bridge River area from BC Hydro and IPP facilities and therefore meets the definition of an extension. Accordingly, the Panel relies on section 45 (5) of the UCA to order that a CPCN be filed for the project. The Panel wishes to ensure that the BCUC evaluates the project alternatives, consultation and other public interest issues whether or not the project meets the $100 million threshold for a CPCN filing under the 2018 Capital Filing Guidelines.

BC Hydro argues that the BR1 U1-4 Project and the Bridge River Transmission Project should be managed separately. The Panel does not take issue with this position, and does not seek to combine their management. However, the Panel differentiates between the approval process for projects and their management. Filing a joint CPCN for review, scrutiny and approval does not inherently imply that the utility must manage all components approved in the CPCN proceeding together.

The Panel finds that the BR1 U1-4 Project and the Bridge River Transmission Project are sufficiently related to warrant a joint CPCN filing. BC Hydro acknowledges that the Bridge River Transmission Project will be timed to meet the higher generation of the Bridge River system once units 1-4 have been replaced, and that a benefit of the Bridge River Transmission Project is to have the increased capacity needed to meet the higher generation needs of the system. To the Panel, this demonstrates that the need for the Bridge River Transmission Project is

[581] BC Hydro Final Argument, p. 154.
[582] BC Hydro Final Argument, p. 155.
[583] BCSEA Final Argument, p. 35.
[584] BCSEA Final Argument, p. 35.

at least in part dependent on the BR1 U1-4 Project, and that without the latter there may be insufficient need for the former. Thus, it makes sense that the two initiatives are reviewed together.

The Panel considers that, for the effective scrutiny of any investment in the Bridge River system, the BCUC should ideally have a view of the entire system. If project alternatives are only considered at the facility level, or even at the lower level of a component within a facility, there is a risk that there will be inadequate consideration of alternatives for the system itself. The proper place to review the Bridge River system and its alternatives is the IRP. However, BC Hydro has not filed an IRP with the BCUC since 2008, and will not do so again until at least February 28, 2021. In the absence of a current IRP, considering the two projects together will allow the BCUC at least a somewhat more complete consideration of the Bridge River system than reviewing the two projects separately.

For these reasons, and pursuant to section 45 (5) of the UCA, the Panel directs that BC Hydro file a joint CPCN for the Bridge River 1 Units 1-4 Generators / Governors Project and the Bridge River Transmission Project.

4.4.3.2 Peace Region Electric Supply Project

BC Hydro states that the Peace Region Electric Supply project (PRES) is a prescribed undertaking and is therefore exempt from CPCN filing.[585] The total cost of the project is $197 to $348 million. The project has a forecast in-service date of fiscal 2022 and the start date of construction is fiscal 2019.[586]

Order in Council (OIC) 101/2017 adds as prescribed undertakings, for the purpose of section 18 of the *Clean Energy Act*, investments in infrastructure in Northeast BC that primarily serve natural gas producers and processors.[587]

BC Hydro submits that the PRES project is a prescribed undertaking under section 18 of the CEA and section 4(2) of the GGRR. BC Hydro explains that the planned in-service date of the PRES project satisfies section 4(2)(b) of the GGRR, and adds that the purpose of the PRES project, "to construct and operate electricity transmission facilities to reduce GHG emissions in BC by enabling the electrification of natural gas production, processing and compression in the South Peace region", is consistent with section 4(2)(a) of the GGRR. [588]

Positions of Parties

BCOAPO,[589] CEABC,[590] CEC,[591] BCSEA,[592] and AMPC[593] agree that the PRES project is a prescribed undertaking.

BCOAPO notes that since the PRES project is not expected to be in-service during the fiscal 2020 to fiscal 2021 period it does not affect the revenue requirement for the Test Period. While section 18(2) of the CEA requires that "the commission must 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," BCOAPO expects these "costs" will be subject to consideration in BC Hydro's next RRA.[594]

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585 Exhibit B-1, Appendix J, Attachment 1, p. 72.
586 Exhibit B-1, Appendix J, Attachment 1, p. 71.
587 https://www.bclaws.ca/civix/document/id/oic/arc_oic/0101_2017
588 BC Hydro Final Argument, pp. 140–141.
589 BCOAPO Final Argument, p. 35.
590 CEABC Final Argument, p. 47.
591 CEC Final Argument, p. 5 .
592 BCSEA Final Argument, p. 33.
593 AMPC Final Argument, p. 8.
594 BCOAPO Final Argument, p. 36.

Ince recommends BCUC review the project, including future electricity servicing alternatives, to minimize the risk of stranded assets and to achieve cost savings for ratepayers.[595]
Gjoshe "urge(s) the Commission Panel to use its legislative mandate, as appropriate, to review upcoming large transmission capital projects such as the Peace Region Electric Supply (PRES) project, the Interconnection project for LNG Canada Phase 2, and the North Montney project, among others, in order to discern potential matters of significant public interest on account of their complexity, magnitude (i.e. cost), and ratepayer risk."[596]
Gjoshe further recommends the BCUC review the project, significant public interest issues and recent global developments, which may further contribute to slowing demand drivers for the project.[597]

In its Reply Argument, BC Hydro notes that the BCUC does not have the jurisdiction to prevent prescribed undertakings or exempt projects, and therefore should not review them.[598] BC Hydro states: "In the event that the BCUC concludes some commentary is required regarding the inclusion of the costs of a prescribed undertaking or exempt projects in rates, BC Hydro submits that the BCUC might consider the language it has employed in approving other such projects. For example, in that context, the BCUC has noted that it has not reviewed the project from a public interest perspective as it is a prescribed undertaking."[599] BC Hydro further notes that the BCUC is not required to make a public interest determination in such projects.

Panel Determination

The Panel finds that the PRES project meets the definition of a prescribed undertaking under section 18 of the CEA and section 4(2) of the GGRR.

The BCUC does not have jurisdiction to review the PRES project because it is a prescribed undertaking, and the BCUC is therefore required by government to allow BC Hydro to recover the costs in rates. Therefore, the Panel will not direct such a review, and has not considered whether or not the PRES project is in the public interest.

4.4.3.3 Minette to LNG Canada Interconnection Project

BC Hydro states that the Minette to LNG Canada Interconnection project is an interconnection project to connect Phase 1 of the LNG Canada facility near Kitimat to the BC Hydro electric grid. A new double-circuit 287kV line will be constructed from the Minette substation to LNG Canada's facility, along with system reinforcements at Minette substation.[600]

The capital expenditures for the Minette to LNG Canada Interconnection project in the Test Period are $28.2 million in fiscal 2020 and $26.6 million in fiscal 2021.[601] BC Hydro adds that LNG Canada will "provide security for the capacitor banks and substation expansion and a cash payment for the double-circuit transmission line from MIN to LNG Canada".[602]

The Transmission Upgrade Exemption Regulation, BC reg 160/2018, amended by Ministerial Order M277/2018, exempts BC Hydro from Part 3 of the UCA in respect of "the construction or operation of a plant or system, or an upgrade or extension of either, to provide service for the following:

(a) an LNG facility in the vicinity of the District of Kitimat;
(b) a facility necessary for the construction of an LNG facility in the vicinity of the District of Kitimat

[595] Ince Final Argument, p. 8.
[596] Gjoshe Final Argument, p. 5.
[597] Gjoshe Final Argument, p. 10.
[598] BC Hydro Reply Argument (May 27, 2020), p. 56.
[599] BC Hydro Reply Argument (May 27, 2020), p. 57
[600] Exhibit B-1, Appendix E, p. 30.
[601] Exhibit B-5, BCUC IR 1.9.
[602] Transcript Volume 12, p. 2292, lines 8–15 (Kumar); Exhibit B-57, BC Hydro Undertaking No. 43.

The exemptions do not apply to "a plant, system, upgrade or extension that, on the date [BC Hydro] decides to construct the plant, system, upgrade or extension, cannot reasonably be expected to come into service before October 1, 2025".[603]

BC Hydro submits that the Minette to LNG Canada Interconnection project is exempt pursuant to the *Transmission Upgrade Exemption Regulation*.[604]

Positions of Parties

BCOAPO,[605] CEABC,[606] AMPC,[607] CEC[608] and BCSEA[609] agree that the Minette to LNG Canada Interconnection Project meets the exemption criteria under the *Transmission Upgrade Exemption Regulation*.

BCOAPO notes that since the project is not expected to be in-service during the Test Period, it does not affect the revenue requirement, although BCOAPO expects the cost of the project will be subject to consideration in BC Hydro's next RRA.[610]

Gjoshe recommends BCUC review the project if it deems appropriate to do so; but the project's relatively narrow scope, geographical footprint, complexity, and system significance likely mitigate potential perceived ratepayer risk.[611]

Ince states "while BC Hydro may argue that this project is a prescribed undertaking, to the extent that there are technically and economically feasible alternative configurations of this project, these warrant review by the BCUC."[612]

BC Hydro submits in reply that the Minette to LNG Canada Interconnection Project is exempt from Part 3 of the UCA and therefore the BCUC should not engage in a review of the need for and alternatives to the project as requested by Gjoshe and Ince.[613]

Panel Determination

The Panel finds that the Minette to LNG Canada Interconnection project meets the criteria in the Transmission Upgrade Exemption Regulation and is therefore exempt from Part 3 of the UCA.

The BCUC does not have jurisdiction to review the Minette to LNG Canada Interconnection Project because it is exempt from Part 3 of the UCA, and the BCUC is therefore required by government to allow BC Hydro to recover the costs in rates. Therefore the Panel will not direct such a review, and has not considered whether or not the Minette to LNG Canada Interconnection Project is in the public interest.

603 https://www.bclaws.ca/civix/document/id/lc/bcgaz2/v61n14_160-2018
604 BC Hydro Final Argument, p. 139.
605 BCOAPO Final Argument, p. 36.
606 CEABC Final Argument, p. 48.
607 AMPC Final Argument, p. 8.
608 CEC Final Argument, p. 5.
609 BCSEA Final Argument, p. 32.
610 BCOAPO Final Argument, p. 37.
611 Gjoshe Final Argument, p. 11.
612 Ince Final Argument, p. 8.
613 BC Hydro Reply Argument (May 27, 2020), p. 56.

4.4.4 Reconsideration Request for Northwest Substations Upgrade Project

In the fiscal 2017 to fiscal 2019 RRA Decision the BCUC ordered BC Hydro to file CPCNs for five upcoming projects, including the Northwest Substation Upgrades project (Direction 3).[614] BC Hydro requests an amendment to Direction 3 to remove the requirement to file a CPCN for the Northwest Substation project as the directive is inconsistent with the Transmission Upgrade Exemption Regulation.[615]

BC Hydro states that it has cancelled the Northwest Substation Upgrade project, due to LNG Canada splitting its load interconnection request into two phases. BC Hydro will satisfy the first phase of LNG Canada's load interconnection request with the Minette to LNG Canada Transmission project, which BC Hydro submits is exempt from Part 3 of the UCA pursuant to the Transmission Upgrade Exemption Regulation. BC Hydro adds that LNG Canada has yet to make a decision to proceed with phase 2 of its load interconnection request, but submits that this too would be exempt from Part 3 of the UCA.[616]

While BC Hydro acknowledges that the cancellation of the Northwest Substation Upgrades Project means that Direction 3 is no longer applicable, it requests that the BCUC reconsider and vary Direction 3 to "clarify that no CPCN would be required or expected by the BCUC for the original project, for the MIN to LNG Canada interconnection, or for other potential projects associated with LNG Canada's updated request that are expected to come into service before October 1, 2025."[617]

Positions of Parties

BCSEA concurs with BC Hydro that the Minette Station to LNG Canada Interconnection project is exempt from Part 3 of the UCA, and supports BC Hydro's request that the BCUC remove Directive 3 requiring BC Hydro to file a CPCN application for the Northwest Substation Upgrade project if BC Hydro intends to proceed with it.[618]

Panel Determination

The Panel varies Directive 3 of the BCUC's Decision on BC Hydro's Fiscal 2017 to Fiscal 2019 Revenue Requirements Application removing the requirement for BC Hydro to file a CPCN for the cancelled Northwest Substation project.

The Panel agrees with BC Hydro that there is no value in submitting a CPCN for a cancelled project. Further, there is no requirement for BC Hydro to submit a CPCN for the Minette to LNG Canada Transmission project, a successor of the cancelled Northwest Substation project, as the Panel has found it is exempt from Part 3 of the UCA in section 4.4.3.3 above.

However, the Panel does not agree with BC Hydro that CPCNs will not be required for "other potential projects associated with LNG Canada's updated request". While a CPCN is no longer required for the cancelled Northwest Substation Project, and the Minette to LNG Canada Interconnection project is exempt from Part 3 of the UCA, there may be other successor projects to the Northwest Substation project which do require CPCNs.

The Panel is not in a position to make any determination as to which future projects related to LNG Canada or to the cancelled Northwest Substation project might be exempt. The Panel encourages BC Hydro to apply to the BCUC to determine whether future projects are exempt from regulation, and expects BC Hydro to apply the approved 2018 Capital Filing Guidelines and CPCN Guidelines to any non-exempt projects.

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614 Decision to Order G-37-18, p. 39 https://www.ordersdecisions.bcuc.com/bcuc/decisions/en/306836/1/document.do.
615 Exhibit B-1, pp. 2-22–2-23.
616 BC Hydro Final Argument, pp. 138–139.
617 BC Hydro Final Argument, pp. 139–140.
618 BCSEA Final Argument, p. 32-33.

4.4.5 Other Issues Regarding Capital

4.4.5.1 Prescribed Undertakings

Chair Morton of the BCUC observed in the Oral Hearing that there are utilities in BC which apply to the BCUC for "in essence an advance ruling" on whether a project qualifies for a GGRR exemption, but that this is not BC Hydro's practice.[619] BC Hydro President and CEO Mr. O'Riley responded that he is not averse to the idea and "the idea of an advance ruling seems to make sense".[620]

BC Hydro confirms that, following this proceeding, it will consider the legal and practical issues with respect to advance rulings on GGRR exemptions, and will initiate further discussions with BCUC staff to explore potential options.[621]

Positions of Parties

BCSEA "supports in principle the development of a mechanism for the BCUC to assess the applicability of the GGRR in advance."[622]

Gjoshe urges the BCUC to direct BC Hydro to start discussions with BCUC staff at the earliest opportunity, and to establish a timeline for it with clear process expectations for the benefit of all involved.[623]

In BC Hydro's view, there is no need for direction of the kind suggested by Gjoshe, as it has already committed to engaging with staff and setting out any process steps now would be premature. BC Hydro requests that the BCUC allow time for BC Hydro to consider the issues involved, which in turn would allow BC Hydro to engage BCUC staff in an informed discussion about the path forward.[624]

Panel Discussion

The Panel acknowledges that the jurisdiction of the BCUC over exempt projects is, by definition, limited. However, as the regulator of public utilities in BC, it determines whether a public utility is exempt from any provision of the UCA by virtue of an exemption granted by the BCUC, a minister, or the Lieutenant Governor in Council.

There are benefits to utilities in ensuring that their projects do indeed qualify for exemptions. If a utility wrongly considered that a project was exempt from Part 3 of the UCA, for example, then the utility might be in breach of the requirements not to start construction or operation of a system or extension without approval, or might find that it had incurred costs which were not recoverable from its ratepayers.

The Panel encourages BC Hydro to follow the practice of other utilities in BC and file applications to allow the BCUC to determine whether a project is exempt from the UCA before incurring expenditures on it. In addition to reducing the risk to BC Hydro of non-recoverability of costs, advance rulings on whether projects are exempt are in the interests of regulatory efficiency as they reduce the burden on RRA proceedings.

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619 Transcript Volume 6, p. 742, line 20; p. 743, line 14 (Morton).
620 Transcript Volume 6, p 743, line 15; p. 744, line 7 (O'Riley).
621 BC Hydro Final Argument, p. 144.
622 BCSEA Final Argument, p. 33.
623 Gjoshe Final Argument June 18, 2020, p. 2.
624 BC Hydro Reply Argument (June 22, 2020), p. 7.

4.4.5.2 Project Write-Off Costs

In the Test Period, BC Hydro began forecasting into the revenue requirement project write-off costs of $9.9 million for fiscal 2020 and $9.7 million for fiscal 2021.[625] In the past, project write-off costs were not forecast into the revenue requirement and thus, not recovered from ratepayers.

BC Hydro submits that as a project's life cycle progresses, "project drivers, scope and leading alternative are generally revisited and reconfirmed prior to advancing into the next phase." This process could result in the cancellation of a project, a change in the project's leading alternative or a reduction in key project scope for reasons that include "evolving asset or system needs and changes to the project cost relative to benefits." BC Hydro further explains that this can result in projects being written-off, "in whole or in part, if the capital costs incurred no longer have future benefit." BC Hydro submits that "these decisions are effective project and investment management practices and are the result of mature portfolio management practices to ensure our capital investments are prudent."[626]

BC Hydro's fiscal 2020 and fiscal 2021 forecast for project write-offs is based on historical trends for capital project write-offs in the Power System and Technology portfolios as historically project write-offs have come from these two capital portfolios.[627] The average 3-year historical actual project write-offs as a percentage of capital spend from fiscal 2016 to fiscal 2018 was 0.9 percent, which BC Hydro then decreased by 0.1 per fiscal year in the Test Period as an estimated impact of its "process improvement efforts to decrease project write-offs by identifying risks to capital expenditure write-offs earlier in the project lifecycle."[628] The resulting forecast project write-offs for fiscal 2020 are $9.9 million based on 0.8 percent of the annual capital expenditures and for fiscal 2021 are $9.7 million based on 0.7 percent of the annual capital expenditures. The annual capital expenditures used for the calculation exclude the Site C project and the 2017 Waneta Transaction.[629] BC Hydro submits that it is not aware of any other utility in Canada that takes a similar approach to forecasting project write-off costs.[630] As at December 31, 2019, BC Hydro's actual project write-offs were $14.1 million, which means that it has already exceeded its budget for fiscal 2020 by $4.2 million.[631]

BC Hydro submits that the BC OAG endorsed its asset management practices in December 2018 with the release of an independent audit of BC Hydro's Capital Asset Management and found that BC Hydro had asset management practices as a result of a decade-long plan and associated efforts. The BC OAG had no recommendations for improvement.[632]

BC Hydro submits that its approach to forecasting project write-offs in the revenue requirement reflects prudent capital management practices.[633] BC Hydro submits that project write-offs should be recovered in rates, just like other costs incurred in the course of providing utility service to customers, because they are "a legitimate cost of serving customers."[634] Furthermore, since the write-offs are prudently incurred, "customers should pay a 'reasonable amount' for those write-offs."[635]

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[625] Exhibit B-1, p. 8-22; Exhibit B-5, BCUC IR 161.1.
[626] Application, p. 8-21.
[627] Exhibit B-5, BCUC IR 161.1.
[628] Application, pp. 8-21–8-22.
[629] Application, p. 8-22.
[630] Transcript Volume 12, p. 2241, lines 22–24, p. 2242, lines 23–25.
[631] Exhibit B-56, Undertaking No. 49, p. 2.
[632] Application, p. 6-9.
[633] BC Hydro Final Argument, p. 160.
[634] BC Hydro Reply Argument (May 27, 2020), p. 74.
[635] BC Hydro Reply Argument (May 27, 2020), p. 75.

BC Hydro clarified during the oral phase of argument that there is no factual driver behind its request to now begin forecasting project write-off costs in its revenue requirement. This request was based on "an exercise of evaluating what was done in the past and whether it made sense based on principle and the current state of the capital planning process."[636] BC Hydro explains that this request "was prompted by a reassessment of how a regulatory principle should be applied in the context of a mature capital planning process." BC Hydro submits that the recovery of these costs is consistent with regulatory principle because "in a revenue requirements context these are accounted for as operating costs, much like other operating costs that are incurred in the course of planning, and they should be approached in the same way." Furthermore, a continued reassessment of whether a project should proceed is part of a mature planning process and should be encouraged.[637]

BC Hydro also clarified that in its view, the proposed treatment of project write-off costs would be the same whether it was a project that was reviewed and approved the BCUC or exempted by Government.[638]

Positions of Parties

MoveUP does not object to BC Hydro's proposal to recover forecast project write-off costs from ratepayers. MoveUP submits, "the right of a utility to recover in rates the cost of writing off capital expenditures depends on the prudency of the decision to incur them when they arose, and the prudency of the decision to terminate or abandon them and write them off." In MoveUP's view, there is no evidence of imprudence in this proceeding and "BC Hydro's submissions regarding the efficacy of the utility's capital planning processes provide relevant context to the prudency issues that arise in this regard."[639]

However, in BCOAPO's view, BC Hydro's proposed approach would shift the cost from the shareholder to the ratepayer while the shareholder's return (i.e. BC Hydro's net income) directed by Direction No. 8 is unchanged from previous years.[640] BCOAPO also notes the lack of "any asserted driver beyond 'we can, so we should'" and suggests BC Hydro's request be considered in the context of the economic impacts of the COVID-19 pandemic. In BCOAPO's view, "the simple fact that there is some regulatory principal that arguably supports this change does not, by itself justify a material change in how BC Hydro is treating its write off expenses."[641]

In response to BCOAPO, BC Hydro submits, "the BCUC's jurisdiction to set rates to recover project write-offs is uninhibited by Direction No. 8." BC Hydro submits that "the subject matter of write-offs is not addressed, either directly or indirectly, in Direction No. 8" and thus, "unless precluded by a provision of a direction, the BCUC retains its discretion to fix just and reasonable rates…" BC Hydro submits that "if the Lieutenant Governor in Council ("LGIC") had meant to require the BCUC to maintain a certain level of shareholder risk, then the LGIC would have had to spell that out in the direction," which the LGIC did not do; therefore, "the subject remains within the BCUC's ratemaking jurisdiction under the *UCA*."[642]

With respect to BC Hydro's allowed shareholder return, BC Hydro submits that since its "allowed ROE for regulatory purposes has been set by Direction No. 8 at a specific dollar amount" that "in effect, by denying reasonable/prudently incurred costs the BCUC would be setting rates that in reality did not meet its obligation under Direction No. 8 specifically, or the requirements of just and reasonable rates more generally."[643]

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[636] Transcript Volume 16, p. 2983, Lines 2–5.
[637] Transcript Volume 16, pp. 2979–2980.
[638] Transcript Volume 16, p. 2985, Lines 7–13, 18–21.
[639] MoveUP Submissions to Oral Arguments, p. 6.
[640] BCOAPO Final Argument, p. 48.
[641] BCOAPO Submissions to Oral Arguments, p. 3.
[642] BC Hydro Reply Argument (May 27, 2020), p. 80.
[643] BC Hydro Reply Argument (May 27, 2020), p. 79.

BC Hydro also submits, “the proper application of regulatory principles is a reasonable basis, in and of itself, to adopt a different treatment of these costs” and that “sound regulatory principle remains relevant and applicable despite the pandemic.”[644]

AMPC submits that it would be “premature” to alter the government’s return framework before the cost of capital proceeding and that by allowing the recovery of write-offs, BC Hydro assumes that all costs written-off were prudently incurred.[645] AMPC also submits that BC Hydro’s proposal is “an unsupported and theoretically unsound approach.” In AMPC’s view, “BC Hydro has long had a mature capital planning program, as have other regulated utilities across Canada, and the fact that BC Hydro has been unable to provide any examples of other utilities that follow a similar approach to recovering project write-off expenses is therefore significant.”[646]

In reply to AMPC, BC Hydro references a Supreme Court of Canada case involving the Ontario Energy Board’s (OEB) approach to a “prudency inquiry” regarding Enbridge. BC Hydro notes that in that case, “the application of the long-standing retrospective prudence test” was articulated, in which the “prudence” inquiry has two stages: (i) “the decision of Enbridge is presumed to have been made prudently unless those challenging the decision demonstrate reasonable grounds to question the prudence of that decision” and (ii) if the presumption of prudence is overcome, “Enbridge must show that its business decision was reasonable under the circumstances that were known to, or ought to have been known to, Enbridge at the time it made the decision.” BC Hydro submits, “the BCUC has full discretion to adopt all aspects of the [prudence test that was applied to Enbridge]” and notes that the BCUC has used the “no-hindsight prudence test” as outlined in the Enbridge case when reviewing past expenditures.[647]

BC Hydro submits, “project write-offs can be the result of effective capital planning processes” because BC Hydro periodically re-evaluates its projects “based on the latest information and cancelled where reasonable to do so. Given BC Hydro’s large capital program, such practices should be encouraged and the consequent costs should be recoverable from customers.”[648] To support this, BC Hydro provides the Ruskin Dam Safety and Powerhouse Upgrade as an example. As part of that project, a study was conducted to determine whether the upper dam crest block needed seismic upgrading. The study concluded that no further work in the asset was required and the $4.6 million expenditure on the study was written-off. In BC Hydro’s view, “incurring the cost of the study was the prudent course of action.”[649]

In BC Hydro’s view, “given the size and complexity of BC Hydro’s system, and continually changing circumstances, project write-offs are an inevitable part of providing safe, reliable and cost-effective service to customers. Therefore, it is just and reasonable for BC Hydro to recover its forecast of project write-off costs over the Test Period.”[650] Furthermore, “it is in the best interests of customers to encourage BC Hydro to make decisions based on the underlying risks and business drivers of projects, without concern that doing the right thing will result in prudently incurred costs being unrecoverable.”[651]

BC Hydro also submits that “regulatory principles should be applied as appropriate to the facts before the BCUC, such that the overall result is just and reasonable” and in BC Hydro’s view, “the principles and the evidence support [its] approach.”[652]

[644] BC Hydro Reply to Interveners on Oral Phase of Argument (June 22, 2020), p. 8.
[645] AMPC Final Argument, pp. 84–85.
[646] AMPC Submissions to Oral Arguments, p. 3.
[647] BC Hydro Reply Argument (May 27, 2020), pp. 75–77.
[648] BC Hydro Reply Argument (May 27, 2020), p. 78.
[649] BC Hydro Reply Argument (May 27, 2020), p. 78.
[650] BC Hydro Reply Argument (May 27, 2020), p. 78.
[651] BC Hydro Reply Argument (May 27, 2020), p. 79.
[652] BC Hydro Reply to Interveners on Oral Phase of Argument (June 22, 2020), pp. 8–9.

Panel Determination

The Panel accepts that some project write-offs are reasonable and to be expected in a utility's normal course of business. However, the Panel is concerned with BC Hydro's proposed approach, particularly in consideration of the lack of examples of other regulated utilities which use a similar approach. The Panel is not persuaded that the proposed approach is reasonable as there is no evidence to support that future write-offs would be at a similar level as past write-offs. In fact, the evidence indicates that write-offs part way through fiscal 2020 have already exceeded the forecast amount. Furthermore, the proposed approach provides no clear linkage between the forecast amount and the specific project and amount that will be written-off. Approving an amount for recovery in advance of examining the details of the projects and the circumstances that led to the decision to write them off does not provide the BCUC with an opportunity to review the circumstances of the write-off. **For these reasons, the Panel disallows recovery from ratepayers any forecast amount for project write-offs in the Test Period revenue requirement as proposed by BC Hydro.**

The Panel, however, is willing to consider a mechanism, such as the establishment of a regulatory account, to capture BC Hydro's actual project write-off costs for future recovery, provided that in future RRAs BC Hydro also lists all of the projects and costs that have been written-off and captured in the regulatory account along with a description of each project, the rationale for incurring the costs and the rationale for the decision to not continue with the project. In the Panel's view, this would provide the BCUC and interveners with an opportunity to review the reasonableness of these costs. The Panel acknowledges that this would cause a delay between when the write-offs were incurred and when they are recovered. However, if the regulatory account balance is to be cleared over each test period, this would result in minimal intergenerational equity issues and balances the need for BC Hydro to recover these costs from ratepayers and the BCUC's ability to examine these costs prior to their recovery. **Therefore, the Panel directs BC Hydro to provide as part of its compliance filing, a proposal for a mechanism to capture the actual project write-off costs in the Test Period for recovery over the subsequent test period.**

With respect to BCOAPO's and AMPC's comments regarding the impact to the government's return framework of shifting project write-off costs to ratepayers, the Panel acknowledges that at this time the BCUC does not have sufficient evidence of BC Hydro's risk profile to assess whether the shareholder's return, as directed by Direction No. 8, is fair. Furthermore, there is a lack of information regarding how the shareholder return, as directed by Government, was determined or the factors that were considered in that determination. Therefore, the Panel cannot assess the amount of risk that is being shifted from shareholder to ratepayer, but also cannot disallow the recovery of a reasonable amount of costs on that basis alone. Until the BCUC has had an opportunity to fully review BC Hydro's overall risk profile, such as in a cost of capital hearing, the Panel cannot make a finding on whether the recovery of project write-off costs from ratepayers would result in the shareholder return being more or less than a fair amount.

The Panel is cognizant of the economic impact of the COVID-19 pandemic, as further discussed in section 5.8 of the Decision. However, the economic impact of a pandemic should not directly impact whether a cost is just and reasonable, rather the assessment should be based on the application of sound regulatory principles.

4.4.5.3 Interconnection Processes

We examine next BC Hydro's customer interconnections process, including issues with timelines, costs, and communications.

BC Hydro provides the following table benchmarking its interconnection activity performance to that of other large utilities in Canada:[653]

[653] Exhibit B-13, AMPC IR 35.6.

Table 4-20: Interconnection Activity Performance Benchmarking

Interconnection Activity	BC Hydro	AESO	Sask Power	Hydro One
System Impact Studies or equivalent	6 to 9 months	37 weeks (9 months)	4 to 12 months	4 to 7 months
Facilities Studies or equivalent	6 to 9 months	52 weeks (12 months)	6 to 18 months	5 to 8+ months
Implementation	No target set	No target set	6 to 18 months	1 to 2+ years

BC Hydro provides the following analysis of the performance of its activities related to large industrial interconnections (transmission service):[654]

Table 4-21: Large Industrial Interconnections (Transmission Service)

	F2017		F2018		F2019		F2020*	
	Total Number	Average Duration	Total Number	Average Duration	Total Number	Average Duration	Total Number	Average Duration
System Impact Studies	10	131	18	84	21	109	9	131
Facilities Studies	3	176	7	215	4	276	0	0
Projects reaching in-service	9	N/A	11	N/A	19	N/A	1	N/A

Notes:
*** Fiscal 2020 data cover the period from April 1, 2019 to July 31, 2019.**

And the following analysis of the performance of its activities related to large industrial interconnections (distribution service):[655]

654 Exhibit B-13, AMPC IR 35.5, p. 2
655 Exhibit B-13, AMPC IR 35.5, p. 2

Table 4-22: Large Industrial Interconnections (Distribution Service)

	F2017		F2018		F2019		F2020*	
	Total Number	Average Duration	Total Number	Average Duration	Total Number	Average Duration	Total Number	Average Duration
Identification Study Phase	14	66	41	60	26	47	16	39
Definition Detailed Design Phase	10	389	6	263	14	387	5	480
Projects reaching in-service	9	N/A	6	N/A	10	N/A	1	N/A

Notes:

*** Fiscal 2020 data cover the period from April 1, 2019 to July 31, 2019.**

Identification Study Phase is from receipt of an acceptable major distribution load connection application to project cost quotation.

Definition Detailed Design Phase is from Definition Funding approval to quotation of Implementation costs.

BC Hydro states that it prioritizes customer interconnections over other capital work.[656] BC Hydro submits internal targets and external benchmarking as evidence it is performing well on customer interconnection requests.[657]

BC Hydro states that in April 2016, it commissioned a benchmarking study on the interconnections requirements and timelines through Black and Veatch, which provided recommendations ranked high, medium, and low priority.[658] From the "Issues" section of the Black and Veatch report, issues marked "high" priority were:[659]

- Inadequate staffing levels to complete studies in a timely manner;
- BC Hydro's new Project and Portfolio Management (PPM) process does not adequately reflect that customer-driven T&D projects are not the same as BC Hydro Generation projects;
- Dependence on individual Project Manager Contractors;
- Time to complete Transmission Generator Interconnection studies greater than stated in the Open Access Transmission (OATT);
- High cost of studies; and
- Level and effectiveness of early discussions with customers is inadequate

Recommendations marked "high" priority were:[660]

- Consider implementation of 'Pre-interconnection Process Studies';
- Increase staffing to complete studies;
- Tailor new PPM process to reflect nature of customer-driven T&D projects;
- Assign small team of delivery project managers to focus on Transmission Generator and Load Customer Interconnection projects;

[656] Transcript Volume 11, p. 1937, lines 19–24 (Kumar).
[657] Exhibit B-13, AMPC IR 35.6; Exhibit B-47, BC Hydro Undertaking No. 32, Attachment 1, pp. 33–35.
[658] Exhibit B-47, Undertaking 32; Further information in confidential exhibit B-47-1.
[659] Exhibit B-47, Undertaking 32, Attachment 1, Black and Veatch report, p. 6-7.
[660] Exhibit B-47, Undertaking 32, Attachment 1, Black and Veatch report, pp. 7–8.

- Improve project meetings to address customers' desire to be more involved in the execution of studies and in decision-making around final design and construction;
- Improve effectiveness of meetings with customers and communication regarding project status; and
- Continue efforts to improve External Service Providers effectiveness and make more efficient the level of BC Hydro review

BC Hydro submits that since this report was prepared, it has "undertaken further internal changes to address the organizational structure issues, matured the delivery process for interconnection work, and implemented several processes improvements which have resulted in the report's recommendations being outdated."[661]

BC Hydro lists several initiatives already undertaken to improve the interconnection process and states it "continues to look for interconnection process improvement opportunities and is open to feedback and ideas from industry, so that we can continue to advance initiatives that will improve the process for both new load customers and BC Hydro."[662] BC Hydro states it has held several workshops and engagement sessions on interconnections with industrial stakeholders,[663] and conducted customer surveys in 2017 and received three responses.[664]

BC Hydro submits that it handles industrial load interconnection requests well, but continues to look for opportunities to improve the process.[665]

Positions of Parties

BCSEA submits that there is room for improvement in BC Hydro's industrial load interconnection regime, particularly in order to foster low-carbon electrification.[666] BCSEA states that BC Hydro's interconnection practices have long been criticized as too slow and too expensive for customers or IPPs wanting to connect.[667]

AMPC states that interconnections have been a longstanding industrial competitiveness concern, and submits that BC Hydro has not made meaningful improvement with respect to staff numbers, timelines and results. AMPC adds that the Application and BC Hydro's testimony do not provide sufficient evidence that BC Hydro is prepared to significantly improve its practices.[668]

AMPC observes that interconnection inquiries, studies and project implementations nearly doubled between fiscal 2017 and fiscal 2019 and BC Hydro expects the volume to stay the same or increase, and yet BC Hydro's staff level handling the workload has remained the same in that period.[669] AMPC adds that BC Hydro has exceeded its internal target of 180 days to complete Facilities Studies for interconnection requests in both fiscal 2018 (average duration 215 days) and fiscal 2019 (average duration 276 days). For the fiscal 2020 period to the end of January 2020, BC Hydro averaged 514 days for Facilities Studies.[670]

AMPC submits that BC Hydro's reliance on benchmark comparisons with other utilities is misplaced. The comparison provided by BC Hydro contains an "apples and oranges" combination of published target durations and actual durations. AMPC further submits that the comparisons are of limited use if BC Hydro is not meeting

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661 Exhibit B-47, Undertaking 32.
662 Exhibit B-13, AMPC IR 35.8.
663 Exhibit B-47, Undertaking 33, p. 1.
664 Exhibit B-47, Undertaking 34.
665 BC Hydro Final Argument, p. 163.
666 BCSEA Final Argument, p. 6.
667 BCSEA Final Argument, p. 37.
668 AMPC Final Argument, p. 7.
669 AMPC Final Argument, pp. 70–71.
670 AMPC Final Argument, p. 72.

its own internal targets, and that BC Hydro did not refer to the 2016 Black & Veatch benchmarking report in its submission.

AMPC submits that the BCUC should direct BC Hydro to prioritize improvements to its interconnections process and to report on concrete steps taken and improvements made as part of the next RRA.[671]

BC Hydro replies that AMPC has misconstrued and overlooked evidence, and has placed undue weight on dated statistics or reports.[672]

BC Hydro states that AMPC has conflated the number of interconnections project managers with the number of projects supported by a different department, and that BC Hydro does augment its interconnections staff with contract staff as needed. BC Hydro submits that the BCUC should find it is prepared to prioritize staffing to support interconnections.[673]

BC Hydro submits its true performance and improvements are not reflected in the metrics cited by AMPC. It states that its customers may be the cause of delays, and that it makes sense for BC Hydro to focus on customer requirements rather than just elapsed days. BC Hydro adds that its metrics can be skewed by a relatively small number of studies that take a long time to complete. [674]

Willis states "it is important for the executives at BC Hydro to keep in mind that they are a monopoly and do not have the natural forces of a competitive environment to motivate them to continually endeavor to provide better connection service."[675] Willis suggests that BC Hydro conduct follow-up interviews with customers who have had recent interconnection work performed to assess the effectiveness of their interconnection service.[676]

CEABC recommends a confidential, statistically valid survey of customers and potential customers be conducted by a third party to determine if the interconnection process is "still too slow, cumbersome, unresponsive and expensive."[677]

BC Hydro submits that the customer surveys recommended by intervener groups are unnecessary, as BC Hydro already receives robust interconnection feedback, including through a recently released survey. BC Hydro states that its online survey tool was implemented in 2020, and will provide "more standard and consistent information to look at trends and service delivery satisfaction." The new survey tool includes an option for the customer to provide further feedback directly to a senior manager in the Interconnections and Shared Assets KBU. BC Hydro adds that its witnesses in the Oral Hearings described positive feedback that it has received with respect to interconnections.[678]

BC Hydro submits there is "no basis for a direction with respect to BC Hydro's interconnection process."[679]

Panel Determination

The Panel acknowledges that BC Hydro has attempted to improve its customer interconnections process. Nonetheless, BC Hydro's own results do not show satisfactory performance, despite these efforts.

Several interveners have suggested that BC Hydro should conduct additional customer interviews or surveys.

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[671] AMPC Final Argument, p. 69.
[672] BC Hydro Reply Argument (May 27, 2020), p. 81.
[673] BC Hydro Reply Argument (May 27, 2020), p. 81.
[674] BC Hydro Reply Argument (May 27, 2020), p. 83–86.
[675] Willis Final Argument, p. 5.
[676] Willis Final Argument, p. 6.
[677] CEABC Final Argument p. 47.
[678] BC Hydro Reply Argument (May 27, 2020), pp. 86–88.
[679] BC Hydro Reply Argument (May 27, 2020), p. 86.

However, the Panel agrees with BC Hydro that this is unnecessary; there is already sufficient evidence that BC Hydro's performance is unsatisfactory, and the Panel considers that further evidence gathering will simply delay efforts to make improvements. What is needed here is progress.

The Panel directs BC Hydro to submit a filing to the BCUC, by December 31, 2020, explaining its progress to date in implementing each of the recommendations included in the Black and Veatch report, plus any other initiatives BC Hydro has or is undertaking to improve its interconnections process.

The Panel further directs that BC Hydro conduct a workshop, by March 31, 2021, with BCUC staff present, to present the information in this filing to current and potential interconnection customers and current and potential IPPs. BC Hydro is directed to submit a further filing to the BCUC, by June 30, 2021, with its most recent performance on interconnections, its activities to date to improve its performance, and a revised plan for further improvement.

Interconnections are important both to customers and to IPPs. BC Hydro is the monopoly provider of transmission services in its service territory and has the power to control access to its transmission network. It is the role of the BCUC as regulator to ensure that this monopoly power is not abused, and that access to the transmission network is not hindered by unreasonable delays or connection charges.

BC Hydro's most recent rate design application (RDA) proceeding excluded a number of topics which were to be addressed in a second module, Module 2, including the topic of transmission extension policy which is contained in Supplement 6 to BC Hydro's Electric Tariff. BC Hydro intended to file Module 2 by summer 2017, and has not yet done so.[680] This application would have given the BCUC the opportunity to review the appropriateness of the transmission interconnection terms and conditions, including the service levels for interconnections. In the absence of this rate design application, the Panel must address interveners' service without waiting for the next RDA. The Panel recommends that the BCUC review the appropriateness of the terms, conditions and charges contained its Electric Tariff Supplement 6 with a view to providing appropriate incentives for BC Hydro to improve the performance of its customer interconnections process.

4.4.5.4 Depreciation Study

BC Hydro confirms that it has not prepared a depreciation study since August 2005. It has confidence in the depreciation rates used in the Application, and states it chose not to update the study due to budget constraints and work requirements. BC Hydro concedes that "performing a depreciation study may be necessary for parties to have confidence in BC Hydro's depreciation rates going forward," and commits to commencing work on a depreciation study after the completion of its fiscal 2020 year-end process.[681]

BC Hydro submits that the depreciation expense in its current RRA is reasonable, but that a new depreciation study "appears to be necessary for some stakeholders to have confidence in BC Hydro's depreciation rates going forward."[682]

Positions of Parties

The CEC accepts BC Hydro's planned approach with respect to the depreciation study.[683]

[680] BC Hydro final argument in the BC Hydro 2015 Rate Design Application proceeding, p. 5.
[681] Exhibit B-43, p. 2.
[682] BC Hydro Final Argument, p. 204.
[683] CEC Final Argument, p. 90.

CEABC agrees with BC Hydro's plans to conduct a depreciation study in the near future. CEABC recommends that the depreciation study explore methods to mitigate excessively high rates of depreciation early in the life of an asset and make depreciation more closely follow the asset survival curves.[684] CEABC further recommends that the depreciation study be extended to include "any Regulatory Accounts whose purpose is to spread the costs over the benefit period."[685]

BCOAPO submits that, given BC Hydro's acknowledgement as to the need for a new depreciation study, the BCUC should direct BC Hydro to complete such a study for filing during the next RRA and, if not practical, no later than the following RRA.[686]

AMPC submits it has no alternative but to accept BC Hydro's late-arriving commitment to complete and file a depreciation study in the coming years.[687] AMPC submits the BCUC should "reject BC Hydro's judgment concerning appropriate depreciation study frequency and timing," and that a standalone BCUC process could consider the depreciation study, if necessary.[688]

AMPC submits there is a material risk that BC Hydro is over-collecting depreciation expense from its current ratepayers and recommends that the BCUC ensures the depreciation study is comprehensive, properly scoped and swiftly executed.[689]

MoveUP states its concerns that the COVID-19 pandemic, and its impacts on loads and the likelihood of a future recession, will de-prioritize BC Hydro's commitment to complete a depreciation study in the near future. Regarding the forthcoming depreciation study, "We trust that the Commission will be prepared to relieve BC Hydro of this task should the course of events demote its priority, as we suspect they will."[690]

BCSEA acknowledges that BC Hydro will conduct a depreciation study in the near future and submits that BC Hydro should not be faulted for not prioritizing a new comprehensive depreciation study until now.[691]

In reply, BC Hydro submits that the scope of the depreciation study should be informed by advice from a depreciation expert. However, BC Hydro expects that the work would include experienced retirement data and consideration of asset condition and technological advancements as AMPC suggests. BC Hydro further submits that, contrary to CEABC's suggestion, the depreciation study should not examine amortization periods for regulatory accounts, most of which have little, if anything, to do with physical assets.[692]

Panel Determination

The Panel agrees with BC Hydro that an updated depreciation study is necessary for parties to have confidence in BC Hydro's depreciation expense and the depreciation rates on which they are based. It is now 15 years since the last depreciation study was prepared, and depreciation expense is a significant component of BC Hydro's revenue requirement.

The Panel rejects CEABC's recommendation that the depreciation study be extended to examine the amortization periods for regulatory accounts. As BC Hydro argues, regulatory accounts have little or nothing to do with physical assets, and the amortization approach for these accounts remains unchanged from when they were approved by the BCUC.

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684 CEABC Final Argument, p. 18-19.
685 CEABC Final Argument, p. 11.
686 BCOAPO Final Argument, p. 46.
687 AMPC Final Argument, p. 6.
688 AMPC Final Argument, p. 59.
689 AMPC Final Argument, p. 61.
690 MoveUP Final Argument, p. 14.
691 BCSEA Final Argument, p. 49.
692 BC Hydro Reply Argument (May 27, 2020), p. 105.

While the Panel is pleased that BC Hydro has committed to filing an updated depreciation study, we wish to have certainty that the depreciation study will be available for review as part of its fiscal 2023 RRA. **Accordingly, the Panel directs BC Hydro to file a depreciation study by no later than the earlier of October 31, 2021 and the date it submits its fiscal 2023 RRA.**

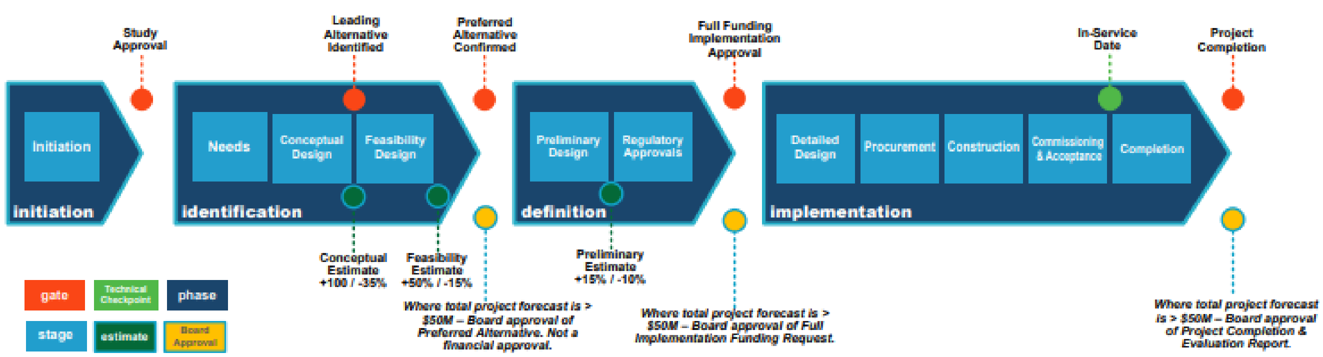
4.4.5.5 Recovery of Cost Overruns due to Geotechnical Issues on Capital Projects

BC Hydro forecasts cost overruns on its Campbell River Substation and Big Bend Substation projects, due in part to geotechnical issues arising during the implementation. The Panel considers the timing of when BC Hydro conducted its geotechnical investigations, and whether the cost overruns related to geotechnical issues are recoverable from ratepayers.

BC Hydro states that its project delivery practices reflect a number of improvements introduced over recent years, including when geotechnical investigations are conducted. The improvements are listed in the Application, including: "Integrated specific geotechnical risk management into the Engineering Design Practice which requires site investigations to be conducted early in the project delivery process and planned, as appropriate, throughout the phases of the project lifecycle."[693]

BC Hydro provides the following diagram of its Project and Portfolio Management (PPM) Project Lifecycle, showing the phases of Initiation, Identification, Definition, and Implementation:[694]

Figure 4-8: PPM Project Lifecycle



BC Hydro states that the forecast actual cost of the Campbell River Substation Project is $32.7 million compared to the expected cost of $25.4 million, for reasons including:[695]

> Unforeseen geotechnical issues: a liquefiable layer was not identified until the geotechnical investigations were undertaken in the Implementation phase. <u>This led to design changes that resulted in additional costs and schedule delay</u>. BC Hydro's practice is now to undertake geotechnical investigations during the Definition Phase. (emphasis added)

BC Hydro explains the costs related to design redundancy for the Big Bend Substation Project:[696]

> For the Big Bend Substation Project, the Implementation phase began in May 2013 and construction started in April 2015. The cost to address the geotechnical issues identified in the

[693] Exhibit B-1, pp. 6-82–6-83.
[694] Exhibit B-1, Figure 6-13, p. 6-65.
[695] Exhibit B-13, response to AMPC IR 36.2, p. 2.
[696] Exhibit B-56, BC Hydro Undertaking No. 41, pdf p. 4.

> Implementation phase was $5 million. This included $2.9 million for the cost increase related to changing the design from piling methodology to deep soil mixing methodology. This change [occurred] during the detailed design stage, prior to the tender and award of the construction contract. The practice at that time did not require substantial design work on the piles during the Definition phase. Piling costs were estimated using the typical piling capacity. <u>Costs related to design redundancy for piling estimates are estimated to be less than $50,000.</u> (emphasis added)

Positions of Parties

AMPC states that BC Hydro has changed its processes regarding geotechnical investigations, but has failed to provide adequate information regarding the costs associated with its prior practice. AMPC submits that the BCUC should direct BC Hydro to identify the costs associated with foreseeable geotechnical-related delay and redundancies on the Campbell River Substation and Big Bend Substation projects and disallow those amounts from the capitalized project costs.[697]

AMPC submits that unforeseen geotechnical concerns led to 70 percent, or around $5 million, of the cost overruns of the Campbell River Substation Project, and that BC Hydro incurred carrying costs associated with the project's delay and additional costs such as project management. Further, AMPC notes that BC Hydro experienced challenges performing geotechnical work at the Big Bend Substation, but chose to move directly into implementation of the project, and AMPC identified $50,000 of design costs for the project which proved unsuitable.[698]

AMPC submits:[699]

> Although BC Hydro's Application begins by explaining that experience with geotechnical issues caused it to change its practices, it now claims through undertaking responses that its prior practice did not have any adverse consequences. It is difficult to reconcile these positions. In consequence, any compliance filing process to this proceeding should require further identification from BC Hydro of the extent of, and costs attributable to, geotechnical related delay for the Campbell River Substation and Big Bend Substation projects. As with the $50,000 design redundancy identified for the Big Bend Substation, those amounts should be disallowed from BC Hydro's capital additions.

BC Hydro submits in reply that AMPC has not accounted for the significance of the change BC Hydro made to its geotechnical practices nor why the change was made. BC Hydro states that in the past its practice varied, sometimes completing all geotechnical work in the Definition phase, while other times completing preliminary geotechnical work in the Definition phase and more detailed investigations in Implementation. For example, for the Big Bend Substation project, BC Hydro conducted what preliminary geotechnical investigations it was able to do prior to acquisition of the property.[700]

BC Hydro submits that the reason for adopting the uniform practice of conducting all geotechnical investigations in the Definition phase was to have a better cost and schedule estimate at the end of the Definition phase, not to avoid costs. Therefore, BC Hydro's variance explanations that indicate that there were "additional cost and delay" due to geotechnical work do not mean that BC Hydro could have avoided those costs by doing all geotechnical work earlier, but that BC Hydro's estimate was inaccurate because it did not undertake all of the geotechnical work earlier. Regardless of when geotechnical work is conducted, if geotechnical issues are found

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[697] AMPC Final Argument, p. 76.
[698] AMPC Final Argument, p. 78-79.
[699] AMPC Final Argument, p. 81.
[700] BC Hydro Reply Argument (May 27, 2020), pp. 66–67.

the project will be impacted in cost and schedule. This is consistent with BC Hydro's evidence that waiting until Implementation to conduct some geotechnical work did not result in any material redundant costs on the Campbell River Substation Capacity Upgrade Project or the Big Bend Substation Project.[701]

In addition, BC Hydro submits that, as a point of principle, its management decisions should be judged based on what it knew or ought to have known at the time, and that the prudence standard is one of reasonableness, not perfection. BC Hydro submits that AMPC offers no evidence BC Hydro knew or should have known at the time it planned past projects that it would have been better to conduct all geotechnical investigations on all projects prior to the Implementation phase. BC Hydro states it has since learned and adjusted its practice to perform all geotechnical investigations prior to Implementation phase, making adjustments based on experience. In BC Hydro's submission, its past and current practices have been reasonable based on its knowledge and the circumstances at the time.[702]

Panel Determination

The Panel finds that there are insufficient grounds for imprudence with regard to BC Hydro's cost overruns for the Campbell River Substation and Big Bend Substation projects related to geotechnical issues, and declines AMPC's request to disallow these costs from BC Hydro's capital additions.

The Panel acknowledges that both projects incurred additional costs as a result of BC Hydro not fully anticipating the geotechnical issues which arose during implementation. However, the question for the Panel is whether there were any material cost overruns as a result of circumstances which were known or ought to have been known by BC Hydro's management when the projects were planned and initiated. The overruns caused by geotechnical issues would largely have been incurred regardless of when the geotechnical investigations had been completed before the projects' implementations began. The costs which AMPC has identified for possible disallowance relate to delays once geotechnical issues had been discovered during implementation, and redundancies in design costs which could have been avoided.

With respect to the cost overruns due to geotechnical issues on the Campbell River Substation Project, the Panel does not consider that there were material costs that could have been avoided by more prudent management by BC Hydro. The geotechnical issues were identified early in the implementation phase while starting the detailed engineering, and the additional implementation work would have been required even if the geotechnical issues had ben identified earlier. The Panel finds that BC Hydro's management decision regarding the Campbell River Substation Project with respect to geotechnical matters was reasonable, and there is no evidence that the cost overruns were not prudently incurred.

In the case of the Big Bend Substation Project, BC Hydro incurred less than $50,000 in piling design costs which proved unsuitable. BC Hydro did conduct preliminary geotechnical work, and only subsequently encountered issues which led to the design costs becoming redundant. The Panel finds that BC Hydro's management decisions regarding the Big Bend Substation Project was reasonable, and there is no evidence that the cost overruns were not prudently incurred.

4.4.5.6 Recovery of WAC Bennett Dam Rip Rap Stockpile Expenditures

BC Hydro seeks to recover expenditures to build a maintenance and emergency stockpile of riprap for the WAC Bennett Dam.[703]

By Order G-78-16 with reasons for decision, the BCUC stated:[704]

[701] BC Hydro Reply Argument (May 27, 2020), p. 67.
[702] BC Hydro Reply Argument (May 27, 2020), pp. 68–69.
[703] Loose stone used to form a foundation for a breakwater or other structure.
[704] BCUC Order G-78-16, directives 1, 3(e).

1. Pursuant to section 44.2 of the Utilities Commission Act, the part, not relating to the Emergency Stockpile Riprap, of BC Hydro expenditure schedule, which has in total a median estimate of $137.1 million for the W.A.C. Bennett Dam Riprap Upgrade Project, is accepted.

2. The part of the Expenditure Schedule concerning the Emergency Stockpile Riprap, which related to the stockpiling of 8,000 cubic metres of riprap for potential future use, is rejected.

   […]

3(e). In future revenue requirement applications that include requests to recover Project expenditures, a statement confirming that no expenditures relating to Emergency Stockpile Riprap were included or BC Hydro shall explain otherwise.

BC Hydro states that, in August 2017, it notified the BCUC that it was proceeding with expenditures for the W.A.C. Bennett Dam maintenance and emergency stockpile of riprap (Riprap Stockpile) and would seek recovery of the costs in accordance with BCUC Order G-78-16. The actual cost for the Riprap Stockpile was $0.7 million, which is $3.6 million less than the $4.3 million estimated in the November 13, 2015 application and the August 2016 update to the BCUC. BC Hydro was able to substantially reduce the cost by adjusting the size of the rock from Class 1 to Class 3 riprap and by reducing the total volume of rock required.[705]

BC Hydro submits that the Riprap Stockpile costs are in the public interest and should be recovered in rates. It explains that the expenditures are prudent and provide good value for ratepayers, as the expected 50-year life of the riprap could be extended by 50 to 100 percent with proper maintenance and repair. BC Hydro explains why the maintenance and emergency stockpile of riprap is prudent, mentioning the value to ratepayers. BC Hydro concludes by stating its request for BCUC approval of expenditures related to the maintenance and emergency stockpile of riprap for the W.A.C Bennett Dam.[706]

Positions of Parties

BCSEA submits it is not aware of any evidence contradicting BC Hydro's justification of the expenditure.[707]

Panel Determination

The Panel finds that the $700,000 spent on the Riprap Stockpile for the W.A.C. Bennett dam was reasonably incurred, and therefore approves the recovery of the amount in the Test Period. BC Hydro has found ways to reduce the cost of building the Riprap Stockpile, and its expenditures are cost effective because they extend the life of the dam's riprap.

4.5 Deferral and Other Regulatory Accounts

In its 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.[708]

BC Hydro's forecast deferral and regulatory account balances for fiscal 2020 and fiscal 2021, as provided in the Evidentiary Update, are $4.486 billion and $4.484 billion, respectively.[709]

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[705] Exhibit B-1, pp. 6-90–6-91.
[706] Exhibit B-1, pp. 6-91–6-93.
[707] BCSEA Final Argument, p. 32.
[708] Exhibit B-1, Chapter 7, Sections 7.7, 7.8, 7.10.
[709] Exhibit B-19, Appendix D, Table D-1, p. 1.

BC Hydro notes that its total net regulatory account balance has been declining since peaking at $5.9 billion during fiscal 2016. At the end of fiscal 2019, the net regulatory account balance was $4.2 billion and by the end of fiscal 2024, is forecast to be $3.8 billion.[710] BC Hydro explains that the primary reason for the decline in the net regulatory account balance was due to the write-off of the Rate Smoothing Regulatory Account in fiscal 2019. Other contributing factors include the ongoing recovery of regulatory account balances in rates, higher than planned Powerex net income and a one-time accounting credit adjustment from the adoption of a new IFRS revenue standard in fiscal 2019.[711]

In the Application, BC Hydro describes its regulatory account policies and principles that guide its treatment of regulatory accounts and requests for approval of new regulatory accounts. It further outlines its plan to reduce the overall regulatory account balances by fiscal 2024. It also sets out the five situations (and types of accounts) where it considers appropriate to use regulatory accounts and the amortization periods (recovery periods) for each type of account. BC Hydro also describes its criteria for assessing whether a risk is controllable or noncontrollable.[712]

BC Hydro discusses what it considers to be an appropriate materiality threshold for creating a new regulatory account – namely, un-forecast and non-controllable expenditures with a net income impact greater than $10 million in a fiscal year.[713]

BC Hydro submits that the BCUC's oversight of its regulatory accounts has been enhanced due to the repeal of Government Directions No. 3, 6 and 7.[714] It submits the underlying rationale for its regulatory accounts remains sound despite the repeal of Government Directions regarding some of BC Hydro's regulatory accounts. In BC Hydro's view, the evidence in the proceeding demonstrates that its "current use of regulatory accounts, its proposals to close and modify some of them, and its forecast additions are just and reasonable, and submits the following:"[715]

- Its approved regulatory accounts are in accordance with IFRS and are consistent with the BCUC's Regulatory Account Filing Checklist;
- Its regulatory accounts should be assessed based on the merits of each account and the benefits it provides to BC Hydro and ratepayers;
- Its current use of regulatory accounts is beneficial to customers;
- The Auditor General's previous qualification on the Government's financial statements regarding BC Hydro's use of rate-regulated accounting has been removed;[716]
- BC Hydro is managing its regulatory account balances using appropriate recovery mechanisms and exercising discipline over controllable costs;
- BC Hydro's proposed changes to regulatory accounts are warranted; and
- BC Hydro's forecast for the Real Property Sales Regulatory Account, as reflected in the Evidentiary Update, is reasonable.

[710] Exhibit B-1, p. 7-2; Exhibit B-19, Appendix D, Table D-2, p. 4.
[711] Exhibit B-1, pp. 7-2–7-3.
[712] Exhibit B-1, Sections 7.5, 7.6, pp. 7-14–7-21.
[713] Exhibit B-1, Section 7.6, p. 7-21.
[714] Exhibit B-1, p. 7-7.
[715] BC Hydro Final Argument, p. 172–173.
[716] Office of the Auditor General of British Columbia, Understanding our Audit Opinion on B.C.'s 2018/19 Summary Financial Statements, pp. 3–4, 9–11, 14: https://www.bcauditor.com/sites/default/files/publications/reports/OAGBC_ROTO-2018-19_RPT.pdf (retrieved on September 24, 2020).

BC Hydro is not requesting approval for any new regulatory accounts. Rather, it is requesting approval of seven changes to certain deferral and regulatory accounts and the closure of four regulatory accounts in the Test Period.

The following table summarizes BC Hydro's requested changes regarding its deferral and regulatory accounts and where in this Decision those requests are discussed: [717]

Table 4-23: Summary of Regulatory Account Orders Requested by BC Hydro

	Requested Change	Section of the Decision
1	Reduce the DARR from 5 percent to 0 percent on April 1, 2019.	Section 4.5.4
2	Amortize into rates, Test Period, the fiscal 2019 net closing balance and the forecast fiscal 2020 and fiscal 2021 net additions and net interest applied to the Cost of Energy Variance Accounts.	Section 4.5.4
3	Defer any variances related to the accounting for EPAs determined to be leases under IFRS 16, which are not eligible for deferral treatment under existing BCUC orders, to the Non-Heritage Deferral Account.	Section 4.5.5
4	Defer any variances between forecast and actual amounts related to the Biomass Energy Program which are not eligible for deferral treatment under existing BCUC orders, to the Non-	Section 4.5.1
5	Continue to defer, on an annual and ongoing basis, any variances between forecast and actual dismantling costs to the Dismantling Cost Regulatory Account, continue to apply interest to the balance of the account and recover the forecast interest charged to 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 4.5.2
6	Defer low-carbon electrification expenditures to the DSM Regulatory Account, consistent with the Direction to the BCUC Respecting Undertaking Costs.	Section 4.6.5
7	Remove the reference to the "Prescribed Standards" from the scope of what may be deferred to the Site C Regulatory Account, as BC Hydro has fully adopted IFRS.	Section 4.5.5
8	Close the Capital Project Investigation Costs Regulatory Account at the end of fiscal 2021 as its balance will be fully amortized into rates at that time.	Section 4.5.5

[717] Exhibit B-1, Section 7.1.1, pp. 7-5–7-7; Exhibit B-19, pp. 6–7; Exhibit B-5, BCUC IR 40.3.1.

9	Close the Rate Smoothing Regulatory Account in fiscal 2020 as this account has a zero balance and BC Hydro is not proposing to smooth rates over the Test Period.	Section 4.5.5
10	Close the Arrow Water Systems Provision Regulatory Account in fiscal 2020.	Section 4.5.5
11	Close the Arrow Water Systems Regulatory Account in fiscal 2020.	Section 4.5.5

With the proposed closure of four regulatory accounts, BC Hydro would reduce its total deferral and regulatory accounts from 29 to 25 by the end of fiscal 2021. In addition, BC Hydro plans to seek approval to close the Rock Bay Remediation Regulatory Account in its next RRA as remediation of the Rock Bay property is complete and the balance in the account is anticipated to be fully amortized by the end of the next test period.[718]

In addition to the above, the Panel also provides a determination with respect to the Real Property Sales Regulatory Account in section 4.5.3 and a determination with respect to other issues raised by interveners regarding BC Hydro's deferral and regulatory accounts in section 4.5.6.

4.5.1 Biomass Energy Program

On April 1, 2019, the Government of BC issued OIC No. 158, which contained direction to the BCUC respecting BC Hydro's Biomass Energy Program. In particular, OIC No. 158 states that the BCUC may not disallow for any reason the recovery in rates of BC Hydro's costs with respect to a biomass contract, as defined in the OIC.[719]

BC Hydro submits that it may need to account for some of the costs related to the Biomass Energy Program as other than cost of energy and it cannot have certainty over the costs or how to account for them until the contracts are signed. BC Hydro explains that variances between forecast and actual costs related to the Biomass Energy Program that are accounted for as cost of energy are already deferred to the Non-Heritage Deferral Account pursuant to existing BCUC orders. In this Application, BC Hydro is requesting this same treatment for variances between forecast and actual costs related to costs related to the Biomass Energy Program that are not accounted for as cost of energy.[720]

Therefore, BC Hydro requests approval to defer to the Non-Heritage Deferral Account any variances between forecast and actual amounts related to the Biomass Energy Program which are not eligible for deferral treatment under existing BCUC orders. BC Hydro submits that this treatment would allow it to recover all of its costs with respect to the Biomass Energy Program.

Positions of Parties

Interveners generally support or take no position on BC Hydro's proposal.[721] In particular, BCOAPO supports BC Hydro's proposal because, in its view, the costs of EPAs are a cost of energy regardless of the accounting classification.[722]

718 Exhibit B-1, p. 7-4.
719 Direction to the BCUC Respecting the Biomass Energy Program, BC Reg. 71/2019, section 4.
720 Exhibit B-1, Section 7.7.1, pp. 7-27–7-28; Exhibit B-5, BCUC IR 147.1.
721 CEC Final Argument, p. 89, paras. 443, 444; BCOAPO FA, p. 42; BCSEA Final Argument, p. 48, para. 189; Zone II RPG Final Argument, p. 2, para. 4.
722 BCOAPO Final Argument, p. 42.

Panel Determination

Given the Government direction in OIC No. 158 and the lack of certainty as to how to account for the costs of the biomass contracts once finalized, the Panel does not take exception to BC Hydro's request to defer the variances between forecast and actual costs of the Biomass Energy Program that are not eligible for deferral under existing BCUC orders, such as costs that are not classified as cost of energy for accounting purposes. However, the Panel does take exception to BC Hydro's request to defer those variances to the Non-Heritage Deferral Account.

In the Panel's view, since OIC No. 158 does not provide the BCUC with any discretion with respect to the recovery of the cost of BC Hydro's Biomass Energy Program contracts, it is important to segregate these costs from other costs held in the Non-Heritage Deferral Account over which the BCUC does have discretion with respect to recovery. Rather than tracking the costs of the Biomass Energy Program within the Non-Heritage Deferral Account, having these costs in a separate deferral account would provide greater transparency and flexibility in the management of the deferred Biomass Energy Program contract costs.

Accordingly, the Panel directs BC Hydro to create a new deferral account and to capture in that account, all variances between forecast and actual amounts related to the Biomass Energy Program. The Panel recognizes that most of these variances would be related to cost of energy. Therefore, the Panel directs that this account be categorized as one of BC Hydro's cost of energy variance accounts and to apply the same mechanisms for interest charges and recovery that are applicable to the Non-Heritage Deferral Account.

4.5.2 Dismantling Cost Regulatory Account

BC Hydro requests approval to continue using the Dismantling Cost Regulatory Account to capture the variance between forecast and actual dismantling costs. Specifically, BC Hydro is requesting approval to:[723]

- Continue to defer, on an annual and ongoing basis, any variances between forecast and actual dismantling costs to the Dismantling Cost Regulatory Account;
- Continue to apply interest to balances in the account, consistent with the application of interest to other variance accounts, based on BC Hydro's current weighted average cost of debt;
- Effective starting in fiscal 2020, and on an ongoing basis, recover the forecast interest charged to the Dismantling Cost Regulatory Account each year from the account each year; and
- On an ongoing basis, recover the forecast account balance at the end of a test period over the next test period.

In the BCUC's Decision to BC Hydro fiscal 2017 to fiscal 2019 RRA, the BCUC approved BC Hydro's request to establish a Dismantling Cost Regulatory Account but limited its use for the fiscal 2017 to fiscal 2019 test period only. In that Decision, the BCUC acknowledged that although there may be some factors that are outside of management's control, it "considers the timing of dismantling activities to be largely within the control of the Company."[724] The BCUC stated that allowing BC Hydro to defer variances for the fiscal 2017 to fiscal 2019 test period would provide BC Hydro with sufficient time to gain more experience in forecasting dismantling costs in subsequent test periods. The BCUC stated it "does not agree, at this time, that BC Hydro should be allowed to recover the variance between planned and actual dismantling costs on an ongoing basis."[725]

The following table shows the variance between forecast and actual dismantling costs from fiscal 2012 to fiscal 2019 and the aggregate variance during this period:[726]

[723] Application, p. 7-31.
[724] BC Hydro F2017 to F2019 RRA Decision, p. 62.
[725] BC Hydro F2017 to F2019 RRA Decision, pp. 62–63.
[726] Exhibit B-16, BCUC IR 297.1.

Table 4-24: Dismantling Cost Variances

($ million)	F2012	F2013	F2014	F2015	F2016	F2017	F2018	F2019	Total
Actual	20.2	16.4	32.2	22.4	24.2	42.4	67.5	42.0	267.3
RRA Plan	34.3	20.9	21.0	24.6	31.2	39.5	35.7	30.6	237.8
Variance from Plan	(14.1)	(4.5)	11.2	(2.2)	(7.0)	2.9	31.8	11.3	29.5
% Variance from Plan	(41.1)	(21.5)	53.3	(8.9)	(22.4)	7.3	89.1	37.0	
Exclude F2018							(31.8)		
Variance excluding F2018	(14.1)	(4.5)	11.2	(2.2)	(7.0)	2.9	-	11.3	(2.3)
Variance from Prior Year	1.1	(3.8)	15.8	(9.8)	1.8	18.2	25.1	(25.5)	
% Variance from Prior Year	5.9	(19.0)	96.5	(30.4)	8.0	75.2	59.2	(37.8)	

BC Hydro submits that over the previous test period, the variances in fiscal 2018 were primarily due to the Salmon River Diversion Decommissioning Project which was originally not anticipated to be decommissioned, an underestimation of costs, and increased dismantling activities due to higher than planned capital expenditures. The variances in fiscal 2019 were primarily due to an underestimation of costs and increased dismantling activities due to higher than planned capital expenditures.[727]

In BC Hydro's view, it should assume financial responsibility for controllable risks and use regulatory accounts for non-controllable risks. Therefore, "un-forecast and non-controllable expenditures of greater than $10 million in a fiscal year would be considered material" and would warrant a new regulatory account to defer the impact for future recovery.[728]

In BC Hydro's view, the nature of dismantling costs makes them difficult to forecast accurately and submits that it is not in a better position now than it was in the previous RRA to accurately forecast these costs. It explains that dismantling costs are difficult to forecast because they are impacted by, among other things: [729]

- Project and program schedules;
- Changes to cost accuracy levels as the project or program moves through the delivery lifecycle; and
- Project or program scope changes.

BC Hydro also submits that emergency dismantling of assets and unplanned dismantling are sometimes required, and cites the decommissioning of the Salmon River Diversion in fiscal 2018 as an example.[730]

BC Hydro submits the rationale for the Dismantling Cost Regulatory Account is the same as the Amortization of Capital Additions Regulatory Account, which captures variances between forecast and actual amortization of capital assets. BC Hydro explains that dismantling costs are "largely driven by BC Hydro's capital plan and are impacted by capital project schedules. Similar to capital projects, dismantling projects may be forecast well in advance of the actual work taking place. Project estimates may be from an earlier stage of the project lifecycle and will have different degrees of accuracy depending on the phase of the project."[731]

BC Hydro submits that it has significant dismantling costs planned for the Test Period of $67 million in fiscal 2020 and $43 million in fiscal 2021, and in the absence of the regulatory account, significant gains or losses could accrue to ratepayers or BC Hydro's shareholder.[732]

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[727] Exhibit B-5, BCUC IR 149.2.
[728] Exhibit B-1, p. 7-21.
[729] Exhibit B-5, BCUC IR 149.2.
[730] Application, p. 7-30.
[731] Application, pp. 7-29–7-30.
[732] BC Hydro Final Argument, p. 199.

In BC Hydro's view, the use of the regulatory account would be more efficient than seeking approval to defer dismantling costs on a case by case basis. For example, BC Hydro notes that in fiscal 2018, it had more than 300 projects with dismantling costs, including 10 projects with dismantling costs greater than $10 million. BC Hydro also points out the BCUC had previously rejected the approach of requesting specific deferral treatment for dismantling costs associated with specific projects.[733]

BC Hydro submits that the magnitude of annual variances, rather than an aggregate variance over an extended period of time, is indicative of future volatility and suggests that variances can continue to be expected in future years. Furthermore, BC Hydro submits that the $28.5 million aggregate variance over the past 8 years is significant and does not provide any "basis to support that the aggregate variance will offset evenly in future periods."[734] Even if the latter were true, the potential for offsetting amounts over the longer term is not a valid basis for ceasing the use of a variance account.[735]

Positions of Parties

Interveners either support or take no position regarding BC Hydro's proposal to continue using the Dismantling Cost Regulatory Account.[736] BCOAPO supports the proposal because "the continued use of the account recognizes the uncertainty associated with the forecast values and means that ratepayers pay the actual costs of dismantling."[737]

Panel determination

The Panel accepts that dismantling costs are largely driven by the capital plan and are impacted by capital project schedules. Given this and the magnitude of the variances in the last test period, the Panel agrees that variances between forecast and actual dismantling costs should be provided deferral treatment similar to the treatment of variances between forecast and actual amortization of capital asset additions.

However, the Panel also notes that dismantling costs have been increasing and is concerned with whether BC Hydro's approach to dismantling costs would result in intergenerational equity issues. In the Panel's view, the dismantling of property, plant and equipment, similar to negative salvage, should be paid for by the customers who benefited from the use of these assets. **Therefore, the Panel directs BC Hydro to provide in its next RRA, an assessment of whether its current practice of expensing dismantling costs as they occur would result in intergenerational inequity and to provide options on how it could calculate and collect dismantling costs to better promote intergenerational equity. For these reasons, the Panel approves the use of the Dismantling Cost Regulatory Account, as requested by BC Hydro, for the Test Period only.**

Given the intergenerational equity concerns, the Panel directs BC Hydro to include in its upcoming depreciation study a net salvage study and, in the RRA immediately after the completion of the depreciation and net salvage studies, report on the results and recommendations, as well as BC Hydro's plan to implement those recommendations.

4.5.3 Real Property Sales Regulatory Account

Since fiscal 2015, BC Hydro has been preparing surplus properties and property rights for sale. The 2013 10-Year Rates Plan included a target of $50 million of net gains from real property sales from fiscal 2015 to fiscal 2019. BC Hydro has increased its net gains target from $50 million to $100 million and extended the timeframe to achieve this target to the end of fiscal 2024. BC Hydro expects the Real Property Sales Regulatory Account to

[733] BC Hydro Final Argument, pp. 199–200.
[734] Exhibit B-16, BCUC IR 297.1.1.
[735] BC Hydro Final Argument, p. 200.
[736] CEC Final Argument, p. 89, paras. 443, 444; BCOAPO Final Argument, p. 43; BCSEA Final Argument, p. 48, para. 190.
[737] BCOAPO Final Argument, p. 43.

self-clear by the end of fiscal 2024, subject to potential interest charges.[738] For this to occur, BC Hydro would need to achieve an annual net gain of $19.1 million for each year from fiscal 2020 to fiscal 2024.[739]

Pursuant to Direction No. 7, the BCUC issued Order G-48-14 establishing the Real Property Sales regulatory account to defer the variances between BC Hydro's actual and forecast real property gain or loss from real estate sales. Interest is also applied to the account. BC Hydro submits that in the absence of this regulatory account, net gains would be to the account of the shareholder consistent with the treatment prior to the establishment of the regulatory account.[740] BC Hydro has been forecasting annual net gains of $10 million from the sale of real property and property rights in its revenue requirement since fiscal 2015. The actual cumulative net gains from fiscal 2015 to fiscal 2019 have been $4.4 million, resulting in a $49.2 million balance recoverable from ratepayers in the Real Property Sales Regulatory Account at the end of fiscal 2019.[741] The fiscal 2019 ending balance in the regulatory account is recoverable from ratepayers pursuant to Direction No. 8.[742] BC Hydro plans to continue its approach by forecasting annual net gains of $10 million into its revenue requirement until fiscal 2024.

BC Hydro submits that the lower than planned gains from real property sales experienced so far were due to the following, which have delayed the sales completions: consultations with First Nations on property dispositions; required subdivision, re-zoning and environmental remediation prior to sale; fluctuating market interest in the properties; and the time required for buyers' due diligence and processes to complete a purchase.[743]

BC Hydro submits that the variances experienced in the past five years are not expected to continue in the next five years because it has already completed property sales in fiscal 2020 with additional sales scheduled to complete in fiscal 2021. Furthermore, the activities required to prepare properties for sale are expected to be completed to allow for the sale of further surplus properties before the end of fiscal 2024.[744] BC Hydro submits that the timing of the completion of real estate transactions is difficult to accurately forecast and this account smooths the recognition of gains and losses from real property sales that could otherwise impact rates in a particular year.[745] BC Hydro submits that the lower than planned gains experienced so far meant that ratepayers have received the benefit of the sales in advance, annually and on a consistent basis since fiscal 2015.[746] BC Hydro submits that it does not consider the period from fiscal 2020 to fiscal 2024 (the period the account is expected to self-clear, subject to interest charges) to create material intergenerational equity issues.[747] BC Hydro also notes that the regulatory account "is about promoting fairness, not benefit matching."[748]

BC Hydro submits that up to the end of January 2020, it had sold 17 properties for net proceeds of $14.65 million. [749] BC Hydro also submits that the actual net proceeds reflect the anticipated net proceeds for those properties and it has made a profit on each sale and expects that to continue.[750] BC Hydro submits that its forecast net gains up to fiscal 2024 are reasonable given that a number of sales have already been completed in

[738] Application, p. 7-41.
[739] Exhibit B-16, BCUC IR 299.3. The difference between the $19.1 million forecast net gains and the $10 million baseline included in the revenue requirements reduces the balance in the Real Property Sales Regulatory Account.
[740] Exhibit B-16, BCUC IR 299.3; BC Hydro Final Argument, p. 181.
[741] Exhibit B-16, BCUC IR 299.3, 301.1; Exhibit B-19, Appendix A, Schedule 2.2, p. 8, Line 143, Column 2.
[742] BC Hydro Final Argument, pp. 182–183; Direction No. 8 to the BCUC, B.C. Reg. 24/2019, section 4(1): "In setting rates for the authority, the commission must not disallow for any reason the recovery in rates of the balance of the authority's regulatory accounts as at March 31, 2019" (http://www.bclaws.ca/civix/document/id/crbc/crbc/24_2019)
[743] Exhibit B-16, BCUC IR 299.1.
[744] Exhibit B-16, BCUC IR 299.2.
[745] Exhibit B-1, p. 7-41.
[746] BC Hydro Final Argument, p. 181.
[747] Exhibit B-16, BCUC IR 299.3.
[748] BC Hydro Reply Argument (May 27, 2020), p. 95.
[749] Transcript Volume 13, p. 2525 (Leonard).
[750] Transcript Volume 13, pp. 2525, 2527 (Leonard).

fiscal 2020 with additional sales scheduled to complete. Furthermore, activities required to prepare properties for sale, including consultation with First Nations, completion of subdivision, re-zoning and environmental remediation prior to sale are expected to be completed before the end of fiscal 2024.[751] BC Hydro also notes that not all of the properties identified as "surplus" need to be sold in order to achieve the $100 million net gains target.[752]

In a confidential response to a BCUC IR, BC Hydro provided a current list of surplus properties (i.e. properties that BC Hydro does not require for operational purposes). BC Hydro submits that some combination of these properties will be sold to achieve the $100M in net gains target by the end of fiscal 2024.[753] BC Hydro explains that the net gains target of $50 million was increased to $100 million and the timeframe to achieve these gains was extended to fiscal 2024 because the value of its surplus properties has increased and BC Hydro also identified additional surplus properties that can be sold.[754]

During the oral hearing, BC Hydro was asked whether its approach was speculative.[755] BC Hydro submits that these properties were acquired decades ago for utility purposes and not as investments or for "flipping" for profit. In BC Hydro's view, "it is appropriate for BC Hydro to try to maximize the return on these properties and that the costs of doing so should be recovered from customers." BC Hydro explains that its approach of recovering the carrying costs (e.g. depreciation and property taxes) from ratepayers is symmetrical in that ratepayers (rather than the shareholder) are benefitting from the sale of these properties. Furthermore, the $100 million net proceeds target "was premised on BC Hydro taking prudent steps to bring the property to market." The carrying and site improvement costs recovered from ratepayers "are dwarfed by the sale proceeds from which they are benefitting."[756]

Currently the net book value of the surplus properties is included in rate base. The forecast depreciation expense that has been included in each year of the Test Period for these assets is $30,000 and the total annual property taxes for the unsold surplus properties were $900,000 in calendar year 2019.[757] BC Hydro states that it will provide in a compliance filing, an update of BC Hydro's determination of whether the properties are used and useful, and address this issue in the next RRA. In BC Hydro's view, this approach is appropriate because BC Hydro's test period net income is set by government direction at a fixed dollar amount rather than based on rate base.[758]

BC Hydro submits that it has not considered alternative approaches to forecasting real property sales, but provides the pros and cons of the following two alternatives posed by BCUC staff:[759]

1. Forecasting net gains:

Pros:	Cons:
• More accurately reflects BC Hydro's experience from fiscal 2015 to fiscal 2019; and • The regulatory account balance would not increase if BC Hydro does not realize the expected	• Higher rates in the test period, specifically a 0.37 percent increase in rates (i.e. a 0.64 percent rate decrease instead of a 1.01 percent rate decrease in fiscal 2021)[760]; and

[751] BC Hydro Final Argument, p. 201.
[752] Transcript Volume 13, pp. 2542–2543.
[753] Exhibit B-16, BCUC IR 299.7; Exhibit B-16-1 (Confidential) BCUC IR 299.7.
[754] Transcript Volume 13, pp. 2522–2523.
[755] Transcript Volume 13, pp. 2545–2546.
[756] BC Hydro Final Argument, pp. 183–184.
[757] Exhibit B-58, Undertaking No. 54, p. 3.
[758] Transcript Volume 16, pp. 2949–2950, 2986 (Ghikas).
[759] Exhibit B-16, BCUC IR 299.3.
[760] Exhibit B-58, Undertaking No. 54, p. 5.

gains, which would result in lower carrying charges applied to the regulatory account.	• The benefits to ratepayers will be delayed until a test period after actual sales are recognized.

2. Forecasting based on expected sales:

Pros:	Cons:
• BC Hydro does not consider there to be any pros due to the high likelihood of forecasting inaccuracies.	• The annual impact on rates will vary and will not be as smooth and stable as the existing approach.

Positions of Parties

Interveners either support the continued use of the regulatory account and the forecast gains or take no position. In particular, BCOAPO and BCSEA support the continued use of the regulatory account and the forecast net gains in the revenue requirement. BCSEA agrees with BC Hydro that the carrying and site improvement costs being paid by customers are minor in comparison with the sale proceeds.[761] AMPC submits that the BCUC should carefully consider any future requests to close this regulatory account and to ensure it obtains customer submissions.[762]

Panel Determination

The Panel acknowledges BC Hydro's submission that the gains and losses from these sales were previously attributed to the shareholder. By recent government direction, the BCUC must now allow the recovery of the $49.2 million balance that has accumulated in this account as at March 31, 2019. Although the account was established with the intention of benefiting ratepayers by allowing ratepayers to obtain a consistent annual amount of the forecast net gains from the sale of real property regardless of the actual timing and amount of the sale proceeds, so far the net gains have not materialized as forecast and the targeted cumulative net gains of $100 million are not guaranteed to be achieved by fiscal 2024. Therefore, although this account was not meant to achieve benefit matching, the Panel cannot ignore that it could result in intergenerational equity issues if BC Hydro continues to forecast $10 million each year and the net gains continue to not materialize.

The Panel is troubled by the fact that the account was originally intended to "self-clear" by fiscal 2019, but has instead been extended because the net gains have not materialized. Notwithstanding, BC Hydro has identified more surplus properties for sale ostensibly for the benefit of ratepayers. Although property sales have been accelerating since fiscal 2019, the Panel is not persuaded that this account will "self-clear" by the new proposed target date of fiscal 2024. Similarly, in light of the history of this account, the Panel is not persuaded that BC Hydro's current approach is reasonable or beneficial to ratepayers in the long run. **Therefore, the Panel disallows BC Hydro's forecast of $10 million net gains in each of fiscal 2020 and fiscal 2021 and instead allows forecast net gains of $0 in the Test Period from the sale of surplus real property.** This will allow the balance accumulated in the regulatory account to decrease if and when the gains materialize from the sale of surplus real property within the Test Period because any variances between the forecast net gains of $0 and the actual net gains in the Test Period would continue to be captured in the regulatory account for the benefit of ratepayers. **Given the Panel's concern with the balance that has already accumulated in the Real Property Sales regulatory account, if a balance recoverable from ratepayers is still expected to exist in this account at the end of the next test period, the Panel directs BC Hydro to provide in its fiscal 2023 RRA, a proposal on how it plans to recover the balance from ratepayers.**

[761] BCOAPO Final Argument, p. 45; BCSEA, p. 43.
[762] AMPC Final Argument, p. 86, para. 289.

The Panel remains concerned that BC Hydro's approach to holding properties no longer required to serve ratepayers amounts to speculation. To quote the Cambridge University dictionary, "speculation" is:

> The act of buying something hoping that its value will increase and then selling at this higher price in order to make a profit.[763]

The Panel acknowledges that BC Hydro acquired these properties for utility purposes, and did not at that time intend them as investments. However, once BC Hydro has determined that properties are no longer required for utility purposes, undue delay in their sale "to maximize the return on these properties" appears to meet the definition of speculation; that is, "hoping [a property's] value will increase and then selling at this higher price in order to make a profit." It is not clear to the Panel that ratepayers should be paying the cost to carry property no longer required for utility purposes, and taking the risk that the property might fall in value.

The Panel directs BC Hydro, as part of its compliance filing, to provide an explanation of why these surplus properties are included in rate base, based on regulatory principles and the provisions of Direction No. 8. The Panel also directs BC Hydro to explain, as part of its compliance filing, whether the gains from the sale of these surplus properties would continue to be applied against BC Hydro's revenue requirement or whether they would revert to the shareholder in the event that the properties are removed from rate base.

4.5.4 Reduction of the Deferral Account Rate Rider and Refund of the Cost of Energy Deferral Accounts

The cost of energy variance accounts consist of the Heritage Deferral Account, the Non-Heritage Deferral Account and the Trade Income Deferral Account. BC Hydro makes the following requests with respect to its cost of energy variance accounts:[764]

i. Reduce the DARR from 5 percent to 0 percent on April 1, 2019; and
ii. Amortize into rates, over the Test Period, the fiscal 2019 net closing balance and the forecast fiscal 2020 and fiscal 2021 net additions and net interest applied to the cost of energy variance accounts.

BC Hydro's proposal would result in a refund to ratepayers during the Test Period of approximately $630.8 million.[765] BC Hydro's proposal involves refunding most of this amount in fiscal 2021 so that adjustments to customer bills, currently based on rates approved on an interim basis, can be avoided. A portion of the $630.8 million balance is from a $319 million one-time accounting adjustment resulting from the adoption of IFRS 15, Revenue from Contracts with Customers. IFRS 15 impacted the recognition of revenues under the Skagit River Agreement by retroactively decreasing unearned revenues and a corresponding adjustment to the Heritage Deferral Account (i.e. refundable to ratepayers).[766] The retroactive decrease effectively means that previous ratepayers have overpaid; thus, BC Hydro submits that its proposal achieves better intergenerational equity.[767]

The balances in the cost of energy variance accounts are recovered using the DARR, which is set at 5 percent by Direction No. 7. BC Hydro submits that since Direction No. 7 has been repealed and the cost of energy variance accounts have a net credit balance cost of energy variance, BC Hydro should refund this credit balance to ratepayers by amortizing it over the Test Period.[768] BC Hydro's proposal would allow this amount to be refunded to ratepayers quicker compared to using the DARR mechanism.

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763 https://dictionary.cambridge.org/dictionary/english/speculation (retrieved on September 18, 2020)
764 Exhibit B-1, Sections 7.7.1, 7.7.1.1, pp. 7-23–7-27.
765 Exhibit B-17, Zone II RPG IR 60.1.
766 Exhibit B-1, p. 7-25.
767 BC Hydro Final Argument, p. 195.
768 Exhibit B-1, pp. 7-25–7-26.

BC Hydro developed this proposal using four principles: (1) recovery of the Test Period revenue requirements; (2) rate stability in the Test Period; (3) avoiding bill adjustments; and (4) avoiding the re-introduction of longer-term rate smoothing.[769] BC Hydro modelled several alternative options for refunding the net balance of the cost of energy variance accounts to ratepayers in response to intervener and BCUC staff IRs.[770] BC Hydro submits that its proposal is "simpler to administer, more transparent, and produces more stable rates during the Test Period."[771]

Positions of Parties

Interveners generally support or do not take a position on BC Hydro's proposal, with the exception of Mr. McCandless. BCOAPO and AMPC, although supportive of BC Hydro's proposal, have some observations and recommendations regarding the effect of the proposal on BC Hydro's rates.[772]

BCOAPO supports BC Hydro's proposal; however, in its view the approach is not very transparent. BCOAPO submits that BC Hydro should clearly communicate to ratepayers that "while the DARR is zero the costs that would have been refunded to ratepayers through the DARR are now included a [sic] cost reductions in the determination of the general rate increase/decrease."[773]

In response to BCOAPO, BC Hydro submits that "[t]he result is the same from the perspective of what customers pay on the bill" and that "communications would be clearer and more easily understood by focussing on the bottom-line impact the Decision has on customer bills."[774]

AMPC supports the proposal, but recommends that the BCUC find that, "absent the redirection of DARR funds into a government-directed ROE, customers would have seen a material rate reduction in F2020, all else equal."[775] AMPC points to InterGroup's submission that the reduction in the DARR has allowed BC Hydro to hide cost increases that it otherwise would have had to more strenuously justify, and questions BC Hydro's proclaimed "culture of cost containment."[776]

In response to AMPC, BC Hydro submits that its Application is transparent regarding cost drivers and the effect of the DARR. Furthermore, the Application contains hundreds of pages on, among other things, BC Hydro's operating costs, cost of energy and finance costs. The proceeding includes five rounds of IRs and an 11-day oral hearing allowing parties ample opportunity to seek information and test the evidence. BC Hydro submits that the evidence in the proceeding demonstrates the steps BC Hydro has taken to control costs.[777]

In McCandless' view, a longer term perspective is required and reducing the DARR to zero and refunding the net balance in the cost of energy deferral accounts in the Test Period would "not prepare ratepayers for a likely steep increase in rates in F24 or F25, when the net cost of the Site C project will be included in the rate request."[778] McCandless cites a May 2019 decision made by the Manitoba Public Utilities Board to moderate the impact on future rates resulting from major projects that are coming into service in the future by increasing rates in the current period. McCandless notes that the Manitoba Public Utilities Board made an exception to the cost of service model, by making a decision that results in Manitoba Hydro recovering more than its cost of

[769] Exhibit B-16, BCUC IR 296.3; BC Hydro Final Argument, p. 246.
[770] Exhibit B-16, BCUC IR 296.3.
[771] BC Hydro Final Argument, pp. 195, 247.
[772] Zone II RPG Final Argument, p. 9, para. 23; BCSEA Final Argument, pp. 48, 72, paras. 186, 293; CEC Final Argument, p. 89, paras. 441, 442; BCOAPO Final Argument, pp. 40–41; AMPC Final Argument, pp. 20, 23–25; McCandless Final Argument, pp. 3–4.
[773] BCOAPO Final Argument, pp. 40–41.
[774] BC Hydro Reply Argument (May 27, 2020), p. 137.
[775] AMPC Final Argument, pp. 20, 25.
[776] AMPC Final Argument, pp. 23–24.
[777] BC Hydro Reply Argument (May 27, 2020), p. 9.
[778] McCandless Final Argument, p. 3.

service in the test period, in an effort to keep customer rate changes stable and predictable. Specifically, the Manitoba Public Utilities Board noted that the costs of some of the major capital projects could potentially enter into Manitoba Hydro's 2020/21 revenue requirement and could lead to rate shock.[779]

Regarding McCandless' position, BC Hydro acknowledges the submission, but did not directly comment on it.[780]

Panel Determination

The Panel shares McCandless' concern regarding potential rate increases when Site C goes into service. However, Site C is not expected to go into service for another 3 to 4 years beyond this Test Period and once in service, is expected to be amortized over a relatively long period. Furthermore, there is a lack of evidence in this proceeding regarding BC Hydro's cost of energy and load resources relative to its load beyond this Test Period; therefore, the Panel is not able to make a finding in this proceeding regarding whether Site C would cause "rate shock" when it comes into service years from now. Given these limitations, it would not be appropriate to attempt to smooth rates several years into the future as doing so may result in intergenerational equity issues.

Considering that a large portion of the net balance of the Cost of Energy Variance Accounts is due to a one-time accounting adjustment resulting from an accounting standard change, the Panel finds that refunding the net balance of the Cost of Energy Variance Accounts as proposed by BC Hydro more effectively promotes intergenerational equity compared to refunding this balance using the DARR mechanism. **Therefore, the Panel approves BC Hydro's request to amortize into rates, over the fiscal 2020 to fiscal 2021 Test Period, the fiscal 2019 net closing balance and the forecast fiscal 2020 and fiscal 2021 net additions and net interest applied to the cost of energy variance accounts. Given that the DARR mechanism will not be used in the Test Period to refund the Cost of Energy Variance Accounts and for the reasons discussed above, the Panel approves BC Hydro's request to reduce the DARR from 5 percent to 0 percent on April 1, 2019.**

With respect to BCOAPO's suggestion that BC Hydro communicate to ratepayers that the costs that would have been refunded to ratepayers through the DARR are now included as cost reductions in the determination of the general rate, the Panel agrees with BC Hydro that communications would be clearer by focussing on the bottom-line impact the Decision has on customer bills.

With respect to AMPC's recommendation that the BCUC find that there would have been a material rate increase in fiscal 2020 to support the government-directed ROE if not for the "redirection of DARR funds," the Panel is not persuaded there is a direct connection between the redirection of the DARR funds and the government-directed ROE.

4.5.5 Remaining Requested Deferral and Regulatory Account Changes

In this section, the following deferral and regulatory account changes, as requested by BC Hydro, are discussed:

- Defer any variances related to the accounting for EPAs determined to be leases under IFRS 16, which are not eligible for deferral treatment under existing BCUC orders, to the Non-Heritage Deferral Account.[781]

  BC Hydro will be adopting a new IFRS 16, *Leases* standard, effective April 1, 2019, which introduces a single lease accounting model for lessees. Under the new single lease model, a lessee will recognize the lease assets and lease liabilities on the balance sheet.[782] IFRS 16 would impact the classification of certain EPAs and the associated lease payments. The expenses attributable to EPAs recognized on the

[779] McCandless Final Argument, p. 4.
[780] BC Hydro Reply Argument (May 27, 2020), p. 135, para. 322.
[781] Exhibit B-1, Section 7.7.1.2, p. 7-27.
[782] Exhibit B-1, pp. 7-22, 7-27, 8-28–8-29.

balance sheet as leases under IFRS 16 are classified as finance charges and depreciation expense instead of as cost of energy[783];

- Remove the reference to the "Prescribed Standards" from the scope of what may be deferred to the Site C Regulatory Account, as BC Hydro has fully adopted IFRS.[784]

  BC Hydro fully adopted IFRS, effective for its fiscal year ending March 31, 2019. Previously, BC Hydro prepared its financial statements in accordance with the Prescribed Standards, which were accounting standards prescribed by Government.[785] BC Hydro submits that the removal of the reference to the "Prescribed Standards" would allow it to continue to defer to the Site C Regulatory Account any costs related to the Site C Project that are not able to be capitalized;[786] and

- Closure of the following regulatory accounts:
  - The Capital Project Investigation Costs Regulatory Account at the end of fiscal 2021.

    BC Hydro submits that the balance in this account will be fully amortized into rates by the end of fiscal 2021, consistent with Order G-77-12A;[787]
  - The Rate Smoothing Regulatory Account in fiscal 2020.

    BC Hydro submits that this account has a zero balance and it is not proposing to smooth rates over the Test Period;[788] and
  - The Arrow Water Systems Provision Regulatory Account and the related Arrow Water Systems Regulatory Account in fiscal 2020.

    BC Hydro has written off the balance in the Arrow Water Systems Provision Regulatory Account in an effort to reduce the number of regulatory accounts.[789]

Positions of Parties

Interveners either support or do not take a position on these requests.[790]

Panel Determination

The Panel approves the following requested changes to BC Hydro's deferral and regulatory accounts:

- **Defer any variances related to the accounting for EPAs determined to be leases under IFRS 16, which are not eligible for deferral treatment under existing BCUC orders, to the Non-Heritage Deferral Account.**

  In the Panel's view, BC Hydro's EPAs are primarily a cost of energy regardless of whether or not the EPAs are classified as leases for accounting purposes and therefore it is appropriate to have consistent treatment of the EPAs for rate setting purposes; and

- **Remove the reference to the "Prescribed Standards" from the scope of what may be deferred to the Site C Regulatory Account, as BC Hydro has fully adopted IFRS.**

  In the Panel's view, there is no reason to continue referring to the Prescribed Standards since BC Hydro has now adopted IFRS.

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[783] Exhibit B-5, BCUC IR 146.1.
[784] Exhibit B-1, Section 7.7.4, pp. 7-32–7-33.
[785] Exhibit B-1, p. 8-25; Government Organization Accounting Standards Regulation 257/2010, Part 3.
[786] Exhibit B-1, p. 7-33.
[787] Exhibit B-1, pp. 7-33–7-34.
[788] Exhibit B-1, p. 7-34.
[789]Exhibit B-1, pp. 7-38–7-39; pp. 7-52–7-53; Exhibit B-5, BCUC IR 40.3.1.
[790] Zone II RPG Final Argument, p. 2; BCOAPO Final Argument, p. 42; BCSEA Final Argument, p. 48; CEC Final Argument, p. 89: CEC notes that its support is "conditioned on the expectation that BC Hydro will advance its depreciation study into the near future."

The Panel accepts that the balance in the following accounts is either zero or anticipated to be zero in the Test Period and BC Hydro does not plan to continue using these accounts. **Therefore, the Panel approves BC Hydro's request to close the following regulatory accounts:**

- **The Capital Project Investigation Costs Regulatory Account at the end of fiscal 2021;**
- **The Rate Smoothing Regulatory Account in fiscal 2020;**
- **The Arrow Water Systems Provision Regulatory Account in fiscal 2020; and**
- **The Arrow Water Systems Regulatory Account in fiscal 2020.**

4.5.6 Other Issues Arising

As discussed in the preceding sections, interveners are either generally supportive or take no position with respect to the specific requests sought by BC Hydro regarding its regulatory accounts.[791] However, with respect to BC Hydro's deferral and regulatory accounts in general, McCandless, AMPC and CEABC have some concerns and recommendations.

Positions of Parties

McCandless notes that BC Hydro records variances between the planned and actual revenue as earned revenue in the Non-Heritage Deferral Account. McCandless submits that this practice "effectively increases the debt to preserve [BC Hydro's] net income. The deferred revenue is treated as a regulatory asset, and one must question whether the BCUC should be giving permission to create this class of asset." McCandless further notes that "[t]he auditor general of Ontario condemned that government's 2017 plan to defer unearned revenue in a regulatory (asset) account." McCandless submits that "[t]he BCUC should seek the opinion of the B.C. auditor general on whether the recording of unearned revenue by BC Hydro conforms to accepted accounting practice."[792]

In response to McCandless, BC Hydro submits that "deferring variances between forecast and actual domestic revenue is a common regulatory practice," often referred to as "revenue decoupling" or "a decoupling mechanism," that is used at other BCUC regulated utilities, such as FBC and FortisBC Energy Inc. BC Hydro also submits that almost half of the North American utilities surveyed by S&P Global utilize some type of decoupling mechanism. Furthermore, seeking the Auditor General of BC's opinion is not necessary because the Auditor General of BC will audit this practice when it audits BC Hydro's fiscal 2020 financial statements.[793]

AMPC notes that it is not the number of regulatory accounts or the magnitude of the account balances that it takes issue with, but rather it is the "overall complexity of BC Hydro's regulatory accounts" and submits that "the accounts dampen shareholder risk and cloud utility transparency and discipline."[794] AMPC submits that "BC Hydro should be directed to, over time, continue reducing the scale and scope of regulatory accounts where feasible" to ensure that its costs are "fully regulated and are transparent to the regulator and impacted parties." In AMPC's view, the BCUC should require rates be "based on the best information about test year costs and appropriate forecasting methodologies, rather than allowing BC Hydro to rely on deferral accounts to postpone addressing forecast inaccuracies."[795] In addition, as AMPC's expert witness, InterGroup, submits, the scope of the regulatory accounts puts BC Hydro's shareholder at very little risk from normal business functions and

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[791] Zone II RPG Final Argument, p. 2, para. 4; BCSEA FA, pp. 47–48; BCOAPO Final Argument , pp. 40, 42–44; CEC Final Argument , p. 89: CEC notes that its support is "conditioned on the expectation that BC Hydro will advance its depreciation study into the near future."
[792] McCandless Final Argument, pp. 5–6.
[793] BCH Reply Argument, pp. 90–91.
[794] AMPC Final Argument, p. 22.
[795] AMPC Final Argument, p. 20.

variances, and thus return on equity should be adjusted "materially downward" if the scope and number of regulatory accounts are not simplified and narrowed.[796]

CEABC notes the impact of BC Hydro's regulatory accounts on BC Hydro's cost of energy and recommends the BCUC "direct BC Hydro to hold consultation sessions including workshops to examine the merits of continuing the use of all these Deferral and Regulatory Accounts." CEABC questions whether BC Hydro's regulatory accounts help "keep a tight control over rising expenditures" and if these accounts make "things clearer and more transparent." CEABC also recommends that BC Hydro's upcoming depreciation study "should be extended to include any Regulatory Accounts whose purpose is to spread the costs over the benefit period."[797]

BC Hydro objects to AMPC's and CEABC's requests for the BCUC to direct BC Hydro to reduce the scale and scope of its regulatory accounts where feasible over time, to hold consultation sessions and workshops to examine the merits of the regulatory accounts, and to include amortization of regulatory accounts in the upcoming depreciation study. BC Hydro submits that AMPC's and CEABC's submissions are too broad and interveners had the opportunity during this proceeding to make submissions regarding the scope and amortization period of the regulatory accounts.[798]

In response to AMPC and CEABC, BC Hydro submits that it "should generally assume financial responsibility for controllable risks and that it should not assume financial responsibility for non-controllable risks." BC Hydro submits that the use of variance accounts results in "fair risk allocation." Since it would be unfair to penalize a utility for circumstances beyond its control, it would similarly be unfair to customers for the shareholder to have windfall gains from uncontrollable variances. BC Hydro also notes that the BCUC, with respect to FortisBC Energy, had previously noted that deferral account treatment is appropriate where certain costs are significant and beyond the control of the utility and could result in windfall benefits or costs to ratepayers.[799]

BC Hydro also submits that "no amount of rigour will ensure that a forecast of an uncontrollable and volatile cost or revenue item exactly matches actual results." BC Hydro elaborates that "[a] utility's ability to exercise 'discipline' is inherently limited when costs are influenced by matters beyond the utility's control, making variance accounts more about stability and fairness than accountability or cost matching."[800] BC Hydro notes that eliminating variance accounts would drive "conservatism in forecasting, not accuracy."[801]

BCSEA and BCOAPO, on the other hand, are more supportive of BC Hydro's regulatory accounts. In particular, BCSEA disagrees with AMPC's expert that the number and scope of BC Hydro's regulatory accounts should be reduced. Furthermore, BCSEA agrees with BC Hydro that the use of its Cost of Energy variance accounts is "a fair and efficient means of addressing emerging conditions during the regulatory process (and after it)."[802] BCOAPO submits that the fact that variances between forecast and actual domestic revenues are captured in BC Hydro's regulatory accounts "lends [its] clients some small comfort in these uncertain times."[803]

BC Hydro submits its regulatory accounts are in accordance with International Financial Reporting Standards, consistent with the BCUC's Regulatory Account Filing Checklist, and beneficial to customers.[804]

[796] AMPC Final Argument, p. 22.
[797] CEABC Final Argument, pp. 9–11.
[798] BC Hydro Reply Argument (May 27, 2020), p. 94.
[799] BC Hydro Reply Argument (May 27, 2020), pp. 92–93.
[800] BC Hydro Reply Argument (May 27, 2020), pp. 92–93.
[801] BC Hydro Reply Argument (May 27, 2020), pp. 93–94.
[802] BCSEA Final Argument, pp, 14–15, 41–42.
[803] BCOAPO Final Argument, p. 15.
[804] BC Hydro Reply Argument (May 27, 2020), p. 95.

Panel Determination

With respect to the comments made by McCandless and AMPC's and CEABC's comments regarding the use of regulatory accounts to postpone addressing forecasting inaccuracies, it is not uncommon for the BCUC to approve regulatory accounts to capture the variances including between forecast and actual domestic revenue arising from variances in actual vs forecast load. Allowing utilities to capture such variances in a regulatory account mitigates the windfall gains and losses realized by either the shareholder or the ratepayers resulting from load variances that are beyond the utility's control. That is one of the reasons for regulators approving the establishment of such accounts. Considering the difficulty in forecasting costs that are largely driven by events beyond the utility's control, the variance account balances risks between ratepayers and shareholder.

Furthermore, in the Panel's view, seeking the Auditor General of BC's opinion "on whether the recording of unearned revenue by BC Hydro conforms to accepted accounting practice" would not directly affect the Panel's review of BC Hydro's load forecast or revenue requirement.

With respect to CEABC's request for consultation sessions and workshops and to include regulatory account amortization within the scope of the upcoming depreciation study, interveners had the opportunity to examine BC Hydro's regulatory accounts during this proceeding to identify specific accounts and recovery methods with which they take issue. The Panel is not persuaded that further consultation sessions and workshops, at this time, would yield additional clarity on BC Hydro's regulatory accounts to justify such an approach. The suggestion to include regulatory account amortization within the scope of the upcoming depreciation study is rejected as discussed in section 4.4.5.4 of the Decision.

With respect to AMPC's request that BC Hydro be directed to "reduce the scale and scope of regulatory accounts where feasible" over time, AMPC has not provided sufficient evidence to persuade the Panel that the complexity of BC Hydro's regulatory accounts is not commensurate with the complexity of the organization. Each regulatory account should be reviewed based on its own merits; therefore, the Panel declines to direct BC Hydro to "reduce the scale and scope of regulatory accounts where feasible" over time as suggested by AMPC. Instead, the Panel invites, in future RRAs, interveners to provide submissions on specific regulatory accounts that should be discontinued.

4.6 Demand Side Management

4.6.1 Approvals Sought

BC Hydro seeks acceptance pursuant to section 44.2 of the UCA of its "traditional DSM" expenditure schedule.[805] BC Hydro defines "traditional DSM" as industry efforts which have historically focused on energy efficiency and conservation as well as capacity-focused initiatives. DSM programs are a low-cost resource that helps to lower utility costs for consumers.[806] BC Hydro's traditional DSM expenditure schedule consists of DSM expenditures of $90.8 million in fiscal 2020 and $89.1 million in fiscal 2021.[807] The DSM expenditure schedule supports a suite of DSM programs targeted at the residential, commercial and industrial sectors during the Test Period (DSM Plan).

BC Hydro also requests approval to defer its Low Carbon Electrification expenditures over the Test Period to the DSM Regulatory Account pursuant to the *Direction to the BCUC Respecting Undertaking Costs*.[808] In contrast to

[805] Exhibit B-1, p. 10-1, as amended by the Evidentiary Update; Exhibit B-11, p. 4.
[806] Exhibit B-1, p. 10-4.
[807] Exhibit B-11, p. 4. BC Hydro's DSM expenditure schedule decreased by $27.2 million in fiscal 2021 from $116.3 million to $89.1 million because two projects that BC Hydro expected to proceed under the Thermo-Mechanical Pulp Program did not submit applications by the required deadline.
[808] B.C. Reg 77/2017, O.C. 100/2017.

traditional DSM, Low Carbon Electrification initiatives fall under the GGRR,[809] and are focused on reducing greenhouse gas emissions. The figure below shows the relationship between the various components of BC Hydro's broader DSM activities. [810]

Figure 4-9: Components of BC Hydro's Broader DSM Activities

BC Hydro further requests the BCUC to reconsider and rescind Directive 61 of the BCUC's Decision on BC Hydro's fiscal 2005 to fiscal 2006 Revenue Requirements Application[811] which directs that a prorated amount of costs from portfolio-level initiatives be added to the cost of each DSM program to assess cost effectiveness.

4.6.2 Overall DSM Funding Envelope and Continuation of the DSM Moderation Approach

BC Hydro submits that the proposed DSM expenditure schedule continues the DSM moderation approach first recommended in its 2013 IRP, given the continued energy surplus and ongoing need to manage upward pressure on rates. In accordance with this moderation approach, BC Hydro has maintained a similar overall level of spending on traditional DSM as in the previous test period.[812]

In assessing potential DSM measures, BC Hydro uses the forecast market price for electricity exports ($30/MWh) as a screening filter for the utility cost of non-specified DSM programs.[813] This means that all non-specified programs within the DSM Plan contribute to a reduction in BC Hydro's overall revenue requirements while BC Hydro is in an energy surplus. This is because the cost of the energy savings from the DSM programs is less than the price BC Hydro could receive on the market for any resulting surplus energy.[814]

Using the results of the latest Conservation Potential Review, BC Hydro proposes to examine options for the level of DSM in future years as part of its next IRP.[815] In the meantime, over the Test Period, BC Hydro is maintaining its DSM program offerings and partnerships with key businesses and trade allies in order to be able to respond to any future direction that may come out of the IRP or the CleanBC Plan. Therefore, BC Hydro

[809] B.C. Reg. 102/2012, O.C. 295/2012.
[810] Exhibit B-1, Figure 10-1, p. 10-4.
[811] Decision and accompanying Order No. G-96-04, p. 192.
[812] Exhibit B-1, Page 10-20; BC Hydro Final Argument, p. 217.
[813] Exhibit B-1, p. 10-20. Specified programs required by the DSM Regulation were not subjected to this requirement.
[814] Exhibit B-1, p. 10-21 .
[815] Exhibit B-1, Application, p. 10-21; Transcript Volume 14, p. 2784, lines 5–9 (Hanlon).

submits that the level of traditional DSM spending proposed is a reasonable and balanced approach and is in the public interest.[816]

Positions of Parties

The CEC[817] and BCSEA[818] advocate for higher levels of expenditure on DSM, calling for all cost-effective measures to be funded. The CEC argues it would be preferable for BC Hydro to pursue more DSM "up to all cost-effective DSM, particularly where there could be significant savings relative to other supply options, or where it could be pursued at a financial gain to ratepayers, if below market cost."[819] BCSEA is concerned that BC Hydro's decision not to achieve all cost-effective energy and capacity savings during the Test Period will create "lost opportunities" by allowing inefficient assets to be locked-in for the long term. BCSEA acknowledges that BC Hydro currently has surplus energy and capacity for planning purposes, and agrees that in this context, the market price screening filter ensures that the traditional DSM activities during the Test Period put downward pressure on rates.[820]

With respect to lost opportunities, BC Hydro states it is still pursuing significant amounts of DSM in all sectors, giving residential, commercial and industrial customers the opportunity to participate in programs that will reduce their bills. It acknowledges that while there may be some lost opportunities, this is one of the trade-offs that are made given other factors.[821]

In light of the fact BC Hydro is no longer facing significant load growth, MoveUP submits that the BCUC should direct BC Hydro to develop new approaches to its DSM/customer service programs that are consistent with the assumptions it uses for the analysis of electrification initiatives and develop new ways to help improve the efficiency of the timing and amount of customers' electricity consumption.[822]

Gjoshe submits that the time for "broad" and "unbridled" BC Hydro-funded DSM provisions may have passed and urges the BCUC to recommend a "re-think" of BC Hydro's DSM philosophy as part of BC Hydro's 2021 IRP processes.[823]

CEABC submits that the success of conservation and efficiency measures can also have a downside when it comes to the general level of rates. Whenever one customer's load is reduced, a portion of BC Hydro's fixed costs will then be transferred to other customers, thus increasing the general rate level for all customers. Participating customers may save on their bills, but the general rate levels will rise for all customers.[824]

Willis similarly notes the negative impact of DSM expenditures on customer revenue, calling for a more balanced approach between conservation and low carbon electrification expenditures, considering the significant benefit from reducing greenhouse gas emissions.[825] Willis submits that there have been structural changes in the electricity market since BC Hydro began its energy efficiency program in 1989, notably that an important justification for conservation programs was to absorb a good portion of the anticipated load growth. While the objective of BC Hydro's Power Smart program was for conservation to absorb 66 percent of new growth, in recent years, the conservation programs have handled more than 100 percent of new growth. Willis recommends that BC Hydro review its rate policy and consider implementing rate options that will be more

[816] BC Hydro Final Argument, pp. 219–220.
[817] CEC Final Argument, pp. 3–4.
[818] BCSEA Final Argument, p. 53.
[819] CEC Final Argument, pp. 3–4.
[820] BCSEA Final Argument, p. 53.
[821] BC Hydro Reply Argument (May 27, 2020), pp. 111–112.
[822] MoveUP Final Argument, p. 11.
[823] Gjoshe Final Argument, p. 20.
[824] CEABC Final Argument, p. 5–6.
[825] Willis Final Argument, p. 4.

consistent with the interest in reducing GHG emissions by encouraging electrification which can be done while still promoting energy efficiency.[826]

In terms of revenue impacts, BC Hydro notes the proposed traditional DSM expenditures will only have beneficial financial impacts, as they will reduce BC Hydro's revenue requirements. This beneficial financial impact is traded off against the potential for upward pressure on rates due to recovering BC Hydro's reduced overall cost from a lower amount of electricity sold. BC Hydro submits that the use of a market screening filter ensures that BC Hydro's revenue requirements will be reduced,[827] and that while there will potentially be upward pressure on rates due to recovering BC Hydro's reduced overall cost from a lower amount of electricity sold, BC Hydro's moderation approach ensures that its traditional DSM expenditures will reduce revenue requirements overall.[828]

BC Hydro states that trade-offs are inevitable in arriving at any particular level of traditional DSM expenditures. BC Hydro submits that the moderation approach strikes a balance that is in the public interest, given the continued energy surplus and need to manage upward pressure on rates, but it will examine the planned level of traditional DSM again in the upcoming IRP.[829]

Panel Determination

While some interveners advocate for an increase in the amount of DSM expenditures, others point out the need for new approaches to DSM based on the structural changes since BC Hydro's launch of its Power Smart program in 1989. There has been a fundamental shift in BC Hydro's planning context, from one predicated on a need for conservation to address anticipated load growth, to the current reality of an energy surplus and a push for electrification.

As for calls for increased DSM funding, however, the Panel finds insufficient evidence to support increased DSM expenditures at this time. The Panel further finds the size of the funding envelope in the proposed DSM expenditure schedule to be reasonable in balancing BC Hydro's need to manage upward pressure on rates and the energy surplus.

However, the Panel directs BC Hydro to present options for the level of DSM in future years for BCUC review as part of BC Hydro's next IRP, using the results of the latest Conservation Potential Review and any other relevant analysis.

4.6.3 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 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 pursuant to section 44.2(5.1) of the UCA:

[826] Willis Final Argument, p. 6-7.
[827] BC Hydro Reply Argument (May 27, 2020), p. 112.
[828] BC Hydro Reply Argument (May 27, 2020), p. 113.
[829] BC Hydro Reply Argument (May 27, 2020), p. 110.

- the interests of persons in British Columbia who receive or may receive service from the authority;
- 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[830] 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. While the Panel must consider each of the above factors in determining whether or not to accept all or part of the expenditure schedule as being in the public interest, it is not obliged to make specific findings in respect of each of those factors.

4.6.4 Proposed DSM Expenditure Schedule

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. The DSM expenditure schedule does not include any low carbon electrification expenditures as they do not constitute "traditional DSM" and are assessed as a prescribed undertaking under the GGRR. We discuss BC Hydro's low carbon electrification expenditures in Section 4.6.5 below.

BC Hydro seeks BCUC acceptance of the following DSM expenditure schedule for the Test Period:[831]

DSM Programs	F2020 Plan ($ million	F2021 Plan ($ million)
Rate Structures	0.5	0.5
Programs		
Residential	18.4	19.7
Commercial	18.9	17.5
Industrial	26.5	27
Supporting initiatives	14.6	14.9
Codes and Standards	5.2	5.3
Capacity focused DSM	6.9	4.3
PORTFOLIO TOTAL	**90.8**	**89.1**

BC Hydro states that while the funding envelope and programs for traditional DSM remain similar to the DSM Plan presented in the 2017-2019 RRA,[832] the DSM programs have been modified in response to BCUC directives, the Government of BC's priorities around affordability and changes in the DSM Regulation.[833] These program changes have increased expenditures for the residential sector by approximately 50 percent, while staying within the overall portfolio spending envelope. [834]

BC Hydro notes the following changes to the DSM portfolio:

- Launching a new Non-Integrated Areas program;
- Taking steps to increase participation for the Low-Income program;

[830] B.C. Reg. 117/2017.
[831] Summary of Exhibit B-1, Appendix X, Table A-1, updated to remove Thermo-Mechanical Pulp Program expenditures following the Evidentiary Update provided in Exhibit B-11, p. 4.
[832] Decision accompanying Order G-47-18, p. 72.
[833] Exhibit B-1, p. 10-5.
[834] Exhibit B-1, p. 10-1.

- Increasing Home Renovation Rebate offers, including expanding heat pump measures to benefit customers in regions without access to natural gas;
- Launching a new Social Housing initiative for qualified social housing providers;
- Reducing commercial and industrial program budgets;
- Re-categorizing energy management activities into a new program called Energy Management Activities within each sector, to align with the DSM Regulation; and
- Improving the presentation of codes and standards savings to make it more understandable.[835]

BC Hydro shows the relative shift in expenditure to the residential sector from the commercial and industrial sectors, compared to the allocation of DSM costs for cost recovery purposes, in the following table.[836]

Table 4-25: DSM Program Spend by Sector

	Residential (including low income) (%)	Commercial and light industrial[352] (%)	Large Industrial (%)
BC Hydro percentage of DSM program spend by sector (excluding Thermo-Mechanical Pulp program)			
F2014 to F2016 Actual	17	51	32
F2017 to F2018 Actual and F2019 Forecast	19	57	24
F2020 to F2021 Forecast	30	38	32
BC Hydro Allocation of DSM costs for cost recovery purposes			
Allocation of DSM costs	40	35	25

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

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

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

BC Hydro submits that the answer to this question is "yes" because the proposed expenditures reflect a broad and cost effective-range of DSM initiatives that provide significant 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.[837]

BC Hydro states that its 2019/20–2021/22 Service Plan shows that BC Hydro's residential bills have consistently ranked in the first quartile over the past ten years, equivalent to the third lowest residential bills based on analysis of the 2018 Hydro Quebec report, Comparison of Electricity Prices in 21 Major North American Cities.[838]

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835 Exhibit B-1, p. 10-24.
836 Exhibit B-1, Table 10-4, p. 10-8.
837 Exhibit B-1, p. 10-14; BC Hydro Final Argument, p. 230-231.
838 Exhibit B-1, Appendix E, p. 20 of 36.

Positions of Parties

BCSEA agrees that the traditional DSM expenditure schedule for the Test Period is in the interests of persons in British Columbia who receive or may receive service from BC Hydro.[839]

No interveners have disputed that the proposed DSM portfolio is in the interests of persons in BC who receive or may receive service from BC Hydro.

Panel Determination

The Panel finds that pursuant to section 44.2(5.1) of the UCA, the proposed DSM expenditure schedule provides customers with access to DSM programs that result in capacity benefits and energy savings that lower their individual electricity bills, while reducing BC Hydro's overall revenue requirement and therefore, is in the interests of persons in BC who receive or may receive service from BC Hydro.

4.6.4.2 British Columbia's Energy Objectives

Section 44.2 (5.1)(a) of the UCA requires the BCUC to consider BC'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 *Clean Energy Act*.[840]

[839] BCSEA Final Argument, p. 64.
[840] Exhibit B-1, Table 10-6, pp. 10-14–10-15.

Table 4-26: DSM Plan Alignment with BC Energy Objectives

Energy Objective	DSM Plan
To achieve electricity self-sufficiency	The DSM Plan's forecast energy and capacity savings will contribute to BC Hydro maintaining electricity self-sufficiency in 2020 and in each year thereafter.
… reducing its expected increase in demand for electricity by the year 2020 by at least 66 per cent	The DSM Plan is forecast to reduce BC Hydro's increase in electricity demand by the end of fiscal 2021 by approximately 103 per cent.
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 X for more detail.
To ensure that BC Hydro's rates remain among the most competitive	The moderation strategy outlined in section 10.4.1 reduces rates relative to the DSM investment level for fiscal 2020 to fiscal 2021 that was contemplated in the 2013 Integrated Resource Plan.
To reduce B.C. GHG emissions	Customers in some DSM programs are forecasted to reduce their natural gas usage along with their electricity usage. The new Non Integrated Areas Program is also expected to reduce GHG emissions by reducing diesel generation. Reductions of 5,000 tonnes of CO_2e/year are forecasted to result from traditional DSM.
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 current DSM efforts create significant economic activity and jobs within the province, estimated at 11,600 person-years of employment over the next 10 years.

Positions of Parties

BCSEA agrees that the traditional DSM expenditure schedule for the Test Period fosters the BC energy objective "to take demand-side measures and to conserve energy." However, BCSEA submits that it cannot be concluded that the DSM expenditure schedule for the Test Period fosters "the objective of [BC Hydro] reducing its expected increase in demand for electricity by the year 2020 by at least 66%" because that particular objective has already been met.[841] In BCSEA's view the 66 percent target is a floor not a ceiling.[842]

[841] BCSEA Final Argument, p. 64.
[842] BCSEA Final Argument, pp. 53.

In reply, BC Hydro submits the 66 percent target has not been treated as a ceiling, as it has exceeded that target by a considerable margin. The fact that BC Hydro has exceeded the 66 percent goal demonstrates that BC Hydro's level of DSM spending is sufficient from the perspective of this energy objective.[843]

Panel Determination

The Panel is satisfied that BC Hydro's DSM expenditure schedule generally aligns with the current BC energy objectives in the *Clean Energy Act* as summarised in Table 4-26 above, and further notes that no interveners have raised any concerns regarding misalignment. Accordingly, the Panel finds that pursuant to section 44.2 (5.1)(a) of the UCA, BC Hydro's DSM expenditure schedule is consistent with and supports the relevant energy objectives set out in the *Clean Energy Act*.

4.6.4.3 Most Recent Long-Term Resource Plan

Under Section 44.2 (5.1)(b), 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 British Columbia under Section 4 of the CEA (now repealed)[844] is the most recent BC Hydro resource plan. That IRP was not subject to BCUC review or approval but is nonetheless the most 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 after February 28, 2021.[845]

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). BC Hydro submits that its proposed DSM Plan nonetheless aligns with the adequacy requirements set out in the DSM Regulation.[846]

BC Hydro submits that BC Hydro's continuation of a moderation approach, given the ongoing energy surplus and need to limit forecast rate increases, is consistent with the 2013 IRP.[847]

Positions of Parties

BCSEA disagrees with BC Hydro that the proposed traditional DSM expenditure schedule for the Test Period is "consistent with the 2013 IRP." While BC Hydro characterizes the fiscal 2020-fiscal 2021 DSM spending as a continuation of the fiscal 2017 to fiscal 2019 spending, BCSEA notes the ongoing reduction in DSM spending compared to the 2013 IRP.[848]

BC Hydro confirms that the moderation approach was originally recommended in the 2013 IRP for fiscal 2014 to fiscal 2016 due to the energy surplus. The energy surplus has continued longer than estimated; therefore, the continuation of the moderation approach in response to that surplus is consistent with the recommended actions in the 2013 IRP. The Government of BC continues to support the moderation approach.[849]

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843 BC Hydro Reply Argument (May 27, 2020), p. 110.
844 Clean Energy Act S3-5 repealed 2019-24-2; Clean Energy Act, SBC 2010, c 22, <http://canlii.ca/t/53hhq> retrieved on 2020-08-12.
845 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, <http://canlii.ca/t/53lxk> retrieved on 2020-08-12.
846 Exhibit B-1, p. 2-11; Exhibit B-1, p.10-17, Table 10-7, pdf p. 1047.
847 BC Hydro Final Argument, p. 232; Exhibit B-1, Application, p. 10-15.
848 BCSEA Final Argument, p. 64.
849 BC Hydro Reply Argument (May 27, 2020), pp. 110–111.

In the Phase One Review, the BC Government noted that after examining the DSM area, BC Hydro proposes to increase the amount of spending for the residential sector and low-income ratepayers, while keeping DSM expenditures at the same level overall.[850]

BCSEA agrees with BC Hydro that the traditional DSM expenditures plan for fiscal 2020-fiscal 2022 would meet the adequacy requirements of the DSM Regulation, if BC Hydro were subject to those requirements.[851]

Panel Determination

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 DSM expenditure schedule. It simply requires us to consider that IRP. As seven years have now elapsed since the 2013 IRP and BC Hydro is in the process of developing its next IRP for BCUC review in 2021, we have considered BC Hydro's 2013 IRP and find alignment between it and the DSM expenditure schedule to be moot.

4.6.4.4 Cost-effectiveness

Section 44.2(5.1)(d) of the UCA requires that, for expenditure schedules including demand side measures, the BCUC must consider whether the demand-side measures are cost-effective within the meaning prescribed by regulation. Section 4 of the DSM Regulation[852] sets out the process for determining cost-effectiveness for the purposes of section 44.2(5)(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.

BC Hydro submits that the DSM portfolio as a whole, as well as rate structures and all programs, are cost effective using the modified total resource cost (mTRC) test required by the DSM Regulation.[853]

The following table presents the benefit cost ratios for the various DSM programs and overall portfolio in the Test Period.[854]

[850] Exhibit B-1, Appendix C, Comprehensive Review of BC Hydro Phase 1 Final Report, p. 40.
[851] BCSEA Final Argument, p. 65.
[852] B.C. Reg. 117/2017.
[853] Exhibit B-5, BCUC IR 175.1.
[854] Exhibit B-5, BCUC IR 175.1. Table A-7 in the original application (Appendix X) covered a 3 year planning period. The updated table covers the Test Period only.

Table 4-27: Benefit Cost Ratios

Benefit Cost Ratios[1]

	LRMC ($105 per MWh)		Market Price ($30 per MWh)
	Modified Total Resource Cost Test	**Total Resource Cost Test excluding NEBs**	**Utility Cost Test**
Rate Structures			
Residential Inclining Block Rate	n/a	n/a	n/a
General Service Rate	n/a	n/a	n/a
Transmission Service Rate	1.4	1.4	10.8
Total Rate Structures	**1.4**	**1.4**	**10.8**
DSM Programs			
Residential Sector			
Low Income	3.7	2.8	1.0
Non Integrated Areas	2.3	1.8	1.8
Retail	6.5	6.8	2.0
Home Renovation Rebate	1.9	1.5	2.3
Residential Sector Total	2.6	2.2	1.6
Commercial Sector			
LEM - C	4.2	2.5	2.5
New Construction	3.0	2.0	1.4
Commercial Sector Total	3.9	2.4	2.2
Industrial Sector			
LEM - I	4.4	3.1	1.8
Thermo-Mechanical Pulp	2.7	2.7	1.2
Industrial Sector Total	3.8	2.9	1.5
Total Programs	**3.6**	**2.6**	**1.7**
Energy Management Activities	n/a	n/a	n/a
Supporting Initiatives	n/a	n/a	n/a
Codes & Standards	n/a	n/a	n/a
PORTFOLIO TOTAL[2]	**2.5**	**1.9**	**1.1**

Notes:
[1] Benefit Cost Ratios are based on expenditures and energy savings from F20 - F21.
2 Energy management activities, supporting initiatives costs and codes and standards costs are included at the portfolio level. Capacity focused DSM is not included in cost-effectiveness calculations.

The Utility Cost Test and Total Resource Cost (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.[855] 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

[855] Exhibit B-1, p. 10-28.

impact of a DSM investment on BC Hydro's revenue requirement. 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.[856]

As required by the DSM Regulation, the LRMC of clean energy is an input into the TRC test. BC Hydro uses the most recent, but now outdated, LRMC of $105. [857] However, BC Hydro confirms that all DSM programs and the DSM portfolio would pass the TRC test with an LRMC of $52/MWh or higher, including delivery to the Lower Mainland .[858] This is sufficient for the DSM portfolio to be cost effective using the most recent estimates of wind power costs, including delivery to the Lower Mainland, which are between $54 and $80/MWh. [859] BC Hydro has committed to updating the LRMC for its next IRP.[860]

Positions of Parties

BCSEA[861] and BCOAPO agree that BC Hydro's proposed traditional DSM portfolio for fiscal 2020-fiscal 2021 is cost-effective using the TRC test and a LRMC of $105/MWh, the value used in BC Hydro's 2017-2019 RRA.[862]

Zone II RPG notes that according to BC Hydro's analysis, the cost-benefit ratio for the NIA DSM program is lower than the Integrated Area but above 1.0. According to this ratio, the Non-Integrated Area DSM program is considered cost effective. This analysis appropriately accounts for higher avoided costs based on the proxy cost of diesel.[863]

Ince submits that BC Hydro has presented ample evidence that its applied-for DSM Plan is cost effective relative to supply-side options, particularly new generation. As long as incremental savings can be shown to be cost effective relative to a market export price, these savings are in the best interest of ratepayers, and should be approved.[864]

No interveners challenge the cost-effectiveness of the proposed DSM portfolio, as defined by the DSM Regulation.

Panel Determination

The Panel finds that, as BC Hydro has acknowledged, the current LRMC of $105/MWh is now outdated. However, the Panel is nonetheless satisfied by BC Hydro's evidence in this proceeding showing that the proposed DSM portfolio would continue to be cost effective using much lower LRMC values of $52/MWh or higher. The Panel therefore accepts the expenditure schedule as meeting the definition of cost-effectiveness as defined in section 4 of the DSM Regulation.

4.6.4.5 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.

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[856] Exhibit B-1, Appendix X, p. 19.
[857] Exhibit B-1, pp. 10-29–10-30.
[858] Exhibit B-12, BCUC IR 2.274.1.
[859] Exhibit B-12, BCUC IR 274.1, pdf p.719.
[860] Exhibit B-1, p. 10-30; BC Hydro Final Argument, p. 232.
[861] BCSEA Final Argument, p. 64-65.
[862] BCOAPO Final Argument, p. 50.
[863] Zone II RPG Final Argument, p. 22.
[864] Ince Final Argument, p. 27.

BC Hydro submits that the BCUC approval of the DSM expenditure schedule for the Test Period is in the public interest.[865]

Positions of Parties

BCSEA supports a determination by the Panel that the traditional DSM expenditure schedule for the Test Period is in the public interest.[866] BCSEA supports increasing the residential component of the DSM spending, although BCSEA would have preferred that this be accomplished by increasing the DSM envelope rather than by decreasing DSM spending aimed at commercial/light industrial customers.[867]

BCSEA supports the Low-Income Program, noting that spending and energy savings under the Low-Income Program continue to follow an upward trend in the proposed DSM expenditure schedule, and participation has continued to increase.[868]

The CEC asserts that in light of the substantial discrimination being experienced by the commercial sector since fiscal 2014 due in part to the ongoing reductions in DSM expenditures, the CEC recommends that the BCUC deny the proposed DSM Plan and recommend that BC Hydro reallocate its spending to provide increased opportunities for cost-effective advancement of conservation and efficiency for BC Hydro's customers, including but not limited to the commercial rate classes.[869]

The CEC submits that DSM spending could be increased overall, and in particular should be increased for the commercial sector.[870] Commercial spending is planned to be 143 percent lower in fiscal 2021 than it was in fiscal 2014, and is planned to decline further by an additional 4 percent in fiscal 2022.[871]

In response to the CEC, BC Hydro acknowledges the decline in commercial DSM expenditure, but notes the change since 2014 where expenditure on commercial DSM was roughly double that of residential. The current reallocation of funding has resulted in a more equitable distribution of spending amongst the residential, commercial and industrial sectors, and is closer to the allocation of DSM costs for cost recovery purposes referenced in Table 4-25 above, and in the BCUC's Decision on the 2017-2019 RRA [872] BC Hydro submits that the CEC has not established substantial discrimination, and that BC Hydro has brought the allocation of DSM spending amongst sectors into better alignment while adhering to the DSM moderation approach.[873]

BC Hydro submits that trade-offs are inevitable in arriving at any particular level of traditional DSM expenditures. In BC Hydro's submission, the moderation approach finds a balance that is in the public interest, given the continued energy surplus and need to manage upward pressure on rates. BC Hydro will be examining the planned level of traditional DSM again in the upcoming IRP.[874]

With regards to the residential sector, BCOAPO submits that BC Hydro has failed to adequately address a key priority of "making life more affordable" listed in the BC Government's April 2018 Mandate Letter.[875] BCOAPO acknowledges that the planned fiscal 2020 and fiscal 2021 expenditures on Low Income programs, totalling $5.8 million and $6.9 million, respectively, are materially higher by 61 percent and 92 percent, respectively, than the

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[865] BC Hydro Final Argument, p. 243.
[866] BCSEA Final Argument, p. 52.
[867] BCSEA Final Argument, p. 54.
[868] BCSEA Final Argument, p. 56.
[869] CEC Final Argument, p. 104.
[870] CEC Final Argument, p. 95 .
[871] CEC Final Argument, p. 99.
[872] Exhibit B-1, Table-10-4; BC Hydro Reply Argument (May 27, 2020), pp. 122–124
[873] BC Hydro Reply Argument (May 27, 2020), p. 125
[874] BC Hydro Reply Argument (May 27, 2020), p. 110.
[875] BCOAPO Final Argument, p. 53.

actual value of $3.6 million for fiscal 2019. BCOAPO submits that BC Hydro's alleged expanding of the Low Income program involves "only increased expenditures and participation for existing programs" without proposing new DSM measures targeted to low income ratepayers. BCOAPO takes issue with the fact that BC Hydro has not proposed any new programs or measures for its fiscal 2020-fiscal 2021 Low Income Program.[876]

BCOAPO further urges the BCUC to direct BC Hydro to modernize its DSM program for low-income customers by incorporating successful measures from other jurisdictions, such as California's multifamily whole-building program, in order to achieve deeper retrofits and deeper savings for significant numbers of eligible low income customers.[877]

In response to BCOAPO, BC Hydro confirms it does monitor what is happening in other jurisdictions, and that while the names of the Energy Saving Kit program and the Energy Conservation Assistance program have remained the same, they have evolved and improved over time. BC Hydro has launched a new Social Housing Retrofit Support Offer for Multi-Unit Residential, providing an opportunity for qualifying social housing providers to minimize their operating costs and improve whole building performance. BC Hydro is also piloting an approach that combines in-suite offers and common area offers for multi-family buildings.[878]

Zone II RPG supports BC Hydro's proposed DSM expenditure schedule, which represents an increase in residential expenditure of approximately 50 percent since the last test period, bringing spending in this sector more in line with expenditures for commercial and large industrial sectors.[879]

While supporting the DSM expenditure schedule on the basis that it is just and reasonable and in the public interest,[880] the Zone II RPG has concerns about the pace of implementation and encourages BC Hydro to continue to engage with Non-Integrated Area communities and fund ongoing comprehensive assessments of their energy plans in order to set priorities and action plans for DSM activities.[881]

Given that BC Hydro's Non-Integrated Area DSM program is nascent, Zone II RPG considers it would be valuable to review this program in the future, including whether it has been effective in reducing barriers for Non-Integrated Area customers in accessing DSM programs, thereby meeting the objective of Directive 23 from the fiscal 2017 to fiscal 2019 RRA. A report on such assessment could be made in BC Hydro's Annual Report on DSM Activities and in its next DSM application.[882]

No intervener other than the CEC has requested denial of the DSM expenditure schedule.[883]

Panel Determination

Based on the Panel's earlier determinations on the relevant factors set out in section 44.2(5.1) of the UCA, the Panel finds BC Hydro's proposed DSM expenditure schedule for the Test Period to be in the public interest, and accepts the DSM expenditure schedule of $90.8 million in fiscal 2020 and $89.1 million in fiscal 2021 under section 44.2 of the UCA.

While we acknowledge the CEC's submission on the decline in commercial DSM expenditure, this decline occurs in the context of a fairly stable overall DSM budget, and reallocation of expenditure from commercial and industrial customers to residential customers. To put the decline in commercial expenditure since 2014 in

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876 BCOAPO Final Argument, pp. 53–54.
877 BCOAPO Final Argument, p. 58.
878 BC Hydro Reply Argument (May 27, 2020), pp. 118–119.
879 Zone II RPG Final Argument, p. 3.
880 Zone II RPG Final Argument, p. 20.
881 Zone II Final Argument, p. 23.
882 Zone II RPG Final Argument, p. 25.
883 BC Hydro Reply Argument (May 27, 2020), p. 108.

context, at that time expenditure on commercial DSM was roughly double that for residential DSM, which did not match the allocation of DSM costs between the two sectors.

Despite BCOAPO's submission that BC Hydro could have gone further in expanding the residential offering, we acknowledge the efforts already undertaken by BC Hydro to bring DSM expenditures more in line with the fully allocated cost of DSM as shown in Table 4-25 above, and to address household affordability by increasing expenditures for the residential sector, in line with the BCUC's recommendations in the 2017-2019 RRA.[884] In recognition of the inevitable trade-offs that have to be made while reallocating funds between sectors in the absence of an increase in overall DSM funding, we find the allocation of DSM expenditures between the customer classes, as reflected in the proposed DSM expenditure schedule, to be reasonable for the Test Period.

As for BCOAPO's request for BC Hydro to modernize its DSM program for low-income customers by incorporating new successful measures from other jurisdictions, we are satisfied with BC Hydro's confirmation that it does monitor developments in other jurisdictions and has evolved and improved its low-income programs over the years, including developing new initiatives and pilots for multi-family dwellings and social housing.

While we recognise the progress BC Hydro has made in developing the DSM initiatives tailored for the Non-Integrated Area customers, we agree with Zone II RPG that it is important and valuable for BC Hydro to review progress in this nascent area. **The Panel therefore directs BC Hydro to report on progress with regards to the Non-Integrated Area DSM Program in its annual DSM report and in its fiscal 2023 RRA. This reporting must include an assessment of whether that program has been effective in reducing barriers for Non-Integrated Area customers in accessing DSM offerings and thereby meeting the objective of Directive 23 from the 2017-2019 RRA.**

4.6.5 Deferral of Low-Carbon Electrification Expenditures to the DSM Regulatory Account

In addition to the traditional DSM activities described above which are aimed at reducing energy use, BC Hydro also requests approval to defer its Low Carbon Electrification expenditures over the Test Period to the DSM Regulatory Account, as per the *Direction to the BCUC Respecting Undertaking Costs*.[885] In contrast to the traditional DSM expenditure schedule which is reviewed pursuant to section 44.2 of the UCA, Low Carbon Electrification initiatives fall under the GGRR as prescribed undertakings,[886] and are focused on reducing GHG emissions. BC Hydro is not requesting BCUC acceptance of these expenditures, only approval to defer the Low Carbon Electrification expenditures to the DSM regulatory account.[887]

<u>Legislative Framework</u>

Sections 18(1) to 18(3) of the *Clean Energy Act* state that the BCUC must set rates to allow BC Hydro to recover the costs of prescribed undertakings, and must not exercise any power that would prevent BC Hydro from carrying out prescribed undertakings.

The Direction to the BCUC[888] Respecting Undertaking Costs states that:

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

[884] Decision accompanying G-47-18, p. 81.
[885] B.C. Reg 77/2017, O.C. 100/2017.
[886] B.C. Reg. 102/2012, O.C. 295/2012.
[887] Exhibit B-1, p. 10-19.
[888] B.C. Reg 77/2017, O.C. 100/2017.

Undertaking costs are defined in the Direction to mean "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 [GGRR]."

Section 4(4) of the GGRR states:

> 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.

The definition of "cost-effective" in the GGRR differs from that set-out in section 4 of the DSM Regulation which the Panel discussed earlier. For the purposes of Low Carbon Electrification expenditures, cost-effective "means that the present value of the benefits of all of the public utility's undertakings within the classes defined in subsection (3) (a) or (b) exceeds the present value of the costs of all of those undertakings when both are calculated using a discount rate equal to the public utility's weighted average cost of capital over a period that ends no later than a specified year." [889]

Description of Low Carbon Electrification Expenditures

BC Hydro describes in its Application[890] the Low Carbon Electrification projects and programs (as distinct from its traditional DSM expenditures) that BC Hydro has undertaken and plans to undertake over the Test Period, which BC Hydro submits are within one or more class of undertakings prescribed under the GGRR.

"LCE Project/Programs" do not include Low Carbon Electrification infrastructure projects, such as the PRES project, which are undertaken pursuant to section 4(2) or section 4(3)(e) of the GGRR, whereas "LCE Project/Programs" are undertaken pursuant to section 4(3)(a) to (d) of the GGRR.[891]

LCE Project/Programs consist of two broad categories of projects:

- The Initial LCE Projects introduced in 2018 to assess and support immediate low carbon electrification opportunities among BC Hydro customers. These projects are within one (or more) class of undertakings defined in subsections 4(3)(a) and 4(3)(c) of the GGRR; and
- BC Hydro's LCE Program, a new BC Hydro funded low carbon electrification program, including components within subsections 4(3)(a), 4(3)(b), 4(3)(c), and 4(3)(d) of the GGRR.[892]

BC Hydro's objectives for its Low Carbon Electrification expenditures and activities in the Test Period include:

- Supporting the Government of BC's climate change objectives by helping customers to reduce their greenhouse gas emissions;
- Assisting customers in pursuing low carbon electrification opportunities that:
  - Increase revenue from additional electricity consumption to reduce pressure on rates over the energy surplus period; and
  - Reduce their greenhouse gas emissions;
- Assessing customer response to program offers and gaining experience with new technologies to help BC Hydro understand potential barriers that customers and BC Hydro may face when developing and advancing low carbon electrification alternatives; and

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[889] B.C. Reg. 102/2012, O.C. 295/2012. Unless determined otherwise by the Minister, the specified year is 2030.
[890] Appendix Y of the Application as updated in Exhibit B-31, BCUC Panel IR 18.2, Attachment 1.
[891] Exhibit B-1, Appendix Y, p. 3; BCSEA Final Argument, p. 68.
[892] Exhibit B-31, BCUC Panel IR 18.1 Attachment 1, pp. 5-6.

- Acting early to capture time-sensitive opportunities.[893]

BC Hydro provides the actual and forecast Low Carbon Electrification expenditures from fiscal 2018 to fiscal 2020 in the following table in response to a BC Hydro Undertaking:[894]

Table 4-28: Low Carbon Electrification Expenditures

	F2018 Actual ($ million)	F2019 Actual ($ million)	F2020 Forecast ($ million)	F2021 Forecast ($ million)	F2022 Forecast ($ million)	F2023 Forecast ($ million)
Initial LCE Projects	0.21	6.85	13.33	3.38	6.00	0.00
LCE Program	0.00	0.48	4.49	4.36	3.13	4.20
Total LCE Projects/Programs	0.21	7.33	17.82	7.74	9.13	4.20

Low Carbon Electrification activities and commitments made in fiscal 2020 include expenditures that will be incurred in fiscal 2021 and fiscal 2022, due to the length of time required for projects to reach completion. New Low Carbon Electrification activities beyond fiscal 2020 will be informed by the outcomes of Phase Two of the Government of BC's Comprehensive Review of BC Hydro (Phase Two Review).[895]

BC Hydro states that it does plan and report on Low Carbon Electrification expenditures separately from traditional DSM expenditures. BC Hydro does not currently report on Low Carbon Electrification expenditures within the DSM Regulatory Account but could do so, if required. The advantage of separately reporting Low Carbon Electrification expenditures within the DSM Regulatory Account would be to allow the BCUC and interveners to distinguish between the amortization of DSM expenditures and the amortization of Low Carbon Electrification expenditures. The disadvantage would be the additional work required to set up new codes and reclassify previous year amounts. From a management perspective, BC Hydro does not see an advantage in separately reporting these expenditures within the DSM Regulatory Account because the amortization periods for both DSM expenditures and Low Carbon Electrification expenditures are the same.[896]

Positions of Parties

The CEC accepts that the LCE projects are prescribed undertakings and therefore recoverable in rates.[897]

BCSEA agrees with BC Hydro that the BCUC must allow BC Hydro to recover its Low Carbon Electrification expenditures over the Test Period by virtue of the GGRR and section 18 of the CEA, and supports a determination by the Panel that BC Hydro's Low Carbon Electrification expenditures should be deferred to the DSM Regulatory Account. [898]

BCSEA submits that Low Carbon Electrification expenditures meet the two broad requirements to fall within the class of prescribed undertakings in sections 4(3)(a) to (d) of the GGRR: [899]

> (a) The LCE expenditures must meet the descriptions in sections 4(3)(a), 4(3)(b), 4(3)(c), or 4(3)(d) of the GGRR; and

[893] Exhibit B-6, BCSEA IR 54.1
[894] Exhibit B-38, BCH Undertaking No. 7.
[895] Exhibit B-12, BCUC IR 277.4.
[896] Exhibit B-12, BCUC IR 277.3.
[897] CEC Final Argument, p. 106.
[898] BCSEA Final Argument, p. 52.
[899] BCSEA Final Argument, pp. 70–71.

(b) At the time BC Hydro decided to undertake the LCE expenditures meeting the descriptions in sections 4(3)(a), 4(3)(b), BC Hydro must have reasonably expected the LCE expenditures to be cost effective as set out in section 4(4) of the GGRR.

While accepting 15 years as appropriate for the amortization of the DSM Regulatory Account based on evidence presented on the average measure life for DSM, BCSEA notes that the measure life of Low Carbon Electrification initiatives is substantially longer than the measure life of traditional DSM measures. BCSEA expects that Low Carbon Electrification expenditures will ramp up in the coming years at a higher rate than traditional DSM expenditures. If so, then Low Carbon Electrification will form an increasing proportion of the DSM Regulatory Account and this will tend to increase the average measure life.[900]

BCOAPO has no issues with BC Hydro's request as it serves to clarify and formalize the direction the BCUC has received from the Provincial Government.[901]

No interveners challenged the nature of the LCE projects as prescribed undertakings under the GGRR.

Panel Determination

The Panel notes that pursuant to the Direction to the BCUC Respecting Undertaking Costs, the BCUC must allow BC Hydro to defer amounts equal to the undertaking costs to the DSM Regulatory Account. The Panel agrees with interveners and BC Hydro that the Low Carbon Electrification expenditures over the Test Period are prescribed undertakings under the GGRR, and finds that these Low Carbon Electrification expenditures must therefore be deferred to the DSM Regulatory Account as required by the Direction to the BCUC Respecting Undertaking Costs. **Therefore, we approve BC Hydro's request to defer low-carbon electrification expenditures up to the undertaking costs to the DSM Regulatory Account.**

Since the DSM Regulatory Account will now include non-traditional DSM expenditures, the Panel sees value in increasing the transparency of the regulatory account and therefore, directs BC Hydro to separately track these expenditures in the DSM Regulatory Account. This will allow parties to distinguish the amount related to Low Carbon Electrification expenditures that will accumulate in the regulatory account and the amount that will be amortized into rates.

The Panel directs BC Hydro to report on the Low Carbon Electrification expenditures within the DSM Regulatory Account annually in its annual DSM report to the BCUC, clearly allocated to the applicable classes defined in section 4 (3) (a), (b), (c) or (d) of the GGRR, including a consolidated table with a break down between the Initial LCE and BC Hydro LCE projects and programs.

4.6.6 Request to Rescind Direction 61 from Order G-96-04

BC Hydro further requests the BCUC to reconsider and rescind Directive 61 of the BCUC's Decision on BC Hydro's Fiscal 2005 to Fiscal 2006 Revenue Requirements Application[902] which directs that a prorated amount of costs from portfolio-level initiatives be added to the cost of each DSM program to assess cost effectiveness.

Directive 61 requires portfolio level costs to be allocated to programs, as follows: "Portfolio Level Costs should be allocated to programs, and BC Hydro is directed to use the same allocation methodology based on kWh savings,"[903] as used in BC Hydro's 2005-2006 RRA proceeding.

[900] BCSEA Final Argument, p. 46.
[901] BCOAPO Final Argument, p. 43.
[902] Decision and accompanying Order No. G-96-04.
[903] Exhibit B-1, p. 10-33. This allocation methodology was demonstrated in Exhibit B1-81 of the 2005 to 2006 RRA Proceeding.

Following the issuance of Directive 61 in 2004, the DSM Regulation[904] came into effect in 2008, with the latest updates in 2017. As already noted, section 4 of the DSM Regulation prescribes how the current industry-standard cost-effectiveness tests are to be applied.

BC Hydro requests that the BCUC rescind Direction 61 from Order G-96-04 on the grounds that it is inconsistent with the DSM Regulation and industry standard practice.[905] Allocating portfolio-level costs to DSM programs is not appropriate for marginal decision-making because this allocation overstates a program's incremental costs when assessing cost-effectiveness. The inclusion of portfolio-level costs could shift the result for a program from a net benefit to a net cost, which could lead to a decision not to implement the individual program. For this reason, it is more appropriate to only consider portfolio-level costs when looking at the cost effectiveness of the overall portfolio, not the cost effectiveness of individual programs. This allows decisions on individual programs to be based entirely on the merits of the programs themselves.[906]

BC Hydro submits that costs should only be attributed to programs if they are solely connected to a specific program. In support of this change, BC Hydro notes the proposed approach:

- is consistent with section 4(4) of the 2017 DSM Regulation which requires that "specified demand side measures" be evaluated at a portfolio level;
- is consistent with industry practice which has emerged since the direction was issued in 2004, and that all BC utilities are not required to provide a similar cost allocation;[907] and
- facilitates marginal decision making, ensuring that the inclusion of portfolio level costs does not shift the cost-effectiveness result for an individual program from a net benefit to a net cost.[908]

Positions of Parties

BCSEA supports BC Hydro's request, and agrees that current industry practice, as expressed in the (US) National Standard Practice Manual in 2017, is that "fixed portfolio-level costs should not be allocated to programs for the purpose of assessing the cost-effectiveness of individual programs."[909] BCSEA submits that decisions on individual programs should be based entirely on the merits of the programs themselves, and that including portfolio-level costs in the evaluation of a program could shift the result from a net benefit to a net cost, which could lead to a program with a net benefit not being implemented. [910]

BCOAPO supports BC Hydro's request based on the fact that, since Directive 61 was issued, the cost effectiveness testing of DSM expenditures has become subject to the DSM Regulation and Directive 61 is inconsistent with the requirements of the DSM Regulation.[911]

No intervener objects to BC Hydro's request.

Panel Determination

The Panel rescinds Direction 61 from Order G-96-04 because it is inconsistent with the DSM Regulation.

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904 B.C. Reg. 326/2008.
905 Exhibit B-1, , p. 10-33.
906 Exhibit B-1, pp. 10-34–10-35.
907 Exhibit B-5, BCUC 172.1; The National Standard Practice Manual (NSPM) is a US based publication of the National Efficiency Screening Project (NESP) https://www.nationalenergyscreeningproject.org/national-standard-practice-manual/.
908 BC Hydro Final Argument, p. 229; Exhibit B-13, BCOAPO IR 153.2.1.
909 Exhibit B-5, BCUC 172.1 pdf p. 1957.
910 BCSEA Final Argument, p. 62.
911 BCOAPO Final Argument, p. 59.

4.6.7 Inter-Year and Inter-Program Transfers

BC Hydro states that it has submitted its DSM Plan with the intention of carrying it out as designed,[912] but retains discretion to reallocate its DSM costs during the Test Period, arguing that flexibility is required to respond to challenges or opportunities in the market. BC Hydro understands that a significant deviation from the breakdown shown in the accepted expenditure schedule could result in cost recovery risk. For instance, underspending as a result of a BC Hydro decision (as opposed to customer driven market uptake), could give rise to cost recovery risk if the portfolio were no longer cost effective.[913]

Positions of Parties

BCSEA agrees that it is important for BC Hydro to have flexibility, and that appropriate checks and balances are in place regarding reallocations made during the Test Period. These include BC Hydro's Financial Approval Authority Policy, and BC Hydro's annual DSM reports. Regarding inter-year transfers, BCSEA notes that the exact timing of the expenditure would not change the assessment of whether the DSM expenditure schedule is still in the public interest. Regarding both inter-year and inter-program transfers, BCSEA suggests that flexibility would reduce the risk of underspending, which has been BCSEA's concern in the past.[914]

BCSEA, BCOAPO, MoveUP and Zone II RPG agree that BC Hydro should retain discretion to implement inter-year and inter-program transfers within an accepted DSM expenditure schedule for the Test Period, without prior BCUC approval but subject to the usual reporting requirements and to cost recovery risk. [915]

However, BCSEA also supports BCUC approval of flexible rules for inter-year and inter-program spending transfers regarding BC Hydro's traditional DSM expenditure schedule for the Test Period. In this respect, consideration should be given to the BCUC's approach in the Decision regarding FortisBC Inc.'s 2019-2022 DSM Plan and Expenditure Schedule, in summary:

- approval of inter-year transfers within the same program area subject to reporting in the annual DSM report; and
- approval of transfers of up to 25 percent of budgeted expenditures from an existing program area to another existing program area, subject to reporting in the annual DSM report.[916]

Despite recognizing the need for flexibility, several interveners comment that flexibility should nonetheless be limited. Among other things, Zone II RPG maintains that BC Hydro must be mindful of the BCUC's previous directions, with respect to the importance of funding Non-Integrated Area DSM initiatives.[917] BCOAPO submits that transfers must be compliant with the requirements that would have been considered by the BCUC had the utility brought forward an application for an amendment to its DSM expenditure schedule, or be subject to cost recovery risk.[918]

In BCSEA's view, the BCUC's jurisdiction to accept a DSM expenditure schedule includes jurisdiction to specify limits on reallocation in order to clarify what expenditures are included in the accepted expenditure schedule for the purpose of recovery in rates. [919]

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[912] Exhibit B-5, BCUC IR 174.1.1.
[913] BC Hydro Final Argument, pp. 233–234.
[914] BCSEA Final Argument, p. 66.
[915] MoveUP Comment on BCH Submissions, p. 2; BCSEA Comment on BCH Submissions, p. 1; Zone II RPG Comment on BCH Submissions, p. 1; BCOAPO Comment on BCH Submission, p. 2.
[916] BCSEA Final Argument, p. 67.
[917] Zone II RPG Comment on BCH Submissions, pp. 1-2.
[918] BCOAPO Comment on BCH Submission, p. 2.
[919] BCSEA Comment on BCH Submissions, p. 1.

BC Hydro submits that even a 25 percent transfer limit is not warranted. Limits on BC Hydro's discretion to respond to opportunities and challenges during a Test Period can only be detrimental to customers. BC Hydro has continually demonstrated that it carries out its DSM initiatives prudently and effectively. BC Hydro should maintain its discretion to do so.[920]

Panel Determination

As several interveners have pointed out, other BCUC regulated utilities are currently subject to rules limiting the proportion of DSM expenditures which can be reallocated between program areas and years without BCUC approval, or be subject to cost recovery risk. The Panel sees no reason why BC Hydro should be an exception. BC Hydro still retains discretion and flexibility, but within defined and transparent limits. The BCUC reviews and accepts or rejects DSM expenditure schedules based on a proposed allocation of funding between sectors and program areas, and an estimated overall portfolio cost-effectiveness. Any substantial reallocation of funds between program areas following acceptance of the DSM expenditure schedule risks affecting the cost-effectiveness of the DSM portfolio, and the balance between sectors as well as the allocation of DSM cost recovery amongst the sectors, and calls into question the premise upon which the expenditure schedule was accepted.

The Panel therefore makes the following determinations:

- **BC Hydro may transfer unspent accepted DSM expenditures in a program area to the same program area in the following year of the Test Period, on the condition that BC Hydro provides information regarding unspent amounts as part of its annual DSM reports so that all amounts transferred within a program area are transparently accounted for from one test year to the next; and**
- **The Panel accepts the DSM expenditure schedule including transfers of up to 25 percent of DSM expenditures from any one existing program area to any other existing program area.**

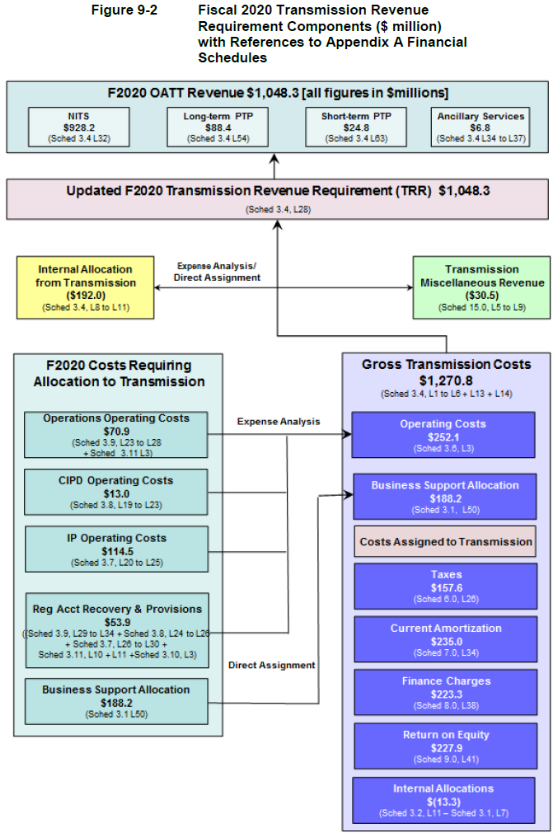
4.7 Transmission Revenue Requirement and Open Access Transmission Tariff

BC Hydro states that the Transmission Revenue Requirement (TRR) is the sum of BC Hydro's net transmission function costs, calculated using a cost of service methodology which allocates or directly assigns forecast costs to and from the transmission business function (Cost Allocation Methodology).[921] The Cost Allocation Methodology is consistent with the method used by BC Hydro in previous revenue requirement applications, by the British Columbia Transmission Corporation, and by BC Hydro in its application for approval of Wholesale Transmission Services.[922]

The TRR includes the current costs associated with the assets used by BC Hydro to provide services related to the Open Access Transmission Tariff (OATT), namely transmission lines and high-voltage station equipment.[923] A portion of BC Hydro's other operating costs is assigned to the TRR from other BC Hydro business functions, and certain costs such as business support costs and taxes are directly allocated, to calculate the gross transmission costs. Subsequently, some of the gross transmission costs are allocated to other BC Hydro business functions, leaving the net transmission costs, or the TRR. The allocations and direct assignments involved in calculating the TRR are set out in BC Hydro's figure 9-2 (the figure 9-2 were subsequently updated in the Evidentiary Update as explained below):[924]

[920] BC Hydro Reply Argument (May 27, 2020), p. 128.
[921] Exhibit B-1, pp. 9-1–9-2.
[922] Order G-43-98.
[923] Exhibit B-1, p. 9-2.
[924] Exhibit B-1-2, Figure 9-2, p. 9-4 (i).

Figure 4-10: Fiscal 2020 TRR Components



BC Hydro allocates to the TRR operating costs from other business functions on the following basis:[925]

- 34 percent of the Integrated Planning Business Group operating costs;
- 20 percent of the Capital Infrastructure Project Delivery Business Group operating costs;
- 25 percent of the Operations Business Group operating costs;
- 19 percent of the Materials Management Department operating costs; and
- 32 percent of the Fleet Services Department operating costs.

BC Hydro directly assigns to gross transmission certain costs such as taxes, amortization, finance charges, return on equity, and business support costs. Each of these assignments is done on a different basis, such as asset analysis, activity analysis and employee (FTE) counts.[926] To calculate the net transmission costs, BC Hydro directly assigns miscellaneous revenues from external OATT customers and FortisBC, and certain other revenues.[927]

The TRR for each of fiscal 2020 and fiscal 2021 is estimated to be $1,091.7 million and $1,089.6 million, respectively. The breakdown of the components of the TRR is reproduced in the following table: [928]

[925] Exhibit B-1, p. 9-15.
[926] Exhibit B-1, pp. 9-16–9-20.
[927] Exhibit B-1, pp. 9-20–9-22.
[928] Exhibit B-11-2, Appendix E, p. 2, Table E-1.

Table 4-29: Transmission Revenue Requirement

		F2020			F2021		
		Plan	Evidentiary Update	Diff	Plan	Evidentiary Update	Diff
		1	2	3	4	5	6
1	Operating Cost	252.1	252.7	0.6	256.5	257.1	0.6
2	Taxes	157.6	157.6	-	163.7	163.7	-
3	Amortization	235.0	233.5	(1.4)	237.3	236.1	(1.2)
4	Finance Charges	223.3	243.9	20.7	209.0	227.6	18.6
5	Return on Equity	227.9	236.1	8.1	224.7	232.9	8.1
6	Business Support Cost	188.2	205.1	17.0	195.2	~~212.1~~ 211.8	~~16.9~~ 16.7
7	Internal Allocations to Transmission						
8	Generation Ancillary Services	2.8	2.8	-	2.8	2.8	-
9	Transmission Capitalized Overhead	(16.1)	(16.1)	-	(16.3)	(16.3)	-
10	Transmission RSRA Writeoff	-	-	-	-	-	-
11	Gross Transmission Costs	1,270.8	1,315.7	44.9	1,273.0	~~1,316.1~~ 1,315.9	~~43.1~~ 42.8
12	Less Internal Allocations from Transmission						
13	Generation Related Transmission Assets	(43.3)	(43.3)	-	(43.3)	(43.3)	-
14	Generation Real Time Dispatch	(2.3)	(2.4)	(0.1)	(2.3)	(2.4)	(0.1)
15	Distribution Real Time Dispatch	(20.0)	(20.7)	(0.7)	(20.4)	(21.1)	(0.7)
16	Substation Distribution Assets	(126.5)	(127.4)	(1.0)	(128.1)	(128.5)	(0.4)
17	Less Miscellaneous Revenues						
18	Fortis General Wheeling Agreement	(5.2)	(5.2)	-	(5.3)	(5.3)	-
19	Secondary Revenues	(6.0)	(6.0)	-	(6.2)	(6.2)	-
20	Interconnections	(2.2)	(2.2)	-	(2.2)	(2.2)	-
21	Amortization of Contributions	(14.8)	(14.6)	0.3	(15.3)	(15.0)	0.3
22	NTL Supplemental Charge	(2.3)	(2.3)	-	(2.3)	(2.3)	-
23	Subtotal	(222.5)	(224.0)	(1.5)	(225.4)	~~(226.3)~~ (226.2)	(0.9)
24	Transmission Revenue Requirement	1,048.3	1,091.7	43.4	1,047.6	~~1,089.9~~ 1,089.6	~~42.2~~ 42.0

While BC Hydro states that its TRR is calculated in a manner consistent with past practice,[929] it acknowledges that some methodological steps from the 2016 cost of service study (COSS) are not applicable to calculating the TRR, and other such steps may not be directly applicable given "changes to BC Hydro's business and financial model (e.g., changes to regulatory accounts and cost definitions)."[930]

BC Hydro states that the TRR and the 2016 COSS were prepared for different purposes using different data sources. The TRR is used only to allocate transmission capacity costs to the OATT rates for recovery. In contrast, the 2016 COSS allocated BC Hydro's total revenue requirement to bundled rate classes to inform BC Hydro's 2015 Rate Design Application and "considered a much broader range of costs" than transmission capacity costs, which in total were then allocated to various customer classes as defined in the Electric Tariff. [931,]

4.7.1 Open Access Transmission Tariff

BC Hydro's TRR is recovered through the Open Access Transmission Tariff (OATT), which sets out the rates for the following services:

1. Network Integrated Transmission Service (NITS);
2. Point-to-point (PTP) Transmission Service; and
3. Ancillary Services[932]

As the main users of the transmission system, BC Hydro and Powerex account for approximately 98.5 percent of the revenue collected through the OATT, while external transmission customers account for approximately 1.5 percent of the revenue.[933]

929 Exhibit B-1, p. 9-10.
930 Exhibit B-12, Response to BCUC IR 267.1.
931 Exhibit B-31, BCUC Panel IR 8.1; Exhibit B-31, BCUC Panel IR 8.2.
932 Application, p. 9-22.
933 Application, p. 9-1.

The PTP Transmission Service is "the reservation and transmission of capacity and energy, on a firm or non-firm basis, from point A to point B, on the transmission system." The PTP Transmission Service rate is designed to recover the TRR other than the Ancillary Service revenues in the theoretical situation that the PTP Transmission Service were used to transfer the maximum capacity on the transmission system, and there were no NITS customer. The PTP Transmission Service rate is calculated by subtracting the Ancillary Service revenue from the TRR, and dividing the result by BC Hydro's total dependable transmission capacity including planned capacity.[934]

Ancillary Services include scheduling, system control and dispatch performed by BC Hydro on behalf of certain customers. The Ancillary Services rate is calculated by dividing the total cost for these services by the total forecasted volume for NITS and PTP Transmission Services.[935]

The derivation of the scheduling fee related to Ancillary Services is presented in BC Hydro's table 9-6:[936]

Table 4-30: Calculation of Scheduling, System Control and Dispatch Rate

		Schedule Reference	F2017 RRA	F2018 RRA	F2019 RRA	F2020 Plan	F2021 Plan
			3	4	5	4	5
1	**PTP Volumes (MWh)**						
2	Long-Term PTP	Schedule 3.4 L51	9,355,680	9,355,680	9,355,680	9,881,280	9,881,280
3	Short Term PTP	Schedule 3.4 L60	10,052,378	10,480,466	10,908,554	9,939,991	10,324,607
4	**Total PTP Volumes**		19,408,058	19,836,146	20,264,234	19,821,271	20,205,887
5	NITS and Secondary Transmission		8,325,721	8,325,721	8,325,721	9,566,902	9,566,902
6	**Total Volumes**	**Schedule 3.4 L47**	27,733,779	28,161,867	28,589,955	29,388,173	29,772,789
7	**Scheduling, Control and Dispatch Cost ($ million)**	Schedule 3.4 L46	2.9	2.8	2.9	3.9	4.0
8	**Scheduling Fee[341] ($/MWh)**	**(L8/L7) =Schedule 3.4 L48**	0.105	0.100	0.100	0.133	0.136

BC Hydro submits that the BCUC should have confidence in its determination of the TRR because the cost allocation methodology used to derive the TRR is based on cost causation and is consistent with past practice. Further, the BCUC should have confidence in the OATT rates because their calculation is consistent with the design of OATT rates previously approved for BC Hydro and the British Columbia Transmission Corporation, including orders issued when the OATT was updated in response to major reforms by FERC of their *pro forma* OATT.[937]

BC Hydro submits that the proposed OATT rates are just and reasonable and should be approved.[938]

Positions of Parties

BCSEA submits it has no reason to disagree with BC Hydro's position that the TRR and OATT rates reflect established cost of service methodology based on cost causation and rate design approved by the BCUC in past proceedings.[939]

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934 Exhibit B-1, p. 9-24.
935 Exhibit B-1, pp. 9-25–9-26.
936 Exhibit B-1, Table 9-6, p. 9-26.
937 BC Hydro Final Argument dated April 1, 2020, pp. 211–212.
938 BC Hydro Final Argument, p. 215.
939 BCSEA Final Argument, p. 50.

BCOAPO submits it has no issues with the derivation of BC Hydro's proposed OATT rates.

The CEC is concerned that OATT rates may not be recovering the full cost of service. The CEC observes that BC Hydro appears only to have allocated transmission capacity costs to OATT rates whereas in the 2016 COSS a much broader range of costs was considered. The CEC recommends that the BCUC accept the TRR in the interim, but that the BCUC should consider whether or not the cost allocation methodology and calculation of OATT rates could be modified to reflect the full cost of transmission service.[940]

In reply to the CEC, BC Hydro submits that accepting the CEC's recommendation would violate the principle of cost causation and contradict multiple BCUC approvals of BC Hydro's OATT rate design. BC Hydro explains that the TRR is correctly limited to BC Hydro's net transmission function costs and that no other costs are caused by OATT customers, therefore the proposed OATT rates fully recover the TRR.[941]

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 BC Hydro has calculated the TRR based on allocations and direct assignment of costs consistent with prior BCUC decisions and approved rate designs.

The Panel acknowledges the concern expressed by the CEC that BC Hydro may not have included all the transmission-related costs in the TRR. However, the CEC has not provided sufficient evidence of which costs have not been properly allocated to the TRR, and the Panel accepts BC Hydro's argument that the TRR calculation in the Application and the 2016 COSS were done for different purposes and based on different sources of data.

4.7.2 OATT Rate Design

BC Hydro's Application for Wholesale Transmission Services, as approved by the BCUC by Order G-43-98, established the initial rate design principles of the current day OATT, including rate designs for NITS and PTP transmissions service, [942] and establishing the NITS customer as paying the residual transmission revenue requirement.[943] Rate designs for the NITS and PTP transmission services were later affirmed by Order G-58-05, dated June 19, 2005, when the OATT replaced the Wholesale Transmission Services.[944]

When the Wholesale Transmission Services was approved, there was a general trend in the North American electricity industry to introduce competition into aspects of the electricity market, as well as expand trading opportunities within the US via Powerex.[945] BC Hydro submits that applications to amend the OATT are filed for approval with the BCUC to maintain consistency with FERC's *pro forma* tariff in order to address changes to the market.[946] The OATT rate design has remained largely unchanged since 2008, when, by Order G-102-09, time of use Short Term PTP pricing principles were established.[947]

In FortisBC's most recent COSA and RDA proceeding, BC Hydro provided a series of reasons why a review of transmission service rate harmonization might be appropriate:[948]

[940] CEC Final Argument, p. 92.
[941] BC Hydro Reply Argument (May 27, 2020), p. 107.
[942] Exhibit B-31, Panel IR 8.5.2.
[943] Decision G-43-98, dated April 23, 1998, p. 32.
[944] Exhibit B-31, Panel IR 14.3.
[945] Exhibit B-31, Panel IR 8.5.
[946] BC Hydro Final Argument, p. 215.
[947] Exhibit B-31, Panel IR 8.5.1.
[948] FortisBC COSA and RDA proceeding, Exhibit C1-4, response to BCUC IR 1.3.

1. OATT Evolution: BC Hydro believes there are issues related to development of the OATT since the adoption of rate harmonization under Order No G-12-99. As an example, in response to an IR asked in the original rate harmonization proceeding, BC Hydro and FBC stated that “the energy imbalance charge will be collected by the utility in whose service territory the load is located.” However, the transmission tariffs of the two utilities on their face would seem to allow the transmission customer to choose from which utility it obtains energy imbalance service despite the joint commitments made by BC Hydro and FBC. In Attachment 1 to BCUC IR 1.3, BC Hydro provides a joint response dated January 6, 1999 to BCUC IRs under the 1998 rate harmonization joint application;
2. BC Hydro Retail Access: Per Order No. G-36-14 issued on March 13, 2014, there is currently no retail access in BC Hydro’s service area. As a result, only the few wholesale customers in BC Hydro’s service area could take advantage of rate harmonization into BC Hydro’s service area from FBC’s service area, with the $0 rate applied by FBC. Because of this, BC Hydro believes that the revenue transfer associated with retail access or wholesale supply from FBC’s service area will have little possibility to benefit BC Hydro ratepayers through BC Hydro point-to-point charges. A broader review of rate harmonization should deal with whether and the extent to which ratepayers and shareholders of each utility can be kept whole in light of Order G-36-14;
3. Operational: FBC has, to date, not implemented an open access same time information system (OASIS). While this may not have been a significant issue as long as there is no significant PTP usage over the points of interconnection (POIs), it may become an issue of transparency if there is more extensive PTP usage over the POIs. Put another way, BC Hydro currently has no visibility into FBC’s provision of open access transmission services, contrary to OATT principles. For example, there will be no OASIS transmission service request (TSR) on the FBC system that can be compared with a TSR on the BC Hydro system in order to confirm appropriate application of rate harmonization; and
4. Today’s Markets: The appropriateness of rate harmonization in BC has not been revisited in light of the fact that markets did not develop as expected as a result of deregulation of the industry around the time of Order G-12-99. These expected developments included significant retail access usage in BC and the formation of Regional Transmission Organizations (RTOs) within the Western Interconnection, with centralized transmission planning and operations. These developments did not occur in BC. Indeed, the British Columbia Transmission Corporation was formed based on these expected developments and has subsequently been re-integrated into BC Hydro. BC Hydro is not aware of rate harmonization being adopted as was originally contemplated almost twenty years ago.

In the FortisBC COSA and RDA decision, the BCUC considered BC Hydro’s logic to be reasonable, notwithstanding that BC Hydro subsequently withdrew its support for a broader review of rate harmonization due to the complexity. On the basis of the evidence in that proceeding, the BCUC recommended “a proceeding to inquire into the broader issues of transmission rate harmonization, with the involvement of transmission owners and transmission customers in the Province.”[949]

BC Hydro states that it is not requesting a determination in this proceeding on OATT rate design, and that the complexity of BC Hydro’s OATT is “readily apparent on the face.” BC Hydro also states that maintenance of an OATT consistent with or superior to the FERC’s *pro forma* OATT is required for Powerex to sell wholesale electricity at market-based rates in the US, which generates Trade Income for the benefit of BC Hydro’s ratepayers. [950]

[949] Order G-40-19, p. 88.
[950] BC Hydro Final Argument, p. 214.

Positions of Parties

BCSEA agrees with BC Hydro that the BC Hydro OATT rate design remains valid, and notes that BC Hydro is not requesting any determination in this proceeding regarding the design of the OATT.[951]

Panel Determination

The Panel agrees with BC Hydro that the OATT rate design is complex, and that changes to it should be made only after consideration of such relevant factors as BC Hydro's compliance with FERC orders.

However, the Panel is concerned that the complexity of the OATT rate design is preventing the examination of important matters which have arisen since the OATT (previously, the Wholesale Transmission Services) rate design principles were reviewed in 1998. The BCUC's recommendation in the FortisBC COSA and RDA proceeding that rate harmonization be reviewed is a good example. While no one transmission service issue on its own might justify the effort to examine the entire rate design, the danger is that the benefits that might come from such an examination will never be realized. There has been no comprehensive review of the OATT since its introduction in 1998.

For these reasons, the Panel recommends that the BCUC initiate a proceeding to review the OATT rate design in a comprehensive manner, including addressing the rate harmonization issue raised in the FortisBC COSA and RDA proceeding.

5.0 Other Issues Arising

5.1 Approach to the Evidentiary Update

On August 22, 2019, BC Hydro filed an evidentiary update to the Application (Evidentiary Update), which changed the requested fiscal 2021 rate to a decrease of 1.01 percent from an increase of 0.72 percent.[952] BC Hydro requested that all rate impacts resulting from the Evidentiary Update be reflected in the fiscal 2021 rates to avoid adjustments to fiscal 2020 bills.[953] The Evidentiary Update reflects the following changes to the Application:[954]

- Replacement of the forecast fiscal 2019 figures with actual results, which primarily impacts the amortization of regulatory accounts in the Test Period;
- Replacement of the October 2018 Energy Study forecast with the June 2019 Energy Study forecast, which includes actual costs for April and May 2019;
- Replacement of the forecast discount rate used to forecast pension costs with the actual discount rate as of April 1, 2019;
- Replacement of the October 2018 Government of BC forecast interest and foreign exchange rates with the January 2019 Government of BC forecast rates. BC Hydro also replaced the September 30, 2018 forward interest rates used for future debt hedges with rates as of May 31, 2019;
- Replacement of the estimated impact of the new lease accounting standard with the impact based on BC Hydro's completed assessment;
- Replacement of domestic sales forecasts for April and May 2019 with the actual financial results; and

[951] BCSEA Final Argument, p. 51.
[952] Exhibit B-11-2, p. 1.
[953] Exhibit B-11, p. 1.
[954] Exhibit B-11, pp. 2–4.

- Reduction of the DSM expenditure request in fiscal 2021 to reflect two projects that are no longer expected to proceed within the Test Period.

BC Hydro submits that it "limited the scope of the Evidentiary Update to targeted adjustments primarily related to fiscal 2019 actuals and the new Cost of Energy forecast." BC Hydro explains that it updated the cost of energy forecast because the original forecast was no longer reasonable due to changing conditions.[955]

BC Hydro submits that "[t]here are a number of costs that could conceivably be updated in an Evidentiary Update" as costs are constantly changing and new information is continuously available. BC Hydro submits that "it is necessary to exercise some judgement over what needs to be updated, and when, or the revenue requirements process would be unworkable." BC Hydro explains that the Evidentiary Update was prepared based on the principle of asking "Is the forecast in the Application still a reasonable basis for setting rates, based on what we know now?" [956]

BC Hydro submits that its regulatory accounts are "an efficient means of addressing new developments and changes from the Cost of Energy and finance charge assumptions reflected in the Evidentiary Update…. If the BCUC is nonetheless minded to base its decision on different information or assumptions, then it should do so holistically to ensure that the overall result remains reasonable."[957]

Positions of Parties

BCSEA supports BC Hydro's approach to the Evidentiary Update and submits BC Hydro's regulatory accounts are "an appropriate way to account for information that became available after the Evidentiary Update."[958]

However, in AMPC's view, the Evidentiary Update was prepared based on achieving certain results rather than based on accurate or consistent information. AMPC submits that BC Hydro's approach is not a principled approach and should not be endorsed.[959]

With respect to BC Hydro's position that existing regulatory accounts will address variances between forecast and actual results in a future test period, AMPC submits that regulatory accounts "should capture changes that arise within the test years after a prospective rate hearing occurs. They should not be an excuse to tolerate an inconsistent application of principles."[960]

In response to AMPC's submission that regulatory accounts "should capture changes that arise within the test years after a prospective rate hearing occurs," BC Hydro submits that the BCUC's Regulatory Account Checklist does not mention such restrictions, it could result in significant "windfalls" when unexpected circumstances, such as the COVID-19 pandemic, arise during a long proceeding, and it would increase the potential for large variances or under-recovery to occur if inputs are updated selectively.[961]

BC Hydro submits that it applied a consistent overarching principle when preparing the Evidentiary Update. BC Hydro submits that it "considered the inputs available at a point in time to determine whether they remained reasonable, and updated the inputs that no longer met that standard." In BC Hydro's view, AMPC's approach only reduces the proposed rates and deviates from accounting principles and previous BCUC orders. Furthermore, AMPC's position of not supporting a holistic approach to updating the Application is "internally inconsistent" given that AMPC's criticism of BC Hydro using "certain stale figures" and "ignore[ing] actuals or

[955] Exhibit B-28, p. 12, Q7.
[956] BC Hydro Final Argument, pp. 250–251, para. 585.
[957] BC Hydro Final Argument, p. 4.
[958] BCSEA Final Argument, pp. 14–15, 73, paras. 48, 296.
[959] AMPC Final Argument, p. 3, paras. 13, 14.
[960] AMPC Final Argument, p. 36, para. 121.
[961] BC Hydro Reply Argument (May 27, 2020), p. 144, para. 343.

undertak[ing] incomplete updates" in the Evidentiary Update.[962] BC Hydro submits that a larger rate decrease in fiscal 2021 would result in a larger rate increase in fiscal 2022, all else equal.[963]

BCOAPO submits that evidentiary updates should be "as comprehensive as possible" rather than "targeted," and requests that BCUC direct that evidentiary updates be comprehensive for future RRAs.[964] In BCOAPO's view, allowing BC Hydro to make "targeted adjustments" of its choosing in the Evidentiary Update results in a "partial update." Therefore, BCOAPO submits that evidentiary updates should update "all values where possible and practical to reflect more recent information."[965]

In response to BCOAPO's submission that the Evidentiary Update should update "all values where possible and practical to reflect more recent information," BC Hydro submits that this approach will be impractical and creates other issues. BC Hydro explains that although BCOAPO's proposed approach would avoid some disputes over what information was updated, it would require significant work and increase the lead time to prepare the Evidentiary Update, which in effect would result in the information becoming stale. For example, BC Hydro explains that the June 2019 Load Forecast could not be incorporated into the Evidentiary Update because BC Hydro needed the inputs "'locked down' well in advance of filing." BC Hydro submits its current approach of focusing on the material changes allows the Evidentiary Update to be completed in a timely manner.[966]

BC Hydro submits that the Evidentiary Update "remains a reasonable basis for setting rate in the Test Period, and regulatory accounts are a pragmatic and fair means of accounting for new information emerging during this protracted process." BC Hydro also submits that its approach "to the content of the Evidentiary Update and to addressing post-Update developments is both fair and efficient."[967] BC Hydro submits that its intent when preparing the Evidentiary Update was to "have Test Period rates reflect what, at a particular point in time, BC Hydro reasonably expects to occur."[968]

BC Hydro submits that BCOAPO and AMPC's submissions regarding the content of the Evidentiary Update should not be accepted because BC Hydro's current approach is both fair and efficient.[969]

Panel Discussion

Although the Panel recognizes that using the most recent information available at the time of the Evidentiary Update has some advantages, the Panel also accepts that attempting to update every piece of information in an Evidentiary Update would not be practical. However, in this case the fiscal 2019 forecasts were already being replaced with the fiscal 2019 actuals in the Evidentiary Update and therefore could have easily been incorporated into the forecasts that involved rolling averages of historical actuals.

With respect to AMPC's comment that regulatory accounts should capture changes that occur after a prospective rate hearing, the Panel generally agrees with AMPC that regulatory accounts should not be used to avoid updating forecasts for known and available information at the time the Evidentiary Update was prepared.

In the following sections, BC Hydro's approach to the Evidentiary Update with respect to trade income, finance costs, and current and non-current pension costs is discussed.

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[962] BC Hydro Reply Argument (May 27, 2020), pp. 137–139, paras. 326–329.
[963] BC Hydro Reply Argument (May 27, 2020), p. 139, para. 330.
[964] BCOAPO Final Argument, p. 8.
[965] BCOAPO Final Argument, p. 47.
[966] BC Hydro Reply Argument (May 27, 2020), pp. 142–143, p. 340.
[967] BC Hydro Reply Argument (May 27, 2020), p. 135, para. 320.
[968] BC Hydro Reply Argument (May 27, 2020), p. 139, para. 330.
[969] BC Hydro Reply Argument (May 27, 2020), p. 142, para. 337.

5.1.1 Trade Income forecast

BC Hydro uses a five-year rolling average of historical actual results to forecast Trade Income and storm restoration costs. Storm restoration costs are discussed in section 4.3.3.2 of the Decision. The Trade Income forecast in the Application was based on fiscal 2014 to fiscal 2018 and was not updated for fiscal 2019 actual results when the Evidentiary Update was prepared. BC Hydro forecasts Trade Income at $120.6 million for each year of the Test Period.[970] BC Hydro submits that its approach is consistent with the approach used in the previous RRA, which used the most recent five-year of actuals at the time the Application was prepared. The previous RRA was filed in July of 2016 and used the average of fiscal 2012 to fiscal 2016 for forecasting. The current Application was filed in February of 2019.[971]

BC Hydro explains that including the fiscal 2019 Trade Income would decrease the revenue requirement by $55.7 million for each year of the Test Period and lower rates for fiscal 2021 by 2.15 percent based on the fiscal 2020 rates being unchanged and refunding the two-year impact in fiscal 2021.[972]

In BC Hydro's view, the original forecast in the Application for Trade Income based on the five-year average from fiscal 2014 to fiscal 2018 continues to be reasonable "based on BC Hydro's assessment of the current state." Furthermore, Trade Income is subject to "significant volatility" and thus incorporating the fiscal 2019 actuals into the historical average used to calculate the Test Period forecast would not be any more or less reasonable than the forecast in the Application. Also, the regulatory account mechanisms in place result in primarily a timing issue and the relatively short amortization period means there would be no intergenerational equity issues.[973]

BC Hydro submits that since the Evidentiary Update, it has nine months of actual information for fiscal 2020 for Trade Income, domestic revenues and cost of energy. BC Hydro submits that for the nine months ended December 31, 2019, Trade Income is $159 million, which is closer to a five year historical average that includes fiscal 2019 actual results. However, BC Hydro submits that there are $36 million in net additions to the other cost of energy variance accounts as at the end of December 2019, primarily from lower than forecast domestic revenues. Therefore, in BC Hydro's view, setting rates based on the Evidentiary Update produces reasonable results overall because "it appears that roughly offsetting amounts will be deferred to the Cost of Energy Variance Accounts in fiscal 2020 when taking into account Trade Income, revenue and cost of energy."[974]

Positions of Parties

AMPC submits that BCUC "should direct BC Hydro to update its test year forecasts to include fiscal 2019 actuals in its Powerex Net Income forecast methodology and adjust rates accordingly."[975]

AMPC submits that the forecasting method for Trade Income is based on the most recent five years, and therefore, should include fiscal 2019. AMPC supports InterGroup's testimony that including the fiscal 2019 data does not assume that the fiscal 2019 results are expected to reoccur going forward because it only affects one-fifth of the forecast. Rather, since the methodology is based on simplicity over accuracy, the methodology should incorporate "the best updated data available."[976] AMPC submits that the "purpose of using a five-year average methodology <u>is to avoid discretion and debates about set-offs and speculation.</u>"[emphasis retained] Irrespective of this, AMPC points out that the Trade Income for the first nine months of fiscal 2020 is closer to an

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[970] Exhibit B-1, Section 8.9, p. 8-17; Section 5.5.2.2, p. 5-23, Table 5-5.
[971] Transcript Volume 8, p. 1083, Lines 2–9.
[972] Exhibit B-16, BCUC IR 313.2.2.
[973] BC Hydro Final Argument, pp. 250–251, paras. 584, 585.
[974] BC Hydro Final Argument, p. 251, paras. 586, 587.
[975] AMPC Final Argument, p. 31, paras. 105, 106.
[976] AMPC Final Argument, p. 32, paras. 108, 109.

updated forecast that incorporates fiscal 2019 data compared to the un-updated forecast.[977] AMPC also points to InterGroup's testimony that the fiscal 2019 data should not be ignored in the context of forecasting Trade Income because (1) the methodology is meant to avoid the need to figure out what may or may not reoccur; (2) from fiscal 2015 to fiscal 2019, Powerex's net income has been under forecast in four out of the five years; (3) BC Hydro updated the market electricity purchases forecast in the Evidentiary Update; and (4) BC Hydro is seeking to extend the 2018 Powerex letter agreement indefinitely to allow forward market purchases of electricity.[978] In AMPC's view, updating the Trade Income forecast based on the actuals available at the time of the Evidentiary Update would be consistent with BC Hydro's approach to updating the load forecast and cost of energy forecast in the Evidentiary Update, which was based on the information available at that time.[979]

BCOAPO submits that the Trade Income forecast should be updated to include fiscal 2019 results because the results were available at the time of the Evidentiary Update and the forecast should reflect more recent information.[980]

Panel Determination

Considering that the Evidentiary Update replaced the fiscal 2019 figures with the actual results, BC Hydro should also incorporate the fiscal 2019 actuals in its forecasts that are based on a rolling average of actual results. Incorporating the fiscal 2019 actuals, which were known and available at the time the Evidentiary Update was prepared, avoids discretion over the information that was updated with respect to its forecasts. **Therefore, the Panel directs BC Hydro to update the Trade Income forecast in the Test Period by using the fiscal 2015 to fiscal 2019 actual results. The Panel also directs that in all future RRAs, if BC Hydro files an evidentiary update, all forecasts that are based on a rolling average of historical actual results be updated to include the most recently completed years' actuals that are reasonably available at the time the evidentiary update is prepared unless BC Hydro can demonstrate to the BCUC strong regulatory justification for not doing so.**

5.1.2 Finance Costs Forecast

To forecast finance costs, BC Hydro uses "a number of market variables and economic forecasts of short and long-term interest rates and foreign exchange rates." For hedged debt that will be issued in the future, it uses a forecast hedged rate. For unhedged debt that it will issue in the future, it uses economic forecasts developed and provided by the Government of BC's Treasury Board.[981]

In the Evidentiary Update, BC Hydro replaced the October 2018 Government of BC forecast interest and foreign exchange rates with the January 2019 forecast rates. BC Hydro also replaced the September 30, 2018 forward interest rates used for future debt hedges with rates as of May 31, 2019. BC Hydro submits that the rate forecasts used in the Evidentiary Update reflect the most current information available from the Government of BC at the time the forecast was prepared. In BC Hydro's view, it is impractical to continually update finance charge forecasts because markets change on a daily basis.[982]

Position of Parties

In AMPC's view the interest rate forecasts used in the Evidentiary Update are stale and it submits that the BCUC should direct BC Hydro to update its finance charge forecasts "for relevant known conditions and values, and use data reasonably available at the time of BC Hydro's Evidentiary Update to set rates." Specifically, AMPC submits:

[977] AMPC Final Argument, p. 33, para. 111.
[978] AMPC Final Argument, p. 33, para. 112.
[979] AMPC Final Argument, p. 35, paras. 117–120.
[980] BCOAPO Final Argument, p. 47.
[981] Exhibit B-1, Section 8.5, pp. 8-10–8-11.
[982] Exhibit B-28, p. 13, Q8.

- For long-term debt the forecast should be updated "to reflect interest rates arising from the debt locked in during the test years and available at the time of the Evidentiary Update in August 2019";
- For short-term debt, the forecast should be updated to include "the BC Ministry of Finance's short-term interest rate forecast published in early September 2019" as this information was accessible in August; and
- For sinking fund income, the forecast should be updated "to reflect the best information regarding test year levels, in line with the timeframes used for long-term debt rates (known actuals from the first part of the F2020 test year) or short-term debt (updated from the BC Ministry of Finance in September 2019)."[983]

In particular, AMPC submits that BC Hydro did not update its long-term debt forecast to reflect the significantly lower interest rates on actual borrowings that occurred in June 2019 or two months prior to the filing of the Evidentiary Update.[984]

AMPC submits that BC Hydro has historically over forecasted interest rates resulting in higher finance charges in its revenue requirements and if the Test Period finance charges are not updated to reflect this known information, it would result in regulatory account accruals of approximately $60 million.[985] AMPC submits that these variances are "known and locked-in cash expenses affecting the test years."[986] In AMPC's view, the Total Finance Charges Regulatory Account should only be used to capture variances from "the best available forecast" rather than used as a replacement for updating for known values. BC Hydro's approach "risks intergenerational inequities, timing issues, and a lack of transparency at the time of the next revenue requirement application."[987]

AMPC submits that BC Hydro had long-term debt issuances two months prior to the filing of the Evidentiary Update that should have been used to update the interest rates. AMPC submits that with respect to the Test Period forecast for sinking fund income, BC Hydro increased the interest rates in the Evidentiary Update "by dividing the sinking fund income for each year by the end of year balance."[988] With respect to BC Hydro's submission that the finance charges forecast should not be updated because markets change on a daily basis, AMPC points out that InterGroup was suggesting that BC Hydro update its forecast based on a quarterly government publication rather than a daily report.

AMPC also notes InterGroup's testimony that it is "common for regulators to require utilities to update their interest expense forecasts prior to final approval of rates, where updated information indicates a material variance from originally filed information."[989]

AMPC submits that pension discount rate forecasts and interest rate forecasts have different uses, specifically: "(a) the pension discount rate is used to evaluate a current liability amount that is then amortized over many years (including the test years), while (b) interest rate forecasts are used to estimate borrowings and costs undertaken within the test years." AMPC notes that BC Hydro did not update the interest rate but did update the pension discount rate, which in AMPC's view, meant that of those two rates, BC Hydro included "only the most speculative and least consequential changes…that raises revenue requirements and not to include known and highly reliable changes that effect actual cash costs and that benefit ratepayers such as interest rates and also the known change to MSP premiums."[990]

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983 AMPC Final Argument, pp. 5, 37–38, paras. 22, 126.
984 AMPC Final Argument, p. 37, para. 125.
985 AMPC Final Argument, p. 37, para. 124.
986 AMPC Final Argument, p. 38, para. 127.
987 AMPC Final Argument, p. 38, para. 128.
988 AMPC Final Argument, p. 37, para. 125, footnote 120.
989 AMPC Final Argument, p. 46, para. 152.
990 AMPC Final Argument, pp. 43–44, para. 141, 142.

With respect to AMPC's recommendation that BC Hydro base its forecasts on interest rates not yet published by Government, BC Hydro submits that since parties would be submitting information requests on the forecast, "there was value in being able to disclose the information" used in the Evidentiary Update.[991] In BC Hydro's view, new information will constantly be available, especially during a protracted regulatory process, and therefore it is important to draw a line somewhere.[992]

Panel Determination

The Panel accepts that the January 2019 forecast interest rates used by BC Hydro were the most recent publicly available forecasts at the time BC Hydro prepared the Evidentiary Update. The Panel also accepts that BC Hydro requires a reasonable amount of time to prepare the forecasts in the Evidentiary Update and in the Panel's view, requesting Government's unpublished rates in the same month that the Evidentiary Update is filed is not a reasonable amount of time. Further, basing the forecast on publicly available rates increases transparency. In addition, although BC Hydro did not use the rates from its actual borrowings in June 2019 to forecast, it did use the forward interest rates as of May 31, 2019 for future debt hedges, which in the Panel's view is a reasonable internal cut-off date to prepare the Evidentiary Update. Therefore, the Panel declines to direct BC Hydro to update its finance charge forecasts as suggested by AMPC.

5.1.3 Current and Non-Current Pension Costs

In the Evidentiary Update, BC Hydro replaced the forecast discount rate of 3.83 percent used to forecast pension costs in the Application with the actual discount rate of 3.33 percent as of April 1, 2019. BC Hydro also included a $70 million gain from the elimination of MSP premiums in fiscal 2020 in the Non-Current Pension Costs Regulatory Account, which will be amortized starting in the next test period or fiscal 2022.[993] BC Hydro submits that its treatment of the pension discount rate and the gain from the elimination of MSP premiums is consistent with accounting rules and previous BCUC directives.

BC Hydro explains that the discount rate impacts the forecast for both the non-current and current pension costs. BC Hydro submits that in the Decision to the previous RRA, the BCUC directed BC Hydro to use the discount rate in effect at the time the forecast is prepared to determine post-employment benefit costs and liabilities. BC Hydro submits it updated the Evidentiary Update to use the March 31, 2019 discount rate because the fiscal 2020 current service costs are determined based on the discount rate at the start of the fiscal year, in accordance with accounting rules. Therefore, BC Hydro updated the Application with the most current discount rate prepared by its pension actuary, which was provided for use in BC Hydro's audited fiscal 2019 financial statements.[994]

BC Hydro submits that movements in pension discount rates and interest rates are generally correlated, and urges "the BCUC to maintain alignment between forecast finance charges and pension costs." Furthermore, in BC Hydro's view, its regulatory accounts "address the variances in pension costs and finance charges in an efficient manner."[995]

BC Hydro also explains that in accordance with accounting rules, the gain related to the elimination of MSP could not be recognized until the elimination became law, which occurred on May 16, 2019. Therefore, the gain was recognized in fiscal 2020 and included in the Non-Current Pension Costs Regulatory Account for amortization beginning in the following test period, which in this case is fiscal 2022.[996]

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[991] BC Hydro Reply Argument (May 27, 2020), p. 100, para. 236.
[992] BC Hydro Reply Argument (May 27, 2020), p. 100, para. 237.
[993] Exhibit B-16, BCUC IR 300.3.
[994] Exhibit B-28, pp. 13–15, Q9; BC Hydro FA, p. 252, para. 589.
[995] BC Hydro Final Argument, pp. 252–253, paras. 590, 591, 592.
[996] Exhibit B-28, pp. 13–15, Q9.

Positions of Parties

AMPC submits the BCUC should direct BC Hydro to not use the updated pension discount rate of 3.33 percent for rate setting purposes. Instead, BC Hydro should be directed to use either the 3.83 percent pension discount rate used in the original Application or preferably, use a five-year average of the discount rates.[997]

AMPC submits that the discount rate is used to estimate BC Hydro's long-term future pension liability and BC Hydro will not actually incur that cost over the Test Period.[998] In AMPC's view, since pension costs are largely "a non-cash expense in the test years and will not be paid out, on average, for many years," pension costs should be calculated in a way that allows ratepayers to contribute "consistently and equally over the long-term to fund future pension costs." AMPC submits that the updated pension discount rate used in the Evidentiary Update resulted in increasing rates by more than $67 million in each test year. In AMPC's view, the updated pension discount rate obtained via an email from BC Hydro's actuary is unsupported and should not be accepted, particularly for a non-cash expense that results in such a significant rate change.[999] AMPC submits that the 0.5 percent change in the discount rate is the largest discount rate change since 2015.[1000]

AMPC clarifies that it does not challenge the credentials of BC Hydro's actuary, but does challenge the absence of detail provided by the actuary, particularly the absence of the 30-year corporate index, when calculating the updated discount rate.[1001] AMPC also clarifies that it does not take issue with BC Hydro's approach for financial reporting purposes, but does take issue with using this approach for rate setting purposes.[1002]

AMPC submits that prior to the currently updated discount rate of 3.33 percent, the previous three rates used since 2015 were in a tighter range, namely between 3.81 percent and 3.94 percent. AMPC submits that during BC Hydro's previous RRA, the discount rates were not as volatile as in the current proceeding and therefore recommends that the BCUC revisit the discount rate using a five-year average for rate setting purposes to bring more stability to its forecast, as proposed by BC Hydro in the previous RRA.[1003] AMPC notes InterGroup's view that there should be "a priority on stability for something that is not being cash out the door, that is just valuing a future liability."[1004] In AMPC's view, calculating the discount rate based on a five-year average for rate setting purposes would: "(a) better stabilize both current and non-current pension costs and external influencing factors (such as discount rates); and (b) better reflect the usefully incurred costs to ratepayers on an annual basis."[1005]

BCOAPO also submits that a five-year historical average approach to forecasting pension costs should be revisited, so that volatility can be minimized.[1006]

MoveUP, on the other hand, supports using the updated pension discount rate as provided by BC Hydro's actuary. MoveUP submits that it "objects to efforts to play with its members' pension funding."[1007]

With respect to the pension discount rate, BC Hydro submits that its approach adheres to a BCUC directive from the previous RRA proceeding.[1008] In BC Hydro's view, AMPC's argument to use an older discount rate is

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[997] AMPC Final Argument, pp. 5–6.
[998] AMPC Final Argument, p. 49, para. 164.
[999] AMPC Final Argument, p. 48, 51, paras. 159, 160, 172.
[1000] AMPC Final Argument, p. 50, para. 169.
[1001] AMPC Final Argument, pp. 50-52, paras. 167, 172, 175.
[1002] AMPC Final Argument, p. 52, para. 177.
[1003] AMPC Final Argument, p. 53, paras. 179, 180.
[1004] AMPC Final Argument, p. 54, para. 182.
[1005] AMPC Final Argument, p. 54, para. 183.
[1006] BCOAPO Final Argument, p. 28.
[1007] MoveUP Final Argument, p. 11.
[1008] BC Hydro Reply Argument (May 27, 2020), p. 140, para. 332.

"untenable."[1009] With respect to AMPC's submission that "the updated discount rate was provided without meeting the burden of proof to support such a marked change," BC Hydro submits that AMPC does not challenge the actuary's credentials and InterGroup conceded that there was "no reason to believe the updated discount rate was unreliable."[1010]

With respect to adopting a five-year average approach for forecasting pension discount rates as proposed by BC Hydro in the fiscal 2017 to fiscal 2019 RRA application, BC Hydro submits that "if the BCUC is to revisit the five-year average approach, then it should be done as part of an overall evaluation of the best way to update uncontrollable inputs as part of a revenue requirement proceeding. It should not be done *ad hoc*, simply because the methodology happens to reduce rates in the current circumstances."[1011]

Regarding the gains from the elimination of MSP premiums, AMPC submits that the gain is "material, is known, affects the test years, and can be easily included in rates." Therefore, AMPC submits that the regulatory account rule should be "var[ied] slightly" to "mitigate the unintended effect of a six-week delay in legislation, to properly match costs with benefits" and the BCUC should direct BC Hydro to incorporate the $70 million gain into the revenue requirement rather than capture it in a regulatory account.[1012]

In response, BC Hydro submits that the principle followed in the Evidentiary Update was to "adhere to (a) accounting rules, and (b) the applicable BCUC order."[1013] In BC Hydro's view AMPC is willing to depart from accounting principles and previous BCUC orders to achieve its objective of lowering rates in the Test Period, which is inconsistent with AMPC's position that not updating Trade Income to include actuals available at the time of the Evidentiary Update is "an exercise of discretion to upset a methodology that, ironically, was specifically designed to avoid discretion."[1014]

Panel Determination

The Panel is not persuaded by AMPC's argument that, due to the minimal impact it has on cash, the discount rate used for rate setting purposes should remain the same or that pension costs should be calculated in a way that smooths ratepayer funding of the expense. In the Panel's view, there are many items in the revenue requirement that are non-cash items, for example depreciation of capital assets, but are adjusted with more recent information. Calculating pension costs based on a more recent discount rate results in better matching of costs and benefits, compared to using an older discount rate. Therefore, the Panel declines to direct BC Hydro to depart from its current approach, which adheres to a previous BCUC directive.

As for AMPC and BCOAPO's recommendation to revisit using a five-year average of discount rates for rate setting purposes, the Panel notes that in the previous RRA decision, the BCUC considered historical actual discount rates that ranged from 3.51 percent to 5.42 percent.[1015] Therefore, the Panel is not persuaded that when the BCUC was considering BC Hydro's proposal in the previous RRA, the discount rates were less volatile, and nor is the Panel persuaded that there is sufficient evidence to revisit a methodology that the BCUC had reviewed relatively recently.

Regarding the MSP gain, even though the Panel accepts that this is a significant and known amount, the Panel is not persuaded that is sufficient reason to recognize the entire $70 million in the Test Period revenue requirement. Amortizing the gain over the expected average remaining service life (EARSL) of the active plan members provides for better matching of costs and benefits. However, considering that the legislation was passed just six weeks into the fiscal 2020 test year, the Panel varies the regulatory account treatment to allow

[1009] BC Hydro Reply Argument (May 27, 2020), p. 140, para. 331.
[1010] BC Hydro Reply Argument (May 27, 2020), p. 140, para. 333.
[1011] BC Hydro Reply Argument (May 27, 2020), p. 141, para. 336.
[1012] AMPC Final Argument, pp. 6, 57, paras. 22(d), 189.
[1013] BC Hydro Reply Argument (May 27, 2020), p. 138, para. 326.
[1014] BC Hydro Reply Argument(May 27, 2020), pp. 138 – 139, para. 328, footnote 614.
[1015] Decision to BC Hydro's F2017 to F2019 RRA, Table 3-19, p. 69.

this gain to be recognized earlier for rate setting purposes. **Therefore, the Panel directs BC Hydro to begin amortizing the gain from the elimination of MSP premiums over the EARSL of the active plan members, in fiscal 2020, and adjust the Test Period revenue requirement and rates accordingly.**

5.2 Debt Management Strategy

Since fiscal 2017, BC Hydro has been entering into financial contracts that hedge the interest rate risk of future long-term debt issuances.[1016] BC Hydro submits that the purpose of its debt management strategy is to provide "increased cost certainty for ratepayers on long-term borrowings" by locking in interest rates, analogous to a fixed rate mortgage.[1017] BC Hydro further explains that the purpose of the strategy is not to target a gain or loss over time.[1018] BC Hydro submits that it reviews its hedging strategy annually in conjunction with Government, which transacts the hedges.[1019]

By Order G-42-16, the BCUC approved the establishment of the Debt Management Regulatory Account to capture mark-to-market gains and losses related to interest rate hedges of future debt. The gains and losses captured in the regulatory account are amortized over the remaining term of the associated long-term debt issuance. The amortization begins in the test period after the test period during which the associated debt is issued.[1020] In the reasons for decision to Order G-42-16, the BCUC stated that it is not able to provide "any guidance or direction on any proposed Debt Management Strategy that encompasses the issuance of these FDHs [future debt hedges]" because BC Hydro is exempt from section 50(1) of the UCA.[1021] The BCUC also stated that because it does not have jurisdiction over BC Hydro's issuance of securities, it "does not make any specific directions at this time for any reporting requirement on the status of hedging activities in future RRAs."[1022]

During the 2016 proceeding that led to Order G-42-16, BC Hydro stated that the execution of future debt hedges, as described in that application, is prudent considering the low interest rate environment at that time.[1023] In that application, BC Hydro proposed to hedge approximately 50 percent of its long-term debt issued from fiscal 2017 to fiscal 2024.[1024] Currently, BC Hydro's debt management strategy involves hedging up to 75 percent of its forecast total borrowing requirements over the next five years.[1025] BC Hydro explains that the decision to hedge up to 75 percent of future long-term borrowings was based on the relative certainty of borrowing requirements over the next five years given that Site C costs comprise a significant portion of its capital plan over that period.[1026]

The balance in the Debt Management Regulatory Account at the end of fiscal 2019 is $163.2 million recoverable from ratepayers, which is comprised of $285.3 million of unrealized net losses and $122.1 million of realized net gains experienced from fiscal 2017 to fiscal 2019.[1027] Specifically, during this period, BC Hydro's gains and losses were as follows: a $187.1 million gain in fiscal 2017, a $29.3 million loss for fiscal 2018, and a $321.0 million loss for fiscal 2019. Additionally, in fiscal 2020 BC Hydro experienced a loss of $100.9 million.[1028] The amount amortized from the regulatory account during the Test Period resulted in a $12.4 million reduction in the

[1016] Exhibit B-1, section 8.5, p. 8-10.
[1017] Exhibit B-1, section 5E.4.1, p. 5E-8, section 7.8.13, p. 7-46; Transcript Volume 7, p. 953, lines 2–16; BC Hydro FA, p. 207, para. 485.
[1018] Transcript Volume 7, p. 956, lines 17–20.
[1019] Transcript Volume 7, p. 954, lines 1–14, p. 965, lines 11–20; Exhibit B-31, Panel IR 17.5.
[1020] Exhibit B-1, section 7.8.13, pp. 7-46–7-47.
[1021] Order G-42-16, Reasons for Decision, p. 6.
[1022] Order G-42-16, Reasons for Decision, p. 10.
[1023] Order G-42-16, Reasons for Decision, p. 7.
[1024] Order G-42-16, Reasons for Decision, p. 6.
[1025] Transcript Volume 7, p. 952, line 3 to p. 953, line 24.
[1026] Transcript Volume 7, p. 954, line 15 to p. 955, line 5.
[1027] Exhibit B-11-2, Appendix A, Schedule 2.2, Line 154; Exhibit B-31, Panel IR 17.1, 17.3.3, Attachment 1.
[1028] Exhibit B-17, AMPC IR 24.4.

revenue requirement, and hence reduction in rates, in each year of the Test Period.[1029] Future debt hedges are sensitive to changes in interest rates, which and will continue to change until the hedges are settled. A one percent change in interest rates results in an $800 million to $900 million increase or decrease in the value of the outstanding future debt hedges.[1030]

Positions of Parties

BCSEA and AMPC address BC Hydro's debt management strategy

BCSEA "accepts that the purpose of the hedging strategy is to lock in a rate, rather than to make a profit." BCSEA also notes that in the 2016 proceeding that led to Order G-42-16, it supported the Debt Management Regulatory Account and BC Hydro's debt management strategy involving future debt hedges.[1031]

On the other hand, AMPC does not support BC Hydro's debt management strategy and submits that "in an environment of lingering low interest rates, ratepayers would benefit more from avoiding short-term hedging than they would from interest rate certainty."[1032] AMPC submits that a majority of the hedges undertaken in fiscal 2018 were for periods of less than a year and cost ratepayers $58.4 million more than if BC Hydro had borrowed when the funds were required.[1033] AMPC submits that BC Hydro's current approach to hedging is focused on cost certainty rather than protecting ratepayers from interest rate risks, in contrast to what was proposed in the 2016 proceeding that led to Order G-42-16.[1034]

AMPC points out that "BC Hydro's hedging strategy increased from 50 percent to 75 percent of long-term debt issuances during a time of sustained low interest rates". It therefore recommends that the BCUC "assess the performance of BC Hydro's current debt hedging strategy to date and make findings about its relative success and impact on rates. The Commission should also direct BC Hydro to identify and report, at the next RRA, on its hedging strategies and outcomes, including how successfully BC Hydro has minimized its cost of debt."[1035]

In BC Hydro's view, ratepayers would be exposed to significant interest rate risk if hedging was not done because over the next five years, it expects to issue billions of dollars in debt while Site C is being constructed.[1036]

BC Hydro also submits that the purpose of its hedging strategy has not changed from the 2016 proceeding that led to Order G-42-16, which is to "create some certainty" regarding finance charges by "mitigate[ing] exposure to risk of higher interest rates." BC Hydro also notes that its hedging strategy is not meant to eliminate interest rate risks as that would involve hedging 100 percent of its anticipated borrowings over the next five years.[1037]

BC Hydro submits that the extent of hedging at 50 percent of long-term borrowing proposed during the 2016 proceeding that led to Order G-42-16 was always meant to change based on changing conditions.[1038] BC Hydro also submits that a report that demonstrates how BC Hydro's debt management strategy has "successfully minimized its cost of debt" is a hindsight assessment and does not reconcile with the purpose of the hedging strategy. BC Hydro explains that the success of the hedging strategy is "the fact that it has mitigated interest rate risk, irrespective of whether BC Hydro has recorded a profit." BC Hydro submits that it takes a long-term

[1029] Exhibit B-11-2, Appendix A, Schedule 2.2.
[1030] Exhibit B-19, Appendix D, p. 3.
[1031] BCSEA Final Argument, p. 49, para. 196.
[1032] AMPC Final Argument, p. 66.
[1033] AMPC Final Argument, p. 66, para. 217.
[1034] AMPC Final Argument, p. 68, para. 227.
[1035] AMPC Final Argument, pp. 7, 63.
[1036] BC Hydro Reply Argument (May 27, 2020), p. 101, para. 239.
[1037] BC Hydro Reply Argument (May 27, 2020), p. 102, para. 240.
[1038] BC Hydro Reply Argument (May 27, 2020), p. 102, para. 241.

view of its hedging strategy since its assets are long-term, and, over time the interest rate that it has locked in is "a very good rate" for ratepayers to have. Ratepayers are going to benefit from a locked-in low interest rate, irrespective of whether there is a gain or loss on the hedge.[1039]

BC Hydro submits that its hedging strategy does not have the benefit of hindsight because hedging decisions are made based on forecasts from credible sources. BC Hydro also points out that AMPC is citing examples from a singular year, fiscal 2018, instead of the entire portfolio. BC Hydro notes, for example, that the gains in fiscal 2017 more than offset the losses experienced in fiscal 2018. Further, BC Hydro points out that it cannot be assumed that interest rates would remain low for the foreseeable future and submits that "interest rate exposure can be significant even on relatively short-term borrowing."[1040]

BC Hydro submits that "the size of the capital portfolio and magnitude of debt issuances have suggested the importance of reducing interest rate exposure," and it its view, its debt management strategy has performed as intended.[1041]

Panel Determination

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 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.

With regards to AMPC's request that the BCUC require BC Hydro to show that it has "successfully minimized its cost of debt," BC Hydro does not claim that its hedging program minimizes the cost of debt. The stated objective is to "create some certainty" regarding finance charges by "mitigate[ing] exposure to risk of higher interest rates."[1042] This strategy (the increase from 50 to 75 percent of debt being hedged) provides greater certainty at a time when, with historically low interests rates, the risk from interest rate increases is significantly higher than the benefit from possible interest rate reductions which is being foregone.

The Panel recognizes that as part of Order G-42-16, the BCUC directed BC Hydro to provide information regarding its Debt Management Regulatory Account.[1043] Accordingly, BC Hydro's annual filing to the BCUC includes an annual status report of the Debt Management Regulatory Account.[1044] In the Panel's view, this report contains much of the information suggested by AMPC for BC Hydro to report on. However, having similar information provided as part of BC Hydro's RRAs would assist the BCUC and interveners in examining the transactions that flow in and out of the Debt Management Regulatory Account and the impact of BC Hydro's hedging activities on rates**. Therefore, the Panel directs BC Hydro to provide in all future RRAs an updated Debt Management Regulatory Account Annual Status Report as provided in its Annual Report to the BCUC.**

5.3 Depreciation Rates for the Burrard Facility and New Asset Classes

In the Application, BC Hydro is requesting approval for the depreciation rates at the Burrard synchronous condense facility and the depreciation rates of new asset classes. Specifically, BC Hydro is requesting approval for:

[1039] BC Hydro Reply Argument (May 27, 2020), p. 103, para. 242.
[1040] BC Hydro Reply Argument (May 27, 2020), p. 102, para. 243.
[1041] BC Hydro Reply Argument (May 27, 2020), p. 104, para. 244.
[1042] BC Hydro Reply Argument(May 27, 2020), p. 102, para. 240.
[1043] Order G-42-16, Reasons for Decision, p. 10.
[1044] BC Hydro F2019 Annual Report to the BCUC dated July 31, 2019, Appendix B.

- The depreciation rates of certain property, plant and equipment at the Burrard synchronous condense facility for fiscal 2020 and fiscal 2021;[1045]
- The depreciation rates of the following new asset classes because the assets are not within the scope of existing asset classes: (1) water rights (finite), (2) infrastructure rights, and (3) LED street lights;[1046] and
- The depreciation of the assets, in the new asset classes created due to the adoption of the new IFRS 16, Leases standard in fiscal 2020, over the lease term.[1047]

Burrard Facility

BC Hydro is seeking approval of the depreciation rates of certain property, plant and equipment at the Burrard synchronous condense facility for the 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.[1048]

Finite Water Rights

Approximately 20 to 25 of BC Hydro's water licenses have a finite term. The remainder of BC Hydro's water licences have perpetual terms. The cost to renew the finite term water licences is capitalized as an intangible asset.[1049] The costs consist of fees paid to the Government of BC, labour costs to prepare the applications and costs of consultation with First Nations and stakeholders required by the Comptroller of Water Rights.[1050] BC Hydro is requesting to depreciate these costs over 40 years.

This will be the first time BC Hydro has renewed a water licence in 40 years. It is currently in the process of renewing water licences for Bridge, Shuswap and Alouette.[1051] The term of water licence renewals for BC Hydro is determined at the discretion of the Comptroller of Water Rights; however, BC Hydro anticipates a 40-year term because it is not aware of any case where the Comptroller of Water Rights has issued a power water license for less than 40 years.[1052]

BC Hydro submits that if the term of the water licence renewals differs from 40 years, it would adjust the depreciation period to reflect the actual term of each licence in the next RRA.[1053] Any variances between the actual and forecast depreciation of these water licences are eligible for deferral to the Amortization of Capital Additions Regulatory Account for future refund or recovery from ratepayers.[1054]

Infrastructure Rights

BC Hydro requests approval to depreciate a new asset class that capitalizes the cost of infrastructure rights for voltage conversion projects involving customer owned equipment over a 35-year period, which is based on the approximate life of the underlying assets. The forecast capital additions for infrastructure rights for fiscal 2020 and fiscal 2021 are $20.5 million and $12.8 million, respectively.[1055]

[1045] Exhibit B-1, section 8.2.1, pp. 8-3–8-5, Table 8-2.
[1046] Exhibit B-1, section 8.2.2, pp. 8-5–8-7.
[1047] Exhibit B-1, section 8.2.3, p. 8-8.
[1048] Exhibit B-1, section 8.2.1, p. 8-3.
[1049] Exhibit B-1, section 8.2.2, p. 8-6.
[1050] Exhibit B-6, CEC IR 74.1.
[1051] Exhibit B-6, CEC IR 74.3.
[1052] Exhibit B-6, CEC IR 74.2; Exhibit B-12, BCUC IR 263.2.
[1053] Exhibit B-12, BCUC IR 263.3.
[1054] Exhibit B-12, BCUC IR 263.5.
[1055] Exhibit B-1, Section 8.2.2, Tables 8-3, 8-4, pp. 8-6–8-7.

BC Hydro submits that “[d]ue to space limitations in certain areas, the transformer and the switchgear are located in the customer premises and are owned and operated by the customer. Therefore, the customer-owned equipment must be upgraded to enable the customer to receive electricity at the new, higher voltage.” BC Hydro incurs the costs to connect the customer to the system, which represents a contribution to the customer.[1056]

BC Hydro submits that system upgrades provide benefits to BC Hydro, such as increased system capacity for customer load growth, increased flexibility for restoration and operations, increased system efficiency by reducing electrical losses, and reduced congestion in heavily populated corridors. Voltage conversion is typically a more economic way to increase feeder capacity. For BC Hydro to benefit from feeder voltage conversions, the primary service customers must be ready to operate at the higher operating voltage.[1057]

BC Hydro submits that the customer is responsible for the maintenance and repair of these assets, and although BC Hydro does not have control of these assets, BC Hydro expects the customer will maintain these assets because they are required for the customer to receive reliable electrical service.[1058]

BC Hydro submits that in the past, these upgrade costs did not commonly occur and were not considered material and were recorded with other voltage conversion capital costs. BC Hydro is now requesting a new asset class because it expects a material increase in expenditures related to customer-owned equipment upgrades.[1059] BC Hydro submits that capitalizing contributions to third-party infrastructure as intangible assets is consistent with other Canadian utilities, such as Toronto Hydro and Altagas.[1060] Furthermore, BC Hydro’s proposed accounting treatment was reviewed by its previous auditor, who issued a clean audit opinion on the fiscal 2019 financial statements.[1061]

LED Streetlights

BC Hydro plans to replace its streetlight luminaire lightbulbs with LED units. The costs of LED units are significantly more than luminaire light bulbs, but the life of the LED units is also expected to be significantly longer, at 20 years. BC Hydro has established a new asset class to capture the cost of the LED units for depreciation over a 20-year period.[1062]

Agreements Recognized as Leases under IFRS 16

As a result of the new IFRS 16 lease standard that commences in fiscal 2020, BC Hydro will be establishing three new asset classes to capture the value of the leased assets in three categories, land and buildings, generation assets, and miscellaneous assets, and depreciate them over the lease term in accordance with the accounting standards. Similarly, BC Hydro is requesting approval to depreciate the assets within these three new asset classes over the lease term for rate setting purposes.[1063]

Positions of Parties

Interveners do not oppose the approval of the depreciation rates requested by BC Hydro.

[1056] Exhibit B-1, Section 8.2.2, pp. 8-6–8-7.
[1057] Exhibit B-5, BCUC 158.6.
[1058] Exhibit B-5, BCUC IR 158.9.
[1059] Exhibit B-5, BCUC IR 158.1.1.
[1060] Exhibit B-5, BCUC IR 158.7.1.
[1061] Exhibit B-12, BCUC IR 260.3.
[1062] Exhibit B-1, section 8.2.2, p. 8-7.
[1063] Exhibit B-1, section 8.2.3, p. 8-8.

Panel Determination

The Panel is generally satisfied that the depreciation rates requested by BC Hydro match the estimated life of the underlying assets and therefore, the Panel finds the requested depreciation rates for the Burrard synchronous condense facility, new water rights and LED street lights asset classes and three new asset classes for agreements recognized as leases under IFRS 16, to be reasonable and approves them.

We are not persuaded that the underlying assets with respect to infrastructure rights necessarily have a useful life of 35 years; however in the absence of any evidence to the contrary, the Panel accepts this figure for the Test Period. **Therefore, the Panel approves the requested depreciation rates for the infrastructure rights asset class for the Test Period only and directs BC Hydro to review the expected useful life of infrastructure rights in its upcoming depreciation study and to identify any differences from the requested 35 year useful life in the RRA immediately following the completion of the depreciation study.**

5.4 BCUC's Uniform System of Accounts

In Directive 57 of the BCUC's Decision on BC Hydro's fiscal 2009 to fiscal 2010 RRA, BC Hydro was directed to include financial information, in all RRAs filed after January 1, 2011, that follows the BCUC's Uniform System of Accounts (USoA). In that Decision, the BCUC stated that it is desirable for all stakeholders to have transparent and consistent historical financial information is comparable .[1064]

In the Application, BC Hydro is requesting the BCUC to rescind the requirement to file information that follows the BCUC's USoA. BC Hydro submits that it had stopped preparing financial information that follows the BCUC's USoA in 2017 after discussion with BCUC staff and thus, the Application does not contain this information.[1065]

In the Application, BC Hydro provided the results of a benchmarking study prepared by The Brattle Group in response to the BCUC's comments regarding the lack of evidence of benchmarking in BC Hydro's previous RRA. The benchmarking study was based on a peer group of U.S utilities, instead of Canadian utilities. This was because US utilities, unlike Canadian utilities, report their financial information in a consistent manner because US utilities follow the Federal Energy Regulatory Commission's (FERC) USoA.[1066] The Brattle Group was able to adjust the presentation of BC Hydro's financial information that followed the BCUC's USoA to compare to the peer utilities in the study. BC Hydro submits that if the BCUC and interveners found The Brattle Group's benchmarking study useful, then reporting based on the FERC USoA would provide greater value going forward than reporting based on the BCUC's USoA.[1067]

BC Hydro submits that at the time of the discussion with BCUC staff regarding ceasing the filing of the BCUC USoA information, BC Hydro had not yet commenced its work with The Brattle Group and was therefore not aware of the potential value of having information under a USoA framework. BC Hydro also acknowledged that it is incumbent upon them to seek formal BCUC approval to rescind a BCUC directive.[1068]

BC Hydro submits that preparing the BCUC's USoA financial schedules is labour intensive and creates additional cost pressures.[1069] BC Hydro estimates the labour to maintain a USoA to be approximately less than half an FTE, and there would be additional labour required to initially set up or restart a USoA framework.[1070] BC Hydro submits that since it had previously never followed the FERC's USoA, the initial effort to setup that framework

[1064] Decision dated March 13, 2009 to BC Hydro's F2009 – F2010 RRA, p. 216.
[1065] Exhibit B-1, Section 1.6, p. 1-33; Exhibit B-5, BCUC IR 54.3.
[1066] Exhibit B-1, Section 5.7.1.2, p. 5-51.
[1067] Transcript Volume 7, p. 1012, line 24 to p. 1014, line 15.
[1068] Transcript Volume 7, p. 1016, line 12 to p. 1017, line 4.
[1069] Exhibit B-5, BCUC IR 54.3.
[1070] Transcript Volume 7, p. 1014, line 26 to p. 1015, line 1.

would likely be greater in comparison to readopting the BCUC's USoA.[1071] Therefore, it would like to maintain its ability to prioritize its work and requests not to be given a directive to report under either the BCUC or FERC USoA.[1072] Rescinding the requirement to file BCUC USoA information would allow BC Hydro the flexibility to prioritize these cost pressures against other requirements and it would provide management with the discretion to determine when to prepare these schedules in the future.[1073]

Positions of Parties

In BCOAPO's view, the directive should not be rescinded and BC Hydro should resume BCUC USoA reporting. Alternatively, the BCUC should require BC Hydro to adopt FERC USoA.[1074] BCOAPO submits that "[h]aving transparent, comparable, and consistent information continues to be beneficial and desirable for all stakeholders."[1075]

BCOAPO also submits that The Brattle Group benchmarking study demonstrated that reporting information on a comparable and consistent basis allows for "effective cost benchmarking". BCOAPO also highlights The Brattle Group's comments regarding the need for standardization and consistency of cost data for effective benchmarking and the challenges presented by the fact that Canadian electric utilities do not consistently employ USoA reporting.[1076]

BCOAPO also submits that it takes issue with BC Hydro ceasing its USoA reporting prior to receiving formal BCUC approval.[1077]

BC Hydro did not provide further submissions in its Reply Argument dated May 27, 2020 regarding its request for the BCUC to rescind the requirement to file information that follows the BCUC's USoA.

Panel Determination

Section 49(a) of the UCA provides that the BCUC may require public utilities of the same class to adopt a USoA specified by the BCUC. The UCA does not specify any particular USoA framework and it provides the BCUC with discretion on whether or not to order the adoption of any USoA framework.

The BCUC's USoA is out of date. Therefore, using the BCUC's USoA does not facilitate benchmarking across utilities without requiring further work to modify that information. The Panel acknowledges that BC Hydro has cost pressures and accepts BC Hydro's desire for flexibility when it comes to when and how to report under a USoA framework. **For these reasons, the Panel approves BC Hydro's request and hereby rescinds Directive 57 of the BCUC's Decision on BC Hydro's fiscal 2009 to fiscal 2010 RRA.** The Panel appreciates BC Hydro's consultation with BCUC staff to explore ways to find regulatory efficiencies; however BC Hydro ceased its USoA reporting prior to receiving formal BCUC approval. We remind BC Hydro that it is required to follow BCUC directives and that it can apply for relief if, in its view, the directive is no longer justified, and should have done so in this case.

It is in the interests of regulatory efficiency to have transparent, comparable, and consistent financial information. In particular, there is substantial value in the ability to compare BC Hydro's operations not only against its own past years but also against other utilities. Given that the BCUC's USoA is out of date and the general lack of a consistent USoA framework among Canadian utilities, the Panel considers financial information that follows the FERC USoA framework as a reasonable alternative. This it is a standard that is accepted by many North American utilities and will be valuable for benchmarking purposes. **Therefore, the Panel directs BC Hydro**

[1071] Transcript Volume 16, p. 2952, line 24 to p. 2954, line 6.
[1072] BC Hydro Final Argument, pp. 106 – 107, paras. 239, 240.
[1073] Exhibit B-13, BCOAPO IR 123.1.
[1074] BCOAPO Final Argument, p. 61.
[1075] BCOAPO Final Argument, p. 60.
[1076] BCOAPO Final Argument, pp. 60–61.
[1077] BCOAPO Final Argument, p. 62.

to maintain its records in such a way that it can produce financial information that follows the FERC USoA. For clarity the Panel, at this time, is not directing BC Hydro to provide in its future RRA filings, financial information that follows the FERC USoA; however, BC Hydro should be prepared to produce such information when directed to do so by the BCUC at that time.

5.5 Tracking Costs Associated with Reconciliation with Indigenous Peoples

BC Hydro confirms its commitment to reconciliation with Indigenous peoples and submits that it is looking at ways to implement the United Nations Declaration on the Rights of Indigenous People (UNDRIP) and the Truth and Reconciliation Commission's Calls to Action.[1078] BC Hydro submits that its Aboriginal Statement of Principles governs its reconciliation efforts.[1079]

BC Hydro does not have an overarching plan for the implementation of UNDRIP, preferring to work with individual Indigenous Nations on a case-by-case basis.[1080] BC Hydro submits that it uses the feedback received from the communities it engages to assess how well it is meeting its commitment to reconciliation.[1081] In addition, BC Hydro uses an external benchmark, its Progressive Aboriginal Relations certification, to provide an objective view on the quality of its engagement with Indigenous peoples.[1082]

BC Hydro submits that the Phase Two Review may provide direction regarding incorporating UNDRIP and the recommendations from the Truth and Reconciliation Commission's Calls to Action into BC Hydro's business. The Phase Two Review includes a focus on future opportunities for Indigenous Nations in the energy sector, which may result in incremental costs that need to be factored into BC Hydro's future revenue requirements. However, in the short-term, BC Hydro has not identified any incremental costs associated with the implementation of UNDRIP and Calls to Action of the Truth and Reconciliation Commission. In future, BC Hydro plans to establish budgets as required and allocate costs using appropriate mechanisms and approval processes.[1083] BC Hydro submits that determining the costs incurred in support of reconciliation on an annual basis would be difficult.[1084] However, it would be "happy" to "report in more detail on its engagement with reconciliation and possibly the costs associated [with it]" in the future.[1085]

Positions of Parties

In Zone II RPG's view, BC Hydro's Aboriginal Statement of Principles is broad and does "not represent a clear action plan for implementing UNDRIP or the [Truth and Reconciliation Commission's] Call[s] to Action by BC Hydro."[1086] While there is value in community engagement, BC Hydro should have "a more thorough and systematic ability to assess its progress on reconciliation." Zone II RPG sees value in requiring BC Hydro to track its costs associated with reconciliation in more detail and to provide a more detailed report to the BCUC on its reconciliation efforts. Zone II RPG submits that it also supports "BC Hydro developing a specific action plan and annual reporting on reconciliation, in consultation with Indigenous peoples."[1087]

In addition, Zone II RPG submits that the activities that BC Hydro had identified as demonstrating its commitment towards reconciliation with Kwadacha and Tsay Keh Dene, although important, are not sufficient to achieve reconciliation. Zone II RPG notes that "renewable energy development (which in the case of the NIA

1078 Transcript Volume 6, p. 629, lines 11–15, 19; p. 630, line 9 (O'Riley).
1079 Exhibit B-6, Zone II RPG IR 12.1, Attachment 1; Transcript Volume 6, p. 631, lines 1–5, (O'Riley); Transcript Volume 13, p. 2401, line 17; p. 2403, line 20 (Leonard).
1080 Transcript Volume 13, p. 2406, lines 2–18.
1081 Transcript Volume 6, p. 636, line 24 to p. 637, line 11 (O'Riley).
1082 Transcript Volume 6, p. 636, lines 9–24.
1083 Exhibit B-13, Ince IR 30.0.
1084 Transcript Volume 6, p. 633, line 14 to p. 636, line 1 (O'Riley).
1085 Transcript Volume 6, p. 638, line 24 to p. 639, line 17 (O'Riley).
1086 Zone II RPG Final Argument, p. 14, para. 29.
1087 Zone II RPG Final Argument, p. 15, para. 35.

must include the objective of reducing reliance on diesel) and demand side management are critical items identified by BC Hydro for fulfilling reconciliation with Zone II RPG members."[1088]

In reply, BC Hydro re-emphasizes its commitment to "advancing reconciliation with Indigenous peoples throughout the province and supports working with the BCUC and with Indigenous peoples to identify ways to provide more visibility to the BCUC with regards to BC Hydro's reconciliation efforts." BC Hydro submits that any directives made by the Panel related to Zone II RPG's request should take into account "the inherent challenges in tracking costs that are embedded throughout the organization" and the format and purpose of the reporting should be informed by further engagement.[1089]

Panel Determination

The Panel agrees with BC Hydro that there are inherent challenges to tracking reconciliation costs. The absence of a specific action plan for BC Hydro to implement UNDRIP and the Truth and Reconciliation Commission's Calls to Action adds to this challenge.

However, the BC *Declaration on the Rights of Indigenous Peoples Act* mandates government to harmonize provincial laws with UNDRIP and it requires government to develop an action plan to achieve this alignment over time.[1090] As such, the Panel accepts that BC Hydro, as a Crown corporation, would need to follow direction from government to develop a plan to implement UNDRIP. This is consistent with BC Hydro's submission that Phase Two of the Government's Comprehensive Review may provide direction regarding incorporating UNDRIP and the Truth and Reconciliation Commission's Call to Action into BC Hydro's business.

Therefore, the Panel declines, at this time, to direct BC Hydro to provide an annual report to the BCUC regarding its reconciliation costs. However, the Panel encourages BC Hydro to work with the BCUC and Indigenous peoples to identify ways to provide more visibility on BC Hydro's reconciliation efforts and on its progress towards reconciliation.

5.6 BC Hydro Electricity Rate Comparison Annual Report

Pursuant to section 8(4) of the *Clean Energy Act*, BC Hydro provides its Electricity Rate Comparison Annual Report to the Minister of Energy and Mines and Petroleum Resources, which compares BC Hydro's electricity rates with those of other North American utilities. The annual report adheres to the Province of BC's Rate Comparison Regulation (Ministerial Order No. M167) and consists of information taken from the Hydro-Quebec rate survey report, "Comparison of Electricity Prices in Major North American Cities."

Positions of Parties

Gjoshe submits that BC Hydro's electricity rates comparisons inform the following BC Hydro processes:[1091]

a) Reports to the Minister of Energy and Mines and Petroleum Resources pursuant to Ministerial Order N167;

b) BC Hydro's corporate scorecard, which is used in performance evaluation and performance pay provisions; and

c) Potentially, load forecasting.

1088 Zone II RPG Final Argument, pp. 15–16, paras. 36, 37.
1089 BC Hydro Reply Argument (May 27, 2020), pp. 151–152, para. 365.
1090 https://www2.gov.bc.ca/gov/content/governments/indigenous-people/new-relationship/united-nations-declaration-on-the-rights-of-indigenous-peoples (retrieved on September 25, 2020).
1091 Gjoshe Final Argument, p. 28.

Gjoshe submits that when comparing electricity bills, specifically in the Electricity Rate Comparison Annual Report, BC Hydro excludes taxes and non-utility levies.[1092] Gjoshe points out that residential customers are charged GST on their electricity bills. Furthermore, taxes and levies would be a consideration for customers when assessing their ability to locate or relocate to BC.[1093] Gjoshe recommends that the BCUC direct BC Hydro to update the format of its future rate competitiveness reports to include the following:[1094]

1) "Rates including GST (where applicable for Canadian jurisdictions or any comparable tax for US jurisdictions); GST is presently charged to BC Hydro electricity bills;" and
2) "Rates including GST and applicable provincial or state taxes (PST in BC and any comparable tax or nonutility levy applicable to other Canadian or US jurisdictions). PST is presently not charged to BC Hydro electricity bills."

BC Hydro explains that its Annual Report to the Ministry excludes taxes and non-utility levies because the Hydro-Quebec rate survey report excludes taxes and non-utility levies.[1095]

Panel Discussion

The Panel acknowledges that BC Hydro's Electricity Rate Comparison Annual Report currently excludes taxes and non-utility levies. However, since this report is provided to the Minister of Energy and Mines and Petroleum Resources pursuant to a ministerial order, it would not be appropriate for the Panel to direct BC Hydro to alter the format of the report. Therefore, the Panel declines to direct BC Hydro to update the format of its future rate competitiveness reports.

5.7 Other BC Hydro Subsidiaries

In its Service Plan, BC Hydro states that it has "created or retained a number of other [than Powerex and Powertech] subsidiaries for various purposes, including holding licences in other jurisdictions, to manage real estate holdings and to manage various risks. All the staff and management needs of the active subsidiaries below are fulfilled by BC Hydro employees, who perform these duties without additional remuneration."[1096]

BC Hydro considers three of these subsidiaries to be active:[1097]

- BCHPA Captive Insurance Company Ltd.
    - Procures insurance products and services on behalf of BC Hydro.
- Columbia Hydro Constructors Ltd.
    - Administers and supplies the labour force to specified projects.
- Tongass Power and Light Company
    - Provides electrical power

In addition, BC Hydro named 11 remaining subsidiaries that "either serve as nominee holding companies … or are considered to be inactive/dormant."[1098]

BC Hydro further described its five active subsidiaries in its most recent annual report to the BCUC as follows:[1099]

[1092] Gjoshe Final Argument, p. 28.
[1093] Transcript Volume 8a, p. 1103, line 26; p. 1105, line 8.
[1094] Gjoshe Final Argument, p. 28.
[1095] Transcript Volume 8a, p. 1107, lines 5–10.
[1096] Exhibit B-1, Appendix E, p. 35 of 36.
[1097] Ibid.
[1098] Exhibit B-1, Appendix E, p. 36 of 36.
[1099] BC Hydro 2019 Annual Report to the BCUC, p. 4-1. https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/regulatory-filings/reports/00-2019-07-31-f19-annual-report-to-commission.pdf

Table 5-1 – BC Hydro Active Subsidiaries

Name of Company Controlled	Kind of Business	Percent Voting Stock Owned	Footnote Reference
Powerex Corp.	Marketer of wholesale energy products and services in Western Canada and the Western United States.	100	Direct Control
Powertech Labs Inc.	Research and technology provider; services include: testing, problem solving and consulting services.	100	Direct Control
BCHPA Captive Insurance Company Ltd	To assist BC Hydro in the management of its insurance program.	100	Direct Control
Columbia Hydro Constructors Ltd	Administers the projects and supplies the labour force for projects primarily on the Columbia River.	100	Direct Control
Tongass Power and Light Company	Company acquired by BC Hydro in 1964 as a "border accommodation" due to Hyder's remoteness from Alaska-based electrical suppliers. Tongass is connected to the BC Hydro system by a distribution line and a transfer pricing agreement formalizes the services provided.	100	Direct Control

Direction No. 7, now repealed, directed that "In setting rates for the authority, the commission must include the net income of the authority's subsidiaries, assuming that the net income of Powerex Corp. equals trade income."[1100]

BC Hydro submits the following amount of subsidiary income is included in the revenue requirement:[1101]

Table 5-2 – Subsidiary Net Income

	($ million)	Schedule Reference	F2017 RRA	F2017 Actual	F2018 RRA	F2018 Actual	F2019 RRA	F2019 Forecast	F2020 Plan	F2021 Plan
			1	2	3	4	5	6	7	8
1	Powerex Net Income	1.0 L17	(115.2)	(130.2)	(115.2)	(136.6)	(115.1)	(205.3)	(120.6)	(120.6)
2	Powertech Net Income	1.0 L18	(4.5)	(2.1)	(4.8)	(3.1)	(5.1)	(3.3)	(3.4)	(3.7)
3	Total Gross Subsidiary Net Income	1.0 L19	(119.7)	(132.4)	(119.9)	(139.6)	(120.2)	(208.6)	(124.0)	(124.3)
4	Deferral Account Additions	2.1 L16	0.0	15.1	0.0	21.4	0.0	90.2	0.0	0.0
5	Deferral Account Recoveries	2.1 L18	48.9	48.9	50.6	50.5	52.9	62.9	(12.6)	(12.6)
6	Total Current Subsidiary Net Income	3.0 L55+L56	(70.8)	(68.4)	(69.3)	(67.7)	(67.3)	(55.6)	(136.6)	(136.9)

Panel Determination

It appears from the table above that the only subsidiaries whose net income is included in the revenue requirement are Powerex and Powertech. **The Panel directs BC Hydro to provide confirmation in its Compliance Filing that only the net income of Powerex and Powertech are included in the revenue requirement.**

In section 4.2.7, we expressed our concern that while it may be appropriate to include positive net income from non-regulated activities in the revenue requirement, it is not appropriate for ratepayers to be at risk for losses incurred by an unregulated subsidiary.

[1100] Section 8, Direction No. 7.
[1101] Exhibit B-1, Table 8-11, p. 8-17.

We have already addressed this issue in detail with respect to Powerex and will apply the same principles to the inclusion of Powertech's net income in BC Hydro's revenue requirements. We first note that there is no floor of $0 as there is with Powerex net income. It is not appropriate to include any losses from the subsidiary. Further, we do not have any evidence of a transfer pricing agreement between BC Hydro and Powertech. **Therefore we direct BC Hydro to file any existing transfer pricing agreement between BC Hydro and Powertech in its compliance filing.**

Unlike Powerex's estimated net income, which is afforded deferral account treatment, Powertech's estimated net income is not. The effect of this difference in treatment is that BC Hydro's shareholder is at risk for the estimated amount of Powertech's net income but will also benefit if its net income exceeds the estimate. The Panel is satisfied that this arrangement is appropriate, provided that there is an approved transfer pricing agreement and that Powertech is not including in its net income activities that are part of BC Hydro's activities that are subject to BCUC regulation and oversight. **Therefore, BC Hydro is required to file annually as part of its annual report to the BCUC, in confidence if necessary, a summary of Powertech's net income in sufficient detail to enable the BCUC to determine whether the inclusion of Powertech's net income is appropriate.**

BC Hydro's revenue requirement does not appear to include any net income from BCHPA Captive Insurance Company Ltd., Columbia Hydro Constructors Ltd. or Tongass Power and Light Company included in BC Hydro's revenue requirements. However, it is not clear whether these subsidiaries are involved in regulated or unregulated activities. A check of the BCUC's records does not reveal any filings for any of these entities. Further, there is no evidence before the Panel of transfer pricing agreements between BC Hydro and these entities, although BC Hydro does state in its Annual Report that one exists between BC Hydro and Tongass Power and Light Company.

BC Hydro is directed, as part of its compliance filing, to further clarify the nature of the operations of BCHPA Captive Insurance Company, Columbia Hydro Constructors Ltd. and Tongass Power and Light Company and whether they are part of BC Hydro's regulated business or operate as separate regulated or unregulated businesses. BC Hydro is also directed to file any transfer pricing agreements with these three subsidiaries along with their most recent financial statements as part of its compliance filing.

As part of its compliance filing, the Panel also directs BC Hydro to provide the net income for its 11 remaining subsidiaries that "either serve as nominee holding companies …or are considered to be inactive/dormant." Any existing transfer pricing agreements between BC Hydro and these 11 subsidiaries must also be filed as part of its compliance filing.

5.8 COVID-19 Pandemic

Subsequent to the closing of evidence for this proceeding, the Government of BC declared a provincial state of emergency in response to the COVID-19 pandemic. The extent and duration of the impact of the pandemic on BC Hydro's operations are uncertain. However, BC Hydro submits that its requested rates should be approved despite the uncertainties caused by the COVID-19 pandemic.[1102]

BC Hydro submits that its existing regulatory accounts, such as the Cost of Energy Variance Accounts, the Amortization of Capital Addition Regulatory Account, and the Total Finance Charges Regulatory Account and the Non-Current Pension Cost Regulatory Account, would largely mitigate the uncertainty by capturing the variances between actual and forecasts for refund or recovery from customers in the next test period.[1103] BC Hydro submits that it will file separate applications with the BCUC if any particular approval is required over the remainder of the Test Period due to the pandemic.[1104]

[1102] BC Hydro Final Argument, pp. 254–255, para. 599.
[1103] BC Hydro Final Argument, p. 254, para. 596.
[1104] BC Hydro Final Argument, p. 254, para. 598.

Positions of Parties

BCOAPO and BCSEA agree with BC Hydro that the evidentiary record should not be reopened and that the regulatory accounts "will mitigate much of the uncertainty caused by the pandemic."[1105] AMPC supports not reopening the evidentiary record because the impact of the pandemic is uncertain.[1106]

Gjoshe recommends the BCUC consider the impact of the pandemic when setting the Test Period rates "if it so deems appropriate."[1107]

Zone II RPG supports the BCUC reviewing the impact of the pandemic in BC Hydro's next RRA "or earlier should the Commission consider it necessary, especially after the full impacts of COVID-19 are better understood."[1108]

McCandless submits that given that we are already into the second year of the Test Period, the BCUC should approve the requested rates because any increase would present an unplanned cost for many customers. McCandless notes that reduced electricity sales, especially to the commercial sector, due to the decline in the economy resulting from the pandemic would not impact BC Hydro's net income because BC Hydro's regulatory accounts transforms shortfalls into debt liability faced by future generations of ratepayers. In McCandless's view, "[t]he reliance on recording unearned revenue lost through the COVID-19 economic contraction makes the whole rate-setting process even more illusory."[1109]

Ince recommends that, within this regulatory process, the BCUC require BC Hydro to provide, as soon as practical, an update based on high-level estimates of the most recent load and revenue impacts, including 5-year projections and associated deferral account balances.[1110]

The CEC submits that the BCUC "should be prepared to ask BC Hydro for adjustments with respect to [finance and interest charges on debt]" because of recent decreases in interest rates in response to the economic impact of the pandemic.[1111]

MoveUP submits "[t]here is no point attempting to adjust the picture now. The best the Commission can do is record the projections, set the rates, and (as with so many dimensions of the economy) reassemble the pieces once the crisis has passed – or at least has stabilized sufficiently to permit rational analysis and forecasts." Rather the BCUC should consider how BC Hydro intends to handle the ongoing effect of the economic downturn resulting from the pandemic and its consequences for BC Hydro and its ratepayers. In MoveUP's view, the BCUC should request BC Hydro to file a report that sets out how it plans to handle the expected revenue shortfall resulting from the pandemic, whether any resulting increases in rates would be combined with more robust low income and business support packages, and what further measures it is contemplating to provide relief to ratepayers.[1112]

In reply, BC Hydro submits that it supports MoveUP's recommendation for reporting on the impacts of the pandemic, but in its view, the reporting is more appropriate in the next RRA when more information is available. BC Hydro submits that it is currently too early to report on the impacts and it also expects this issue to arise in the context of the upcoming IRP. With respect to relief measures, BC Hydro submits that it has already

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1105 BCSEA Final Argument, pp. 11, 15, 73; BCOAPO Final Argument, p. 15.
1106 AMPC Final Argument, p. 3.
1107 Gjoshe Final Argument, p. 3.
1108 Zone II RPG, Final Argument, p. 6.
1109 McCandless Final Argument, p. 6.
1110 Ince Final Argument, p. 3.
1111 CEC Final Argument, p. 3.
1112 MoveUP Final Argument, pp. 5–6.

implemented a number of COVID-19 relief initiatives and reports on them to the BCUC. In its view, reporting on other potential initiatives under consideration as envisioned by MoveUP may not be practical.[1113]

Panel Discussion

The COVID-19 pandemic is an extraordinary event, which has impacted not only the economy, but has disrupted the day-to-day life of society on a global level. The pandemic impacts all of BC Hydro's customers and has created additional challenges in forecasting BC Hydro's load, which in turn impacts the forecast for capital expenditures, financing and DSM expenditures, among others.

The Panel agrees that the impact of the COVID-19 pandemic on the economy is uncertain and the uncertainty will likely continue for a number of months. Given the uncertainty and the anticipated duration of the pandemic, reopening the evidentiary record would not provide sufficient additional certainty and thus, BC Hydro's revenue requirement should be reviewed based on the evidentiary record at the time the evidentiary record was closed. Further, the Panel is satisfied that BC Hydro's existing regulatory accounts would capture much of the impact of the pandemic on BC Hydro's operations. The existing regulatory accounts would mitigate the uncertainty of recovery of the costs resulting from the largely uncontrollable and unpredictable events of the pandemic. Therefore, the Panel declines the CEC's request to ask BC Hydro for adjustments to its finance and interest charges. Similarly, the Panel declines Ince's recommendation to require BC Hydro to provide an updated load forecast and associated regulatory account balances.

However, the Panel agrees with MoveUP that there is value in BC Hydro reporting on the impact of the COVID-19 pandemic with respect to its operations. **Therefore, the Panel directs BC Hydro to report in all future RRAs, until directed otherwise, on the impact of the COVID-19 pandemic with respect to its operations and how it plans to handle the resulting impact on its revenue requirement, rates and regulatory accounts.** The Panel acknowledges that since the pandemic began, BC Hydro has implemented a number of COVID-19 related relief measures for its customers and provides reports to the BCUC regarding these measures. The approval of specific COVID-19 relief measures is generally not within the BCUC's purview, but rather the BCUC's jurisdiction is with respect to the recovery of the costs related to the relief measures. Therefore, the Panel declines MoveUP's recommendation for BC Hydro to report on potential COVID-19 related relief measures that it is contemplating.

With respect to McCandless' submission that BC Hydro's regulatory accounts effectively negate any impacts the COVID-19 pandemic would have on BC Hydro's net income by increasing the debt borne by ratepayers, this is addressed in section 4.5.6 of the Decision where BC Hydro's use of regulatory accounts is discussed.

5.9 Rate Design

The BCUC last reviewed BC Hydro's rate design when BC Hydro filed a rate design application (RDA) in 2015, which was the third such application filed in BC Hydro's history. The RDA contained BC Hydro's fiscal 2016 Cost of Service (COS) study, proposals for default Residential, Small General Service, Medium General Service, Large General Service and Transmission Service rates; and proposals for its Electric Terms and Conditions.

During the current proceeding, interveners made submissions regarding BC Hydro's rate design.

Positions of Parties

MoveUP submits that BC Hydro should file with the BCUC a report that comprehensively re-examines BC Hydro's rate designs by "building from clearly-articulated objectives that are in tune with the needs of our time and the rapid evolution of the energy sector…."[1114]

[1113] BC Hydro Reply Argument, p. 6, paras. 11, 12.
[1114] MoveUP Final Argument, p. 14.

Willis recommends BC Hydro consider rate design options that encourage electrification.[1115]

Zone II RPG supports a review of BC Hydro's rate design in the near future and submits that BC Hydro needs to prioritize the review of Zone II rates as committed to in the 2015 Rate Design proceeding to ensure Zone II rates are affordable relative to Zone I rates.[1116]

AMPC submits that the BCUC should direct BC Hydro to file a new COS study and RDA before calendar 2023. AMPC submits that this is "a normal and required part of fulfilling the legislative requirement for just and reasonable rates, and was committed to by BC Hydro multiple times." AMPC submits that BC Hydro should not continue to use the current COS methodology, the product of a truncated process, because it does not fully and properly address many important issues, such as the design of the industrial Tier 1 and 2 rates.[1117] AMPC notes that although the BCUC is prevented by statute from directing BC Hydro to rebalance its rates, it is not restricted from making a finding "that BC Hydro's rates would benefit from scrutiny of its cost of service methodology."[1118]

The CEC recommends the BCUC "explicitly recognize the concern with existing and ongoing discrimination imbalance" and "direct BC Hydro to consult with the CEC in regard to addressing an appropriate balance, including for DSM programming, development of a Freshet rate, increased COVID-19 related relief, evacuation relief and any other programs and services that could suitably be provided to the commercial rate class."[1119]

In reply, BC Hydro submits that this proceeding's evidentiary record was not developed for the purpose of rate design. Therefore, the BCUC should not make directions regarding a future RDA proceeding "in an evidentiary vacuum."[1120] Furthermore, BC Hydro submits that following phase 2 of the Government's review, it will be consulting with customers and other stakeholders to inform any resulting RDAs.[1121] BC Hydro also notes that rate rebalancing was not within the scope of the current proceeding because it is a rate design matter. Notwithstanding this, there is currently a prohibition on rate balancing.[1122] Thus, the CEC's recommendation would result in the BCUC commenting on the merits of current Government policy.[1123] BC Hydro submits it "would respond positively to any invitation" from the CEC and individual commercial customers regarding potential programs and services.[1124]

Panel Determination

The Panel generally agrees with BC Hydro that rate rebalancing and rate design were not within the scope of this current proceeding and there is insufficient information in the evidentiary record to issue specific directions to BC Hydro with respect to the scope of a future RDA proceeding. Furthermore, since the issuance of the final report on phase 2 of the Government's Review is anticipated in the near future and the results of the review are expected to inform BC Hydro's future rate designs, there is little value in attempting to redesign the rates prior to the issuance of the final report. Also, BC Hydro would need sufficient time to consult with stakeholders and compile evidence to develop a robust and comprehensive RDA.

The Panel, however, shares the parties' concerns that BC Hydro's current rate design may be out of date and may no longer achieve the objectives that it was meant to achieve. We also agree with AMPC that BC Hydro's current COS methodology was the product of a truncated process. The last BC Hydro rate design application was

[1115] Willis Final Argument, pp. 6–7.
[1116] Zone II RPG, Final Argument, pp. 5, 11.
[1117] AMPC Final Argument, p. 21.
[1118] AMPC Final Argument, p. 29.
[1119] CEC Final Argument, p. 112.
[1120] BC Hydro Reply Argument (May 27, 2020), p. 147, para. 350.
[1121] BC Hydro Reply Argument (May 27, 2020), p. 147, para. 351.
[1122] Direction No. 8 to the BCUC, Section 5; UCA, Section 58.1.
[1123] BC Hydro Reply Argument (May 27, 2020), pp. 147–148, para. 349.
[1124] BC Hydro Reply Argument (May 27, 2020), p. 151.

reviewed and approved by the BCUC in 2015, in which its COS methodology was approved by the BCUC. This proceeding was done through a Negotiated Settlement Process, as a result of the government's Rate Rebalancing Amendment in the UCA, which states that the BCUC must not set rates for the purposes of changing the revenue to cost ratio for a class of customers.[1125] However prior to this, our public records indicate that a more robust review of BC Hydro's COS methodology was conducted in 2007 during its RDA proceeding, over 13 years ago. Although section 5 of Direction No. 8 continues to prohibit the BCUC from initiating rate rebalancing, , a review of BC Hydro's COS study and methodology is still within its jurisdiction.

The Panel further notes that in the BCUC's reasons for decision to BC Hydro's Residential Inclining Block Fiscal 2021 and Fiscal 2022 Rate Pricing Principles Extension Application, the BCUC had directed BC Hydro to file a report with the BCUC one year later, or by March 26, 2021, that discusses its progress regarding the development of its next residential RDA and the anticipated filing date of that application. The report is to also include details of BC Hydro's activities to date and its planned activities regarding the development of that application.[1126] **Therefore, the Panel directs BC Hydro to also include in that report, a discussion of its progress regarding the development of its next RDA for commercial and industrial customers, as well as for customers in the NIA. The report should also include results of the most recent fully allocated COS study and a discussion on whether BC Hydro's COS methodology should be adjusted and if not, its rationale for not doing so.**

With respect to the CEC's recommendation that the BCUC "explicitly recognize the concern with existing and ongoing discrimination imbalance" regarding commercial customers, the Panel notes that this is largely a rate design matter, which is not within in the scope of this proceeding, and as such there is insufficient evidence for the Panel to make such a finding. Regarding the CEC's recommendation for the BCUC to "direct BC Hydro to consult with the CEC in regard to addressing an appropriate balance," the Panel notes that BC Hydro has expressed a willingness to work with the CEC and individual commercial customers regarding potential programs and services, and the Panel encourages BC Hydro to do so. Therefore, the Panel at this time does not see the need for such a direction.

5.10 Rate of Return Review

BC Hydro's return on equity (ROE) in the Test Period is established pursuant to government direction. Specifically, section 3 of Direction No. 8 states that the BCUC must set rates that enable BC Hydro to achieve a rate of return on deemed equity that would yield a distributable surplus of $712 million for each of fiscal 2020 and fiscal 2021. The interpretation of section 3 of Direction No. 8 is discussed in section 5.12 of this Decision. Prior to fiscal 2020, BC Hydro's ROE was also established pursuant to government direction. In the absence of further government direction with respect to BC Hydro's ROE, the BCUC would establish the ROE for fiscal 2022 and onwards.

During the current proceeding, interveners made submissions regarding the review of BC Hydro's rate of return for fiscal years 2022 and beyond. In particular, AMPC filed evidence prepared by InterGroup that included recommendations related to BC Hydro's ROE in future test periods, including the factors that should be considered.[1127]

BC Hydro submits that "the Panel should not opine on matters related to the upcoming cost of capital proceeding. This Panel cannot fetter the discretion of the BCUC Panel hearing a future application." In BC Hydro's view, there is insufficient evidence in this proceeding regarding this matter for the Panel to make recommendations to a future BCUC panel.[1128]

[1125] UCA, section 58.1.
[1126] Order G-62-20, Appendix A, Reasons for Decision dated March 26, 2020, p. 7.
[1127] Exhibit C11-11, InterGroup Report, Recommendations 4 to 6.
[1128] BCH Final Argument, pp. 209–210, para. 491.

Positions of Parties

In BCSEA's view, "it would be premature for the Current Panel to address the content of the future determination of BC Hydro's future return on equity."[1129]

AMPC recommends the BCUC direct BC Hydro "to identify, and where possible, quantify contributors to the uncompetitiveness of rates arising from government actions…." AMPC submits that the cost impact of projects that the BCUC cannot review "is relevant to the risk BC Hydro's shareholder assumes, and in turn, the level of return that is fair."[1130] AMPC also recommends the BCUC clarify the scope for the rate of return hearing within this proceeding's Decision and specifically direct BC Hydro to address the following:[1131]

- The basis for justifying a return to the shareholder;
- Whether the Province has made material equity investment in BCH;
- The extent of risk borne by the shareholder; and
- The extent of benefits already provided to the BC government in the form of policy directives that have led to above-cost energy.

Gjoshe supports AMPC's recommendation to direct BC Hydro "to identify the costs of legislated policies even if the BCUC cannot direct associated changes, so as to ascertain the 'least cost nature' of all costs that continue to be included in the revenue requirement, including costs associated with government directions."[1132]

In reply, BC Hydro submits that the orders AMPC is seeking are intended to determine the scope of the upcoming ROE proceeding before that panel has had a chance to consider the relevance of the evidence. In addition, considering affordability in a ROE hearing contradicts previous BCUC rulings which stated that the BCUC does not consider the rate impacts of the revenue required to yield the fair return.[1133] Notwithstanding, BC Hydro submits that BCUC direction regarding the content of the upcoming ROE application would not be necessary because the only item sought by AMPC that may require material evidence would be business risks, which BC Hydro already anticipates providing to support its application. Also, there would be an IR process to request additional information once AMPC sees BC Hydro's ROE application and AMPC would have the opportunity to file intervener evidence. BC Hydro reiterates that the Panel "should avoid encroaching on the discretion of the Panel assigned to hear the ROE proceeding."[1134]

Panel Discussion

The Panel generally agrees with BC Hydro that the scope of the current proceeding is not directly related to determining BC Hydro's ROE. The Panel expects that much of the information sought by AMPC could be addressed in the upcoming ROE proceeding without the need for direction. Therefore, the Panel is not persuaded by AMPC's request for the BCUC to direct BC Hydro to provide such information.

5.11 Timing of Next Revenue Requirements Application

Subsequent to the close of evidence and final arguments, the Panel sought additional comments from all parties pertaining to the timing of BC Hydro's next revenue requirement application and comments on Section 3 of Direction No. 8.

[1129] BCSEA Final Argument, p. 50, para. 197.
[1130] AMPC Final Argument, p. 21.
[1131] AMPC Final Argument, pp. 26–27.
[1132] Gjoshe Final Argument, p. 13.
[1133] BC Hydro Reply Argument (May 27, 2020), p. 149, para. 357.
[1134] BC Hydro Reply Argument (May 27, 2020), p. 148, para. 353.

In its letter dated July 6, 2020, the Panel outlined its concerns regarding the timing of BC Hydro's revenue requirements applications and observed that it was now approximately 16 months into the 24-month Test Period. If BC Hydro were required to make any adjustments to its spending as a result of our final decision, it would be very difficult to do so within the time remaining and likely impossible to make them retroactively. The letter also stated that:

> Not allowing sufficient time to review a revenue requirements application (RRA) contributes to regulatory inefficiency and diminishes the effective role of the regulator, thereby putting both the ratepayer and the shareholder at risk. [1135]

Accordingly, the Panel invited parties to provide submissions on several questions pertaining to an approach in setting rates for BC Hydro in fiscal 2022 and beyond. This included the concept of a rate setting mechanism for fiscal 2022 as a "Gap Year" upon which rates would be set based on some mechanism, such as an inflation factor applied to fiscal 2020 rates or costs.

In response, BC Hydro supported establishing a cycle that would allow BCUC decisions on BC Hydro's RRAs to occur earlier, so that it would have more time to adjust to BCUC directives affecting the test period under review. BC Hydro stated that it is prepared to change its budgeting processes and timelines so that RRAs can be filed earlier and this process will begin with a fiscal 2022 RRA being filed in December 2020. BC Hydro also suggests that considerations be made for: various issues such as the uncertainty created by the COVID-19 pandemic; the BCUC's careful scoping of a fiscal 2022 RRA to support a streamline review process; and areas within operating costs where additional investments beyond inflationary adjustments may be necessary, such as vegetation management, cybersecurity and employee training. BC Hydro also requests the Panel's consideration of previous BCUC orders in which a number of its regulatory accounts are recovered "over the next test period" or in other words, over a single year.[1136]

Positions of Parties

Most interveners that provided submissions agree with the Panel's suggestion for a streamlined review process and concept for the "gap year" although some suggest the use of a hybrid method where some costs are aligned with inflation and some based on another cost driver mechanism.[1137] Most interveners also supported BC Hydro's suggestion for a more scoped review in the next RRA.[1138] Concerns were also raised over the uncertainties caused by the Covid-19 pandemic,[1139] with some interveners questioning how the pandemic would impact the implementation of Performance Based Regulation.[1140] While there appears to be unanimous agreement on streamlining the next RRA review, there is wide disagreement on the length of the test period and the type of review. In addition to these general submissions, some interveners also provided specific comments as outlined below.

McCandless submits that the time required for the review of the current RRA has been excessive in relation to the value of the rate change requested, or for the policy implications involved in BC Hydro's planned expenditures. However, McCandless indicates that BC Hydro is redirecting funding for paying down deferred costs to funding operational costs, and using a one-time credit to offset other expenditure increases. McCandless is also skeptical about whether a prolonged process heightens the risk to the ratepayer, given the large number of regulatory and deferral accounts for BC Hydro. McCandless also suggests that BC Hydro's ROE and the appropriate debt to equity ratio be areas of focus in the next application.[1141]

[1135] Exhibit A-37, p. 1.
[1136] Exhibit B-59, p. 3.
[1137] Exhibit C6-10, p. 2, Exhibit C5-13, p. 1.
[1138] Exhibit C1-9, p. 2, Exhibit C6-10, p. 1, Exhibit C8-8, p. 1; Exhibit C9-18, p. 3.
[1139] Exhibit C12-8, p. 1; Exhibit C6-10, p. 2; Exhibit C14-9, p. 2; Exhibit C9-18, p. 7.
[1140] Exhibit C5-13, p. 2; Exhibit C6-10, p. 2, Exhibit C7-5, p. 2, Exhibit C9-18, p. 7.
[1141] Exhibit C4-3, pp. 1–3.

BCOAPO supports the “extra time we have spent in this RRA hearing” indicating it will pay dividends in the next RRA review and that it will serve to limit the need to delve into those same issues in detail and scope in future reviews.

Zone II RPG submits that there is value in combining at least two test years and does not support foregoing a full cost of service review for fiscal 2022.[1142]

Willis suggests that the BCUC’s hearing process be completed within five to six months of a new rate cycle and that government comments be sought as to how the overall economic conditions impact electric rates.[1143]

Ince submits that the most substantive pending cost issues for BC Hydro are unrelated to inflation, and therefore a simple inflation or escalation-based forecast of these costs would not be adequate.[1144]

BCSEA generally supports BC Hydro’s submissions but does not support going as far as modelling the process after the processes for FortisBC Energy Inc. and FortisBC Inc. annual reviews under their multi-year rates plan.[1145]

The CEC proposes that the fiscal 2022 RRA include high level, quantitative reviewable business metrics for each “area” with minimal description-type information or explanations.[1146] It also suggests that future BC Hydro RRAs could serve as pilot for the development of a significantly more refined, and valuable, RRA model. The CEC also provides a discussion on how each chapter of the RRA might be treated.[1147] The CEC further recommends that the review of capital be removed from the RRA altogether and instead should be reviewed on an ongoing basis through other capital oversight proceedings such as CPCNs and project progress reviews.[1148]

CEABC prefers BC Hydro to delay its fiscal 2022 RRA filing to January 2021 instead of December 2020 so it can use the latest updated load forecast and capital plan approved by the Board, so as to avoid the need for an evidentiary update. CEABC also proposes an early Negotiated Settlement process to determine any partially formulaic relationships. [1149]

AMPC submits that the BCUC should reject BC Hydro’s hybrid approach to setting fiscal 2022 rates and should instead proceed with the inflationary approach originally suggested by the Panel. AMPC is concerned that BC Hydro’s approach would not result in a fair assessment of its costs for fiscal 2022 and may not take into account cost decreases in other categories. While AMPC accepts the need for an efficient hearing process it disagrees with using broad scoping restrictions as a primary tool.[1150] AMPC further submits that the BCUC should not delay its decision and reasons for the fiscal 2020–fiscal 2021 RRA to include reasons concerning the process to set BC Hydro’s fiscal 2022 rates.

In reply to AMPC, BC Hydro clarifies its proposal for a cost of service approach for the fiscal 2022 RRA, focused on incremental requirements, would also include any identified cost decreases and the proceeding would provide a full opportunity for the BCUC and interveners to test the accuracy of any cost increases and cost decreases. BC Hydro also argues that AMPC’s proposal for an inflationary approach provides little or no

[1142] Exhibit C5-13, pp. 1–2.
[1143] Exhibit C7-5, pp.1–2.
[1144] Exhibit C12-8, p. 2.
[1145] Exhibit C8-8, p. 2.
[1146] Exhibit C9-18, p. 3.
[1147] Exhibit C9-18, pp. 4–6.
[1148] Exhibit C9-18, pp. 5–6.
[1149] Exhibit C10-29, p. 2.
[1150] Exhibit C11-28, pp. 1–3.

opportunity to test the assumptions around its fiscal 2022 RRA plan amounts, other than the assumptions around an inflation factor.[1151]

BC Hydro does not object to CEC's proposal to include high-level, quantitative reviewable business metrics in the fiscal 2022 RRA, so long as it is limited to the metrics that BC Hydro actually uses to manage its operations, such as those provided in BC Hydro's response to BCUC IR 62.1. BC Hydro argues that including metrics outside of its regular course of business would run counter to the objective of regulatory efficiency. BC Hydro also observes that CEC's proposed pilot approach appears to be similar in nature to their proposal recently rejected by the BCUC in its Decision on the BC Hydro Review of Regulatory Oversight of Capital Expenditures and Projects. BC Hydro also states that the CEC's suggestion to remove the review of capital from the RRA entirely is contrary to the BCUC's recently established Capital Filing Guidelines.[1152]

BC Hydro submits that CEABC's proposed delayed filing to January 2021 would undermine the objective of advancing the RRA regulatory cycle, as well as delay BC Hydro's subsequent filing of the fiscal 2023 RRA. Alternatively, advancing the submission date further, to November 1, 2020, as suggested by Willis would not be feasible. BC Hydro also argued that many of the assumptions made by the CEABC in its proposal are not possible to verify and be used as a "strawman" in a negotiated settlement process and that the BCUC should thus refrain from directing an approach with any specificity.[1153]

In response to McCandless, BC Hydro also states that it expects to submit a separate application to the BCUC to set its allowed net income (return on equity), and these two processes should remain separate. The regulatory process to review and set allowed net income is complex, relies heavily on expert evidence and is distinct from the matters addressed within an RRA.[1154]

Panel Determination

Our review of this Application is somewhat compromised by its timing, which resulted in the decision being unavoidably issued halfway through the second fiscal year of the two year test period. This provides very little opportunity for BC Hydro to implement any directives concerning costs without the risk of a significant rate impact. Given the time required for the preparation of the RRA process, it appears that unless steps are taken to avoid it, the next RRA review will likely suffer from the same shortcoming — it appears unlikely that a multi-year RRA application can be completed in sufficient time to complete a review by the start of the 2022 fiscal year.

The Panel finds it necessary for BC Hydro to realign its future RRA filings in order to better address the issues of regulatory efficiency and ratepayer risk. **Accordingly, the Panel directs BC Hydro to file its next RRA by December 2020, and for that RRA to encompass a one-year test period for fiscal 2022.** The Panel further anticipates that BC Hydro would submit its application for fiscal 2023 rates (and possibly additional years) by no later than mid 2021.

BC Hydro's fiscal year begins on April 1. Given the cycle of past BC Hydro RRAs, rate applications were filed in late February (or, in the fiscal 2017 to 2019 RRA, the filing was received in July several months into the first year of the test period in review). The Panel is concerned that if its final decision required the utility to make spending adjustments, it will be very difficult for BC Hydro to make those adjustments for the time remaining and likely impossible to make them retroactively.

Based on the submissions received, there is general consensus among the parties that the fiscal 2022 RRA and proceeding should be streamlined to reflect a "gap" or transitional year. Most interveners were supportive of BC

[1151] Exhibit B-61, p. 2.
[1152] Exhibit B-61, pp. 2-3.
[1153] Exhibit B-61, p. 3.
[1154] Exhibit B-61, p. 3.

Hydro's proposal in setting rates for fiscal 2022 and beyond, although there is disagreement on some aspects of the review such as the timing of the next application, and the scope and form of the review.

While the Panel appreciates McCandless' submissions, he did not provide any comments related to the Panel's requested submissions on the "gap year" proposal. McCandless instead appears to comment on BC Hydro's costs and spending on the current Application. The Panel is also concerned about McCandless' proposal for a full ROE review in the next RRA and agrees with BC Hydro that a separate application should be filed for review.

McCandless has raised concerns over the necessary time spent in the review of this Application. We do not agree with this view. Given the lengthy hiatus in full regulation, it is important for both the BCUC and Interveners to conduct as thorough a review as possible. BC Hydro is a large and complex organization, one of Canada's largest utilities and therefore a thorough review is necessarily time consuming. Further, just because the rate increase applied for may be relatively small, it doesn't necessarily mean that a small increase is warranted – it is entirely possible that the facts could support a rate decrease. Rates must be looked at in concert with the revenue requirement.

Zone II RPG's proposal for combining at least two test years without foregoing a full cost of service review for fiscal 2022 appears to put the BCUC in the same position as this current Application. We find this argument to be unclear as to how it would support a realignment of the next RRA or support regulatory efficiencies.

The Panel is concerned with CEC's proposal that the review of capital be removed from the RRA altogether and instead should be reviewed on an ongoing basis through other capital oversight proceedings. The Panel agrees with BC Hydro that this proposal is contrary to the BCUC's recently established Capital Filing Guidelines and therefore dismisses this proposal. As for the CEC's proposal for BC Hydro to include high-level, quantitative reviewable business metrics in it fiscal 2022 RRA, we note that BC Hydro does not object so long as it is limited to the metrics that it uses to manage its operations. **The Panel therefore directs BC Hydro to include the metrics it uses to manage its operations, such as those metrics included in its response to BCUC IR 62.1, in its fiscal 2022 RRA**.

The Panel does not agree with CEABC's preference for BC Hydro to delay filing its next fiscal 2022 RRA to January so that it can incorporate the latest updated load forecast and capital plan approved by its Board. The Panel finds that it is not always necessary nor required to have utilities file an evidentiary update to every application. This appears to be a preference of the applicant rather than a need of the BCUC. We therefore support BC Hydro's commitment to a December 2020 filing date which better aligns with the interest of a more efficient and timely review process for its fiscal 2022 test year.

The Panel makes no recommendations at this time as to whether the review of the fiscal 2022 RRA should be conducted through a negotiated settlement process or whether it should be similar in manner to the FortisBC's Annual Review process. This decision should be left to the discretion of the panel assigned to review that application.

As for the scope and form of the fiscal 2022 RRA, the Panel finds that the comprehensive details in this Decision should be used to inform BC Hydro of the areas of particular concern to the BCUC.

Finally, it may be appropriate to apply an inflationary adjustment to some elements of BC Hydro's cost of service while other components may require a different indexing mechanism or consideration. We rely on BC Hydro to bring forward evidence to support its positions for any adjustments beyond inflation and further expects BC Hydro to equally identify and incorporate any anticipated cost decreases along with its costs increases for review in its fiscal 2022 RRA.

5.12 Interpretation of Section 3 of Direction No. 8

In its letter dated July 15, 2020, the Panel acknowledged the requirement provided in section 3 of Direction No. 8 to the BCUC, which specifically states:

> In regulating and setting rates for the authority for F2020 and F2021, the commission must ensure that those rates allow the authority to collect sufficient revenue in each fiscal year to enable the authority to achieve an annual rate of return on deemed equity that would yield a distributable surplus of $712 million.

The Panel then invited parties to provide submissions on various questions in order to clarify the interpretations of the above legislation. The questions in summary relate to whether section 3 of Direction No. 8 to the BCUC equates to an "opportunity" to earn the stated amount of $712 million or whether it is a guaranteed return.

BC Hydro submits that the legal effect of section 3 of Direction No. 8 is that the fair return standard is deemed to have been met in the Test Period if BC Hydro has a reasonable opportunity to earn a distributable surplus of $712 million in each year, and the BCUC's fundamental obligation under the UCA is the same irrespective of how much of the Test Period has passed. Although Direction No. 8 has prescribed recovery of a number of costs, BC Hydro states that it has otherwise left it open to the BCUC to undertake a review the reasonableness of its forecast costs.[1155] Specifically, BC Hydro states that if the BCUC disagrees, based on a fair assessment of the evidence, it should exclude those costs regardless of whether they have been incurred.[1156] BC Hydro further submits that the legislation does not mean that ratepayers must pay the deficiency in the subsequent test period and the approach is the same as an investor owned utility, with the only difference being that section 3 of Direction No. 8 deems an allowed return of $712 million to be a fair return for the years in the current Test Period.[1157]

Positions of Parties

All of the interveners that provided submissions on this matter agree with BC Hydro's interpretation.

MoveUP and AMPC submit that an excessively literal interpretation of section 3 could lead to an absurd result, where it would effectively negate the entire process of prudency review by the BCUC, and the regulator would be left with no jurisdiction to review those expenditures.[1158]

McCandless maintains that BC Hydro's response to Panel question 5 is contrary to the scope of the Non-Heritage Deferral Account, which allows variances between actual and planned revenue to be deferred for future recovery from/refund to ratepayers.[1159]

BCOAPO submits that the BCUC's statutory mandate to review BC Hydro's forecast revenue requirements is the same irrespective of how much of the Test Period may have passed, and that the stated $712 million in each year of the Test Period is not an unqualified guarantee. BCOAPO further agrees with BC Hydro that, should the utility fall short of its target return despite rates having been set to allow it the opportunity to achieve that result, the utility cannot then go back to ratepayers and collect that shortfall.[1160]

[1155] Exhibit B-60, pp. 1–2.
[1156] Exhibit B-60, p. 3.
[1157] Exhibit B-60, p. 5.
[1158] Exhibit C1-10, pp. 2-3; Exhibit 11-28, p. 3.
[1159] Exhibit C4-3, pp. 5–6.
[1160] Exhibit C6-10, pp. 4–5.

The CEC, along with other interveners, agrees with BC Hydro that shifting towards earlier filing dates for revenue requirements applications and striving to shorten the length of future proceedings will contribute to fair and efficient regulation moving forwards.[1161]

In addition to supporting the interpretations made by BC Hydro and other parties, CEABC makes a number of other observations with respect to BC Hydro's operations and decision making: the proliferation of BC Hydro's deferral and regulatory accounts has muffled an objective evaluation of management decisions in key areas of its operations; CEABC prefers the BCUC to provide guidance to BC Hydro about its related expenditures and management practices of its deferral and regulatory accounts; BC Hydro's load has been flat while expenditures have been increasing and therefore "dumping any surplus electricity into the spot markets will not solve the problem"; and BC Hydro's uncertain financial future as it relates to geotechnical and budgetary problems at its Site C dam.[1162]

In response to McCandless, BC Hydro clarifies that it should be read as stating that the difference between BC Hydro's planned and actual net income in a given year, whether higher or lower, does not need to be recovered from or refunded to ratepayers in the subsequent test period.[1163]

Panel Discussion

Most interveners either support BC Hydro's position on the effect of section 3 of Direction No. 8[1164] or express no opinion.

We agree with BC Hydro that section 3 of Direction No. 8 does not mean that ratepayers must pay, in the subsequent test period, for any deficiency in the actual return on equity earned in the Test Period and the approach is the same as for any other utility. Further, we agree with MoveUP's interpretation that section 3 of the UCA empowers the Lieutenant Governor in Council to substitute its judgment for that of the BCUC and in this instance the former has exercised that power by substituting the stipulated return in the place of the operation of section 60 (1) (b) (ii) of the UCA. This section has been interpreted by the BCUC and the courts as providing the <u>opportunity</u> but not a guarantee to earn a fair and reasonable return. Therefore, we find that under section 3 of Direction No. 8, BC Hydro's opportunity to earn $712 million is the same as the opportunity for any other utility to earn a fair return.

5.13 Affordability

BC Hydro states that the approvals it is seeking in the Application "balance affordability and reliability to deliver value to our ratepayers",[1165] and explains that many of its residential customers face affordability challenges and many of its commercial and industrial customers face "challenging market conditions."

BC Hydro states that its average 2018 residential bills were the third lowest in the Hydro Quebec annual survey of electricity costs in 22 cities in Canada and the US, and were within the first quartile, consistent with the goal "Help make electricity more affordable for our customers" in BC Hydro's Service Plan.[1166] However, during the oral hearing Mr. Layton conceded that BC Hydro's lower rates, and overall ranking in the Hydro Quebec Report were enabled in part by the write-off of $1.1 billion in the rate smoothing account .[1167]

[1161] Exhibit C9-19, p. 2; Exhibit C12-8, p. 2.
[1162] Exhibit C10-30, pp. 1–2.
[1163] Exhibit B-61, p. 4.
[1164] Exhibit C1-10; Exhibit C4-3, p.2; Exhibit C5-13, p. 2; Exhibit C6-10, pp. 4-5; Exhibit C8-9; Exhibit C9-19; Exhibit C10-30; Exhibit C12-8
[1165] Exhibit B-1, p. 1-41.
[1166] Exhibit B-1, p. 1-3–1-4; BC Hydro 2018/19 – 2020/21 Service Plan, Performance Plan, Goal 2, pp. 11–12.
[1167] Transcript Volume 8A, p. 1108–1109 .

Also, Mr. O'Riley stated in the Oral Hearing, "BC Hydro's ability to absorb costs is being challenged and tested by the increasing complexity in the business, in areas particularly such as critical infrastructure protection, mandatory reliability standards, cyber security, increasing service expectations, societal expectations, and diverse regulatory requirements." [1168] These are just a few areas that are necessary for BC Hydro to meet its requirements, as a public utility, to maintain safe, reliable service for its ratepayers.

During his testimony, Mr. O'Riley further acknowledged some of these increased cost drivers:

> And there are areas where we should expect to see operating cost increases beyond inflation in future revenue requirement processes. Three areas that are of particular concern to me are vegetation management, cyber security and employee training necessary to ensure we meet evolving safety and regulatory requirements.
>
> These areas are all very critical to our ability to operate effectively and provide safe and reliable service in the future, and I'm sure this will be a topic of further discussion in this process.[1169]

Position of the Interveners

Zone II RPG submits that BC Hydro's proposed rates for the Test Period meet the criterion of affordability, which is "particularly important to Zone II RPG communities and their members with low income".[1170]

In the CEC's view, comparisons to other utilities and only considering residential rates do not provide an appropriate objective for BC Hydro with respect to affordability of bills. The CEC submits that BC Hydro should consider affordability for all rate classes, not just the residential class, and should compare affordability for commercial and industrial rate classes against other jurisdictions against whom these customers compete. The BCUC, in the CEC's view, should place minimal weight on BC Hydro's comparisons against other jurisdictions based on residential rates, but instead "identify metrics that hold BC Hydro accountable for ongoing improvement in the cost-effectiveness of its performance."[1171]

The CEC also submits that commercial energy consumers "pay a disproportionate amount for their electricity relative to their costs." Using figures from BC Hydro's fiscal 2017 cost of service study, the CEC states that in fiscal 2017 commercial energy consumers paid between 103.9 percent and 123.6 percent of their costs, whereas residential energy consumers paid 93.2 percent of theirs.[1172]

[1168] Transcript Volume 5, p. 337.
[1169] Transcript Volume 5, pp. 358-359.
[1170] Zone II RPG Final Argument, p. 9.
[1171] CEC Final Argument, pp. 38–40.
[1172] CEC Final Argument, pp. 108–109.

Table 5-3 – Revenue to Cost Ration

	Revenue to Cost Ratios				
Rate Class	F2014 Actual (%)	F2016 Forecast (%)	F2016 Actual (%)	F2017 Actual (%)	Percentage Point Change (F2016 Actual to F2017 Actual) (%)
Residential	92.9	93.3	90.8	93.2	2.4
GS < 35 kW	123.5	111.9	122.6	123.6	1.0
MGS	119.5	117.2	123.5	115.1	-8.4
LGS	101.5	101.3	103.9	103.9	0.0
Irrigation	90.3	87.6	95.1	89.5	-5.6
Street Lighting – BC Hydro Owned	129.4	173.6	183.6	198.4	14.8
Street Lighting – Customer Owned		104.8	101.8	95.1	-6.7
Transmission	97.3	102.6	98.8	95.4	-3.4
Total	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**

The CEC submits that this is fundamentally unfair. Further, having revenue-to-cost ratios exceeding 5 percent difference from unity is particularly unfair, and when compounded over times this is egregiously unfair.[1173]

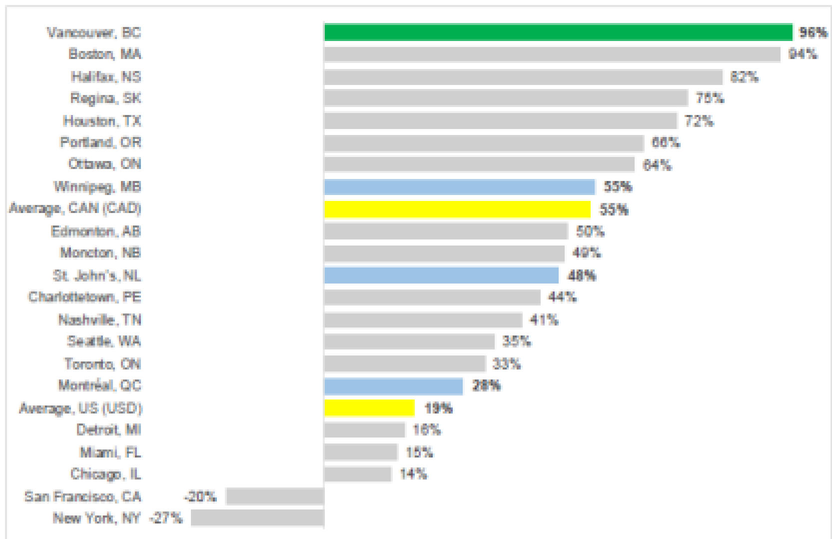
AMPC submits that uncompetitive rates are a disproportionate concern for customers in the industrial rate class. AMPC adds that if these customers reduce their consumption or new loads do not materialize, then all BC Hydro's customers' rates must rise to compensate for the lost revenue. Therefore, AMPC submits, "it is in the interests of BC Hydro, all ratepayers, and the Province of BC to mitigate the risk of industrial load migration through more competitive rates." [1174]

AMPC submits that the evidence from InterGroup, reproduced below, clearly shows that the pace of BC Hydro's rate increases for large-power customers exceeds that of any comparator:[1175]

1173 CEC Final Argument, p. 109.
1174 AMPC Final Argument, pp. 13–15.
1175 AMPC Final Argument, p. 17.

Figure 5-1 – Electricity Prices Growth in Major North American Cities in Last 16 Years

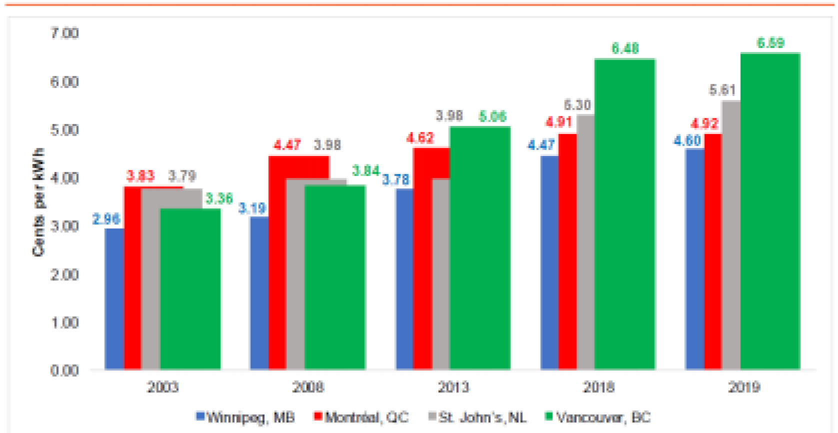
Figure B-4: Electricity Prices Growth in Major North American Cities in last 16 years where in CAD for Canadian Cities and USD for US Cities (from April 1, 2003 to April 1, 2019)[6]



AMPC adds that the comparison of average prices for large-power customers between BC Hydro and three other jurisdictions with large proportions of hydro electricity is more powerful yet:[1176]

Figure 5-2 – Comparison of Average Electricity Prices in Vancouver for Large Power Customers

Figure 4-1: Comparison of average electricity prices in Vancouver for Large-Power Customers to other Canadian cities where the power source is predominantly from hydro[20]



AMPC's recommendation to the BCUC, to find that industrial rate competitiveness is a high priority in this and future proceedings, is intended to provide directional guidance to BC Hydro and communicate the severity of this issue. [1177]

BC Hydro acknowledges its rate increases over the past 15 years have affected its position relative to other surveyed utilities. However, it adds that InterGroup's presentation of the survey data cited by AMPC "obscures

[1176] AMPC Final Argument, p. 18.
[1177] AMPC Final Argument, p. 19.

the reality that, despite past rate pressures, BC Hydro remains in the top (i.e., most favourable) quartile among the surveyed North American jurisdictions," and that BC Hydro's industrial rates remain very competitive. [1178]

BC Hydro submits that its current industrial competitiveness is best defined in relation to "a peer group consisting of jurisdictions that do or could support industrial activity similar to the type of industrial activity in British Columbia; and the relative rate level expressed in dollars per kW/h." BC Hydro acknowledges that is has the highest industrial rates of the peer group selected by AMPC, but observes that the other 18 comparators in the Hydro Quebec study not chosen by AMPC all have higher industrial rates. [1179]

BC Hydro submits it is cognizant of the need for affordability and industrial rate competitiveness, and that the evidence demonstrates BC Hydro is "exercising cost discipline throughout the organization."[1180] BC Hydro adds that it is also focusing on revenue generation, by pursuing capital investments related to electrification to increase sales.

BC Hydro also disputes AMPC's use of InterGroup's rate comparison that highlights percentage changes in rates as opposed to changes in $/kWh. BC Hydro submits that this makes little sense when considering competitivity as it fails to consider the starting point for the rates of each utility.[1181]

Panel Discussion

The Panel understands that its decisions regarding the recoverability of BC Hydro's costs have a direct impact on the affordability of electricity for BC Hydro's customers. In this section we explain how this Decision affects affordability and some of the limitations to making rates more affordable.

Affordability is a reasonable objective for BC Hydro; ultimately its corporate existence depends on its customers being able to afford to buy its services. Affordability may also be a matter of public policy in which the government of BC may choose to take an interest and pass legislation or take other measures. However, the BCUC has no legislative mandate to make rates affordable, either for all customers or for specific groups of customers. The BCUC made this clear in its decision on BC Hydro's 2015 Rate Design Application[1182] when it rejected a request for a low-income rate which was unsupported by an economic or cost of service justification. Rate setting principles are set out in the UCA, and subject to government regulations and directions, the BCUC must not approve which are "unjust, unreasonable, unduly discriminatory or unduly preferential."[1183]

For rates to be just and reasonable, we must be satisfied that the utility is able to recover only sufficient funds to enable it to continue to provide safe and reliable service, and to provide an appropriate return on the utility's invested capital. While we have authority over more of BC Hydro's costs than in recent RRAs, we are still restricted in our review of some costs, as the Panel explained in section 2.0 above. Notwithstanding, we have examined BC Hydro's proposed costs, and to the extent possible we have ensured that they are required to provide service to ratepayers and are not excessive. Where we have identified costs not related to providing service, we have directed BC Hydro to remove them from the revenue requirement and not recover them from customers.

While the Panel is satisfied that most of BC Hydro's costs are reasonable, we understand there are many costs which either cannot or should not be reduced, at least not in the short term. Excessive reduction of some expenses, such as equipment maintenance, would be a false economy, leading to increased reliability risk and increased future spending. In some areas, such as vegetation management and cyber-security, the Panel is

[1178] BC Hydro Reply Argument (May 27, 2020), p. 13.
[1179] BC Hydro Reply Argument (May 27, 2020), pp. 13–15.
[1180] BC Hydro Reply Argument (May 27, 2020), pp. 10–11.
[1181] BC Hydro Reply Argument (May 27, 2020), p. 15.
[1182] Order G-5-17, reasons for decision, p. 80
[1183] UCA, section 59.

concerned that BC Hydro should be increasing its spending to improve reliability and to reduce risk and future expenditures. While we encourage BC Hydro to look for sensible economies, “affordability above all” is simply not prudent.

We are concerned that a singular focus on keeping rates low, while salutary, may encourage any utility to cut corners and focus on cutting costs in areas that may have detrimental effects. These effects could be in the Test Period but could also manifest in a future test period(s).

For rates not to be unduly discriminatory or unduly preferential, the BCUC must ensure that a utility’s costs are recovered from those customers who benefit from them, and not recovered from other customers or future generations. The Panel has examined BC Hydro’s costs to ensure, as far as possible, that they are allocated to the appropriate customer classes, and will be recovered in the appropriate time periods when the benefits of costs are realized. However, allocation of costs between customer classes is determined by BC Hydro’s current rate design, and currently some classes of customer are paying more than is required to provide service to them.

For instance, BC Hydro’s commercial customers are paying between 103.9 percent and 123.6 percent of their costs, while its residential customers pay only 93.2 percent for theirs. However, pursuant to section 5 of Direction No. 8 the BCUC may not set rates to rebalance rates between customer classes. To the extent that rebalancing rates would make bills more affordable for some customers, the BCUC is unable to act. However, rate rebalancing is a “zero-sum game”, and any improvement in affordability for one customer class must come at the expense of another class.

In summary, the Panel cannot and does not address affordability directly in its decision-making. We do acknowledge that it is appropriate and beneficial for BC Hydro to set an affordability goal for itself, but we share the CEC’s concern that the focus is too heavily weighted to affordability for residential customers. We would prefer BC Hydro’s performance measures to give more weight than they presently do to commercial and industrial competitiveness, as we believe this is in the interests of BC Hydro’s long-term financial health, as AMPC observes.

We acknowledge BC Hydro’s criticisms of AMPC’s analysis of industrial rate competitiveness and AMPC’s choice of the three most competitive jurisdictions in the Hydro Quebec survey as comparators. However, BC Hydro does not dispute the InterGroup analysis, based on the results of the Hydro Quebec survey, which shows that since 2003 its industrial rates have risen faster than any other jurisdiction in the Hydro Quebec survey. Regardless of the rates at the starting point of the analysis, BC Hydro cannot continue to have the highest rate increases in the survey group and expect to remain competitive.

With regard to the one comparator BC Hydro does use to evaluate its affordability against other jurisdictions, its ranking in the Hydro Quebec survey of residential rates, the Panel considers this a useful tool. Rebalancing rates so that residential customers paid their full share of BC Hydro’s costs could lower BC Hydro’s ranking in the survey. Further, as BC Hydro acknowledges, the write-off of the $1.1 billion rate smoothing account “absolutely contributes to our place in the survey.” Notwithstanding these factors, BC Hydro will need to continue to contain costs to retain its position in future rankings in the Hydro Quebec survey, and therefore the use of this performance metric has value.

6.0 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.	BC Hydro is directed to re-calculate its revenue requirements based on the Panel's determinations in this Decision, in a compliance filing within 60 days of this Decision. 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.	8
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.	13
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.	18
4.	Accordingly, the Panel directs BC Hydro to adjust its load forecast for the entire Test Period by the percentage variance experienced between April 1, 2019 and December 31, 2019 for each customer class, respectively. 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 extent of any variance that is attributable to and independent from the COVID-19 pandemic, respectively.	21
5.	To address the Panel's concerns discussed above, BC Hydro is directed to, as part of its compliance filing: 1. Provide the BCUC with general time estimates to prepare: a comprehensive load forecast, "partial updates" and "adjustments"; 2. Provide information on benchmarking studies regarding the time required to prepare BC Hydro's load forecast models compared to Manitoba Hydro, Quebec Hydro, Bonneville Power – or any other comparable utility; and 3. Provide suggestions on ways to streamline its load forecasting methodology without a material loss of accuracy.	23
6.	The Panel directs BC Hydro, in its compliance filing, to clarify what its system optimization objective is. This filing should include clarification of the basis of consolidation for net revenue.	27
7.	The Panel directs BC Hydro, in its compliance filing, to clarify whether its system optimization objective is to maximize net revenue or net income.	28
8.	The Panel directs BC Hydro to address, in its compliance filing, how price risk and availability risk are recognized in the system optimization objective.	29
9.	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 3) a plan to have an independent third party test the Market Model.	35
10.	Accordingly, 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.	36

	Directive	Page No.
	BC Hydro is further directed to provide a report on the results of back testing and benchmarking once the testing activities have been completed.	
11.	Further, BC Hydro appears to use the terms “in month planning” and “short term operational requirements” interchangeably. It is not clear to the Panel exactly what time horizon is implied by the term “operational requirements” as used in the Energy Study Audit. BC Hydro is directed in its compliance filing, to clarify the use of these terms.	36
12.	Therefore, as part of its compliance filing, BC Hydro is directed to: 1. Clarify the use of the terms “in-month planning” and “short term operational requirements”, including the time horizon implied by the term “operational requirements”; 2. Describe how the short-term planning models/tools interface work and how they interface with the Energy Studies models; 3. Explain whether the Energy Study models were originally designed to serve short term operational planning needs and whether upgrades recommended in the Energy Study Audit would allow the Energy Studies to do so; 4. Explain whether tools used for within-month planning, such as spreadsheets, database applications and propriety software, meet all of BC Hydro’s short term operational planning requirements; 5. Provide a brief description for each of the within-month planning tools used, which includes: a. the age of each tool; b. how frequently each tool is reviewed and updated; c. whether source code or documentation exists that supports each tool; and d. the process used to validate/verify/benchmark each tool; and 6. Provide the most recent audit report that identifies the scope and results of the review of the within-month planning tools.	36–37
13.	The Panel directs BC Hydro to explain, in its compliance filing, the existing controls on Powerex’s ability to use the system to support import and export activities and whether they are sufficient.	37
14.	Therefore, in its Compliance Filing, BC Hydro is directed to report on any EPA renewing during the Test Period that has an associated forbearance agreement.	43
15.	Therefore the Panel directs the establishment of a load forecast variance account and directs BC Hydro to move all balances related to load forecast variance from the Non Heritage Deferral Account to the load forecast variance account. BC Hydro is directed to use the load forecast variance account to capture the variances between planned and actual domestic customer load. The Panel directs that the load forecast variance account be categorized as one of BC Hydro’s cost of energy variance accounts and that BC Hydro apply the same mechanisms for interest charges and recovery that are applicable to the Non-Heritage Deferral Account.	43
16.	However, in the absence of any better evidence concerning the cost of energy and in the	50–51

	Directive	Page No.
	interests of regulatory efficiency, we approve the forecast provided. BC Hydro is directed, in its Compliance Filing to clarify its proposed changes to the fiscal 2021 allocations to its deferral accounts as described in the 2020 TPA regarding the following : • the difference between the actual System Exports and System Imports and zero; • the difference between the actual Surplus Sales and Market Electricity Purchases amounts and zero; and • the treatment of domestic transmission costs.	
17.	Therefore, the Panel directs that no actual Powerex net income be captured in the Trade Income Deferral Account absent further review and approval by the BCUC.	55
18.	Therefore, as part of its fiscal 2023 RRA, the Panel directs that BC Hydro summarize: 1) the operating cost pressures it experienced during the Test Period and how it alleviated those costs pressures; and 2) where it was unable to alleviate the cost pressure, describe the activities BC Hydro had to forego and the risks resulting from not doing the activity.	59
19.	Therefore, the Panel directs BC Hydro to update the storm restoration cost forecast in the Test Period by using the fiscal 2015 to fiscal 2019 actual results.	69
20.	Accordingly, the Panel directs BC Hydro to begin tracking and measuring the annual actual vacancy factor savings and reporting on these in future RRAs, as well as providing the rationale for any significant differences from the forecast savings.	69–70
21.	However, given the Panel’s concerns, we direct that BC Hydro ensure that it also address the adequacy of its cybersecurity programs with respect to its distribution and head office systems in the next RRA.	71
22.	However, given the Panel’s concerns, we direct that BC Hydro ensure that it also address the adequacy of its vegetation management funding in its next RRA.	72
23.	Therefore, the Panel directs BC Hydro, in its fiscal 2023 RRA, to evaluate its safety data to determine whether it could achieve more aggressive lost time injury frequency and lost time injury duration targets, and if so, the additional costs, if any, that achieving such more aggressive targets may entail.	74
24.	For this reason, the Panel directs BC Hydro to report in its fiscal 2023 RRA on any additional maintenance spending that has occurred as a result of the reduced sustainment capital spending during the Test Period. Further, the Panel directs BC Hydro to present in its fiscal 2023 RRA a trend analysis of maintenance spending on capital for the ten most recently completed fiscal years.	86
25.	For these reasons, the Panel directs BC Hydro to provide, as part of its compliance filing, a proposal for including customers from Non-Integrated Areas in the index of customer satisfaction with reliability.	86
26.	For the following reasons, the Panel finds that the Property Purchases meet the tests set out in the definition of rate base in Direction No. 8, and therefore the Panel approves the purchase of land for the West End Substation as additions into BC Hydro’s rate base.	90

	Directive	Page No.
27.	The Panel determines that BC Hydro’s capital expenditures in EV charging infrastructure are not recoverable from ratepayers at this time. The Panel directs BC Hydro to remove all capital expenditures for EV charging infrastructure from rate base.	93
28.	The Panel directs BC Hydro to remove from its revenue requirement all forecast operating costs related to EV charging infrastructure in the Test Period, including those identified in the department of the Vice President, Customer Service Department and the Distribution Planning Department, and also the cost of energy to serve BC Hydro-owned EV charging stations in the Test Period. BC Hydro is further directed to remove from the appropriate cost of energy deferral account the cost of energy incurred prior to the Test Period to serve BC Hydro-owned EV charging stations. BC Hydro is also directed to provide in its compliance filing a report of all the adjustments directed in this section and any supporting calculations.	93–94
29.	For these reasons, and pursuant to section 45 (5) of the UCA, the Panel directs that BC Hydro file a joint CPCN for the Bridge River 1 Units 1-4 Generators / Governors Project and the Bridge River Transmission Project.	100
30.	The Panel finds that the Minette to LNG Canada Interconnection project meets the criteria in the Transmission Upgrade Exemption Regulation and is therefore exempt from Part 3 of the UCA.	102
31.	The Panel varies Directive 3 of the BCUC’s Decision on BC Hydro’s Fiscal 2017 to Fiscal 2019 Revenue Requirements Application removing the requirement for BC Hydro to file a CPCN for the cancelled Northwest Substation project.	103
32.	For these reasons, the Panel disallows recovery from ratepayers any forecast amount for project write-offs in the Test Period revenue requirement as proposed by BC Hydro.	107
33.	Therefore, the Panel directs BC Hydro to provide as part of its compliance filing, a proposal for a mechanism to capture the actual project write-off costs in the Test Period for recovery over the subsequent test period.	107–108
34.	The Panel directs BC Hydro to submit a filing to the BCUC, by December 31, 2020, explaining its progress to date in implementing each of the recommendations included in the Black and Veatch report, plus any other initiatives BC Hydro has or is undertaking to improve its interconnections process.	112
35.	The Panel further directs that BC Hydro conduct a workshop, by March 31, 2021, with BCUC staff present, to present the information in this filing to current and potential interconnection customers and current and potential IPPs. BC Hydro is directed to submit a further filing to the BCUC, by June 30, 2021, with its most recent performance on interconnections, its activities to date to improve its performance, and a revised plan for further improvement.	112
36.	Accordingly, the Panel directs BC Hydro to file a depreciation study by no later than the earlier of October 31, 2021 and the date it submits its fiscal 2023 RRA.	114
37.	The Panel finds that the $700,000 spent on the Riprap Stockpile for the W.A.C. Bennett dam was reasonably incurred, and therefore approves the recovery of the amount in the Test Period.	118

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38.	Accordingly, the Panel directs BC Hydro to create a new deferral account and to capture in that account, all variances between forecast and actual amounts related to the Biomass Energy Program. The Panel recognizes that most of these variances would be related to cost of energy. Therefore, the Panel directs that this account be categorized as one of BC Hydro's cost of energy variance accounts and to apply the same mechanisms for interest charges and recovery that are applicable to the Non-Heritage Deferral Account.	121
39.	Therefore, the Panel directs BC Hydro to provide in its next RRA, an assessment of whether its current practice of expensing dismantling costs as they occur would result in intergenerational inequity and to provide options on how it could calculate and collect dismantling costs to better promote intergenerational equity. For these reasons, the Panel approves the use of the Dismantling Cost Regulatory Account, as requested by BC Hydro, for the Test Period only.	124
40.	Given the intergenerational equity concerns, the Panel directs BC Hydro to include in its upcoming depreciation study a net salvage study and, in the RRA immediately after the completion of the depreciation and net salvage studies, report on the results and recommendations, as well as BC Hydro's plan to implement those recommendations.	124
41.	Therefore, the Panel disallows BC Hydro's forecast of \$10 million net gains in each of fiscal 2020 and fiscal 2021 and instead allows forecast net gains of \$0 in the Test Period from the sale of surplus real property. Given the Panel's concern with the balance that has already accumulated in the Real Property Sales regulatory account, if a balance recoverable from ratepayers is still expected to exist in this account at the end of the next test period, the Panel directs BC Hydro to provide in its fiscal 2023 RRA, a proposal on how it plans to recover the balance from ratepayers.	127
42.	The Panel directs BC Hydro, as part of its compliance filing, to provide, an explanation of why these surplus properties are included in rate base based on regulatory principles and the provisions of Direction No. 8. The Panel also directs BC Hydro to explain, as part of its compliance filing, whether the gains from the sale of these surplus properties would continue to be applied against BC Hydro's revenue requirement or whether they would revert to the shareholder in the event that the properties are removed from rate base.	127
43.	Therefore, the Panel approves BC Hydro's request to amortize into rates, over the fiscal 2020 to fiscal 2021 Test Period, the fiscal 2019 net closing balance and the forecast fiscal 2020 and fiscal 2021 net additions and net interest applied to the cost of energy variance accounts. Given that the DARR mechanism will not be used in the Test Period to refund the Cost of Energy Variance Accounts and for the reasons discussed above, the Panel approves BC Hydro's request to reduce the DARR from 5 percent to 0 percent on April 1, 2019.	129
44.	The Panel approves the following requested changes to BC Hydro's deferral and regulatory accounts: • Defer any variances related to the accounting for EPAs determined to be leases under IFRS 16, which are not eligible for deferral treatment under existing BCUC	130–131

	Directive	Page No.
	orders, to the Non-Heritage Deferral Account. • Remove the reference to the "Prescribed Standards" from the scope of what may be deferred to the Site C Regulatory Account, as BC Hydro has fully adopted IFRS.	
45.	Therefore, the Panel approves BC Hydro's request to close the following regulatory accounts: • The Capital Project Investigation Costs Regulatory Account at the end of fiscal 2021; • The Rate Smoothing Regulatory Account in fiscal 2020; • The Arrow Water Systems Provision Regulatory Account in fiscal 2020; and • The Arrow Water Systems Regulatory Account in fiscal 2020.	131
46.	However, the Panel directs BC Hydro to present options for the level of DSM in future years for BCUC review as part of BC Hydro's next IRP, using the results of the latest Conservation Potential Review and any other relevant analysis.	136
47.	The Panel therefore directs BC Hydro to report on progress with regards to the Non-Integrated Area DSM Program in its annual DSM report and in its fiscal 2023 RRA. This reporting must include an assessment of whether that program has been effective in reducing barriers for Non-Integrated Area customers in accessing DSM offerings and thereby meeting the objective of Directive 23 from the 2017-2019 RRA.	147
48.	Therefore, we approve BC Hydro's request to defer low-carbon electrification expenditures up to the undertaking costs to the DSM Regulatory Account. Since the DSM Regulatory Account will now include non-traditional DSM expenditures, the Panel sees value in increasing the transparency of the regulatory account and therefore, directs BC Hydro to separately track these expenditures in the DSM Regulatory Account.	150
49.	The Panel directs BC Hydro to report on the Low Carbon Electrification expenditures within the DSM Regulatory Account annually in its annual DSM report to the BCUC, clearly allocated to the applicable classes defined in section 4 (3) (a), (b), (c) or (d) of the GGRR, including a consolidated table with a break down between the Initial LCE and BC Hydro LCE projects and programs.	150
50.	The Panel rescinds Direction 61 from Order G-96-04 because it is inconsistent with the DSM Regulation.	151
51.	The Panel therefore makes the following determinations: • BC Hydro may transfer unspent accepted DSM expenditures in a program area to the same program area in the following year of the Test Period, on the condition that BC Hydro provides information regarding unspent amounts as part of its annual DSM reports so that all amounts transferred within a program area are transparently accounted for from one test year to the next; and • The Panel accepts the DSM expenditure schedule including transfers of up to 25	153

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	percent of DSM expenditures from any one existing program area to any other existing program area.	
52.	The Panel finds that the proposed OATT rates are just and reasonable and approves the OATT rates as applied for.	157
53.	Therefore, the Panel directs BC Hydro to update the Trade Income forecast in the Test Period by using the fiscal 2015 to fiscal 2019 actual results. The Panel also directs that in all future RRAs, if BC Hydro files an evidentiary update, all forecasts that are based on a rolling average of historical actual results be updated to include the most recently completed years' actuals that are reasonably available at the time the evidentiary update is prepared unless BC Hydro can demonstrate to the BCUC strong regulatory justification for not doing so.	163
54.	Therefore, the Panel directs BC Hydro to begin amortizing the gain from the elimination of MSP premiums over the EARSL of the active plan members, in fiscal 2020, and adjust the Test Period revenue requirement and rates accordingly.	167
55.	Therefore, the Panel directs BC Hydro to provide in all future RRAs an updated Debt Management Regulatory Account Annual Status Report as provided in its Annual Report to the BCUC.	170
56.	The Panel is generally satisfied that the depreciation rates requested by BC Hydro match the estimated life of the underlying assets and therefore, the Panel finds the requested depreciation rates for the Burrard synchronous condense facility, new water rights and LED street lights asset classes and new asset classes for agreements recognized as leases under IFRS 16, to be reasonable and approves them.	172
57.	Therefore, the Panel approves the requested depreciation rates for the infrastructure rights asset class for the Test Period only and directs BC Hydro to review the expected useful life of infrastructure rights in its upcoming depreciation study and to identify any differences from the requested 35 year useful life in the RRA immediately following the completion of the depreciation study.	172–173
58.	For these reasons, the Panel approves BC Hydro's request and hereby rescinds Directive 57 of the BCUC's Decision on BC Hydro's fiscal 2009 to fiscal 2010 RRA.	174
59.	Therefore, the Panel directs BC Hydro to maintain its records in such a way that it can produce financial information that follows the FERC USoA.	174
60.	The Panel directs BC Hydro to provide confirmation in its Compliance Filing that only the net income of Powerex and Powertech are included in the revenue requirement.	178
61.	Therefore we direct BC Hydro to file any existing transfer pricing agreement between BC Hydro and Powertech in its compliance filing.	179
62.	Therefore, BC Hydro is required to file annually as part of its annual report to the BCUC, in confidence if necessary, a summary of Powertech's net income in sufficient detail to	179

	Directive	Page No.
	enable the BCUC to determine whether the inclusion of Powertech's net income is appropriate.	
63.	BC Hydro is directed, as part of its compliance filing, to further clarify the nature of the operations of BCHPA Captive Insurance Company, Columbia Hydro Constructors Ltd. and Tongass Power and Light Company and whether they are part of BC Hydro's regulated business or operate as separate regulated or unregulated businesses. BC Hydro is also directed to file any transfer pricing agreements with these three subsidiaries along with their most recent financial statements as part of its compliance filing.	179
64.	As part of its compliance filing, the Panel also directs BC Hydro to provide the net income for its 11 remaining subsidiaries that "either serve as nominee holding companies …or are considered to be inactive/dormant." Any existing transfer pricing agreements between BC Hydro and these 11 subsidiaries must also be filed as part of its compliance filing.	179
65.	Therefore, the Panel directs BC Hydro to report in all future RRAs, until directed otherwise, on the impact of the COVID-19 pandemic with respect to its operations and how it plans to handle the resulting impact on its revenue requirement, rates and regulatory accounts.	181
66.	Therefore, the Panel directs BC Hydro to also include in that report, a discussion of its progress regarding the development of its next RDA for commercial and industrial customers, as well as for customers in the NIA. The report should also include results of the most recent fully allocated COS study, results, and a discussion on whether BC Hydro's COS methodology should be adjusted and if not, its rationale for not doing so.	183
67.	Accordingly, the Panel directs BC Hydro to file its next RRA by December 2020, and for that RRA to encompass a one-year test period for fiscal 2022.	187
68.	The Panel therefore directs BC Hydro to include the metrics it uses to manage its operations, such as those metrics included in its response to BCUC IR 62.1, in its fiscal 2022 RRA.	188

DATED at the City of Vancouver, in the Province of British Columbia, this 2nd day of October 2020.

Original signed by:

D. M. Morton
Panel Chair / Commissioner, Panel Chair

Original signed by:

A. K. Fung, QC
Commissioner

Original signed by:

E. B. Lockhart
Commissioner

Original signed by:

R. I. Mason
Commissioner

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ORDER NUMBER
G-246-20

IN THE MATTER OF
the *Utilities Commission Act*, RSBC 1996, Chapter 473

and

British Columbia Hydro and Power Authority
Fiscal 2020 to Fiscal 2021 Revenue Requirements Application

BEFORE:
D. M. Morton, Panel Chair
A. K. Fung, QC, Commissioner
E. B. Lockhart, Commissioner
R. I. Mason, Commissioner

on October 2, 2020

ORDER

WHEREAS:

A. On February 25, 2019, the British Columbia Hydro and Power Authority (BC Hydro) filed its Fiscal 2020 to Fiscal 2021 (F2020–F2021) Revenue Requirements Application (Application) with the British Columbia Utilities Commission (BCUC) pursuant to sections 44.2, 58 to 61 and 99 of the *Utilities Commission Act* (UCA) requesting, among other things:

    (i) approval of a reduction of the Deferral Account Rate Rider (DARR) from 5 percent to 0 percent effective April 1, 2019;

    (ii) approval of an increase in rates by 6.85 percent effective April 1, 2019;

    (iii) approval of an increase in rates by 0.72 percent effective April 1, 2020; and

    (iv) approval of the F2020–F2021 Open Access Transmission Tariff (OATT) rates as set out in Table 9-8 of the Application effective April 1, 2019 and April 1, 2020, respectively;

B. BC Hydro requested these changes be made effective on an interim basis, pending a final BCUC decision on the Application;

C. By Order G-45-19, the BCUC approved, on an interim basis, the requested rate increase of 6.85 percent and the reduction of the DARR to 0 percent, effective April 1, 2019, and the requested OATT rates for F2020. Order G-45-19 also established the regulatory timetable for the review of the Application;

D. By Orders G-146-19, G-218-19, G-268-19, G-279-19, G-312-19 and G-63-20, the BCUC amended the regulatory timetable for the review of the Application, which included a BC Hydro workshop, four rounds of BCUC and intervener IRs and two rounds of Panel IRs to BC Hydro, Intervener Evidence and IRs on that evidence, rebuttal evidence from BC Hydro, an oral hearing, followed by written final and reply arguments from all parties, and an oral phase of argument with BC Hydro, written submissions from all parties, and a written reply submission from BC Hydro;

E. On August 22, 2019, BC Hydro filed an evidentiary update to the Application (Evidentiary Update), adjusting its rate request effective April 1, 2020 from an increase of 0.72 percent to a decrease of 0.99 percent and revising its F2020-F2021 OATT rates as set out in Table E-2 of Appendix E to the Evidentiary Update;

F. On January 21, 2020, BC Hydro filed a correction to the Evidentiary Update, further adjusting its rate request effective April 1, 2020 from a decrease of 0.99 percent to a decrease of 1.01 percent and further revising its F2020-F2021 OATT rates;

G. On February 14, 2020, BC Hydro applied for approval of interim and refundable rates reflecting the 1.01 percent decrease effective April 1, 2020 and interim approval of the requested OATT rates for F2021;

H. By Order G-32-20, the BCUC approved, on an interim basis, the requested rate decrease of 1.01 percent, effective April 1, 2020, and the requested OATT rates for F2021;

I. On July 6 and 15, 2020, the BCUC sought further submissions from BC Hydro and registered interveners on certain matters; and

J. 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, 45, 46, 56, 58 to 61, 90 and 99 of the UCA, and for the reasons outlined in the decision issued concurrently with this order, the BCUC orders as follows:

1. The requested final rate increase of 6.85 percent to be applied as set out in Appendix EE of the Application is approved, effective April 1, 2019.
2. The requested final rate decrease of 1.01 percent is approved, effective April 1, 2020, subject to the adjustments resulting from the determinations and directives contained in the decision issued concurrently with this order.
3. The requested final reduction of the DARR from 5 percent to 0 percent is approved effective April 1, 2019.
4. The following requested changes to deferral and regulatory accounts and the associated financial treatment are approved:
    a. Amortize into rates, over the fiscal 2020 to fiscal 2021 test period, the fiscal 2019 net closing balance and the forecast fiscal 2020 and fiscal 2021 net additions and net interest applied to the Cost of Energy Variance Accounts;
    b. Defer any variances related to the accounting for electricity purchase agreements determined to be leases under International Financial Reporting Standard (IFRS) 16, which are not eligible for deferral treatment under existing BCUC orders, to the Non-Heritage Deferral Account;
    c. Defer low-carbon electrification expenditures up to the undertaking costs to the Demand-Side Management Regulatory Account;

   d. Remove the reference to the “Prescribed Standards” from the description of what may be deferred to the Site C Regulatory Account;
   e. Closure of the Capital Project Investigation Costs Regulatory Account at the end of fiscal 2021;
   f. Closure of the Rate Smoothing Regulatory Account in fiscal 2020;
   g. Closure of the Arrow Water Systems Provision Regulatory account in fiscal 2020; and
   h. Closure of the Arrow Water Systems Regulatory Account in fiscal 2020.

5. The following requested changes to deferral and regulatory accounts and the associated financial treatment are denied:
   a. Defer any variances between forecast and actual amounts related to the Biomass Energy Program, which are not eligible for deferral treatment under existing BCUC orders, to the Non-Heritage Deferral Account; and
   b. Continue to defer, on an annual and ongoing basis, any variances between forecast and actual dismantling costs to the Dismantling Cost Regulatory Account, continue to apply interest to the balance of the account and recover the forecast interest charged to the account each year, and continue to recover the forecast account balance at the end of a test period over the next test period.
6. The requested depreciation rates for the Burrard synchronous condense facility, for new Water Rights, and LED Streetlights and asset classes for three new asset classes for agreements recognized as leases under IFRS 16, *Leases* are approved on an ongoing basis.
7. The requested depreciation rate for Infrastructure Rights are approved for fiscal 2020 and fiscal 2021 only.
8. The requested final OATT rates for fiscal 2020 and fiscal 2021, as set out in Table E-2 of the correction to the Evidentiary Update, are approved effective April 1, 2019 and April 1, 2020, as applicable, subject to any adjustments resulting from the determinations and directives contained in the decision issued concurrently with this order.
9. The requested demand side management (DSM) expenditure schedule of $90.8 million in fiscal 2020 and $89.1 million in fiscal 2021, including transfers of up to 25 percent of expenditures from one program area to another, is accepted.
10. The request for reconsideration of Directive 3 of the BCUC’s Decision on BC Hydro’s Fiscal 2017 to Fiscal 2019 Revenue Requirements Application which directs BC Hydro to file a certificate of public convenience and necessity (CPCN) application for the Northwest Substation Upgrade project is allowed, and Directive 3 is varied to no longer require BC Hydro to file a CPCN for the Northwest Substation Upgrade project.
11. The requested reconsideration is allowed with respect to the following directives, which are rescinded:
    a. Directive 61 of the BCUC’s Decision on BC Hydro’s Fiscal 2005 to Fiscal 2006 Revenue Requirements Application from Order G-96-04 which directed that a prorated amount of costs from portfolio-level initiatives be added to the cost of each DSM program to assess cost effectiveness; and
    b. Directive 57 of the BCUC’s Decision on BC Hydro’s Fiscal 2009 to Fiscal 2010 Revenue Requirements Application from Order G-16-09 which directed that BC Hydro revenue requirement applications filed after January 1, 2011 contain financial information that follows the BCUC’s Uniform System of Accounts.

12. 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.

13. BC Hydro is directed to file within 60 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.

14. 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 2nd day of October 2020.

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 2020 to Fiscal 2021 Revenue Requirements Application
BC Hydro, Authority	British Columbia Hydro and Power Authority
BC OAG	Office of the Auditor General of BC
BCNPHA	BC Non-Profit Housing Association
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
Catalyst	Catalyst Paper Corporation
CEA	*Clean Energy Ac*t
CEABC	Clean Energy Association of BC
CEC	Commercial Energy Consumers Association of British Columbia
CBoC	Conference Board of Canada
COS	cost of service
COSS	Cost of Service Study
CPCN	Certificate of Public Convenience and Necessity
DARR	Deferral Account Rate Rider
Davis-Associates	Steve Davis & Associates Consulting Ltd.
Direction No. 7	Direction No. 7 to the British Columbia Utilities Commission, OIC 097/2014 and amended OIC 405/2015
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
DNV GL	DNV GL consulting
EARSL	expected average remaining service life
EMF	effective measure life
EPA	electricity purchase agreement
EV	electric vehicle

Evidentiary Update	Evidentiary update to the RRA dated August 22, 2019 and revised January 21, 2020
FBC	FortisBC Inc.
FERC	Federal Energy Regulatory Commission
FortisBC	FortisBC Energy Inc. and FortisBC Inc.
FTE	Full Time Equivalents
GHG	greenhouse gas
Gjoshe	Edlira Gjoshe
GGRR	Greenhouse Gas Reduction Regulation
HDA	Heritage Deferral Account
IFRS	International Financial Reporting Standards
Ince	David Ince
IPP	Independent Power Producer
IR	information request
IRP	integrated resource plan
KBU	Key Business Unit
LGIC	Lieutenant Governor in Council
LNG	liquefied natural gas
LRMC	long-run marginal cost
LTAP	Long Term Acquisition Plan
McCandless	Richard McCandless
MoveUP	Movement of United Professionals
MRS	Mandatory Reliability Standards
NHDA	Non-Heritage Deferral Account
NIA	Non-Integrated Areas
NITS	Network Integrated Transmission Service
O&M	operations and maintenance
OATT	Open Access Transmission Tariff
OIC	Order in Council
Phase One Review	Phase One of the Government of BC’s Comprehensive Review
Phase Two Review	Phase Two of the Government of BC’s Comprehensive Review
PRES	Peace Region Electrical Supply project

PTP	Point-to-point (PTP) Transmission Service
RDA	rate design application
RIB	Residential Inclining Block
ROE	return on equity
RRA	Revenue Requirements Application
RS	Rate Schedule
RSRA	Rate Smoothing Regulatory Account
SINTEF	SINTEF Energy Research
SMI	Smart Metering Infrastructure
SOP	Standing Offer Program
Test Period	fiscal 2020 to fiscal 2021 test period
TMP	Thermo-Mechanical Pulp
TPA	Transfer Pricing Agreement
TRC	Total Resource Cost
TRR	Transmission Revenue Requirement
UCA	*Utilities Commission Act*
UNDRIP	United Nations Declaration on the Rights of Indigenous People
USoA	Uniform System of Accounts
Willis	Paul Willis
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
F2020 to F2021 Revenue Requirements Application

EXHIBIT LIST

Exhibit No.	Description
Commission documents	
A-1	Letter dated February 26, 2019 – Appointing the Panel for the review of British Columbia Hydro and Power Authority F2020 to F2021 Revenue Requirements Application
A-2	Letter dated March 1, 2019 – BCUC Order G-45-19 establishing the Regulatory Timetable
A-3	Letter dated March 28, 2019 – Panel Information Request No. 1 to BC Hydro
A-4	Letter dated April 23, 2019 – BCUC Information Request No. 1
A-5	Letter dated May 22, 2019 – BCUC response to BC Hydro's Confidentiality Request (Exhibit B-1-1)
A-6	Letter dated May 24, 2019 – Community Input Session Information
A-7	Letter dated June 14, 2019 – Procedural Conference Information
A-8	Letter dated June 28, 2019 – BCUC Order G-146-19 furthering the Regulatory Timetable
A-9	Letter dated July 26, 2019 – BCUC Information Request No. 2 to BC Hydro
A-10	Letter dated August 2, 2019 – Request for Comments on Proposed Regulatory Timetable
A-11	Letter dated August 15, 2019 – BCUC response to Zone II RPG's Extension Request for Comments on Proposed Regulatory Timetable (Exhibit C5-5)
A-12	Letter dated August 22, 2019 – Community Input Session Information
A-13	Letter dated September 11, 2019 – BCUC Order G-218-19 amending the Regulatory Timetable

A-14	Letter dated September 13, 2019 – Community Input Session Cancellation
A-15	Letter dated September 19, 2019 – BCUC Information Request No. 3 to BC Hydro
A-16	**CONFIDENTIAL** - Letter dated September 19, 2019 – BCUC Confidential Information Request No. 3 to BC Hydro
A-17	Letter dated September 27, 2019 – Request for Comments on BC Hydro's Performance Based Regulation Report Review Process
A-18	Letter dated October 11, 2019 – BCUC Order G-244-19 establishing a separate process to review the PBR Report
A-19	Letter dated October 30, 2019 – BCUC Information Request No. 1 to BC Hydro
A-20	Letter dated November 1, 2019 – BCUC Order G-268-19 amending the Regulatory Timetable
A-21	Letter dated November 13, 2019 – BCUC Order G-279-19 amending the Regulatory Timetable with Reasons for Decision
A-22	Letter dated November 14, 2019 – Procedural conference information
A-23	Letter dated November 29, 2019 – BCUC Order G-311-19 establishing the scope of the oral hearing
A-24	Letter dated November 29, 2019 – BCUC Order G-312-19 amending the Regulatory Timetable with Reasons for Decision
A-25	Letter dated December 12, 2019 – Panel Information Request No. 2 to BC Hydro
A-26	Letter dated December 17, 2019 – BCUC Submitting Information Request No 1 to ZoneII RPG on Intervener Evidence
A-27	Letter dated December 17, 2019 – BCUC Submitting Information Request No 1 to AMPC on Intervener Evidence
A-28	Letter dated January 13, 2020 – Oral Hearing Information
A-29	Letter dated February 26, 2020 – BCUC Order G-32-20 approving F2021 Interim Rates
A-30	Letter dated March 5, 2020 – Final Submissions Schedule and Amended Regulatory Timetable
A-31	Letter dated March 26, 2020 – Panel Request regarding Final Arguments and BCUC Order G-63-20 amending the Regulatory Timetable

A-32	Letter dated March 27, 2020 – Panel reopening the evidentiary record
A-33	Letter dated May 1, 2020 – Providing information regarding oral phase of argument
A-34	Letter dated June 2, 2020 – Further information regarding oral phase of argument
A-35	Letter dated June 9, 2020 – Panel Questions to BC Hydro for the oral phase of argument
A-36	Letter dated June 16, 2020 – Panel response to BC Hydro Additional Submissions and Timetable Extension
A-37	Letter dated July 6, 2020 – Panel request for comments
A-38	Letter dated July 15, 2020 – Panel request for comments on Section 3 of Direction 8

COMMISSION STAFF DOCUMENTS

A2-1	Letter dated April 23, 2019 – British Columbia Hydro and Power Authority Compliance Filing to Order G-47-18, Responses to BCUC Staff Questions dated August 23, 2018
A2-2	Letter dated April 23, 2019 - British Columbia Hydro and Power Authority Compliance Filing to Order G-47-18 dated April 27, 2018
A2-3	Letter dated September 20, 2019 – BCUC Community Input Session Staff Presentation
A2-4	Letter dated December 5, 2019 – BCUC Staff Capital Projects Submission for Oral Hearing
A2-5	Letter dated January 23, 2020 – BCUC Staff Submitting page 34 of 118 from Order G-47-18 at the Oral Hearing
A2-6	Letter dated January 23, 2020 – BCUC Staff Submitting excerpt from BC Hydro Application for Approval of Debt Management Regulatory Account pages 3, 6, 7 and 10 at the Oral Hearing
A2-7	Letter dated January 23, 2020 – BCUC Staff Submitting excerpts from BC Hydro F2009/2010 RRA Decision dated March 13, 2009 at the Oral Hearing
A2-8	Letter dated February 24, 2020 – BCUC Staff Submitting BCUC Order G-199-19 dated August 23, 2019 at Oral Hearing
A2-9	Letter dated March 2, 2020 – BCUC Staff Submitting excerpt from BC Hydro Bridge River System Upgrades dated February 24, 2020 at the Oral Hearing
A2-10	Letter dated March 2, 2020 – BCUC Staff Submitting excerpt from BC Hydro F2017/2019 RRA Decision to Order G-47-18 at the Oral Hearing

A2-11 Letter dated March 2, 2020 – BCUC Staff Submitting Review of the Regulatory Oversight of Capital Expenditures and Projects, B-4, CEABC 1.18.0 dated April 24, 2018 at the Oral Hearing

A2-12 Letter dated March 2, 2020 – BCUC Staff Submitting Review of the Regulatory Oversight of Capital Expenditures and Projects, B-4, BCUC 1.5.2 Attachment 1 at the Oral Hearing

APPLICANT DOCUMENTS

B-1 **BRITISH COLUMBIA HYDRO AND POWER AUTHORITY (BC HYDRO)** - Letter dated February 25, 2019 – Submitting the F2020 to F2021 Revenue Requirements Application

B-1-1 **CONFIDENTIAL** – Letter dated February 26, 2019 – BC Hydro Submitting Confidential Appendices I, J, K and Y to the Application

B-1-2 Letter dated March 7, 2019 – BC Hydro Submitting Supplemental Information to the Application

B-1-3 **CONFIDENTIAL** - Letter dated March 7, 2019 – BC Hydro Submitting Confidential Supplemental Information to the Application

B-1-4 Letter dated March 26, 2019 – BC Hydro Submitting Supplemental Information – Summary Audit Report and Management Audit Report

B-2 Letter dated March 19, 2019 - BC Hydro presentation from March 15, 2019 Workshop

B-3 Letter dated March 19, 2019 - BC Hydro providing notifications in Compliance with BCUC Order G-45-19

B-4 Letter dated April 3, 2019 – BC Hydro Submitting responses to Panel Information Request No. 1

B-4-1 **CONFIDENTIAL** - Letter dated April 3, 2019 – BC Hydro Submitting Confidential responses to Panel Information Request No. 1

B-5 Letter dated June 6, 2019 – BC Hydro Submitting responses to BCUC Information Request No. 1

B-5-1 **CONFIDENTIAL** - Letter dated June 6, 2019 – BC Hydro Submitting Confidential responses to BCUC Information Request No. 1 (Letter)

B-5-1-1 **CONFIDENTIAL** - Letter dated March 2, 2020 – BC Hydro Submitting Revised Confidential responses to BCUC Information Request No. 1

B-5-2 Letter dated January 17, 2020 – BC Hydro Submitting revised response to BCUC Information Request No. 1.164.1

B-5-3	Letter dated March 2, 2020 – BC Hydro Submitting Revised responses to BCUC Information Request No. 1
B-6	Letter dated June 6, 2019 – BC Hydro Submitting responses to Intervener Information Request No. 1
B-6-1	**CONFIDENTIAL** - Letter dated June 6, 2019 – BC Hydro Submitting Confidential responses to Intervener Information Request No. 1 (Letter)
B-6-2	Letter dated January 17, 2020 – BC Hydro Submitting revised response to BCOAPO Information Request No. 1.16.2
B-7	Letter dated June 6, 2019 – BC Hydro Submitting updated Appendix J of the Application in response to BCUC IR 1.121.1.2
B-8	Letter dated June 19, 2019 – BC Hydro Submitting Comments on Procedural Matters
B-9	Letter dated July 26, 2019 – BC Hydro Submitting update on Government of BC's Public Accounts release
B-10	Letter dated August 15, 2019 – BC Hydro Submitting Comments on Proposed Regulatory Timetable
B-11	Letter dated August 22, 2019 – BC Hydro Submitting Evidentiary Update
B-11-1	**CONFIDENTIAL** - Letter dated August 22, 2019 – BC Hydro Submitting Confidential Evidentiary Update
B-11-2	Letter dated January 21, 2020 – BC Hydro Submitting correction in Appendix A of Evidentiary Update
B-12	Letter dated September 3, 2019 – BC Hydro Submitting responses to BCUC Information Request No. 2
B-12-1	**CONFIDENTIAL** – Letter dated September 3, 2019 – BC Hydro Submitting Confidential responses to BCUC Information Requests No. 2
B-12-2	Letter dated January 17, 2020 – BC Hydro Submitting revised response to BCUC Information Request No. 2.267.1
B-13	Letter dated September 3, 2019 – BC Hydro Submitting responses to Intervener Information Request No. 2
B-13-1	**CONFIDENTIAL** – Letter dated September 3, 2019 – BC Hydro Submitting Confidential responses to Intervener Information Requests No. 2
B-14	Letter dated October 2, 2019 – BC Hydro Submitting Comments on review process for BC Hydro's Performance Based Regulation Report
B-15	Letter dated October 3, 2019 – BC Hydro Submitting a 20 Year Load Forecast

B-15-1	**CONFIDENTIAL -** Letter dated October 3, 2019 – BC Hydro Submitting a Confidential 20 Year Load Forecast
B-16	Letter dated October 10, 2019 – BC Hydro Submitting Responses to BCUC Information Request No. 3
B-16-1	**CONFIDENTIAL -** Letter dated October 10, 2019 – BC Hydro Submitting Confidential Responses to BCUC Information Request No. 3
B-17	Letter dated October 10, 2019 – BC Hydro Submitting Responses to Intervener Information Requests No. 3
B-17-1	**CONFIDENTIAL -** Letter dated October 10, 2019 – BC Hydro Submitting Confidential Responses to Intervener Information Requests No. 3
B-17-1-1	**CONFIDENTIAL -** Letter dated March 2, 2020 – BC Hydro Submitting Revised Confidential Responses to AMPC Information Requests No. 3
B-17-2	Letter dated March 2, 2020 – BC Hydro Submitting Revised Responses to AMPC Information Requests No. 3
B-18	**CONFIDENTIAL -** Letter dated October 10, 2019 – BC Hydro Submitting Responses to BCUC Confidential Information Request No. 3
B-19	Letter dated October 18, 2019 – BC Hydro Submitting un-redacted version of the Evidentiary Update
B-20	Letter dated October 18, 2019 – BC Hydro publicly release some Information Responses previously considered Confidential
B-21	Letter dated November 8, 2019 – BC Hydro Submitting Extension Request to File Information Request Responses
B-22	Letter dated November 14, 2019 – BC Hydro Submitting responses to BCUC Information Request No. 4
B-22-1	**CONFIDENTIAL** - Letter dated November 14, 2019 – BC Hydro Submitting responses to BCUC Information Request No. 4
B-22-2	Letter dated December 13, 2019 – BC Hydro Response to BCUC Information Request No. 4 on 20-Year Load Forecast
B-23	Letter dated November 14, 2019 – BC Hydro Submitting responses to Intervener Information Request No. 4
B-23-1	**CONFIDENTIAL -** Letter dated November 14, 2019 – BC Hydro Submitting responses to Intervener Information Request No. 4
B-23-2	Letter dated November 19, 2019 – BC Hydro Submitting remaining responses to Intervener Information Requests No. 4

B-23-3	Letter dated December 13, 2019 – BC Hydro Responses to Interveners Information Request No. 4 on 20-Year Load Forecast
B-23-4	Letter dated January 17, 2020 – BC Hydro Submitting revised response to CEABC Information Request No. 4.58.4
B-24	Letter dated November 18, 2019 – BC Hydro Submitting written submission prior to procedural conference
B-25	Letter dated November 19, 2019 – BC Hydro Submitting response on Attachment A of Exhibit B-21
B-26	Letter dated December 13, 2019 – BC Hydro Submitting update on the Peace Kelly Lake Capacitors Project
B-27	Letter dated January 9, 2020 – BC Hydro Submitting witness panels for upcoming oral hearing
B-28	Letter dated January 15, 2020 – BC Hydro Submitting Rebuttal Evidence
B-28-1	**CONFIDENTIAL** - Letter dated January 15, 2020 – BC Hydro Submitting Confidential Rebuttal Evidence
B-28-2	Letter dated January 17, 2020 – BC Hydro Submitting revised Rebuttal Evidence
B-29	Letter dated January 15, 2020 – BC Hydro Submitting Updated Information on Technology Capital Projects and the Metro North Transmission Project
B-30	Letter dated January 16, 2020 – BC Hydro Submitting Chris O'Reilly oral hearing Opening Statement
B-31	Letter dated January 17, 2020 – BC Hydro Submitting responses to Panel Information Request No. 2
B-31-1	**CONFIDENTIAL** - Letter dated January 17, 2020 – BC Hydro Submitting Confidential responses to Panel Information Request No. 2
B-32	Letter dated January 21, 2020 – BC Hydro Submitting Undertaking No. 1 from CEABC at Oral Hearing
B-33	Letter dated January 21, 2020 – BC Hydro Submitting Undertaking No. 2 from CEABC at Oral Hearing
B-34	Letter dated January 22, 2020 – BC Hydro Submitting F07-08 Revenue Requirements Appendix F at the Oral Hearing
B-35	Letter dated January 23, 2020 – BC Hydro Submitting BC Hydro Undertaking No. 8 at the Oral Hearing

B-36	Letter dated January 23, 2020 – BC Hydro Submitting BC Hydro Undertaking No. 9 at the Oral Hearing
B-37	Letter dated January 23, 2020 – BC Hydro Submitting BC Hydro Undertaking No. 10 at the Oral Hearing
B-38	Letter dated January 23, 2020 – BC Hydro Submitting BC Hydro Undertaking No. 7 at the Oral Hearing
B-39	Letter dated January 23, 2020 – BC Hydro Submitting BC Hydro Undertaking No. 5 at the Oral Hearing
B-40	Letter dated January 24, 2020 – BC Hydro Submitting BC Hydro Undertaking No. 13 at the Oral Hearing
B-41	Letter dated January 24, 2020 – BC Hydro Submitting BC Hydro Undertaking No. 15 at the Oral Hearing
B-42	Letter dated January 24, 2020 – BC Hydro Submitting BC Hydro Undertaking No. 16 at the Oral Hearing
B-43	Letter dated February 14, 2020 – BC Hydro Submitting response to Oral Hearing Feedback
B-44	Letter dated February 14, 2020 – BC Hydro Submitting response to remaining Undertakings from the Oral Hearing
B-45	Letter dated February 14, 2020 – BC Hydro Submitting request for Interim Fiscal 2021 Rates
B-46	Letter dated February 27, 2020 – BC Hydro Submitting BCOAPO Undertaking dated January 22, 2020 at Oral Hearing
B-47	Letter dated February 28, 2020 – BC Hydro Submitting CEABC Undertaking dated February 25, 2020 at Oral Hearing
B-47-1	**CONFIDENTIAL** – Letter dated February 28, 2020 - BC Hydro Submitting Confidential CEABC Undertaking dated February 25, 2020 at Oral Hearing

B-48	Letter dated February 28, 2020 - BC Hydro Submitting CEC Undertaking dated February 25, 2020 at Oral Hearing
B-48-1	**CONFIDENTIAL** - Letter dated February 28, 2020 - BC Hydro Submitting Confidential CEC Undertaking dated February 25, 2020 at Oral Hearing
B-49	Letter dated March 2, 2020 - BC Hydro Submitting Intervener Undertakings dated February 24, 2020 at Oral Hearing
B-49-1	**CONFIDENTIAL** - Letter dated March 2, 2020 - BC Hydro Submitting Confidential Intervener Undertakings dated February 24, 2020 at Oral Hearing
B-50	Letter dated March 2, 2020 - BC Hydro Submitting AMPC Undertaking dated February 28, 2020 at Oral Hearing
B-50-1	Letter dated March 20, 2020 – BC Hydro Submitting Supplemental Response to Undertaking No. 37
B-51	Letter dated March 3, 2020 - BC Hydro Submitting Undertakings No. 25 from Gjoshe, No. 39 from AMPC and No. 47 from Commissioner Fung at Oral Hearing
B-51-1	**CONFIDENTIAL** - Letter dated March 3, 2020 - BC Hydro Submitting Confidential Undertaking No. 39 from AMPC at Oral Hearing
B-51-2	Letter dated March 20, 2020 – BC Hydro Submitting Supplemental Response to Undertaking No. 39
B-52	Letter dated March 3, 2020 - BC Hydro Submitting Undertakings No. 29 from Mr. Miller and No. 53 from Commissioner Morton at Oral Hearing
B-53	Letter dated March 3, 2020 - BC Hydro Submitting Undertakings No. 35 from AMPC and No. 46 from BCOAPO at Oral Hearing
B-53-1	Letter dated March 20, 2020 – BC Hydro Submitting Supplemental Response to Undertaking No. 35
B-54	Letter dated March 3, 2020 - BC Hydro Submitting Undertaking No. 50 from BCUC Staff at Oral Hearing
B-55	Letter dated March 4, 2020 - BC Hydro Submitting Undertakings No. 55 from Commissioner Lockhart and No. 56 from Commissioner Morton at Oral Hearing

B-55-1	**CONFIDENTIAL** Letter dated March 4, 2020 - BC Hydro Submitting Confidential Undertaking No. 56 from Commissioner Morton at Oral Hearing
B-56	Letter dated March 6, 2020 - BC Hydro Submitting remaining Undertakings Nos. 41, 45, 49 and 51
B-57	Letter dated March 13, 2020 – BC Hydro Submitting Undertaking Nos. 36, 42, 43, 48, 52, 57, 58, 59, 60, 61, 63, 64, 65 and 66 from Oral Hearing
B-57-1	**CONFIDENTIAL** - Letter dated March 13, 2020 – BC Hydro Submitting Confidential Versions of Undertaking Nos. 43 and 48 from Oral Hearing
B-57-2	Letter dated March 20, 2020 – BC Hydro Submitting Supplemental Response to Undertaking No. 58
B-58	Letter dated March 20, 2020 – BC Hydro Submitting Responses to Undertakings No. 44, 54 and 62
B-58-1	**CONFIDENTIAL** - Letter dated March 20, 2020 – BC Hydro Submitting Responses to Undertakings No. 44 and 54
B-58-2	Letter dated March 26, 2020 – BC Hydro Submitting Supplemental Response to Undertaking No. 62
B-59	Letter dated July 24, 2020 – BC Hydro Submitting response to Panel Request for comment
B-60	Letter dated July 24, 2020 – BC Hydro Submitting response to Panel Questions in Exhibit A-38
B-61	Letter dated August 20, 2020 – BC Hydro Submitting response to Intervener comments

C1-1	**MOVEMENT OF UNITED PROFESSIONALS (MOVEUP)** Letter dated March 1, 2019 Request to Intervene by Susanna Quail
C1-2	Letter dated May 2, 2019 – MoveUP Information Request No. 1 to BC Hydro
C1-3	Letter dated September 19, 2019 – MoveUP Information Request No. 3 to BC Hydro
C1-4	Letter dated October 18, 2019 – MoveUP Information Request on 20-Year Load Forecast to BC Hydro
C1-5	Letter dated November 14, 2019 – MoveUP advising Dr. Marvin Shaffer to assist MoveUP
C1-6	Letter dated December 13, 2019 – MoveUP Submitting Information Request No. 1 to AMPC
C1-7	Letter dated January 24, 2020 – MoveUP Submitting document entitled Cost of IPP Energy at the Oral Hearing
C1-8	Letter dated January 24, 2020 – MoveUP Submitting one page excerpt from ZAPPED Report at the Oral Hearing
C1-9	Letter dated August 11, 2020 – MoveUP Submitting response to Panel Request for comments
C1-10	Letter dated August 11, 2020 – MoveUP Submitting response to Panel Request for comments on Section 3 of Direction 8
C2-1	**CATALYST PAPER CORPORATION (CATALYST)** Letter dated March 4, 2019 Request to Intervene by Carlo Dal Monte
C3-1	**FORTISBC ENERGY INC. AND FORTISBC INC. (FORTISBC)** Letter dated March 13, 2019 Request to Intervene by Doug Slater
C3-2	Letter dated May 2, 2019 – FortisBC Information Request No. 1 to BC Hydro
C3-3	Letter dated August 12, 2019 – FortisBC Comment on Proposed Regulatory Timetable
C4-1	**RICHARD MCCANDLESS (MCCANDLESS)** Letter dated March 14, 2019 Request for Intervener Status
C4-2	Letter dated May 1, 2019 – McCandless Information Request No. 1 to BC Hydro
C4-3	Letter dated August 10, 2020 – McCandless Submitting response to Panel Requests for comments
C5-1	**KWADACHA NATION AND TSAY KEH DENE NATION, TOGETHER THE ZONE II RATEPAYERS GROUP (ZONE II RPG)** Letter dated March 18, 2019 Request to Intervene by Jana McLean
C5-2	Letter dated May 2, 2019 – Zone II RPG Information Request No. 1 to BC Hydro

C5-3	Letter dated May 2, 2019 – Zone II RPG Submitting Confidentiality Declarations
C5-4	Letter dated August 1, 2019 – Zone II RPG Submitting Information Request No. 2 to BC Hydro
C5-5	Letter dated August 14, 2019 – Zone II RPG Submitting an Extension Request
C5-5-1	Letter dated August 14, 2019 – Zone II RPG Submitting Details Regarding the Extension Request
C5-6	Letter dated August 19, 2019 – Zone II RPG Submitting Comments on Proposed Regulatory Timetable
C5-7	Letter dated September 18, 2019 – Zone II RPG Submitting Information Request No. 3 to BC Hydro
C5-8	Letter dated October 30, 2019 – Zone II RPG Submitting Information Request No. 4 to BC Hydro
C5-9	Letter dated December 3, 2019 – Zone II RPG Submitting Intervener Evidence
C5-10	Letter dated December 17, 2019 – Zone II RPG Submitting Information Request No 1 to AMPC on Intervener Evidence
C5-11	Letter dated January 10, 2020 – Zone II RPG Submitting Response to CEC Information Request No. 1 on Zone II RPG Intervener Evidence
C5-12	Letter dated January 10, 2020 – Zone II RPG Submitting Response to BCUC Information Request No. 1 on Zone II RPG Intervener Evidence
C5-13	Letter dated August 14, 2020 – Zone II Submitting response to Panel Request for comments

C6-1	**British Columbia Old Age Pensioners' Organization et al. (BCOAPO)** Letter dated March 20, 2019 Request to Intervene by Leigha Worth & Irina Mis
C6-2	Letter dated May 2, 2019 – BCOAPO Information Request No. 1 to BC Hydro
C6-3	Letter dated August 1, 2019 – BCOAPO Information Request No. 2 to BC Hydro
C6-4	Letter dated August 19, 2019 – BCOAPO Submitting Comments on Proposed Regulatory Timetable
C6-5	Letter dated September 19, 2019 – BCOAPO Information Request No. 3 to BC Hydro
C6-6	Letter dated October 30, 2019 – BCOAPO Submitting Information Request No. 4 to BC Hydro on 20-Year Load Forecast and Cost of Energy Evidentiary Update
C6-7	Letter dated December 3, 2019 – BCOAPO Submitting capital projects for cross-examination at oral hearing
C6-8	Letter dated January 20, 2020 – BCOAPO Submitting Ministry of Energy, Mines and Petroleum Resources Press Release 'Government will help low-income families manage electricity costs' at Oral Hearing
C6-9	Letter dated March 3, 2020 – BCOAPO Submitting Customer Energy Use Profiles from Low Income Advisory Committee dated September 26, 2019 at Oral Hearing
C6-10	Letter dated August 14, 2020 – BCOAPO Submitting response to Panel Request for comments
C7-1	**Paul Willis (Willis)** Letter dated March 19, 2019 Request for Intervener Status
C7-2	Letter dated May 2, 2019 – Willis Information Request No. 1 to BC Hydro
C7-3	Letter dated August 1, 2019 – Willis Information Request No. 2 to BC Hydro
C7-4	Letter dated October 23, 2019 – Willis Information Request No. 3 to BC Hydro
C7-5	Letter dated August 14, 2020 – Willis Submitting Comments on Hearing Process
C8-1	**BC Sustainable Energy Association and Sierra Club (BCSEA)** - Letter dated May 20, 2019 Request to Intervene by William Andrews
C8-2	Letter dated May 2, 2019 – BCSEA Information Request No. 1 to BC Hydro
C8-3	Letter dated August 1, 2019 – BCSEA Information Request No. 2 to BC Hydro

C8-4	Letter dated August 2, 2019 – BCSEA Comments on Proposed Regulatory Timetable
C8-5	Letter dated September 19, 2019 – BCSEA Information Request No. 3 to BC Hydro
C8-6	Letter dated October 30, 2019 – BCSEA Submitting Information Request No. 4 to BC Hydro
C8-7	Letter dated December 13, 2019 – BCSEA Submitting Information Request No. 1 to AMPC
C8-8	Letter dated August 12, 2020 – BCSEA Submitting response to Panel Request for comments
C8-9	Letter dated August 12, 2020 – BCSEA Submitting response to Panel Request for comments on Section 3 of Direction 8
C9-1	**COMMERCIAL ENERGY CONSUMERS ASSOCIATION OF BRITISH COLUMBIA (CEC)** Letter dated March 21, 2019 Request to Intervene by Christopher Weafer
C9-2	Letter dated April 23, 2019 – CEC Submitting Confidential Undertakings for David W. Craig, Janet Rhodes and Christopher P. Weafer
C9-2-1	Letter dated April 24, 2019 – CEC Submitting additional Confidential Undertaking for Patrick J. Weafer
C9-3	Letter dated May 2, 2019 – CEC Information Request No. 1 to BC Hydro
C9-4	Letter dated August 1, 2019 – CEC Information Request No. 2 to BC Hydro
C9-5	Letter dated August 14, 2019 – CEC Comments on Proposed Regulatory Timetable
C9-6	Letter dated September 19, 2019 – CEC Information Request No. 3 to BC Hydro
C9-7	Letter dated October 30, 2019 – CEC Submitting Information Request No. 4 to Hydro on 20-Year Load Forecast
C9-8	Letter dated October 30, 2019 – CEC Submitting Information Request No. 4 to BC Hydro on Cost of Energy Update
C9-9	Letter dated November 14, 2019 – CEC Submitting extension request to Information Request responses
C9-10	Letter dated November 22, 2019 – CEC Additional Submission at Procedural Conference
C9-11	Letter dated December 3, 2019 – CEC Submitting capital projects for cross-examination at oral hearing
C9-12	Letter dated December 17, 2019 – CEC Submitting Information Request No 1 to AMPC on Intervener Evidence
C9-13	Letter dated December 17, 2019 – CEC Submitting Information Request No 1 to Zone II RPG on Intervener Evidence

C9-14	Letter dated January 20, 2020 – CEC Submitting excerpt from SAP Inquiry Report at Oral Hearing
C9-15	Letter dated January 20, 2020 – CEC Submitting article from Vancouver Sun at Oral Hearing
C9-16	Letter dated January 20, 2020 – CEC Submitting Review of BC Hydro's Purchase of Power from IPPs conducted for the Minister of Energy, Mines and Petroleum Resources at Oral Hearing
C9-17	Letter dated January 23, 2020 – CEC Submitting excerpt from BCUC Reasons for Decision regarding BC Hydro … Application for Electricity Purchase Agreement Renewals … dated November 8, 2019 at the Oral Hearing
	Moved to Argument
C9-18	Letter dated August 14, 2020 – CEC Submitting response to Panel Request for comments
C9-19	Letter dated August 14, 2020 – CEC Submitting response to Panel Request for comments on Section 3 of Direction 8
C10-1	**CLEAN ENERGY ASSOCIATION OF BC (CEABC) -** Letter dated March 21, 2019 Request to Intervene by Martin Mullany
C10-2	Letter dated May 2, 2019 – CEABC Information Request No. 1 to BC Hydro
C10-3	Letter dated August 1, 2019 – CEABC Information Request No. 2 to BC Hydro
C10-4	Letter dated August 16, 2019 – CEABC Comments on Proposed Regulatory Timetable
C10-5	Letter dated September 19, 2019 – CEABC Information Request No. 3 to BC Hydro
C10-6	Letter dated October 30, 2019 – CEABC Information Request No. 4 to BC Hydro
C10-7	Letter dated November 15, 2019 – CEABC Submission regarding Extension Request to file Attachment A Information Requests
C10-8	Letter dated December 17, 2019 – CEABC Submitting Information Request No 1 to AMPC on Intervener Evidence
C10-9	Letter dated January 20, 2020 – CEABC Submitting excerpt from Shareholder's Letter of Expectations at Oral Hearing
C10-10	Letter dated January 20, 2020 – CEABC Submitting excerpt from BC Hydro's Service Plan at Oral Hearing

C10-11	Letter dated January 20, 2020 – CEABC Submitting MEMPR Letter reference 98538 dated February 16, 2017 at Oral Hearing
C10-12	Letter dated January 20, 2020 – CEABC Submitting excerpt from MEMPR Letter dated August 24, 2017 at Oral Hearing
C10-13	Letter dated January 21, 2020 – CEABC Submitting BC Hydro Dam Safety 1 Report – F2014 Executive Summary at Oral Hearing
C10-14	Letter dated January 21, 2020 – CEABC Submitting response to Zapped Allegation of Overspending Billions on IPPs at Oral Hearing
C10-15	Letter dated January 21, 2020 – CEABC Submitting California Public Utilities 2018 Annual Report on Renewable Portfolio Standard at Oral Hearing
C10-16	Letter dated January 21, 2020 – CEABC Submitting excerpt from Zapped: A Review of BC Hydro's Purchase of Power from IPPs at Oral Hearing
C10-17	Letter dated January 24, 2020 – CEABC Submitting excerpt from Transcript Volume 12 dated October 20, 2008 from BC Hydro F2009 and F2010 RRA at the Oral Hearing
C10-18	Letter dated January 24, 2020 – CEABC Submitting BC Hydro Undertaking from BCH 2004/05 and 2005/06 RR Hearing dated June 8, 2004 at the Oral Hearing
C10-19	Letter dated January 24, 2020 – CEABC Submitting graph headed Load Compared to System Energy including IPPS at the Oral Hearing
C10-20	Letter dated January 24, 2020 – CEABC Submission from BC Hydro 2020-21 Revenue Requirements Application B-23-3 at the Oral Hearing
C10-21	Letter dated January 24, 2020 – CEABC additional Submission from BC Hydro 2020-21 Revenue Requirements Application B-23-3 at the Oral Hearing
C10-22	Letter dated January 24, 2020 – CEABC Submitting Enbridge News Article at the Oral Hearing
C10-23	Letter dated January 24, 2020 – CEABC Submitting Exhibit B-8 from BC Hydro Waneta 2017 Transaction at the Oral Hearing

C10-24	Letter dated February 25, 2020 – CEABC Submitting Exhibit B-15 excerpt from BC Hydro F2017-F2019 Revenue Requirements dated January 23, 2017 at the Oral Hearing
C10-25	Letter dated February 25, 2020 – CEABC Submitting Exhibit B-15 excerpt from BC Hydro F2017-F2019 Revenue Requirements dated January 23, 2017 at the Oral Hearing
C10-26	Letter dated February 25, 2020 – CEABC Submitting Industrial Electricity Policy Review Task Force Final Report dated October 31, 2013 at the Oral Hearing
C10-27	Letter dated February 25, 2020 – CEABC Submitting BC Hydro 2016/17 – 2018/19 Service Plan at the Oral Hearing
C10-28	Letter dated February 25, 2020 – CEABC Submitting Times Colonist article date January 12, 2020 at the Oral Hearing
C10-29	Letter dated August 14, 2020 – CEABC Submitting response to Panel Request for comments
C10-30	Letter dated August 14, 2020 – CEABC Submitting response to Panel Request for comments on Section 3 of Direction 8
C11-1	**ASSOCIATION OF MAJOR POWER CUSTOMERS OF BRITISH COLUMBIA (AMPC) -** Letter dated March 21, 2019 Request to Intervene by Matthew D. Keen
C11-2	Letter dated April 30, 2019 – AMPC Submitting Confidential Undertakings
C11-3	Letter dated May 2, 2019 – AMPC Information Request No. 1 to BC Hydro
C11-4	Letter dated June 24, 2019 – AMPC Outline Submitted at Procedural Conference
C11-5	Letter dated August 1, 2019 – AMPC Information Request No. 2 to BC Hydro
C11-6	Letter dated August 19, 2019 – AMPC Submitting Comments on Proposed Regulatory Timetable
C11-7	Letter dated September 19, 2019 – AMPC Information Request No. 3 to BC Hydro
C11-8	Letter dated October 23, 2019 – AMPC Extension Request to file Intervener Information Request Response
C11-9	Letter dated October 30, 2019 – AMPC Submitting Information Request No. 4 to BC Hydro on 20-Year Load Forecast and Cost of Energy Evidentiary Update
C11-10	Letter dated November 15, 2019 – AMPC Submission regarding Extension Request to file Attachment A Information Requests
C11-11	Letter dated December 3, 2019 – AMPC Submitting Intervener Evidence

C11-12	Letter dated December 3, 2019 – AMPC Submitting capital projects for cross-examination at oral hearing
C11-13	Letter dated January 10, 2020 – AMPC Submitting responses to MoveUP, Zone II RPG and BCSEA information requests on intervener evidence
C11-14	Letter dated January 13, 2020 – AMPC Submitting responses to BCUC, CEABC and CEC information requests on intervener evidence
C11-15	Letter dated January 20, 2020 – AMPC Submitting Terms of Reference for the Comprehensive Review of BC Hydro at Oral Hearing
C11-16	Letter dated January 20, 2020 – AMPC Submitting response from F2012 to F2014 Revenue Requirement Application at Oral Hearing
C11-17	Letter dated January 20, 2020 – AMPC Submitting aid to cross 9 "News" dated May 16, 2018 at Oral Hearing
C11-18	Letter dated January 21, 2020 – AMPC Submitting Aid to Cross 11 at Oral Hearing
C11-19	Letter dated January 22, 2020 – AMPC Submitting First Quarterly Report 2019 at Oral Hearing
C11-20	Letter dated January 22, 2020 – AMPC Submitting Aid to Cross 2-BC Hydro Letter of Agreement at Oral Hearing
C11-21	Letter dated February 4, 2020 – AMPC Submitting Confidential Undertaking for Alexander Baer
C11-22	Letter dated February 24, 2020 – AMPC Submitting Opening Statement of Patrick Bowman
C11-23	Letter dated February 28, 2020 – AMPC Submitting excerpt from Industrial Connections dated February 23, 2020 at the Oral Hearing
C11-24	Letter dated February 28, 2020 – AMPC Submitting Business Practice for Load Interconnection Queue Management dated November 10, 2014 at the Oral Hearing
C11-25	Letter dated February 28, 2020 – AMPC Submitting article from Alaska Highway News dated February 27, 2020 at the Oral Hearing
C11-26	Letter dated February 28, 2020 – AMPC Submitting Undertaking No. 1 from Zone II RPG at Oral Hearing

C11-27	Letter dated February 28, 2020 – AMPC Submitting F2017–F2019 RRA, Exhibit B-14, BCUC IR 2.318.1 at Oral Hearing
C11-28	Letter dated August 14, 2020 – AMPC Submitting response to Panel Request for comments
C12-1	**DAVID INCE (INCE) -** Letter dated March 21, 2019 Request for Intervener Status
C12-2	Letter dated May 1, 2019 – Ince Information Request No. 1 to BC Hydro
C12-3	Letter dated May 6, 2019 – Ince Submitting Confidential Undertaking
C12-4	Letter dated August 1, 2019 – Ince Information Request No. 2 to BC Hydro
C12-5	Letter dated September 19, 2019 – Ince Information Request No. 3 to BC Hydro
C12-6	Letter dated October 30, 2019 – Ince Submitting Information Request No. 4 to BC Hydro on 20-Year Load Forecast
C12-7	Letter dated November 12, 2019 – Ince Submitting Response to BC Hydro letter dated November 8, 2019 (Exhibit B-21)
C12-8	Letter dated August 14, 2020 – Ince Submitting response to Panel Request for comments
C13-1	**STEVE DAVIS & ASSOCIATES CONSULTING LTD. (DAVIS-ASSOCIATES) -** Letter dated March 21, 2019 Request to Intervene by Steve Davis
C14-1	**EDLIRA GJOSHE (GJOSHE)** Letter dated March 21, 2019 Request to Intervene by Edlira Gjoshe
C14-2	Letter dated May 2, 2019 – Gjoshe Submitting Information Request No. 1 to BC Hydro
C14-3	Letter dated August 1, 2019 – Gjoshe Submitting Information Request No. 2 to BC Hydro
C14-4	Letter dated September 19, 2019 – Gjoshe Submitting Information Request No. 3 to BC Hydro
C14-5	Letter dated October 30, 2019 – Gjoshe Submitting Information Request No. 4 to BC Hydro
C14-6	Letter dated October 30, 2019 – Gjoshe Submitting Information Request No. 5 to BC Hydro
C14-7	Letter dated December 3, 2019 – Gjoshe Submitting capital projects for cross-examination at oral hearing
C14-8	Letter dated February 27, 2020 – Gjoshe Submitting article dated February 20, 2020 at the Oral Hearing
C14-9	Letter dated August 14, 2020 – Gjoshe Submitting response to Panel Request for comments

C15-1 **BC NON-PROFIT HOUSING ASSOCIATION (BCNPHA) -** Letter dated April 2, 2019 – Late Request to Intervene by Ian Cullis

C15-2 Letter dated May 1, 2019 – BCNPHA Information Request No. 1 to BC Hydro

INTERESTED PARTY DOCUMENTS

D-1 **MOVEUP** - Party Status Changed to Intervener (Exhibit C1-1)

D-2 **BRITISH COLUMBIA MINISTRY OF ENERGY, MINES AND PETROLEUM RESOURCES (MEMPR)** – Letter dated March 19, 2019 Request for Interested Party Status by Jack Buchanan

D-3 **KING, MARTIN (KING)** - Submission dated July 5, 2019 Request for Interested Party Status

D-3-1 **KING** - Letter of Comment dated July 5, 2019

D-4 **WAUTHY, J. (WAUTHY) –** Submission dated February 4, 2020 Request for Interested Party Status

LETTERS OF COMMENT

E-1 Dempsey, B. – Letter of Comment dated March 1, 2019

E-2 Griffin, L. – Letter of Comment dated March 2, 2019

E-3 Wright, J. – Letter of Comment dated March 10, 2019

E-4 Stoppard, C. – Letter of Comment dated August 30, 2019

E-5 Harrap, K. – Letter of Comment dated November 8, 2019

E-6 Danes, B. – Letter of Comment dated December 13, 2019

E-6-1 Danes, B. – Letter of Comment dated December 15, 2019

E-7 Barton, K. – Letter of Comment dated January 18, 2020

E-8 Morven, M. – Letter of Comment dated January 19, 2020