FASKEN

Fasken Martineau DuMoulin LLP
Barristers and Solicitors
Patent and Trade-mark Agents

550 Burrard Street, Suite 2900
Vancouver, British Columbia V6C 0A3
Canada

T +1 604 631 3131
+1 866 635 3131
F +1 604 631 3232

fasken.com

Matthew Ghikas
Direct +1 604 631 3191
Facsimile +1 604 632 3191
mghikas@fasken.com

April 1, 2020
File No.: 301539.00025/14797

By Electronic Filing

British Columbia Utilities Commission
Suite 410, 900 Howe Street
Vancouver, BC V6Z 2N3

Attention: Patrick Wruck, Commission Secretary

Dear Sirs/Mesdames:

Re: British Columbia Hydro and Power Authority ("BC Hydro")
F2020 to F2021 Revenue Requirements Application ~ Project No. 1598990

We enclose for filing BC Hydro's Final Submission in the above-noted proceeding.

Yours truly,

FASKEN MARTINEAU DuMOULIN LLP

[Original signed by]

Matthew Ghikas
Personal Law Corporation

MTG/lh
Enclosure

BRITISH COLUMBIA UTILITIES COMMISSION

IN THE MATTER OF THE *UTILITIES COMMISSION ACT*,

R.S.B.C. 1996, CHAPTER 473

and

BRITISH COLUMBIA HYDRO AND POWER AUTHORITY

FISCAL 2020 TO FISCAL 2021 REVENUE REQUIREMENTS APPLICATION

Final Submission of BC Hydro

April 1, 2020

FASKEN MARTINEAU DuMOULIN LLP
Matthew Ghikas, Christopher Bystrom and Tariq Ahmed

TABLE OF CONTENTS

PART ONE: INTRODUCTION AND OVERVIEW

A. INTRODUCTION

1. In broad terms, BC Hydro has had two objectives for this proceeding. The first is to provide the British Columbia Utilities Commission (the "BCUC"), interveners and customers with an open and transparent view of its operations and cost structure and to be open to feedback and suggestions received through this process.[1] The second is to convey that BC Hydro's revenue requirements and requested rate changes reflect a pervasive culture of restraint and cost containment in the face of external cost pressures and an increasingly complex operating environment. BC Hydro respectfully submits that it has accomplished both objectives.

2. The robust evidentiary record is a product of a comprehensive Application, BC Hydro's considered responses to thousands of information requests, the testimony of 19 witnesses and a number of hearing undertakings. BC Hydro and its representatives have, throughout the process, demonstrated candour and a willingness to engage with all stakeholders.

3. BC Hydro's evidence demonstrates the appropriateness of BC Hydro's forecast fiscal 2020 and fiscal 2021 (the "Test Period") revenue requirements, and the resulting rates (a 5% decrease in the Deferral Account Rate Rider and a 6.85% rate increase in fiscal 2020, for a net bill increase of 1.76%, followed by a 1.01% rate decrease in fiscal 2021).[2] The Demand-Side Management ("DSM") expenditure schedule provides broad access to cost-effective DSM, while continuing with the moderation strategy that recognizes BC Hydro already has sufficient energy resources at this time to meet demand. As Chris O'Riley, President and Chief Executive Officer of BC Hydro, said in his opening statement, BC Hydro has put forward a business plan that is consistent with the objective of affordability and "I'm proud of the efforts we've made to

[1] On February 14, 2020, BC Hydro filed Exhibit B-43, setting out actions BC Hydro is taking in response to feedback received during the first part of the Oral Hearing for this proceeding.

[2] Exhibit B-11-2 corrected the rate requests in the Evidentiary Update.

maintain our competitive position against a backdrop of increasing complexity in our operating environment."[3]

4. The BCUC should approve the proposed rates, and rate-related orders (as set out in Appendix B of the Evidentiary Update, corrected by Exhibit B-11-2), as just and reasonable. It should find that the proposed DSM expenditure schedule is in the public interest.

B. SUBMISSION OVERVIEW AND KEY POINTS

5. These Final Submissions are organized around the following key points:

- ***Part Two: Legal Framework and the Proper Scope of the Proceeding*** – With the repeal of Direction No. 7, the BCUC now has much broader discretion regarding BC Hydro's rates; however, some important limits remain. The BCUC's decision should remain focussed on matters that truly require a determination, leaving other matters for more pertinent future processes.

- ***Part Three: Providing Safe, Reliable and Cost Effective Service in an Increasingly Complex Environment*** – BC Hydro's revenue requirements reflect concerted effort to contain costs throughout the organization in the face of external cost pressures.

- ***Part Four: Load and Revenue Forecasts*** – BC Hydro's Load Forecast is reasonable for the purposes of setting rates in the Test Period, being the product of an improved methodology and reasonable inputs.

- ***Part Five: Forecast Cost of Energy*** – Forecast increases in Cost of Energy are primarily associated with Electricity Purchase Agreements ("EPAs") that either pre-date fiscal 2017 or are part of the Biomass Energy Program, for which cost recovery is mandated. The BCUC will conduct public interest reviews of future EPAs under section 71 of the *Utilities Commission Act* (the "*UCA*"). The Cost of

[3] Tr. 5, p. 358, ll. 2-6 (O'Riley).

Energy Variance Accounts ensure that customers only pay the actual Cost of Energy.

- ***Part Six: Operating Costs*** – BC Hydro absorbed controllable cost pressures within existing budgets. Operating cost increases during the Test Period are generally attributable to uncontrollable factors.

- ***Part Seven: Capital Expenditures and Additions*** – BC Hydro has planned forecast capital spending in the Test Period to fund necessary investments in safety and reliability while moderating spending in response to consistent system performance and a reduced rate of demand growth.

- ***Part Eight: Regulatory Accounts*** – BC Hydro's regulatory accounts are beneficial to ratepayers and consistent with BCUC guidelines and decisions. Appropriate recovery mechanisms are in place for the balance in those accounts that currently require recovery.

- ***Part Nine: Other Revenue Requirements Items*** – Some significant Other Revenue Requirement Items flow from the legislative framework and prior BCUC orders. Other items are based on objective and consistent forecasts.

- ***Part Ten: Transmission Revenue Requirements*** – BC Hydro's Transmission Revenue Requirement reflects the revenue reasonably required from transmission customers for the safety and reliability of the transmission system.

- ***Part Eleven: Demand-Side Management*** – The proposed DSM expenditure schedule continues BC Hydro's moderation strategy, while still enabling broad and cost-effective DSM with increased residential expenditures in response to previous BCUC feedback.

- ***Part Twelve: Implementation of Rates and Consideration of New Information*** – BC Hydro's proposal to set permanent rates for fiscal 2020 at the same level approved on an interim basis, followed by a rate decrease of 1.01% on April 1,

2020, produces the best outcome for customers. BC Hydro's 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. This includes revenue-related developments due to COVID-19 that have occurred since the hearing record closed, and will continue to unfold in the coming months. 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.

PART TWO: LEGAL FRAMEWORK AND THE PROPER SCOPE OF THE PROCEEDING

6. Chapter 2 of the Application details the regulatory and legal framework and its implications for the BCUC's determinations in this proceeding. Although the BCUC's discretion is much broader now, cost recovery is still mandated for certain matters:

(a) the balance of BC Hydro's regulatory accounts as at March 31, 2019, which is the entire balance as of the start of the Test Period (see Part Eight);[4]

(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;[5]

(c) the costs incurred by BC Hydro with respect to energy supply contracts entered into before April 1, 2016[6], which includes the vast majority of BC Hydro's forecast Independent Power Producer ("IPP") costs in the Test Period (See Part Five, Section B);

(d) debt servicing costs on amounts borrowed in relation to the rate smoothing regulatory account;[7]

(e) the costs associated with "prescribed undertakings" under the *Greenhouse Gas Reduction (Clean Energy) Regulation* (the "GGRR"), which includes the Peace Region Electricity Supply ("PRES") project (see Part Seven, Section J);

(f) the prescribed return on equity of $712 million for each of fiscal 2020 and fiscal 2021 (see Part Nine, Section D).[8]

7. InterGroup Consultants Ltd. ("InterGroup"), on behalf of AMPC, advocates that the BCUC identify the costs of legislated policies even if the BCUC cannot direct associated changes.

---

[4] Direction No. 8 to the BCUC, B.C. Reg. 24/2019 ("Direction No. 8"), section 4(1).

[5] Direction No. 8, section 4(1).

[6] Direction No. 8, section 4(1).

[7] Direction No. 8, section 4(1).

[8] Direction No. 8, section 3.

It also contends that the 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.[9] BC Hydro submits that the exercise contemplated by InterGroup is, in effect, an attempt to second-guess legislated government policy. The BCUC, as a creature of statute, derives its mandate from the existing legislation and must operate within that framework.

[9] Exhibit C11-11, InterGroup Evidence, Recommendations 9 and 10.

PART THREE: PROVIDING SAFE, RELIABLE AND COST EFFECTIVE SERVICE IN AN INCREASINGLY COMPLEX ENVIRONMENT

8. At the outset of the oral hearing, BC Hydro identified themes that run through the evidence in this proceeding. In addition to the importance placed on transparency, the themes centred on (1) BC Hydro's concerted effort to contain costs, and (2) the mounting cost pressures associated with an increasingly complex operating environment.[10]

A. BC HYDRO HAS DEMONSTRATED ITS ATTENTION TO CONTAINING CONTROLLABLE COSTS

9. In his Opening Statement, Mr. O'Riley emphasized that "a lot of rigour goes into our budgeting process".[11] He elaborated that difficult decisions went into developing the Test Period budget, and that accommodating additional work within the budget is unrealistic:

> Well, as I said in the opening, we are absolutely open to feedback and open to suggestions. And if those can be brought forward, that is fantastic, and we will take them. We're going to start right into a budgeting process very quickly for the coming—the next test period. And what Mr. Wong and I are saying is, we put a tremendous effort into ensuring we had the right budget. We are nine and a half months into the first year of the two year test period, and pretty much on track. Lots of pressures on the budget, pretty much on track. We are not expecting within the test period to come in well below the budgets. That's not a likely expectation.
>
> Absolutely, if we get suggestions for where we can make improvements going forward, we'll do that. I do note that most of the suggestions that have come forward in the process have been suggestions to do additional work, and there is a long list of suggestions of studies and programs and things that we could add to the budgets. There have not been a lot of suggestions of things we could remove.
>
> One of the things I note in my role that's very—I meet with a lot of outside groups, including customer groups, and almost invariably I receive suggestions where BC Hydro could be more effective by spending additional money, or having another program, or investing over here, almost invariably, and I find the implicit part of my job description is actually saying no. And I've actually—that's

[10] Tr. 5 p. 336, l. 13 to p. 337 l. 21 (Ghikas).

[11] Tr. 5, p. 358, ll. 11-19 (O'Riley).

> slightly counter to my nature, I don't like saying no, but I've had to come up with ways of doing that.[12]

10. Mr. O'Riley's testimony was echoed by other members of the Executive Team and senior management that have the day-to-day responsibility for budgets across the organization. As David Wong, Executive Vice President of Finance, Technology, Supply Chain and Chief Financial Officer, explained:

> Well, first of all, when we put together this application we pushed hard to recreate [sic] budgets that I would say are hard to deliver on what we need to deliver on. And we are actually finding that this year.
>
> I mean, [there] are pockets of groups within our company [that] are finding it really challenging. Just the technology as an example, in our area.
>
> And so a lot of effort went in [to the] development of this application to find those savings, and now what we need to do is actually realize on them, which I think we are doing a really good job of. We are working hard every day to rationalize and manage our costs.[13]

11. The lengths to which BC Hydro has gone to assess the operations, find savings and create capacity throughout the organization during the Test Period are discussed throughout the remainder of this Final Submission. The attention to cost control is particularly evident in the context of Cost of Energy, Operating Costs, Capital and DSM.

B. THE DEMANDS ON BC HYDRO ARE INCREASING AS WORK BECOMES MORE COMPLEX

12. At the same time, the demands on the company have increased: "While BC Hydro's core work has remained the same, the type, complexity, and volume of work BC Hydro performs has changed and increased since the Previous Application."[14] BC Hydro has thus far attempted to absorb additional costs associated with these demands. However, BC Hydro "expect[s] that it will be difficult to continue to do so, depending on factors such as the pace and nature of

[12] Tr. 5 p. 376 l. 1 to p. 377, l. 6 (O'Riley).

[13] Tr. 5, p. 373, ll. 12-26 (Wong).

[14] Exhibit B-5, BCUC IR 1.64.1.

changes."[15] The magnitude of the task is highlighted by the fact that BC Hydro, at the time of the oral hearing, was tracking slightly over budget on operating costs in fiscal 2020. The Executive Team was working to identify further cost reductions to stay on budget for the year.[16]

13. BC Hydro highlighted, in particular, a number of changes in the law and regulatory requirements that are driving increased costs:

- ***New NERC Critical Infrastructure Protection ("CIP") requirements:*** In order to comply with Mandatory Reliability Standards ("MRS"), BC Hydro and other utilities in North America must, among other things, abide by a series of reliability and cyber security standards set by the North American Electric Reliability Corporation ("NERC"). These standards impact how BC Hydro plans, builds, and operates its system. The standards introduce new complex work. Costs for maintaining compliance, which have been increasing, are embedded within overall operating costs across the organization.[17]

  - NERC CIP version 5 expanded cyber and physical security standards to 43 medium impact substations.[18]

  - In addition, NERC CIP has had significant and growing impact on BC Hydro's front-line operations teams.[19]

  Sustainment costs are expected to increase in the future as new standards come into effect.[20]

---

[15] Exhibit B-12, BCUC IR 2.214.1.

[16] Tr. 5, p. 374, ll. 4-14 (Wong).

[17] Exhibit B-12, BCUC IR 2.214.1.

[18] Exhibit B-5, BCUC IR 1.64.1. An example of new work from these standards is that BC Hydro is now mandated to check and evaluate security patches for more than 2,000 in scope assets on a monthly basis and must apply most of the applicable patches to operational assets within a one year time frame. In many cases, this involves evaluating complex options to determine how to apply patches without impacting reliability in aging systems.

[19] Exhibit B-5, BCUC IR 1.64.1. For example, any intrusion alarm within critical physical security areas requires a response within 15 minutes and all NERC keys and authorizations must be reviewed quarterly or annually based on security level.

- ***New general cybersecurity requirements:*** Assets that fall outside of MRS requirements still require cybersecurity investment. The recent audit report from the Office of Auditor General of British Columbia included a series of cybersecurity recommendations that are expected to result in additional operating costs.[21]

- ***Safety regulation changes:*** Changes to safety regulations require new equipment, upgrades to existing equipment, and training on new, and often more complex, work procedures.[22] The costs of achieving and maintaining regulatory compliance are incurred within overall actual operating costs.

- ***Archaeological work:*** Increased consultation and engagement with First Nations directly in archaeological protection has also required subject matter expert support and Indigenous cultural monitors to both facilitate discussions as well as ensure BC Hydro incorporates Indigenous perspectives in the work. Amendments to the *Heritage Conservation Act* and additional provincial permitting and reporting requirements (such as new requirements for permit notification content and annual blanket permit reporting) have also necessitated additional subject matter expert involvement in ensuring programs and projects are fully addressing regulatory requirements.

---

[20] Exhibit B-12, BCUC IRs 2.214.1 and 2.257.20.

[21] For example, as noted in BC Hydro's responses to BCUC IR 1.123.2.1 (Exhibit B-5) and BCUC IR 2.257.1 (Exhibit B-12), BC Hydro expects to incur a cost of $0.3 million for a related risk assessment. This cost was not included in the Application as the need for (and cost of) the assessment was unknown at the Application currency date. BC Hydro continues to evaluate the recommendations for adoption. The audit report can be found at: https://www.bcauditor.com/sites/default/files/publications/reports/OABGC_Cybersecurity-ICS-BC-Hydro_RPT.pdf.

[22] Exhibit B-5, BCUC IR 1.64.1. For example, new heat stress assessment tools and procedures have added complexity to work procedures and additional costs to acquire new tools. BC Hydro has introduced a policy that an Occupational Health and Safety Specialist must now attend every entry into a confined space (approximately 500 per year) unless otherwise authorized.

- ***Environmental regulatory requirements:*** New environmental requirements have increased workload and required additional investment. For instance:[23]

  - Provincial *Water Sustainability Act*: Amendments to this Act in 2016 resulted in increased regulatory requirements for groundwater use and for managing activities in non-fish bearing streams. These requirements increase regulatory compliance activities, increase mitigation efforts to avoid impacts in streams, and increase the time required to conduct work in transmission corridors.

  - Species at risk: The number of terrestrial and aquatic species being recommended for listing has increased, which has increased planning and regulatory requirements.

  - Invasive species: Since the Previous Application, BC Hydro has been supporting the Government of B.C.'s invasive mussel defence program at a cost of $1.3 million, which has been absorbed over recent years.

14. Mr. O'Riley also emphasized increasing customer service and societal expectations that go beyond complying with regulations:

> Having served in the president's role for two and a half years now, I am very conscious of the service expectations on BC Hydro and I feel these responsibilities keenly. Some of these are obvious in terms of the importance of reliability. On January 2nd I was in the Lumby area and able to see firsthand the tremendous efforts required to restore power to customers in the rural areas on Mable Lake Road after the snowstorm. Some of these expectations are more subtle, such as a growing expectation by customers to be kept updated during storms and outage events, and for BC Hydro to meet best practices in processes as articulated in audits. Other expectations come through the growing regulatory requirements on BC Hydro for safety, environment, reliability, as well as the higher expectations for conduct from society in general. I think societal expectations on institutions are increasing across the board, and correspondingly

[23] Exhibit B-5, BCUC IR 1.64.1.

> societal risk tolerance is decreasing. And this in itself becomes a cost pressure for a critical infrastructure provider such as BC Hydro.[24]

Overall, the consequence of the changes discussed above, and others, is that "it is increasingly difficult to get front-line work done within existing resource levels and that opportunities to find new efficiencies are quickly negated by increases to work volume or complexity."[25]

C. ADDITIONAL INVESTMENT WILL BE NECESSARY AFTER THE TEST PERIOD

15. Company-wide initiatives like Work Smart and "make it easier to get work done" (discussed in Part 6, Section F) help to avoid cost increases. However, Mr. O'Riley tempered expectations about BC Hydro's ability to continue absorbing cost pressures associated with changing expectations:

> So perhaps one of the things that we may have not made clear enough is the context we operate in, and there are, all over the place, new and rising expectations on BC Hydro, and I don't think you should expect to see operating costs going down in real terms given the rising expectations. And I feel, as a management team, that we swim against that, and work really hard to absorb those expectations and requirements in the company in the context of inflation. But I think we have no business expecting real decreases in operating costs for a company like BC Hydro in the environment it operates. No business at all. And I want to be clear that that's not something I think is reasonable or even prudent given the service expectations on the company, and the compliance expectations.[26]

16. Mr. O'Riley identified three areas in particular where he expects budgets will need to increase in subsequent test periods: vegetation management, cybersecurity and employee training to meet evolving safety and regulatory requirements.[27]

---

[24] Tr. 5, p. 359, l. 9 to p. 360, l. 5 (O'Riley).

[25] Exhibit B-5, BCUC IR 1.64.1.

[26] Tr. 5, p. 372, l. 19 to p. 373, l. 9 (O'Riley).

[27] Tr. 5, p. 359, ll. 1-8 (O'Riley).

PART FOUR: LOAD AND REVENUE FORECASTS

A. INTRODUCTION

17. BC Hydro's requested rates in the Evidentiary Update reflect actual sales for the first two months of fiscal 2020 (April and May 2019), and the October 2018 Load Forecast for the remainder of the Test Period. BC Hydro described the October 2018 Load Forecast in Chapter 3 of the Application and Appendix O.[28] The evidence discussed in this Part demonstrates that the October 2018 Load Forecast, and the associated Revenue Forecast, are reasonable for the purposes of setting rates in the Test Period. In particular, the evidence supports the following findings:

- First, the load forecast methodology has performed well in recent years.
- Second, the October 2018 Load Forecast reflects improvements in BC Hydro's load forecast methodology, including improvements to address feedback from the BCUC and audit recommendations.
- Third, the confidence interval around the mid forecast, represented by the high / low forecasts, is a critical part of the context when defining the reasonableness of using the October 2018 Load Forecast for setting Test Period rates.
- Fourth, the June 2019 Load Forecast results, on average, remained within 0.1 per cent of the October 2018 Load Forecast for the Test Period.
- Fifth, the October 2018 Load Forecast already assumed that electricity sales to the forestry sub-sector would decline.
- Sixth, while considerable upside potential exists with the CleanBC Plan, BC Hydro took the reasonable approach of including only those elements of the CleanBC Plan that were already in place or were close to being enacted. The next Integrated Resource Plan ("IRP") will be the appropriate venue to discuss

[28] Exhibit B-1, Application, Appendix O, Electric Load Forecast Report Fiscal 2019 to Fiscal 2024 (October 2018).

medium and longer-term planning and load forecast implications of electrification.

- Seventh, variances between actual and forecast cost of energy arising from differences between forecast and actual domestic customer load are deferred to the Cost of Energy Variance Accounts, thus keeping customers whole.

- Eighth, once the Load Forecast has been determined, the Revenue Forecast based on it is a straightforward calculation. The methodology is unchanged from the Previous Application.

B. SNAPSHOT OF THE OCTOBER 2018 LOAD FORECAST UNDERLYING THE EVIDENTIARY UPDATE

18. The October 2018 Load Forecast is summarized in the table below. Overall, the mid load forecast shows demand increasing by approximately 650 GWh or 1.2% from fiscal 2019 to fiscal 2021. Over the five year period from fiscal 2018 to fiscal 2023, average growth is 0.5% per year.[29]

Electricity Sales Summary after Rates after DSM Savings

	F2019	F2020	F2021
	Forecast (GWh)	Forecast (GWh)	Forecast (GWh)
Residential	**18,049**	**18,258**	**18,330**
Commercial and Light Industrial	**18,976**	**18,973**	**19,030**
Large Industrial	**14,003**	**14,702**	**14,243**
Other	**1,575**	**1,634**	**1,650**
Total Domestic Sales	**52,604**	**53,567**	**53,253**
	F2019	**F2020**	**F2021**
Low Band	**51,716**	**52,244**	**51,364**
Mid Load Forecast	**52,604**	**53,567**	**53,253**
High Band	**53,507**	**54,907**	**55,189**

[29] Exhibit B-1, Application, pp. 3-37 and 3-38; corrected in Exhibit B-6, BCOAPO IR 1.17.1 (though with a typographical error in the last column that has been corrected in these Submissions). Mid Load Forecast for fiscal 2019 includes six months of actuals, and six months of forecast data.

19. Messrs. Rich and Clendinning provided a concise explanation as to how to interpret the mid, high and low forecasts. They explained that the mid forecast represents the sum of the sector forecasts, which are prepared using various methodologies and modelling (A+B=C). The low and high forecasts represent a confidence interval that is generated by Monte Carlo analysis.

20. Mr. Rich elaborated: "…our mid-forecast is actually not a P50 forecast, it's a deterministic forecast. So we are aiming in an unbiased, objective way to get it right, and so the uncertainty band is a probabilistic method of creating a confidence interval around that."[30] Section D below highlights the improvements in the methodology used to arrive at the deterministic mid forecast. Section E outlines types of uncertainties captured in the confidence interval.

21. Mr. Clendinning confirmed that the combination of the deterministic and probabilistic approaches "make a robust way in order to do forecasting over the short and the longer-term and there's a solid basis for ratemaking."[31]

C. THE LOAD FORECAST METHODOLOGY HAS PERFORMED WELL IN RECENT YEARS

22. The Load Forecast for the Previous Application was developed in May 2016 and has performed well. Actual results for fiscal 2017, fiscal 2018, and fiscal 2019 tracked within 0.1% to 0.5% of the forecast, which is well within a range of expectancy based on industry benchmarks.[32] Two of those years were underforecast, and the other was overforecast. Ms. Daschuk stated that, " …if you look at the last three years, I would actually say that we've done an exceptional job in terms of forecasting."[33]

23. Most of the variance in longer term outlooks is due to the large industrial sector, which is largely based on the resources industry, which is inherently uncertain and for which it is very

[30] Tr. 8B, p. 1300, ll. 14-20 (Rich).

[31] Tr. 8B, p. 1300, ll. 21 to p. 1302, l. 12 (Clendinning).

[32] Exhibit B-1, Application, p. 3-4.

[33] Tr. 8B, p. 1304, l. 15 to p. 1305, l. 1 (Daschuk).

difficult accurately project future demand.[34] The initial years of each forecast vintage, which are of greatest relevance when setting rates for a single test period, tended to be reasonably accurate.[35] The next IRP is a more appropriate venue to explore long-term forecasting.

D. THE TEST PERIOD LOAD FORECAST IS BASED ON AN IMPROVED METHODOLOGY

24. Since the May 2016 Load Forecast, BC Hydro made improvements to its load forecast methodology and governance based on feedback from the BCUC and internal audit recommendations.[36] In December 2018, the Auditor General of B.C. characterized the load forecasting process as "robust", concluding that, "BC Hydro has a load-forecasting capability that compares favourably with industry standards."[37] The improved methodology, which was incorporated into the October 2018 Load Forecast, provides a sound basis on which to set rates in the Test Period.

(a) Improvements to the Methodology Respond to BCUC Commentary

25. Table 3-1 of the Application identified concerns raised by the BCUC in the Previous Application and the Site C Inquiry and how BC Hydro addressed them:

[34] Tr. 10, p. 1633, l. 15 to p. 1634, l. 16 (Rich).

[35] Tr. 10, p. 1633, ll. 20-25 (Rich).

[36] Tr. 8B, p. 1290, l. 22 to p. 1291, l. 18 (Rich).

[37] Exhibit B-1, Application, p. 3-9.

Table 3-1 Summary of BC Hydro's Response to BCUC Recommendations and Comments

Fiscal 2017 to Fiscal 2019 Revenue Requirements Application Decision	
BCUC Recommendations/Comments	**Location of BC Hydro's Response**
"Panel acknowledges the concerns of AMPC regarding price elasticity use for industrial customers," but is nevertheless "satisfied that the issue of price elasticity for future unknown price increases is not an issue in the test period."[75]	BC Hydro engaged DNV GL consulting to review price elasticity and recommended increasing elasticity values from -0.05 to -0.1 and applying price elasticity across all customer sectors. Please refer to section 3.2.6.2.
"Panel further notes that other utilities such as Pacific Northern Gas, FortisBC (natural gas) and Fortis BC (electricity) use a different load forecast methodology for their short term forecast for setting rates as compared to its long term forecast for resource planning."[76]	We reviewed alternative short- term methodologies and developed a comparator forecast using FortisBC (electricity) methods. Please refer to section 3.2.11 and Table 3-2.

BCUC Site C Inquiry Final Report	
BCUC Recommendations/Comments	**Location of BC Hydro's Response**
"Panel 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."[77]	We have now aligned how we forecast sales to LNG customers in a manner consistent with other large industrial customers: using the probabilistic assessment approach. Please refer to section 3.2.8.2.
"Panel finds the GDP and disposable income used by BC Hydro are higher than similarly Conference Board of Canada estimates."[78]	As part of BC Hydro's normal competitive procurement practices, the Conference Board of Canada was the successful proponent on an RFP for economic consulting services to provide us with a sub-regional and aggregate economic forecast for the province.

26. BC Hydro's short-term methodology performed favourably to FortisBC Electric's methodology when applied to the same input data used in the May 2016 Load Forecast.[38]

(b) BC Hydro Has Incorporated Audit Recommendations on Methodology and Governance

27. An August 2017 audit of BC Hydro's load forecasting function endorsed the overall load forecast methodology, while making some specific recommendations for improvement. As

[38] Exhibit B-1, Application p. 3-36, Exhibit B-6, CEC IR 1.10.2: The purpose of this comparison was to inform a decision with regards to whether to adopt an alternative short-term load forecast methodology. Exhibit B-13, CEC IR 2.93.2: The variance in accounts for fiscal 2019 would have been greater if the alternative forecast based on the FortisBC Electric short-term method was used. See also, Exhibit B-13, CEC IR 2.94.5.

discussed below, BC Hydro is implementing the audit recommendations and many are already reflected in the October 2018 Load Forecast.[39]

28. The audit of BC Hydro's forecasting function was completed by BC Hydro Audit Services, a department that operates subject to strict rules and protocols designed to ensure objectivity.[40] BC Hydro Audit Services retained independent subject matter experts, GDS Associates Inc. ("GDS"), to perform the assessment.[41] GDS's findings, which were incorporated in the Audit Report, included:[42]

- "Overall, the load forecasting function at BC Hydro compares favorably to industry standards and to other large electric utilities in North America. No critical weaknesses were found."
- "Load forecasting methodologies are consistent with best practices and load forecast outputs are provided to users and stakeholders on a timely basis."
- "The greatest risk of load forecasting inaccuracy falls on the industrial class and is due to the uncertainty of future economic activity and the volatility of many individual customer loads."
- "Areas for improvement identified primarily relate to making adjustments to forecast models and inputs to enhance overall forecast accuracy."

[39] Exhibit B-6, BCOAPO IR 1.14.2.

[40] Exhibit B-1, Application, Appendix P, Load Forecast Internal Audit.

[41] Exhibit B-5, BCUC IR 1.12.1.

[42] Exhibit B-1, Application, Appendix O, Electric Load Forecast Report Fiscal 2019 to Fiscal 2024 (October 2018), p. 16.

BC Hydro Has Implemented Governance Recommendations

29. BC Hydro has completed all of the audit recommendations related to governance:[43]

Audit Recommendations	Management Actions Status
1 • Review adequacy of existing resources and consider increases to current staffing level.	Complete • Two staff have been added to the Load Forecast team. • The annual consultant and subscription services budget has been increased from approximately $200,000 to $300,000.
2 • Prepare load forecasting detailed procedural documentation to supplement the high-level process documentation.	Complete • The Load Forecasting procedural manual was updated to include process maps and supplemental information related to the procedures to prepare the BC Hydro load forecast.
3 • Consider developing a dashboard to highlight key information and current assumptions/outlook that impact the load forecast	Complete • BC Hydro prepares a monthly load variance report highlighting key information related to load and revenue variances in each of the key customer sectors.

Updated Elasticity Factor Was Among the Methodology Changes Flowing from Audit Recommendations

30. BC Hydro has similarly implemented changes in response to each of GDS's recommendations on forecast methodology.[44] As described below, those changes include updating BC Hydro's elasticity factors.

31. As a result of the audit, BC Hydro retained DNV GL to conduct a review of price elasticity. Based on their findings, BC Hydro has increased the electricity price elasticity value used for all of the main customer sectors in the Load Forecast from -0.05 to -0.10. The impact

[43] Exhibit B-12, BCUC IR 2.203.2.

[44] Exhibit B-6, BCOAPO IR 1.14.2 summarizes the status of the audit recommendations related to forecast methodology. See also, Exhibit B-1, Application, p. 3-5; Exhibit B-12, BCUC IR 2.203.1.

of changing the elasticity, all else equal, is a small net change to the total Load Forecast of about 21 GWh in fiscal 2020 and about 37 GWh in fiscal 2021.[45]

32. In response to an Information Request, BC Hydro performed a sensitivity analysis using elasticity assumptions of 0.05, -0.1 and -0.15. Changing the price elasticity assumption had minimal impact on the overall Load Forecast.[46]

33. BC Hydro's continued use of a single price elasticity for all customer sectors reflects DNV GL's recommendation.[47] DNV GL recommended that BC Hydro continue to use the same price elasticity estimate for all sectors, citing (a) practices at other utilities, and (b) BC Hydro's complementary use of a site-by-site assessment for industrial facilities, which captures the price effect for a selection of energy intensive facilities:

> In general, we find BC Hydro's application of price elasticity to be consistent with that of many of the Canadian and U.S. utilities we reviewed. DNV GL supports the continuation of BC Hydro's approach to load forecasting which involves building up sector specific forecasts, including site-specific large commercial and industrial forecasts, and applying a single price elasticity to account for price changes in the forecast. Given that BC Hydro employs a site by site assessment for industrial facilities which captures price effect for a selection of energy intensive facilities, such as pulp mills; and precedent elsewhere, of applying the same price elasticity across all three sectors, we recommend that BC Hydro continue to use the same price elasticity estimate for all sectors.[48]

(c) BC Hydro Has Made Sector-Specific Methodology Improvements for All Four Sectors

34. BC Hydro has made methodology improvements across all four sectors (Residential, Commercial and Light Industrial, Large Industrial and Other), discussed below.

[45] Exhibit B-1, Application, p. 3-17; Exhibit B-6, AMPC IR 1.1.7.

[46] Exhibit B-5, BCUC IR 1.8.1. See also, Exhibit B-6, INCE IRs 1.8.7 and 1.8.9.

[47] Exhibit B-5, BCUC IR 1.8.4.

[48] Exhibit B-1, Application, Appendix Q, Elasticity Study and GDP Study, p. 19.

Residential Sector Improvements

35. BC Hydro has made the following methodology improvements to the Residential Sector Load Forecast:

(a) Recalibrated residential account growth relationship to housing starts by updating BC Hydro's approach to forecasting account growth;[49]

(b) Updated customer response to temperature after reviewing the relationship between temperature and residential use per account using smart meter data;[50]

(c) Recalibrated the relationship between economic variables and electricity, including disposable income and use per account, for all residential statistical adjusted end-use ("SAE") models;[51] and

(d) Adjusted the price elasticity assumption from -0.05 to -0.10 based on a price elasticity study conducted by the consultant, DNV GL.[52]

Commercial and Light Industrial Sector Improvements

36. Improvements to the Commercial sector methodology were similar to the SAE model-related improvements from the Residential Sector Load Forecast. They include:

(a) Updated customer response to temperature;

(b) Recalibrated relationship of economic variables to electricity sales based on an updated 10-year model calibration period; and

[49] Exhibit B-1, Application, pp. 3-14 and 3-15.

[50] Exhibit B-1, Application, p. 3-15. BC Hydro provided the magnitude of the impact over the Test Period in response to Exhibit B-5, BCUC IR 1.11.2. In Exhibit B-6, INCE IR 1.8.21, BC Hydro prepared a comparison of forecasts developed with different assumptions on normal temperature. They showed that there is less than one per cent difference in the sales for each sector between the two scenarios.

[51] Exhibit B-1, Application, p. 3-15.

[52] Exhibit B-1, Application, pp. 3-15 to 3-17.

(c) Updating price elasticity from -0.05 to -0.10, consistent with the results of the independent elasticity study discussed above.[53]

Large Industrial Sector Improvements

37. BC Hydro has approximately 190 large industrial customers, representing approximately 26% of total sales.[54] As in prior years, BC Hydro forecasted sales to the large industrial sector on an individual customer account basis; however, it has made a number of methodological improvements.[55]

38. BC Hydro develops the Large Industrial Sector Load Forecast using information from a variety of sources:[56]

- For existing customers, the key customer data is historical sales.[57] BC Hydro uses the other sources of information noted above to develop a probability weighting representing a risk assessment of the likelihood of future sales increasing, decreasing or remaining steady.[58]

- For new customers or customers requesting expanded service, the customer specifies its anticipated demand, which BC Hydro verifies using information from market research and industry experts. BC Hydro also assigns a probability weighting to the forecast with regards to when and how much of the new demand may materialize.[59]

39. The "bottom-up / top-down" approach, and the collaborative nature of the process, allows for different perspectives and addresses the risk of bias in self-reported information.[60]

---

[53] Exhibit B-1, Application, p. 3-20.

[54] Exhibit B-1, Application, p. 3-22.

[55] Exhibit B-1, Application, p. 3-23.

[56] Exhibit B-1, Application, p. 3-24.

[57] Exhibit B-5, BCUC IR 1.9.1. This process is described on pages 61 and 62 of Appendix O of the Application.

[58] Exhibit B-1, Application, p. 3-24.

[59] Exhibit B-5, BCUC IR 1.9.1. This process is described on pages 61 and 62 of Appendix O of the Application.

[60] Exhibit B-5, BCUC IR 1.9.1.1. See also, Exhibit B-5, BCUC IR 1.9.2.

40. The improvements made to BC Hydro's Large Industrial Sector Load Forecast methodology include:

(a) The use of external subject matter experts to provide a comprehensive analysis of B.C. shale gas development, which fed into the Oil and Gas subsector forecast;[61]

(b) Revising price elasticities for this sector from -0.05 to -0.10 (discussed above);[62]

(c) Updating the methodology for forecasting sales to LNG customers to use a probabilistic assessment approach (e.g., a 10% probability would still result in 10% of the forecast load being included), similar to that used for the long-term forecasts other large industrial customers;[63] and

(d) Changing from a probabilistic approach to a binary approach (i.e., in or out) for the first three years of the Large Industrial Sector Load Forecast. Under a binary approach, a customer with a less than 50% probability of taking service in a particular year is included as zero for that year.[64] BC Hydro explained: "Given that we have good information to make the binary call, we believe forecasting load in this manner is preferred over the test years rather than having partial load and partial revenue projections."[65]

41. BC Hydro cautioned that, on an aggregate sector total basis, the binary approach for the Large Industrial Sector Load Forecast in the first three years of a forecast may or may not improve load forecast accuracy over the Test Period; positive variances in one sub-sector may offset negative variances in another. However, BC Hydro expressed that this approach addresses why the most recent variances have occurred and will improve load forecast

[61] Exhibit B-1, Application, p. 3-30; Exhibit B-12, BCUC IR 2.212.1. See also, Tr. 8B, p. 1313, ll. 21-26 (Rich).

[62] Exhibit B-1, Application, p. 3-30.

[63] Exhibit B-1, Application, pp. 3-27 to 3-30.

[64] Exhibit B-1, Application, pp. 3-28 and 3-29. See also, Tr. 8B, p. 1309, l. 10 to p. 1311, l. 11 (Rich).

[65] Exhibit B-1, Application, Appendix O, Electric Load Forecast Report Fiscal 2019 to Fiscal 2024 (October 2018), p. 20.

accuracy within specific segments where probability-weighted forecasts are influenced by account-specific risk assessments.[66] BC Hydro explained that, over the longer-term, a probabilistic-based approach continues to be the best method for developing the large industrial sector forecast on an aggregate basis.[67] This methodology is preferred to other methods as it provides greater flexibility to quantify relevant factors for the sector and individual customer energy sales. It also provides greater detail for tracking and explaining forecast variances.[68]

42. BC Hydro's work to improve the forecasts will continue. For instance, BC Hydro is retaining third-party experts to provide market assessments for emerging segments (cryptocurrency and cannabis), inform the methodology development and identify trends for future load forecasts for these segments.[69]

Other Sector Improvements

43. The Other sector currently represents approximately 3% of the total sales demand in the Load Forecast. Demand in this sector comes from irrigation and street light customers, sales to other inter-utility sales (City of New Westminster and FortisBC Electric), and firm exports (Seattle City Light and Hyder). BC Hydro revised the price elasticities from -0.05 to -0.10 across all customers in this sector for which applying an elasticity factor is appropriate.[70] The rationale for the revision of the price elasticities from -0.05 to -0.10 is the same as that discussed in Subsection (b) above.

[66] Exhibit B-1, Application, p. 3-30; Exhibit B-13, BCOAPO IR 2.96.2.

[67] Exhibit B-1, Application, p. 3-30.

[68] Exhibit B-1, Application, Appendix P, Load Forecasting Internal Audit, p. 4.

[69] Exhibit B-22, BCUC IR 4.320.1.

[70] Exhibit B-1, Application, pp. 3-30 to 3-31. Elasticity factors are not required for Seattle City Light and FortisBC Electric. Seattle City Light loads are established under the Skagit River Treaty. Sales to ForticBC Electric have the elasticity impact implicitly built into the methodology.

E. THE CONFIDENCE INTERVAL AROUND THE MID FORECAST CAPTURES A VARIETY OF UNCERTAINTIES

44. The confidence interval, represented by the high / low forecasts, is a critical part of the context when defining the reasonableness of using the October 2018 Load Forecast for setting Test Period rates.

45. As Mr. Rich observed,[71] it is inevitable that actual results will vary from forecasts. The challenge of producing accurate forecasts has only increased in recent years with what Mr. Clendinning referred to as a "paradigm shift in load". He emphasized that, in the context of this greater uncertainty, the confidence interval takes on new importance:

> The mid-forecast is obviously important, especially in the short term when we're setting rates over a one or two-year period. No doubt accuracy is important. But I think as we get into this period, as you described it, paradigm shift in load, and a lot of increasing uncertainty of where the past can't be used. I fall back to the confidence in our load forecast.
>
> So, what are the high and low bands? And what are we trying to capture with those in terms of the risks that are facing us? And so, it's an easier concept to understand what's your percentage accuracy versus the mid-forecast. Are you high or low, and to use words like over-forecasting and under-forecasting.
>
> But to answer your question about performance, you know, if we're saying the high and low bands represent an 80 percent confidence interval, over a 10 year period I'd expect the electricity demand from our customers to fall outside that band, and for me that would represent good performance. And I think we're shifting our mindset. Other utilities are as well, and I think intervenors and regulators are coming to terms with the increased uncertainty of this post-2016 political and post-2008 economic environment.
>
> So I really look to the confidence intervals in addition to forecast accuracy. And I encourage the team to compare their performance, not just against other load forecasts, which on a one, three, and six-year basis, we are performing better than—for example our model supplier for residential is ITron. You know, performing much better than those customers.
>
> But against other economic forecasts, how are we doing relative to the province of British Columbia or private economic institutes forecasting GDP? That's an

[71] Tr. 10, p. 1633, ll. 6-10 (Rich).

> input to ours. So if they have difficulty in forecasting GDP, you can imagine that that gets multiplied as it goes through. And we're in the range of—the same range that we have for the load forecast, so sub-5 percent, sub-2 percent in some cases.[72]

46. BC Hydro was asked about whether the Load Forecast accounts for the potential of a recession, which had been an issue in the last revenue requirements proceeding. BC Hydro elaborated that, although BC Hydro does not forecast any specific period of economic recession or recovery, the modelling does consider recessionary effects[73] and accounts for the possibility of recessions.[74] The use of a perturbation process for GDP based on data from a 20 year period that included a recession (B.C.'s annual GDP growth was -2.4% in fiscal 2009) means the Monte Carlo modelling itself contains simulations with recessions.[75] Generally speaking, a mild to moderate recessionary period (e.g., -1 to -3 percentage point real GDP change over 3 quarters) would likely fall within the high and low forecast uncertainty band.[76] Mr. Clendinning expanded on this at the hearing:

> We dug a bit deeper into our Monte Carlo simulations, and one of the things that it varies in those simulations is GDP. And so in doing the Monte Carlo simulations and producing that low-end of the band, we looked at for all the variables that were changing, how often in each of those thousands of simulations of potential future load did we see recessions? And in the 20 years of historical GDP that is included in our forecasting that we use for that model, it included the 2008 recession and so that's an input into that Monte Carlo simulation. You should at least go that low on GDP to see negative growth.
>
> And so what we found was of the 30,000 samples that we took, 13 percent of the time the simulation included periods of recession. So, those are actually quite deep recessions, because the model only works on a yearly basis. So a recession is defined on a per quarterly basis of negative GDP, but these were years, whole years of negative GDP. So what I will say is, I think our responses in the past have said we don't make those predictions about exactly when a recession will happen, but we do feel confident that our Monte Carlo processes do incorporate the risks associated with recessions and other potential negative

[72] Tr. 8B, p. 1297, l. 16 to p. 1299, l. 5 (Clendinning).

[73] Exhibit B-1, Application, p. 3-51; Exhibit B-5, BCUC IR 1.7.2.

[74] Exhibit B-6, CEC IR 1.13.3.

[75] Exhibit B-5, BCUC IR 1.7.2.

[76] Exhibit B-5, BCUC IR 1.7.1. See also, Exhibit B-6, CEC IR 1.13.2.

> consequences to customer demand for load that could in aggregate really hurt us. And that is where we get that lower part of the band.[77]

47. BC Hydro's modelling also accounts for weather (temperature) uncertainties and potential climate trends. The model forecasts are based on a ten-year rolling average of monthly heating and cooling degree days for BC Hydro's service area, which better reflects current trends relative to longer-term averaging periods. BC Hydro's Monte Carlo model also reflects uncertainty in the impact of temperature on load through a random simulation of the heating degrees over the past ten years.[78]

F. THE JUNE 2019 20-YEAR LOAD FORECAST UPDATE IMPACTS THE YEARS AFTER THE TEST PERIOD

48. BC Hydro completed the June 2019 Load Forecast after it had finalized the financial inputs for the Evidentiary Update. It did not propose any further adjustments to the Evidentiary Update revenue forecast (beyond the subsequent correction to the financial schedules[79]). BC Hydro submits that this was a reasonable approach:

(a) The Evidentiary Update already incorporated two months of actual results for fiscal 2020.

(b) The June 2019 Load Forecast was prepared as an interim step to inform BC Hydro's capital planning cycle and the February 2020 Service Plan. BC Hydro filed it in this proceeding to fulfil a commitment made at the March 15, 2019 Workshop and in response to information requests received.[80] BC Hydro will complete an updated comprehensive 20-year load forecast to inform the 2021 IRP.

---

[77] Tr. 8B, p. 1356, l. 21 to p. 1357, l. 23 (Clendinning).

[78] Exhibit B-6, CEC IR 1.14.1.

[79] Exhibit B-11-2.

[80] Exhibit B-15, Twenty-Year Load Forecast, p. 1; Tr. 8B, p. 1261, ll. 17-22 (Rich). In Exhibit B-12, BCUC IR 2.209.1 BC Hydro described how and when it updates its load forecasts.

(c) The June 2019 Load Forecast is, on average, within 0.1 per cent of the October 2018 Load Forecast for the Test Period.

(d) Load changes constantly in response to any number of factors. It is impractical to continually update forecasts and expect to bring the regulatory process to a timely resolution. Variances between forecast and actual revenue would be deferred in the normal course for future recovery from, or refund to, ratepayers.[81]

G. THE OCTOBER 2018 LOAD FORECAST ALREADY ASSUMED FORESTRY SUB-SECTOR DECLINE

49. There is no doubt that the forestry sub-sector has continued to face difficulties since BC Hydro prepared the June 2019 Load Forecast.[82] Continued reliance on the October 2018 Load Forecast nonetheless remains reasonable because it already assumed that electricity sales to the forestry sub-sector would decline.

50. The October 2018 Load Forecast projected mid sales to decline by 1,285 GWh or 18% from fiscal 2018 to fiscal 2024, with a decline of over 1,000 GWh between fiscal 2020 and fiscal 2024.[83] Mr. Rich, who was asked to provide a current assessment, stated:

> Yeah, I mean the industry has faced its structural challenges and it has been for a number of years. I would say that for a number of load forecasts, at least over the long-term we are projecting a decline as a result of those. I would say that what's happened this past summer is what is somewhat expected, it's just happening sooner and harder.[84]

[81] Exhibit B-15, Twenty-Year Load Forecast, pp. 2-3 and 5.

[82] Exhibit B-22, BCUC IR 4.319.1.

[83] Exhibit B-1, Application, Appendix O, Electric Load Forecast Report Fiscal 2019 to Fiscal 2024 (October 2018), p. 82.

[84] Tr. 8B, p. 1318, ll. 1-8 (Rich). See also, Tr. 8B, p. 1348, ll. 15-22 (Rich).

51. Mr. Rich later elaborated as to the reasons why the forecasted decline happened "sooner and harder":

> Well, I think I said, when we were [here] in January, that our load forecasts for that sector do project, and have projected a decline in the sector over the long term. And they are largely structurally related. And basic example of the demand for newsprint is declining as digital media has replaced the demand for that particular product. So, the sector is expected to decline over the long term.
>
> The recent phenomena is I would say is best described is it is happening sooner and harder than we anticipated. When we spoke to our forestry consultants as to why that happened sooner and harder than was anticipated, the example that was demonstrated or highlighted to us with regards to lumber prices, for example, which is driven by U.S. housing starts, it was in part driven by a perfect storm of a wet summer, a dump of supply if you will from Europe, because they are facing their own beetle infestation. So there are a couple things that happened at the same time, that literally cause lumber prices in the U.S. to fall overnight. And that triggered a number of closures.[85]

52. Despite the significant decline in forestry sub-sector, BC Hydro's overall year-to-date fiscal 2020 sales as of December 31, 2019 were 2.6 per cent below the forecast provided in the Evidentiary Update.[86]

H. THE LOAD FORECAST INCLUDES THE PORTION OF THE CLEANBC "UPSIDE" POTENTIAL THAT CAN REASONABLY BE ASSESSED AT THIS TIME

53. Although the ongoing challenges in the forestry sub-sector have been at the forefront of public attention, upside potential also exists from electrification. Mr. Clendinning indicated that the CleanBC plan represents incremental load potential.[87] 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.

[85] Tr. 9, p. 1652, l. 12 to p. 1653, l. 7 (Rich).

[86] Exhibit B-41, BC Hydro Undertaking No. 15.

[87] Tr. 1, p. 47, ll. 12-18 (Clendinning). See also, Tr. 1 p. 50, ll. 14-19 (O'Riley).

(a) The June 2019 Load Forecast Reflects Some, but Not All, of the CleanBC Initiatives

54. The June 2019 Load Forecast incorporated legislative and policy measures related to CleanBC that were already in place or were close to being enacted, giving them a higher degree of certainty.[88] These initiatives, which represent approximately 75% of the initiatives under the CleanBC Plan,[89] include electric vehicles (based on the legislative target for electric vehicle sales by 2024) and low carbon electrification in the oil and gas sector.[90]

55. There may be potential load growth from electrification in the Test Period that is not yet reflected in the Evidentiary Update.[91] Mr. Clendinning explained:

> I think we do see in our traditional sectors, our traditional customer segments, you know, a moderating of growth, and so I think the forecast that we've put forward in the range of 0.5 to 1 percent. That said, I think as everyone in the room knows, there's the potential for electrification as we respond to the climate crisis. There are other industries that are evolving that could provide additional growth, and so sometimes the rearview mirror is a useful way to chart your—navigate your way forward, but it comes with risks.[92]

56. The Government of B.C. has not yet released its plans to achieve the remaining 25% of the 2030 goals. BC Hydro anticipates that, when fully implemented, these remaining initiatives will introduce additional demand in the years beyond the Test Period. It is premature to incorporate loads in the forecast before a quantitative analysis of these initiatives can be undertaken.[93] The IRP will be the appropriate venue to discuss longer-term load forecast implications of electrification.[94]

---

[88] Exhibit B-22, BCUC IR 4.325.2. Mr. Rich: "…we do have the low-carbon electrification program which predated the public release of the CleanBC plan but it's entirely consistent with the objectives of the plan. So that's reflected in the October 2018 load forecast." Tr. 8B, p. 1362, ll. 11-16 (Rich).

[89] Exhibit B-6, CEABC IR 1.9.1.

[90] Tr. 8B, p. 1362, ll. 11 to p. 1363, l. 20 (Rich and Clendinning).

[91] Tr. 10, p. 1683, ll. 11-18 (Rich).

[92] Tr. 8B, p. 1295, ll. 1-11 (Clendinning).

[93] Exhibit B-6, BCSEA IR 1.9.1.

[94] In undertaking an assessment of the impact of CleanBC in future load forecasts, BC Hydro will examine several factors including the level of detailed planning undertaken, the funding allocated to achieve the objectives, the enactment of legislation and regulations, and the expected availability of enabling technologies. Exhibit B-12, BCUC IR 2.207.2. See also, Exhibit B-22, BCUC IR 4.325.2; Tr. 8B, p. 1365, ll. 6-16 (Clendinning).

57. The approach that BC Hydro is taking when recognizing the potential upside of the CleanBC Plan is appropriate. The BC Hydro witnesses explained that the load forecasting function is intended to be unbiased and data driven. Ms. Daschuk put it this way "…it's not intended to be optimistic or pessimistic, it's intended to be our best view of what the future is based on the information we have."[95]

(b) BC Hydro Continues to Work to Build Load and Remove Barriers to Electrification

58. The fact that BC Hydro forecasts with the intent of being neither optimistic, nor pessimistic, based on current information must be distinguished from BC Hydro's substantial efforts to build load.

59. As Mr. Rich put it, there is a difference between a load forecast and a sales target:

> We are not going to put stuff in the load forecast that is speculative at this time. And so we have an entire other group within BC Hydro called Business Development, within Customer Service, they are also working with Key Account Management. And that's their function. So they are looking at, to the extent that the province is developing economically, and to the extent that there is electrification potential combined with provincial policy measures and legislation linked to the province's Clean B.C. objectives.
>
> At some point when those projects become real they will be reflected in the load forecast.
>
> So there is a bit of a divide between what I'll call a sales target versus what we can reliably assume to occur in terms of future demand for electricity recognizing that there's uncertainty in that future demand and that's why we develop uncertainty bounds around it.[96]

60. There is ample evidence on the record of BC Hydro's ongoing work to build load to reduce greenhouse gas emissions. Mr. O'Riley responded to questions by counsel for CEABC by stating, for instance:

> But in particular there was a question about the extent to which the CleanBC plan is reflected in the load forecast and there was talk of 4,000 gigawatt hours

[95] Tr. 13, p. 2430, ll. 22-25 (Daschuk).

[96] Tr. 10, p. 1682, l. 25 to p. 1683, l. 10 (Rich).

> of that and only a portion of that is in the load forecast, though we're working on all aspects of that 4,000 gigawatt hours. And when the load becomes sufficiently probable, it will show up in the load forecast.[97]

Mr. O'Riley cited recent initiatives of the Better Buildings program, developing charging stations to remove barriers to electric vehicle adoption, and the development of the Dawson Creek/Chetwynd Area Transmission ("DCAT") project in the Montney region.[98] BC Hydro has planned to spend $28 million on low carbon electrification over the Test Period, which are "prescribed undertakings" under the GGRR.[99]

61. BC Hydro has 27 FTEs within the Key Account Management Department of the Customer Service Key Business Unit. Key Account Managers are BC Hydro's "sales force". As part of their role, Key Account Managers work directly with customers and promote opportunities for both traditional DSM as well as low carbon electrification. Approximately 13 of these Key Account Managers are budgeted under demand-side management.[100]

62. The PRES Project, discussed in Part Seven of these Submissions, is another example of how BC Hydro is investing to remove barriers to low carbon electrification. The infrastructure must be in place in order to realize the significant potential for electrification in the oil and gas sector. Mr. Kumar explained:

> So our expectation is that the load is going to materialize, and actually the potential for load materializing is even going to be higher than what's shown in the latest load forecast. So I think that's the driver for PRES, and we feel confident that we have captured all the uncertainty in this load forecast in this mid-forecast that we are showing over there and there is potential, actually, to go higher than what's shown on here depending how phase 2 review of the government goes and some of the initiatives that may come out of that.[101]

---

[97] Tr. 5, p. 516, ll. 8-15 (O'Riley).

[98] Tr. 5, p. 488, l.9 to p. 489, l.6; p. 515, l.1 to p. 516, l.6 (O'Riley).

[99] Tr. 1, p. 71, l. 13 to p. 72, l. 22 (Hobson). The expenditures on low carbon electrification projects/programs that are prescribed undertakings under the GGRR. are shown in the updated version of Appendix Y, provided as Attachment 1 to BC Hydro's response to Exhibit B-31, BCUC Panel IR 2.18.2.

[100] Exhibit B-36, BC Hydro Undertaking No. 9.

[101] Tr. 12, p. 2312, l. 23 to p. 2313, l. 18 (Kumar).

63. Through its capital planning process, BC Hydro is also investing in three other projects to encourage new load growth and revenue through electrification: (1) the Bear Mountain Terminal to Dawson Creek Transmission Voltage Conversion,[102] (2) the North Montney Transmission Development;[103] and (3) the Prince George to Terrace Capacitors Project.[104] Mr. O'Riley explained: "So what we have included in our capital plan is the upfront money for those projects, for the three projects, so we're investing. We are investing ahead of need relatively modest amounts but ensuring that we're leaving open the possibility of electrifying those customers."[105] Given the early stage of these projects and given that customers have not yet committed to taking service,[106] BC Hydro has not yet included the load from those projects in the forecast. As stated by Ms. Daschuk:

> …we mentioned earlier and Mr. O'Riley mentioned three projects that we're doing preliminary investigation on. That would be the North Montney projects, the Bear Mountain project and the Prince George to Terrace project. We did not include any load in our forecast for those because they were—we did not make the decision to go ahead with those projects. So I think that we've taken also a balanced approach to say we're not including the revenues in the estimates in the forecast but neither are we including the costs of some of the projects that we might need to do to attract those customers.[107]

64. The Phase Two Comprehensive Review final report, once issued, and the upcoming IRP will inform BC Hydro's further efforts in this regard.

I. REGULATORY ACCOUNTS TRUE-UP ANY VARIANCES FROM THE LOAD FORECAST

65. As described in Part Five below, variances between actual and forecast Cost of Energy arising from differences between forecast and actual domestic customer load are deferred to the Non-Heritage Deferral Account. A regulatory variance account is a fair and efficient means of addressing emerging conditions during the regulatory process (and after it). It is

[102] Exhibit B-12, BCUC IR 2.254.2.

[103] Exhibit B-12, BCUC IR 2.254.2.

[104] Exhibit B-12, BCUC IRs 2.247.6 and 2.247.6.1.

[105] Tr. 5, p. 544, ll. 17-22 (O'Riley).

[106] Tr. 8B, p. 1315, ll. 16-19 (Rich).

[107] Tr. 8B, p. 1314, ll. 15-26 (Daschuk).

symmetrical. It provides an alternative to "data chasing", which is problematic when (a) interveners may tend to focus on updating factors that reduce rates, such that the overall outcome may be unreasonable (see Part Twelve of this Submission for further discussion of how this has occurred in the present proceeding), and (b) it impedes the timely resolution of proceedings.

66. The Non-Heritage Deferral Account will, for similar reasons, permit the fair and efficient management of load variances associated with the ongoing COVID-19 pandemic that has emerged in the weeks after the closure of the evidentiary record. BC Hydro addresses COVID-19 in Part Twelve of these Submissions.

J. REVENUE FORECAST IS INDUSTRY STANDARD AND CONSISTENT WITH PAST PRACTICE

67. The Revenue Forecast, summarized in Section 3.5 of the Application, is used to determine the revenue shortfall and the proposed rate increases to meet BC Hydro's forecast revenue requirements. The forecast methodology uses load and customer projections from the Load Forecast and applies approved fiscal 2019 tariff rates to calculate revenue. The Revenue Forecast is a straightforward calculation, relative to the preparation of the Load Forecast, and the method is unchanged from the Previous Application.[108]

K. CONCLUSION AND REQUESTED FINDINGS

68. The BCUC should find that the Load Forecast and Revenue Forecast for the Test Period reflected in the Evidentiary Update are reasonable. The Load Forecast for years following the Test Period will be updated in the upcoming IRP filing.

[108] Exhibit B-1, Application, p. 3-52.

PART FIVE: FORECAST COST OF ENERGY

A. INTRODUCTION

69. In broad terms, BC Hydro's 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. The evidence discussed in this Part demonstrates that BC Hydro's forecast Cost of Energy, as updated in the Evidentiary Update, is reasonable for the purpose of setting rates in the Test Period.

70. We focus on the following supporting points:

- First, the increase in the forecast Cost of Energy since the Previous Application is primarily driven by an increase in costs related to IPPs and Long-Term Commitments.[109] The vast majority of those costs are associated with existing EPAs, the terms of which are fixed, and for which cost recovery is mandated by Direction No. 8.

- Second, BC Hydro is taking available steps to reduce IPP energy costs, including exercising contractual rights under EPAs and suspending the Standing Offer Program ("SOP") indefinitely.

- Third, the forecast Cost of Energy for the Test Period reflects prudent system operations.

  - 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[110] value of its energy

[109] Costs for EPAs on the integrated system are categorized under "IPPs and Long-Term Commitments".

[110] Maximizing the value of BC Hydro's energy supply portfolio on an "expected" basis does not mean that BC Hydro attempts to predict what inflows will actually be at some point in the future, as described further in this Part.

supply portfolio within a range of outcomes. This approach brings significant benefits for ratepayers.

  - BC Hydro's Energy Studies, which inform decisions made to achieve this objective, are based on a sound methodology that has been endorsed by independent experts as part of a recent audit.

- Fourth, BC Hydro's approach to operating the system and capital planning both ensure that ratepayers are getting the most out of BC Hydro's Heritage Assets.

- Fifth, although the forecast Cost of Energy is used in determining BC Hydro's revenue requirements, through the use of regulatory accounts, customers ultimately only pay the actual Cost of Energy.

71. BC Hydro is not, as part of this Application, proposing any generation projects or seeking acceptance of any EPA. Long-term resource planning and its effect on Cost of Energy after this Test Period will be addressed in the upcoming IRP. The next IRP will be informed by the results of Phase Two of the Comprehensive Review as well as the CleanBC Plan.[111]

B. FORECAST INCREASE IN THE COST OF ENERGY DRIVEN BY EXISTING EPAS, FOR WHICH COST RECOVERY IS DIRECTED

72. The forecast increase in Cost of Energy in the Application is primarily driven by an increase in costs related to IPPs and Long-Term Commitments. The vast majority of those costs are associated with existing EPAs,[112] the terms of which are fixed and for which cost recovery is mandated.[113]

---

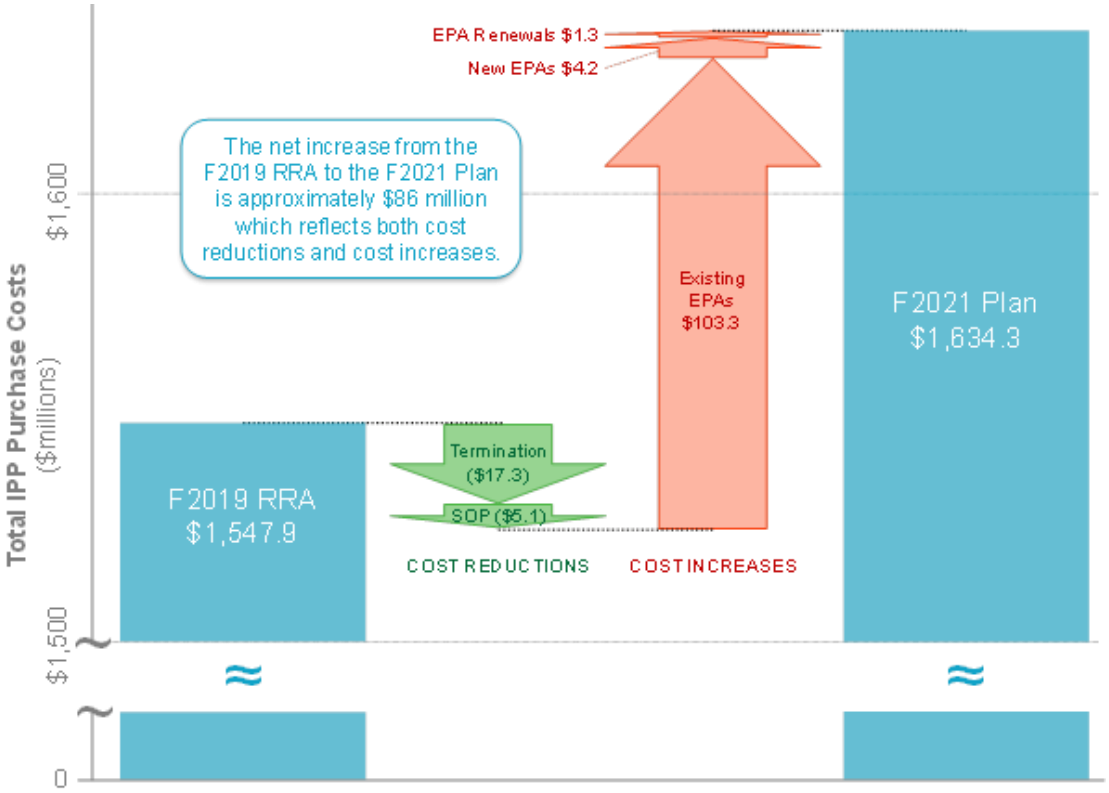
[111] Exhibit B-6, CEC IR 1.1.2.

[112] In the confidential response to Exhibit B-5-1, BCUC IR 1.18.3 BC Hydro provided a list of existing IPP contracts included in the cost of energy forecast for the test period, including their respective resource type, levelized price $2019 (c/GWh), expected energy delivery (GWh), Cumulative Annual Energy (GWh/yr), and earliest expiration date.

[113] Direction No. 8 and *Clean Energy Act*, s. 8.

(a) The Vast Majority of Total IPP Purchase Cost Increases Are Related to Existing EPAs

73. Figure 4-2 in the Application,[114] included below, provides an indicative view of the key drivers of changes to the Total IPP Purchase Cost forecast between the fiscal 2019 Plan values from the Previous Application and the fiscal 2021 Plan values in this Application.[115] The figure illustrates that vast majority of total IPP cost increases relate to existing EPAs.



Costs Under Existing EPAs Increased Due to Price Escalation Clauses, Coming into Service and Volume Changes

74. The net increase in costs associated with existing EPAs reflects operational changes at IPP facilities or other changes, as permitted under existing agreements, which impact the forecast cost of IPP energy. These types of changes include price escalation, capacity increases, and forecast delivery changes resulting from a partial-year forecast becoming a full-year forecast. More than half of the forecast IPP cost increase (before savings) can be attributed to

[114] Exhibit B-1, Application, p. 4-32.

[115] Exhibit B-5, BCUC IR 1.17.1.

increased forecast deliveries from two IPP facilities, as permitted under their respective agreements.[116]

Cost Recovery Is Mandated for Existing EPAs Entered into before April 1, 2016

75. Direction 8 provides that the BCUC must not disallow for any reason the costs incurred by BC Hydro with respect EPAs entered into before April 1, 2016.[117] As a result, the recovery of the increase in IPP costs under most existing EPAs has been mandated by Government.

(b) A Small Portion of the Total IPP Purchase Cost Relates to EPA Renewals, which Includes Directed Biomass Purchases, and New EPAs

76. As illustrated in Figure 4-2 of the Application reproduced above, costs associated with EPA renewals[118] and new EPAs represent only a small portion of the total IPP purchase cost forecast increases. The net cost increase shown as "EPA renewals" includes the costs of expiring EPAs, the costs for hydro renewals (renewed at lower prices than the original contracts) and the costs associated with the government-directed Biomass Energy Program (renewed at lower costs than the original contracts but at higher volumes than compared to the 2013 IRP).[119] Mr. Chow explained BC Hydro's approach to IPP renewals:

> Yes, so at this point, for the test period, there are really only a limited number of EPA renewals happening. So there are six biomass energy program contracts, that are biomass EPAs that are expiring, due to expire, and they are all covered by the biomass energy program. And then there were two small hydro projects – less than – in total they are less than 4 megawatts.

[116] Exhibit B-1, Application, p. 4-32.

[117] Direction No. 8, s. 4(1)(b).

[118] The $1.3 million value for EPA renewals in Figure 4-2 represents the net change in cost (i.e., certain new EPAs to replace existing expiring EPAs are forecast to increase in cost and others are forecast to decrease) from the Previous Application to the fiscal 2021 Plan of those EPAs that have been renewed since the Previous Application (as of May 2016) and those EPAs that are assumed to be renewed during the Test Period. Exhibit B-1, Application, section 4.7.1.2; Exhibit B-6, CEC IR 1.22.1. See also, Exhibit B-5, BCUC IR 1.15.1.1 and Exhibit B-16, BCUC IR 3.303.1.

[119] Exhibit B-6, CEC IR 1.22.1. See also, Exhibit B-5, BCUC IR 1.15.1.1 and Exhibit B-16, BCUC IR 3.303.1.

> So what we've said in our filings is that we are adopting a conservative internal approach for at least for the hydro renewals, and that would be to evaluate those at market value.[120]

77. It is appropriate to include these costs in the forecast Cost of Energy, for the following reasons:

- BC Hydro has considered cost benchmarks when evaluating the cost effectiveness of renewing hydro EPAs (which are subject to a process under section 71 of the *UCA*). These benchmarks include (i) an estimate of the IPP's cost of service (including a rate of return), (ii) the IPP's opportunity cost, (iii) the impact to BC Hydro rates, and (iv) system benefits and support characteristics (if applicable).[121]

- BC Hydro and the Government of B.C. worked together to develop a biomass energy strategy to deal with biomass generating facilities with expiring EPAs. One outcome of the biomass energy strategy is the Biomass Energy Program, which BC Hydro is responsible for implementing. The Biomass Energy Program applies to the seven biomass generating facilities with EPAs that are due to expire before March 31, 2022.[122] Under the Biomass Energy Program, BC Hydro will potentially renew up to 80% of the historical aggregate deliveries for eligible projects. As a result, up to 1,280 GWh per year will be renewed under the program.[123] Under Order in Council No. 158, the Government of B.C. has provided a direction to the BCUC with respect to the biomass contracts and to require the costs associated with the program to be recovered from customers.[124]

---

[120] Tr. 9, p. 1400, l. 23 to p. 1401, l. 11 (Chow).

[121] Exhibit B-16, BCUC IR 3.303.3.

[122] Exhibit B-6, BCSEA IR 1.11.5.

[123] Exhibit B-6, BCSEA IR 1.11.7.

[124] Exhibit B-6, BCSEA IRs 1.11.2 and 1.11.7. The *Direction to the British Columbia Utilities Commission Respecting the Biomass Energy Program*, B.C. Reg. 71/2019, provides that the BCUC may not disallow for any reason the

78. BC Hydro expects that its EPA renewal approach beyond the Test Period will be revisited as part of the process for the next IRP filing.[125]

C. BC HYDRO IS TAKING AVAILABLE STEPS TO MITIGATE IPP ENERGY COSTS

79. BC Hydro is managing energy costs from IPPs to the extent possible within the parameters of its contractual obligations under EPAs.

- ***Exercising turn-down rights:*** BC Hydro enforces its rights and obligations in EPAs to reduce cost commitments, such as exercising turn down rights when it is cost effective to do so.[126]

- ***Terminations for cause and by agreement:*** BC Hydro does not have unilateral rights to terminate its EPAs, i.e., to terminate without cause.[127] In general, BC Hydro only has a right of termination under an EPA if the counterparty triggers a termination right, such as failing to reach commercial operation by the required date or taking actions that constitute a material default under the specific EPA.[128] BC Hydro monitors its EPA portfolio to ensure that IPPs are in compliance with the terms of their agreements and to consider exercising termination rights when such rights arise. In addition, BC Hydro may exercise an opportunity to terminate an EPA by mutual agreement, provided that it is in the interest of customers to do so.[129] Between fiscal 2015 and the filing of the Application, BC Hydro terminated three EPAs. In addition, BC Hydro did not renew three other expiring EPAs.[130]

---

recovery in rates of BC Hydro's costs with respect to a biomass contract for biomass facilities listed in the regulation.

[125] Exhibit B-6, CEC IR 1.22.4.

[126] Exhibit B-1, Application, p. 4-10. See also, Exhibit B-5, BCUC IRs 1.17.1, 1.17.2, 1.17.3 and 1.18.1.

[127] Exhibit B-5, BCUC IR 1.18.1. See also, Exhibit B-5, BCUC IR 1.18.3.1.

[128] Exhibit B-5, BCUC IR 1.18.1.

[129] Exhibit B-5, BCUC IR 1.18.1.

[130] Exhibit B-1, Application, p. 4-10.

80. BC Hydro has taken additional steps to proactively manage IPP costs such as pursuing selective renewals at lower prices that are subject to BCUC acceptance of applications under section 71 of the *UCA*,[131] as described above.

BC Hydro Has Indefinitely Suspended the Standing Offer Program

81. The SOP was created in response to provincial policy direction. In February 2019, as part of the Phase One Comprehensive Review, the Government of B.C. issued a regulation that allowed BC Hydro to suspend the SOP indefinitely.[132] Existing SOP EPAs, none of which expire before fiscal 2030, will remain in place.[133] Since there is no present obligation associated with the indefinite suspension of the SOP, no costs associated with the suspension have been included in the Test Period forecast.[134] In any event, recovery of SOP EPA costs is prescribed by section 8 of the *Clean Energy Act*.

D. FORECAST COST OF ENERGY REFLECTS HOW BC HYDRO OPERATES THE SYSTEM

82. BC Hydro plans its resources to meet domestic load and then, in the operating time-frame, makes decisions to dispatch resources and to undertake Electricity Purchases or Surplus to maximize the expected value of its energy supply portfolio within a range of outcomes. The capability of BC Hydro's supply resources is shown through the planning view and a forecast of how that portfolio will actually be operated, based on expected conditions, is shown through the operating view.[135] As Mr. Clendinning explained:

> And so those are the medium of what we're doing, and to Ms. Matthews's points, we're looking at when and how to pr[o]cure additional resources. As we get closer in the timeframe that resource stack – if I'll call it that – gets fixed. And

[131] Exhibit B-1, Application pp. 4-8 to 4-12.

[132] Exhibit B-1, Application, p. 4-9. The SOP includes the Micro-Standing Offer Program. BC Hydro will not be executing any other SOP EPAs, with the exception of five First Nations' clean energy projects that are part of Impact Benefit Agreements with BC Hydro and/or are mature projects that have significant First Nations involvement.

[133] Exhibit B-6, CEC IR 1.6.1.

[134] Exhibit B-5, BCUC IR 1.19.2.1.

[135] The differences between the planning view and the operating view are described in Exhibit B-13, CEABC IR 2.28.1.

> so how we then work with that fixed constraint on the system, that's really where the operational view takes over and I know Ms. Matthews can get into that more detailed world in a bit.[136]

83. The forecast Cost of Energy for the Test Period is based on the operating view, which is informed by outputs from BC Hydro's Energy Studies.[137] As discussed below, 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. The Energy Studies support this objective by developing an optimal set of reservoir and generation station operations and modelled market transactions with Powerex, given the current forecasts of water inflow, market prices, and weather adjusted load.[138] BC Hydro has established an appropriate objective for its system operations, as demonstrated by recent events in 2018 (fiscal 2019), and the Energy Studies are a robust tool to help BC Hydro deliver on it.

(a) BC Hydro's Operating Horizon Objective (Meeting Load First While Maximizing Value Within a Range of Outcomes) Is in the Best Interests of Ratepayers

84. In 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.

85. Electricity Purchases or Surplus Sales are undertaken to both cost-effectively meet load requirements and to take advantage of trade opportunities. As Ms. Matthews explained:

> 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 purpose of what the two companies do are quite different. They are trying to [maximize] 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

[136] Tr. 8B, p. 1271, ll. 7-15 (Clendinning).

[137] Tr. 9, p. 1425, ll. 3-11 (Matthews).

[138] Exhibit B-1, Application, pp. 4-13 and 4-14.

> we need it to meet our domestic needs, which could be for a number of reasons.[139]

86. Surplus Sales (also referred to as domestic sales) are sales to Powerex that occur because BC Hydro has a surplus. Market Electricity Purchases are purchases from Powerex to cost-effectively meet load. Net Purchases (Sales) from Powerex are transactions with Powerex to generate Trade Income.[140] Powerex also generates Trade Income from a wide range of activities that are not connected to BC Hydro's system.[141] Ratepayers receive the full benefit of Trade Income generated by Powerex's activities and bear no downside risk under BC Hydro's definition of Trade Income, which has the effect of assigning any net loss in Trade Income to the Government of B.C.[142]

87. While Powerex is able to use the residual capability of the BC Hydro system to generate Trade Income, BC Hydro makes all of the decisions related to system operations and has the ability to put constraints on Powerex's activities. As Ms. Matthews emphasized:

> So yes, Powerex imports and exports out of the system for trade, but 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. Like especially when we're coming up to a peak. Like we're going to be conservative making sure we're holding back.

---

[139] Tr. 9, p. 1480, ll. 9-19 (Matthews).

[140] Exhibit B-1, Application, pp. 4-6 and 4-7. Trade Income is the greater of (a) the amount that is equal to BC Hydro's consolidated net income, less BC Hydro's non-consolidated net income, less the net income of BC Hydro's subsidiaries except Powerex, less the amount that BC Hydro's consolidated net income changes due to foreign currency translation gains and losses on intercompany balances between BC Hydro and Powerex; and (b) zero: Exhibit B-1, Application, p. 1-41.

[141] Exhibit B-17, AMPC IR 3.3.2.

[142] BC Hydro forecasts Powerex's net income based on its historical five year average. The difference between forecast Powerex net income and actual Powerex net income is deferred to the Trade Income Deferral Account. However, if Powerex's net income is less than zero, the amount deferred to the Trade Income Deferral Account is the difference between zero and the forecast amount.

> So like last week when we had the high winter peak, so it's us who are setting like what are we needing to have, and if there's leftover capability, then Powerex can use, but we decide how we use our resources.[143]

88. While different imports or exports to/from the BC Hydro system may occur for different reasons, the overall objective is the same: to meet load first while maximizing the expected value of the energy supply portfolio to ratepayers, within a range of outcomes. BC Hydro often refers to this objective as "maximizing consolidated net revenue", but the implicit starting point phraseology is that domestic load is being met first.[144] This is evident, for instance, in Ms. Matthews' response as to why she considers meeting domestic load and maximizing the expected value for ratepayers to be complementary, rather than conflicting, objectives:

> No, I don't think they are, because the – I guess within the energy studies the first thing you have to do is meet load, and then how we're meeting it is to then maximize the consolidated net revenue. So I don't see that as a conflict. It's more like meeting the load is a given as part of the modeling and it's part of how we operate.[145]

89. The fact that there is uncertainty and risk around domestic requirements does not mean the objectives themselves are inconsistent. But it does require an assessment of probabilities, which is done as part of the Energy Studies.

90. BC Hydro maximizes the value of BC Hydro's energy supply portfolio on an "expected" basis. This does not mean that BC Hydro attempts to predict what inflows will actually be at some point in the future. Rather, it means that BC Hydro makes decisions based on probabilities. The probabilities are informed by historical ranges, and become more refined as the year rolls forward and more information about conditions becomes known. As Ms. Matthews explained:

---

[143] Tr. 9, p. 1447, l. 22 to p. 1448, l. 11 (Matthews). See also, Tr. 10, p. 1746, ll. 10-16 (Matthews).

[144] Ms. Matthews explained the phrase this way: "Yeah, so 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": Tr. 9, p. 1426, l. 22 to p. 1427, l. 2.

[145] Tr. 10, p. 1746, ll. 10-16 (Matthews).

> As I had asked the question, you know, earlier, if you're going to guess at whether it rains or not in April, what you'd do is you look back at historics. So we're not trying to use physical weather forecasting models to do it, we're just looking at what's the probability and we know the probability. We know it's not right.
>
> Like, we're not trying to guess, that's the point. What we're doing is we've got a range of probabilities and then as we go forward we're always adjusting as we get more information. And what we're doing is we're not betting that it's going to be wet and we're not betting it's going to be dry, we're just going forward economically kind of always aiming for the middle and adjusting as it goes.[146]

91. BC Hydro's approach recognizes that actual conditions will be different than expected conditions. While decisions are made to maximize value, BC Hydro manages those decisions to maintain its ability to respond to a range of probable future conditions. As Ms. Matthews explained:

> So to answer your question about the risk, we use energy studies to give the economic picture and then we evaluate and look at – I tend to call them the tails. They are the outliers on the distribution. So we keep an eye on our tails.[147]

92. Adopting an unduly risk averse approach that withholds exports in anticipation of very low probability events occurring, would produce higher rates. Ms. Matthews explained:

> Now, we did in a few places talk about --- I think there were some IRs that asked about what if your objective was something different. I'm trying to find those there. But within that IR I think how we answered it was that if we had a different objective, It might address one risk versus another, but our overall value of the system would be less. So I don't see that our objective of maximizing consolidated net revenue feeds into increasing that risk.[148]

93. The following section demonstrates that BC Hydro's approach is in the best interest of ratepayers, with reference to BC Hydro's recent ability to maximize value for ratepayers while managing through significant events that occurred in 2018 (fiscal 2019).

---

[146] Tr. 9, p. 1464, ll. 2-16 (Matthews).

[147] Tr. 9, p. 1455, ll. 8-12 (Matthews).

[148] Tr. 10, p. 1779, ll. 2-11 (Matthews).

(b) In 2018, BC Hydro Managed Through Significant Events While Maximizing Value for Ratepayers

94. In the summer of 2018, BC Hydro had a forecast surplus and sold energy to take advantage of high prices for the benefit of ratepayers. As Ms. Matthews explained:

> So, in the summer of 2018, as we came through and we have a forecast of surplus, we had a threshold sale price set, and the prices were really high, so a lot of sales were made from the system, and those were allocated to domestic. Then towards the end of the summer we got to the point where we were actually on balance. And BC Hydro, we really try not to sell and then need to buy back, that really is Powerex's job, so we removed our threshold sale price at that point. But that was towards the end of the summer. So, those sales were economic.[149]

95. While BC Hydro's load and resources were approximately balanced following these exports, three significant events then occurred, which then created a need for imports:[150]

- First, dry conditions in the Williston basin resulted in four consecutive months of low inflows, with September, October and November being the third, second and fourth lowest in 60 years.

- Second, the Enbridge pipeline explosion in October caused a high-level of gas supply uncertainty in B.C. and the Pacific Northwest with only 80% of normal capacity expected throughout the winter. This affected western wholesale electricity markets by creating an increased demand for electricity to replace gas-generating units that would have otherwise been able to run.

- Third, B.C. experienced a record-breaking cold February, which resulted in three electricity demand records being broken that month, followed by the driest March on record in parts of the province. These dry conditions impacted inflows into BC Hydro's reservoirs as well as energy supply from IPPs. Run-of-river projects were producing less than projected because of low water levels. In addition, wind projects also delivered less

[149] Tr. 9, p. 1482, ll. 4-14 (Matthews).

[150] Exhibit B-17, AMPC IR 3.3.1, Attachment 1.

than expected. For example, in February, run-of-river and wind projects only produced 29% and 50% respectively of what they were forecast to produce.

96. In order to secure the imports required to meet load in this environment, at as reasonable a price as possible, BC Hydro entered into the Powerex Letter Agreement to reduce BC Hydro's risk and secure the required imports.[151] As Ms. Matthews noted:

> So similarly if you look at the total numbers for the year, I think the imports and exports are total imports, or you could almost say wash, because we sold a bunch in the summer and then bought it back in the winter.[152]

97. Ms. Matthews summarized the results of these events, stating:

> I mean, making those sales was the appropriate thing to do at that time. I think we sold them at 76, in the end we bought back at about 50. We made a gain of $26, on what we did in the most difficult year.
>
> So we do have to be very careful and watch those [tails]. But I think the flexibility of the system, I mean we always talk in concept how important the flexibility of the system is, but last year was I think the first time where I really felt it. And you really realize how benefit [sic] that system is, and the flexibility that we have, especially when we could look forward and say, "Okay, with the pipeline and really high prices in December, we are not wanting to be buying then, and we had the ability to look forward."
>
> Now, coming to the February and March, that was also an event that was, I would say, outside the historical dataset of what we had. We had a six-week cold period. And it was still cold in March. Now, in March and end of February it's not as cold as let's say it was last week. But for that time of year, it was still extremely cold, and that six-week period was—actually coming back to the weather forecast that we had coming into that section, that seasonal forecast was actually saying it should be warmer than normal, and we ended up having like a six week very cold period.
>
> But so that actually proved out that that was really the sort of risks that we were protecting against, and it actually happened to occur—I don't think in the fall I

[151] Exhibit B-16, BCUC IR 3.314.1.

[152] Tr. 9, p. 1509, ll. 21-26 (Matthews).

> had any idea or thought that—you know, that that sort of thing is definitely is going to happen but we had to protect against the chance that it might.[153]

98. Ms. Matthews explained that it was not "luck" that led to the favourable results for BC Hydro's customers, but rather the outcome of making operational decisions based on informed probabilistic analysis:

> So I disagree with the comment that it's not sure if it is luck or skill. I mean, that's what the energy studies does in terms of looking at the range of possible outcomes. I wasn't trying to guess what the year would turn out to be, but I was being careful to make sure that we managed those tails.
>
> And really for all probability, it might have not turned out to have that February, and we might have, you know, bought energy at—I think it was in the—I just can't remember, 30s, 40 dollars or the total cost was, I think, $50 that we might not have needed. But that still would have been worth it and we could have still then, you know, eventually sold that back into the market at perhaps, you know, usually probably around that cost anyway.
>
> So the whole thing on mismanagement is you're not actually trying to guess what the year is going to be. And what I really find is that—I mean that's why we have to look at the data. Like everybody tends to have current-itis on what is happening now. Like I mean think of last summer. May and June how dry that was. And there was fires already starting up north, and there was a lot of talk about how bad the fire season was going to be. Like I think everybody was betting on a dry summer, but we just have to look at the data and the probabilities and still protect the ends. And that's what we did and do.
>
> So I guess what I'm saying is like we—we always—all we can really do is look at what those probability are as the range of outcomes. We base our decisions on the economics where we are, and we watch our tails.[154]

99. Ms. Matthews explained that even with the benefit of hindsight, she wouldn't have made any changes:

> THE CHAIRPERSON: So you just used the term "protecting against risks". So I think what I'm hearing you say is that there was—I think there was three particular risks that crystalized earlier last year. One is a cold February, second is a drought and third is the Enbridge pipeline explosion. And you wouldn't

[153] Tr. 9, p. 1483, l. 12 to p. 1484, l. 20 (Matthews).

[154] Tr. 9, p. 1488, l. 21 to p. 1490, l. 1 (Matthews).

normally even attempt to protect against the pipeline explosion, presumably, let alone all three of those risks occurring at the same time. Is that—

MS. MATTHEWS: A Yes, that's fair to say.

THE CHAIRPERSON: That's fair?

MS. MATTHEWS: A That's correct.

THE CHAIRPERSON: But I think I'm hearing you say though that in spite of that it was still, in retrospect, turned out to be the right decision to make the sales in 2018 that you did because you made enough money off those sales to cover even those three unexpected events all together.

MS. MATTHEWS: A Yes.

THE CHAIRPERSON: Did I hear you say that? And I—

MS. MATTHEWS: A Yes. No, that's correct that the—I mean, I think the sales that we made in the summer were maybe slightly less than actually what we had bought back, I'd have to check the numbers, but certainly I stand by that those sales that we made in the summer were the correct things to do and I'd do them again.

THE CHAIRPERSON: So with hindsight you would go back and do exactly the same thing anyway?

MS. MATTHEWS: A Yes.[155]

100. In summary, Ms. Matthews concluded:

We face every day making decisions in uncertainty. That's actually what my job is. So that's part of what we do all the time. If we had a perfect forecast of everything we'd all be rich probably and life would be easy.

But the other thing I would say is that I think if you really want to look at the success of fiscal '19 you actually just have to look at the results. We managed through the most difficult period that we've had and we've saved money for the ratepayers. And that's something I'm actually very proud of, and so I think that's where you actually look if you look at what was the success of that year.[156]

[155] Tr. 9, p. 1484, l. 24 to p. 1486, l. 1 (Matthews).

[156] Tr. 9, p. 1470, ll. 9-21 (Matthews).

(c) Energy Study Methodology Produces a Sound Price Signal that Enables BC Hydro to Achieve its Operating Objective

101. BC Hydro's Energy Studies, which it uses to achieve its operating horizon objective (discussed above), are based on a sound methodology that has been endorsed by independent experts as part of a recent audit.

Energy Studies Identify Probabilities, Allowing Data-Driven Risk/Reward Decisions

102. BC Hydro outlined in the Application how an Energy Study works, and Ms. Matthews elaborated at the hearing.[157] At its core, the Energy Study provides price signals that allow BC Hydro to decide (a) which basins to use, and (b) at what price BC Hydro should undertake Electricity Purchases or Surplus Sales.[158] As Ms. Matthews described:

> When we're actually in operations, like the shift office that I had talked about previously, what they are doing is doing a load resource balance for the next hour. So we use that term a lot and we can use it in different times, but for the energy studies what it is a load resource balance on the energy out across the operating time period.
>
> And so what the energy studies also really do is it – it's really looking at the probabilities. So there is the key factors that are the drivers into the energy studies are the inflows, and that's the biggest one. Also the load. And then the market prices. So those three tend to be the big ones that change things a lot.
>
> Also included that can have an impact is any outages or system constraints that we have in. So that's all in the energy study.
>
> So what they do is they model it out and they give an optimal set of where you are now versus all the things that can happen. And so we see that going out, and that gives us the price signals.[159]

103. Operationally, BC Hydro fills its system storage during the freshet, when inflows exceed loads. The precise amount of refill depends on reservoir elevations at the end of winter,

---

[157] Tr. 9, p. 1421, l. 17 to 1442, l. 4 (Matthews); Tr. 9, p. 1445 l. 11 to p. 1451, l. 25 (Matthews); Tr. 9, p. 1452, l. 22 to p. 1470, l. 21 (Matthews); Tr. 9, p. 1472, l. 23 to p. 1490, l. 1 (Matthews); Tr. 9, p. 1490, l. 13 to p. 1503, l. 10 (Matthews); Tr. 9, p. 1504, l. 17 to p. 1507, l. 12 (Matthews).

[158] Tr. 8B, p. 1269, ll. 9-15 (Matthews).

[159] Tr. 9, p. 1453, l. 11 to p. 1454, l. 6 (Matthews).

snowpack (and to a lesser extent, spring precipitation), generation from other resources (e.g., IPPs) and loads. While reservoir levels at the end of winter are largely dependent on load and start-of-winter elevations, BC Hydro is able to adjust end of period storage levels through market purchases and/or sales and thermal generation.[160] Ms. Matthews explained that BC Hydro makes use of multi-year storage, which means that in any given year BC Hydro might end up storing into the system storage or drafting from the storage.[161]

104. The Energy Study models account for the trade-offs (risk/reward) between selling now and selling later, or buying now and buying later.[162] There are potential risks with decisions to act (i.e., buy/sell), as well as decisions not to act (i.e., not buy/not sell).

- Short-term decisions that result in market purchases or surplus sales will always result in changes in longer-term probabilities of the need to either purchase or sell energy, or re-operate to manage system storage. Making sales in the high priced summer period also would increase the probability of the need for purchases in the coming fall and winter.[163]

- There is similarly risk associated with a decision to forego purchases or sales. There is always a risk that foregone opportunities to sell (at a lower price) or purchase (at a higher price) will turn out to have been economically beneficial. In addition, inflows may come in higher than forecast such that the volume of sales should have been higher (thus selling at a lower price), or vice versa.[164]

[160] Exhibit B-5, BCUC IR 1.20.6.

[161] Tr. 9, p. 1424, l. 22 to p. 1425, l. 15 (Matthews).

[162] Exhibit B-31, BCUC Panel IR 2.6.3. In more technical terms, the Energy Study optimization trades off the financial benefit of withdrawing energy from storage while accounting for a decrease in the amount of generation per unit of water due to operating at the lower reservoir levels. See Exhibit B-5, BCUC IR 1.20.3.

[163] Exhibit B-31 BCUC Panel IR 2.6.3.

[164] Exhibit B-31 BCUC Panel IR 2.6.3.

BC Hydro manages trade-offs in short-term and long-term risks by modelling the system over a five-year time horizon, which takes into account the longer-term impacts of any shorter-term benefits or costs.[165]

105. A key output of the Energy Studies is a forecast of the marginal value of water in BC Hydro's two largest reservoirs (Williston and Kinbasket).[166] The forecast monthly marginal value of water provides a price signal — a relative measure that guides the operation of these reservoirs in the context of market and system conditions. In other words, it informs when (a) domestic energy resources should be dispatched versus purchases made from Powerex, or (b) when additional domestic resources should be dispatched to facilitate sales to Powerex.[167]

106. The Energy Studies account for a wide range of potential occurrences. The use of weather year ensembles ensures that the variability in inflows, prices, loads, and resources due to the impacts of weather are well represented in the models. This range captures both dry and wet periods. It represents the historic geographic correlation in weather among the regions included in the modeling.[168] Each year, the most recent year of historic data is added to the modeled weather sequences, so that the range adjusts over time and always includes the most recent data. For this reason, impacts of climate change are implicitly included in the forecast.[169] Ultimately, the range of potential occurrences is sufficiently large that the average of the resulting forecast represents an unbiased estimator of the drivers, and hence how the system will be operated.[170]

---

[165] Exhibit B-16, BCUC IR 3.309.1. See also, Exhibit B-5, BCUC IR 1.29.2.1; Exhibit B-6, AMPC 1.15.4; Exhibit B-6, BCOAPO 2.108.1; Exhibit B-49, BC Hydro Undertaking No. 28; Exhibit B-31, BCUC Panel IR 2.5.2.1.

[166] Exhibit B-1, Application, pp. 4-13 and 4-14.

[167] Exhibit B-1, Application, pp. 4-13 and 4-14.

[168] Exhibit B-1, Application, Appendix DD, Energy Studies Process Internal Audit. See also, Exhibit B-5, BCUC IR 1.31.1; Exhibit B-6, AMPC IR 1.15.8; Exhibit B-13, AMPC IR 2.48.7.

[169] Exhibit B-6, CEC IR 1.17.1. See also Exhibit B-23, GJOSHE IR 4.2.1.

[170] Exhibit B-1, Application, Appendix DD, Energy Studies Process Internal Audit. See also, Exhibit B-5, BCUC IR 1.31.1; Exhibit B-6, AMPC IR 1.15.8; Exhibit B-13, AMPC IR 2.48.7.

Energy Studies are Updated Monthly and Are Augmented With Additional Analysis

107. BC Hydro updates the Energy Studies monthly with new input data pertaining to import/export transmission limits and market prices.[171] BC Hydro also incorporates the most recent actual load data, augmented by the latest approved load forecast.[172] On a weekly basis, the forecast is compared to actuals and changes to key drivers are reviewed. BC Hydro augments the Energy Studies with a number of other models, which are used for daily and weekly analysis to verify that the Energy Studies are working as intended.[173]

BC Hydro's Energy Studies Process Endorsed by Recent Audit

108. In fiscal 2019, BC Hydro undertook an internal audit of its monthly Energy Studies process.[174] BC Hydro's Internal Audit group retained SINTEF, an organization with expertise in load forecasting, risk management, hydrothermal market modelling and hydropower scheduling models.[175] The internal audit concluded that:

(a) BC Hydro has a well-established Energy Studies process in place;

(b) Key models are appropriate; and

(c) The methodologies applied are in line with leading industry practices.

(d) The Lower Cost of Energy Forecast in the Evidentiary Update Reflects Shift from Run-of-River IPP Power to Lower Cost Market Purchases Due to Low Water Conditions

109. The forecast Cost of Energy in the Evidentiary Update, which is based on the June 2019 Energy Study, was materially lower than the forecast in the Application.[176] In fiscal 2020, BC

[171] Exhibit B-5, BCUC IR 1.20.5.1

[172] Exhibit B-12, BCUC IR 2.208.1.

[173] Exhibit B-5, BCUC IR 1.31.3. Ms. Matthews elaborated on the tools that BC Hydro uses for within-month planning: Tr. 10, p. 1752, l. 19 to p. 1753, l. 23 (Matthews).

[174] The internal audit report is provided as Appendix DD to the Application.

[175] Tr. 10, p. 1788, l. 16 to p. 1789, l. 1 (Matthews). The working paper that SINTEF prepared for the BC Hydro Internal Audit team for the Energy Studies Internal Audit was filed as Exhibit B-52, BC Hydro Undertaking No. 29.

[176] Exhibit B-19, Evidentiary Update, p. 7. See also, Exhibit B-16, BCUC IR 3.307.1. The Cost of Energy forecast in the Application was based on BC Hydro's October 2018 Energy Study.

Hydro's total Cost of Energy is forecast to increase by $41.9 million from the fiscal 2020 Plan. In fiscal 2021, total Cost of Energy is forecast to decrease by $185.6 million from the fiscal 2021 Plan. Overall, the updated Cost of Energy forecast in the Test Period represents a decrease of $143.7 million compared to the forecast in the Application.[177]

110. The primary driver of the decreased Cost of Energy in the Evidentiary Update was lower costs for IPPs and Long-Term Commitments.[178] Dry conditions and lower water inflows decreased planned hydroelectric generation (water rentals) and purchases from hydroelectric IPPs and Long-Term Commitments. The decreased Cost of Energy is was also attributable to updates to historical average deliveries to incorporate the fiscal 2019 actual deliveries for operating projects, which resulted in a lower IPP forecast compared to the Application,[179] as well as delayed commercial operation dates.[180] The decrease in hydroelectric generation and purchases from IPPs and Long-Term Commitments result in lower planned surplus sales and higher planned market electricity purchases.[181] The forecast market price was lower than the forecast delivered cost of IPP energy, such that the overall Cost of Energy decreased. As Ms. Matthews explained:

> So, if BC Hydro is buying from Powerex, what's the price of those versus the price of the IPPs? And then to the extent that the market prices are lower then that will show a savings and I think that is what's being shown in those figures there.[182]

E. BC HYDRO IS GETTING THE MOST OUT OF ITS HERITAGE ASSETS

111. In its Decision on the Previous Application, the BCUC questioned whether Heritage Assets are providing optimal value to BC Hydro customers.[183] The evidence, discussed below,

---

[177] Exhibit B-19, Evidentiary Update, Appendix C, p. 1.

[178] Exhibit B-19, Evidentiary Update, p. 9.

[179] Exhibit B-19, Evidentiary Update, Appendix C, p. 3.

[180] Exhibit B-19, Evidentiary Update, Appendix C, pp. 1-2. See also, Exhibit B-6, CEABC IRs 1.7.2 and 1.7.3.

[181] Exhibit B-19, Evidentiary Update, p. 8.

[182] Tr. 9, p. 1397, ll. 22-26 (Matthews).

[183] Decision on the Previous Application, p. 24.

demonstrates that they are providing optimal value in both the operating and planning time horizons.

(a) Operating Horizon: Prioritizing Operating Specific Heritage Assets Over Existing EPAs Would Be Detrimental to Ratepayers

112. BC Hydro's approach of operating the system in an integrated manner is better for ratepayers than prioritizing operating specific Heritage Assets. While Heritage Assets are generally lower cost than IPP purchases, in the operating horizon the resource stack available to BC Hydro is essentially fixed.[184] EPAs with IPPs are take-or-pay. BC Hydro's monthly Energy Studies optimize the operational management of all sources of energy supply on BC Hydro's integrated system. Over the operating horizon, BC Hydro operates the system to meet its objective of meeting load and otherwise maximizing net revenue for the benefit of its ratepayers.[185] The price signals that come out of the Energy Studies are used to determine which basins to run, and in what order, or whether BC Hydro is willing to either import or export.[186] This approach means that over the operating horizon, BC Hydro will obtain energy in the most economic manner possible, rather than prioritizing lower cost sources of energy.

(b) Planning Horizon: Capital Planning Maximizes the Long-Term Benefits from Heritage Assets

113. BC Hydro is in a multi-decade period of significant renewal of its Heritage Assets. Investments are prioritized and staged to maintain overall system reliability and spread capital costs to avoid sudden rate impacts. For facilities that are not a significant contributor to overall system reliability, investments to restore generation have been deferred until such time that there is a system need for energy and capacity; and they are of a high enough priority to be included within BC Hydro's 10 year Capital Plan.[187]

---

[184] Tr. 9, p. 1503, l. 1 to p. 1505, l. 1 (Matthews and Clendinning).

[185] Tr. 8B, p. 1268, l. 25 to p. 1269, l. 8 (Matthews).

[186] Tr. 8B, p. 1269, ll. 9-15 (Matthews).

[187] Exhibit B-5, BCUC IR 1.32.3.1.

114. Investments to renew Heritage Assets are currently proposed in the next 10 to 20 year period. The current strategy includes the necessary preventative maintenance and capital investments to mitigate risks related to safety, water conveyance, and the environment.[188] BC Hydro's witnesses explained the analysis that BC Hydro undertakes in deciding whether to cease investing in a particular asset.[189]

115. Cost is an important consideration informing investment decisions across different resources (e.g., choices between IPP renewals and investments in Heritage Assets).[190] The cost of individual IPP EPA renewals depend on many factors (e.g., resource type, location, age or condition of generation assets, energy profile, reliability) and such costs are not known until negotiations are completed. The cost of incremental Heritage Asset capital investments to increase energy and/or capacity output depends on the scale, location, and timing of the project as well as whether they are conducted in concert with other necessary asset investments.[191]

F. VARIANCE ACCOUNTS ENSURE CUSTOMERS PAY ACTUAL COST OF ENERGY

116. BC Hydro's costs of energy will inevitably vary from planned amounts for a number of reasons including weather, water inflows, timing of delivery, and market conditions. In recognition of this fact, the BCUC has thus approved the deferral of variances between planned and actual costs of energy to either the Heritage Deferral Account or the Non-Heritage Deferral Account. The Non-Heritage Deferral account also captures the variances between planned and actual domestic customer load, referred to as the Domestic Revenue Variance. These accounts have been in place for a number of years, and continue to play an important role for both

[188] Exhibit B-5, BCUC IR 1.32.3.1.

[189] Tr. 11, p. 1885, l. 20 to p. 1893, l. 20 (Darby and Kumar).

[190] Please refer to BC Hydro's response to Exhibit B-5, BCUC IR 1.32.3.1 for a description of some of the other factors that influence the investment decisions with regard to Heritage Asset upgrades or expansions.

[191] Exhibit B-5, BCUC IR 1.32.3.3.

customers and BC Hydro. In the end, although BC Hydro's revenue requirements are based on a forecast Cost of Energy, customers only pay the actual costs.[192]

G. CONCLUSION AND REQUESTED FINDINGS

117. The BCUC should find that BC Hydro's forecast Cost of Energy for the Test Period is reasonable, being based on a sound methodology and appropriate assumptions. The BCUC's determination on the forecast, while necessary for rate setting purposes, will not impact the *actual* Cost of Energy paid by customers that is "trued-up" using existing variance accounts.

[192] Exhibit B-1, Application, p. 4-19.

PART SIX: OPERATING COSTS

A. INTRODUCTION

118. In this Part, we address the evidence demonstrating BC Hydro's successful efforts to contain controllable operating costs throughout the company. These efforts are a manifestation of the culture of cost-containment highlighted by Messrs. O'Riley and Wong (the Policy Panel), among other witnesses.[193] While there will be increasing pressure to increase operating cost budgets after this Test Period,[194] BC Hydro's efforts to date have delivered immediate benefits for customers.

119. We focus on the following points:

- First, BC Hydro has provided detailed operating cost information and benchmarking in response to the BCUC's comments and recommendations.
- Second, 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.
- Third, BC Hydro absorbed controllable cost pressures within existing budgets. Operating cost increases during the Test Period are generally attributable to uncontrollable factors.
- Fourth, 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 a vacancy factor; re-purposing the unallocated funds

[193] See Part Three of these Submissions.

[194] See Part Three of these Submissions.

budget; lease consolidations; reduced spending on advertising; paperless billing; the Work Smart Program; and, the "making it easier to get work done" initiative.

- Fifth, operating Full-Time Equivalents ("FTEs") 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.

- Sixth, 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.

- Seventh, BC Hydro operating expenses benchmark favourably.

B. OPERATING COSTS SNAPSHOT: COST PRESSURES WITH OFFSETTING TEST PERIOD SAVINGS

120. In the Application, base operating costs were budgeted to increase by only 1.1% in fiscal 2020 and 1.3% in fiscal 2021, which is less than forecast inflation.[195] The planned increases were largely due to uncontrollable factors, since BC Hydro absorbed controllable cost increases within existing budgets. In the Evidentiary Update, operating costs increased relative to the Application because the discount rate used to value BC Hydro's pension costs (which is uncontrollable and correlated with interest rates) had decreased; this increased BC Hydro's current service pension costs.[196]

121. The following table provides an overall snapshot of BC Hydro's operating costs, after incorporating the impacts of the Evidentiary Update (as corrected by Exhibit B-11-2).[197]

[195] Exhibit B-5, BCUC IR 1.40.2. Please refer to Table 5-4 on page 5-21 and Table 5-6 on page 5-25 of Chapter 5 of the Application for further information on these cost savings.

[196] Exhibit B-19, Evidentiary Update, p. 12.

[197] Exhibit B-11-2, Evidentiary Update, Appendix A, Schedule 5, Lines 1 to 9.

Total Base Operating Costs (Fiscal 2019 - Fiscal 2021) ($ million)												
				F2019			F2020			F2021		
			Reference	RRA	Actual	Diff	Plan	Update	Diff	Plan	Update	Diff
Line		Column		1	2	3 = 2 - 1	4	5	6 = 5 - 4	7	8	9 = 8 - 7
		Operating Costs by Business Group										
1		Integrated Planning	5.1 L8	270.1	285.9	15.8	290.8	290.8	0.0	293.0	293.0	0.0
2		Capital Infrastructure Project Delivery	5.2 L6	81.9	85.9	4.0	80.1	80.1	0.0	81.1	81.1	0.0
3		Operations	5.3 L9	216.2	215.6	(0.6)	237.3	237.3	0.0	240.1	240.1	0.0
4		Safety	5.4 L6	54.9	53.6	(1.3)	56.8	56.8	0.0	57.5	57.5	0.0
5		Finance, Technology, Supply Chain	5.5 L5	265.0	261.2	(3.8)	262.6	262.6	0.0	264.8	264.8	0.0
6		People, Customer, Corporate Affairs	5.6 L9	122.5	105.5	(17.0)	110.6	110.6	0.0	111.9	111.9	0.0
7		Other	5.7 L6	(251.6)	(250.5)	1.0	(260.2)	(244.3)	15.9	(260.5)	(244.4)	16.1
8		F17-F19 RRA Compliance Filing Adjustment		10.4	0.0	(10.4)	0.0	0.0	0.0	0.0	0.0	0.0
9		**Total Base Operating Costs**		769.5	757.2	(12.2)	777.9	793.8	15.9	787.8	803.9	16.1

C. BC HYDRO ADDRESSED THE BCUC'S RECOMMENDATIONS AND COMMENTS ON OPERATING COSTS

122. The BCUC's Decision on the Previous Application stated that the Panel did not have "a high degree of comfort in BC Hydro's starting point, being the 2016 base operating cost."[198] The BCUC also commented on the absence of benchmarking. Section 5.2 of the Application outlines how BC Hydro has considered and responded to each of the BCUC's comments and recommendations.

123. Relative to the Previous Application, BC Hydro filed additional information in support of its forecast revenue requirements, including:

- Seven chapters (Chapters 5A to 5G), consisting of hundreds of pages of evidence, on the composition, drivers and outcomes of the overall budget of each of BC Hydro's Key Business Units ("KBUs") and their Departments. The information provided differs from the Previous Application in that it goes beyond justifying the incremental amounts sought and provides support for the entire budgeted amount.

- Detailed discussion of BC Hydro's budgeting process (addressed in Section D below).

- An explanation of various initiatives and steps that have resulted in BC Hydro's revenue requirements being lower than they would have otherwise been (addressed in Section F below).

[198] Decision on the Previous Application, p. 33.

124. BC Hydro also addressed benchmarking. The absence of evidence on benchmarking in the Previous Application likely created the incorrect impression that BC Hydro does not use benchmarking for internal purposes. While not all KBUs lend themselves to the use of benchmarks or metrics, there are a number of KBUs that do use benchmarks and metrics to help inform management decisions.[199] In this proceeding, BC Hydro has discussed the Morneau Shepell compensation benchmarking and the Navigant and First Quartile maintenance benchmarking. BC Hydro also summarized in Table 5-16 of the Application a number of other metrics that it uses.[200] In addition, BC Hydro retained the Brattle Group ("Brattle") to prepare an independent benchmarking report of BC Hydro's operating costs, and undertook a high-level comparison against three Canadian electric utilities (discussed further in Section I below).[201]

125. Lastly, in the sections below, BC Hydro has addressed the BCUC's remaining comments and recommendations with regards to operating costs:

- Section E below provides evidence of the value of BC Hydro's Total Rewards program. Specifically, BC Hydro has been able to achieve above average employee retention at compensation levels that are below median market rates.

- Section F below explains how BC Hydro made decisions to replace contractors with employees under the Workforce Optimization Program, including consideration of long-term costs.

- Section F below also sets out why ratepayers benefit from BC Hydro's approach to its Work Smart Program, which aims to deliver capacity hours gained rather than labour budget or FTE reductions.

---

[199] Exhibit B-1, Application, Chapter 5, p. 5-63.

[200] Exhibit B-1, Application, Chapter 5, p. 5-64. In Exhibit B-6, CEC IR 1.37.1, BC Hydro confirmed that this is a complete list, i.e., it was not being selective. The details of the peer group for the metrics appearing in Table 5-16 are set out in Exhibit B-5, BCUC IR 1.62.3 and other details about the results of individual benchmarking are set out in Exhibit B-5, BCUC IR 1.62.1 to 1.63.15. Further discussion of these benchmarks are provided as part of the operating costs and FTEs discussion for various KBUs in Exhibit B-1, Application, Chapters 5A through 5G.

[201] Exhibit B-1, Application, Section 5.7.

- Section G below reviews BC Hydro's FTE increases over time. Operating FTEs have been flat since 2012. Recent FTE increases have been driven by capital requirements as well as initiatives that have reduced overall costs.

126. BC Hydro submits that the materials filed, and evidence presented by the witnesses in this proceeding should give the BCUC much greater confidence that the forecast operating costs are reasonable and reflect an organization-wide focus on cost containment.

D. BC HYDRO'S ROBUST BUDGETING AND GOVERNANCE PROCESSES DRIVE COST CONTAINMENT EFFORTS

127. The forecast operating costs presented in this Application are the product of a budgeting process that involves top-down and bottom-up elements. As discussed below, this process has advantages over zero-based budgeting, and it produced a lower Test Period budget. BC Hydro's governance processes provide the requisite oversight of operating costs, including vacancy management and tracking performance of KBUs against budget.[202]

(a) BC Hydro's Budgeting Approach Assessed More than Just Incremental Requirements and Imposed Limits on Funding

128. BC Hydro's budgeting approach, described in Chapter 5 of the Application, goes beyond examination of incremental changes from the prior year. It requires Business Groups and individual KBUs to consider, and articulate to the Executive Team, their overall responsibilities, cost drivers, FTEs and targeted outcomes.[203] Since the Previous Application, BC Hydro has enhanced its process:

> The budgeting process used for this Application is consistent with the process used in the Previous Application, with the enhanced examination and information on the overall starting base budget in addition to detail on incremental changes.
>
> An examination of each Key Business Unit's full operating budget was performed, which allowed for validation and confidence in the starting base

[202] BC Hydro's response to Exhibit B-5, BCUC IR 1.40.3.1 provides a list of accounts along with examples of cost control mechanisms.

[203] Exhibit B-1, Application, p. 5-14.

> budget. This examination allowed more insight into the base budgets and a greater understanding of the drivers behind the cost pressures and savings that were identified.
>
> The Business Groups undertook an examination of their operations to identify areas requiring additional funding while also identifying cost savings to mitigate the cost increases requested. Explanations for the cost pressures and savings were provided and reviewed by the Executive Team.[204]

129. The "top down" aspect of the budgeting process ultimately dictated the budget amounts during the Test Period. BC Hydro did not fund the specific cost pressures identified by KBUs during the "bottom-up" assessment; rather, BC Hydro determined to fund only the non-controllable, organization-wide cost pressures, which were offset by identified cost savings.[205]

(b) The Advantages of BC Hydro's Budgeting Approach Over Zero-based Budgeting Include $24 Million Lower Budgeted Operating Costs

130. In its Decision on the Previous Application, the BCUC identified zero-based budgeting as an area for further exploration. BC Hydro submits, for the reasons discussed below, that customers are better served by the budgeting approach that BC Hydro has employed.

131. Zero-based budgeting is a method of budgeting in which the budget is essentially re-created "from scratch" for each new period. BC Hydro's budgeting approach did incorporate many of the zero-based budgeting principles, such as a detailed and transparent examination of resources and cost drivers by each KBU. BC Hydro explained:

> In the Application, we have provided supportive arguments and justifications for the total budget, not just the incremental increase. BC Hydro underwent an in-depth exercise examining its fiscal 2019 budget at a granular level to demonstrate that the current level of resources are in fact still required to achieve business objectives and that those resources are being managed responsibly. We have also identified opportunities for process and operational improvements resulting in cost savings as shown in Table 5-6 of Chapter 5 of the Application.[206]

---

[204] Exhibit B-5, BCUC IR 1.34.1.

[205] Exhibit B-1, Application, section 5.5.2.2;Exhibit B-5, BCUC IR 1.34.1.

[206] Exhibit B-5, BCUC IR 1.34.3.

132. Zero-based budgeting lacks the top-down constraint on costs that might otherwise be suggested by workload and new cost pressures. The top-town constraint was critical when developing the Test Period budgets. BC Hydro explained that zero-based budgeting would have produced a materially higher operating cost budget:

> In addition to being very labour intensive, a formal zero-based budgeting approach can result in the determination that more resources are required to perform activities, potentially resulting in an overall recommended budget increase. Given this would not be consistent with BC Hydro's focus on limiting base operating cost increases, this would not have been an acceptable outcome.
>
> Business Groups identified significant cost pressures in their respective areas during the fiscal 2020 budgeting cycle. Using the top-down, bottom-up budgeting approach these costs were not funded as the approach did not allow for costs related to these items beyond the existing budget to be funded. These costs had to be accommodated within the Business Group's existing budgets, allowing us to limit our costs increases to $8.5 million and $9.9 million in fiscal 2020 and fiscal 2021 respectively. Using a formal zero-based budgeting approach could have resulted in an additional $24 million in significantly higher base operating cost budgets.[207] [Emphasis added.]

133. Mr. O'Riley reiterated this point at the hearing:

> As a result of a changing operating environment, a lot of rigour goes into our budgeting process. The Commission had questions about our budgeting coming out of our last revenue requirements application and my strong view is that our top-down and bottom-up budgeting process has limited operating and capital cost increases and that a fully zero-based budgeting approach that lacks the top-down constraint would see greater cost increases.[208]

(c) BC Hydro's Governance Process Includes Vacancy Management, Performance Metrics and Regular Reporting

134. BC Hydro has appropriate oversight processes in place so that it operates within its budgets and targets. This includes a vacancy management process, performance metrics and regular reporting.

---

[207] Exhibit B-5, BCUC IR 1.34.3.

[208] Tr. 5, p. 358, ll. 11-19 (O'Riley).

135. BC Hydro's vacancy management process has two main elements. First, filling vacancies requires the prior review and approval by an Executive Team member or Director of a KBU. Second, any request to create a new position that is not within BC Hydro's established FTE and budget plans is supported by a business case and accommodated with offsetting cost reductions or incremental cost savings.[209]

136. Senior and executive management establishes performance criteria in advance of each fiscal year and results are tracked on Business Group dashboards, Business Group performance packages, or KBU scorecards.[210] BC Hydro's response to BCUC IR 1.62.1[211] provides a lengthy (over nine pages) list of the specific measures that are included on performance measurement dashboards for each Business Group. Each KBU has a performance measure based on its ability to maintain actual annual expenditures at or below the annual operating plans, while completing the related annual KBU work plans. Each Business Group "is expected to manage within their operating budget".[212]

137. Internal reporting is regular and extensive:

- The Finance KBU prepares monthly financial reporting at the KBU, Business Group and overall BC Hydro levels to track progress against budget. The reporting also includes forecasts for the remainder of the year, along with expenditures from prior years for validation purposes.[213] These reviews consider corrective action options such as advancing or delaying work. They may result in funding reallocations between Business Groups or KBUs, while keeping BC Hydro's overall budget the same.[214]

---

[209] Exhibit B-1, Application, p. 5-15; Exhibit B-5, BCUC IR 1.42.4.

[210] Exhibit B-5, BCUC IR 2.228.1. See also, Exhibit B-13, CEC IR 2.92.2, which discusses the use of BC Hydro's Service Plan to determine cost effectiveness.

[211] Exhibit B-5.

[212] Exhibit B-12, BCUC IR 2.231.5.

[213] Exhibit B-5, BCUC IR 1.36.1.

[214] Exhibit B-5, BCUC IRs 1.36.3 and 1.36.2.1.

- Quarterly financial reports published for external reporting purposes compare actual spend to prior year amounts.[215]

- Periodically, multi-year comparisons are reviewed to confirm budget planning assumptions. In addition, there may be specific cost items where multi-year trend analysis is reviewed on a regular basis (e.g., bad debt expenditures).[216]

138. Similar processes and procedures apply to costs that are to be recovered in regulatory accounts.[217] As BC Hydro's Chief Accounting Officer, Ryan Layton, explained:

> And we know that if something gets in that rate, it needs to be paid down. And since we are collecting almost all of our regulatory accounts in rates already, what's in those accounts matters a lot to us and matters a lot to every revenue requirements application that we bring forward.[218]

E. BC HYDRO ABSORBED CONTROLLABLE COST PRESSURES WITHIN EXISTING BUDGETS, WITH INCREASES GENERALLY ATTRIBUTABLE TO UNCONTROLLABLE COSTS

139. During the budgeting process for this Application, which occurred in conjunction with the Phase One Comprehensive Review, BC Hydro's Executive Team determined that all cost pressures would be managed within the existing (i.e., fiscal 2019 forecast) operating cost budget, with the exception of (a) storm restoration costs, which are uncontrollable, (b) the Employer Health Tax and rising benefits costs, which are uncontrollable costs that affect the Standard Labour Rate,[219] and (c) wage increases, which also affect the Standard Labour Rate

---

[215] Exhibit B-5, BCUC IR 1.36.1.

[216] Exhibit B-5, BCUC IR 1.36.1.

[217] Further information, organized by regulatory account, is provided in the response to Exhibit B-5, BCUC IR 1.40.3.1.

[218] Tr. 6, p. 824, ll. 9-17 (Layton).

[219] Exhibit B-1, Application, p. 5-48: Standard Labour Rates are calculated at the beginning of each budgeting cycle and are based on forecasts of wage and salary increases, employee benefits, current service pension costs, gainsharing under our union contracts, sick days, annual vacation, and flex day entitlements; Exhibit B-12, BCUC IR 2.231.5; Exhibit B-1, Application, p. 5-1. Per Exhibit B-13, BCOAPO IR 2.112.1: Existing budgets refer to the Business Groups' fiscal 2019 budgets. Fiscal 2019 budgets are the Business Groups' approved net operating cost budgets adjusted for the BCUC approved expenditures relating to the Waneta two-thirds operating costs, the Customer Crisis Fund operating costs, and budget transfers between Business Groups which net to zero across BC Hydro.

and are an area where BC Hydro has limited flexibility in practice.[220] In the Evidentiary Update, the updated pension discount rate determined by BC Hydro's external actuary increased forecast operating costs. The evidence regarding these cost drivers is discussed below.

(a) Non-Controllable Storm Restoration Costs Are a Significant Driver of Operating Costs Increases

140. Increases in forecast storm restoration costs, attributable to the use of an updated five-year average (fiscal 2014 to fiscal 2018), contribute significantly to the increase in forecast operating costs.

141. BC Hydro uses a five-year average to forecast storm restoration costs, as required by a previous BCUC order, Order No. G-16-09. Variances between forecast (based on an average of the actual storm restoration costs for the five most recent normal weather years) and actual storm restoration costs are deferred to the Storm Restoration Costs Regulatory Account, in accordance with that order.[221] Amounts deferred to the account in a test period are recovered over the following test period. As a result, ratepayers only pay for the actual storm restoration costs incurred and these costs are recovered over a reasonably short period of time.[222]

142. The output of the five-year average used in the current Application had increased relative to the Previous Application because BC Hydro had experienced greater storm activity in recent years.

143. Storm restoration costs increased further in the Evidentiary Update because more severe storms, including the December 2018 storm, resulted in higher than planned storm restoration costs in fiscal 2019. The variance was deferred to the Storm Restoration Costs

---

[220] Exhibit B-1, Application, p. 5-22.

[221] BCUC Order No. G-16-09, Decision on BC Hydro's Fiscal 2009 to Fiscal 2010 Revenue Requirements Application, Directive 42: "The Commission Panel directs BC Hydro to include in its base OMA for the test period average storm-related restoration costs in 2009 dollars for F2009, and 2010 dollars for F2010, respectively, to be calculated as the average of actual costs for the five most recent "normal weather" years: e.g. F2003, F2004, F2005, F2006, and F2008 would be used for F2009; and to record any variance from the average amount for each test year in a separate regulatory account ("the Storm Damage Regulatory Account") to be dealt with in its next RRA."

[222] Exhibit B-12, BCUC IR 2.232.4.

Regulatory Account, consistent with the BCUC's order, for amortization over the current Test Period, which increased the required recovery in fiscal 2020 and fiscal 2021.[223]

144. The impact of the amortization of a larger fiscal 2019 starting balance in the Storm Restoration Costs Regulatory Account is a different issue than whether the five year average should be updated to include fiscal 2019 actuals when forecasting costs in the current Test Period. The latter issue is addressed in Part Twelve.

(b) The Employer Health Tax and Rising Cost of Health Care Contribute to Standard Labour Rate Increases

145. In the current Test Period, the Standard Labour Rates are forecasted to increase due to the Employer Health Tax,[224] which is a new tax that must be paid by employers.

146. Statutory benefits (e.g., Employment Insurance premiums), over which BC Hydro has no discretion, are increasing over time.[225] Costs for the existing employee benefit programs are increasing over time due to the rising cost of health care, such as dental fees and prescription drug costs.[226] BC Hydro has taken steps to minimize cost impacts such as implementing a generic drug policy and requiring prior authorization for certain prescription drugs.[227]

147. It is unrealistic to suggest that BC Hydro should have reduced benefits coverage, whether unilaterally for management and professional employees or through collective bargaining for union employees. As discussed next, BC Hydro salaries are, on average, 11% below the market median and it is only by virtue of the pension and other benefits that total compensation approaches the market median (BC Hydro is 2% below market when total compensation is considered). Benefit programs are a part of the overall package necessary to remain competitive with market rates and to be able to attract and recruit employees.[228]

---

[223] Exhibit B-19, Evidentiary Update, p. 12.

[224] Exhibit B-5, BCUC IR 1.42.1.

[225] Exhibit B-5, BCUC IR 1.42.1.

[226] Exhibit B-5, BCUC IR 1.42.1.

[227] Exhibit B-5, BCUC IR 1.42.1.

[228] Exhibit B-5, BCUC IR 1.42.1.

(c) Salary Increases Are Needed to Keep Pace With the Market After Years of Restraint

148. Planned salary increases over the Test Period are 2% for union employees and 2.5% for management and professional employees. The evidence is that these increases are, in any practical sense, necessary.

Compensation Levels Will Remain 2% Below Market Even With Increases

149. Annual union salary percentage increases from fiscal 2012 through to fiscal 2019 averaged only 1.43%.[229] The planned increase of 2% per year for unionized employees is consistent with the bargaining mandate set by the Public Sector Employers Council ("PSEC").[230] BC Hydro's evidence was that it is improbable that collective agreements could be renewed without providing an increase that is consistent with this mandate.[231]

150. BC Hydro has similarly had limited ability to increase management and professional salaries since 2012, due to the PSEC prior salary freeze policy.[232] No salary increase was provided from 2012 to 2014.[233] The maximum annual increase that could be provided under PSEC guidelines to an individual employee between 2015 to 2018 was 2% per year, but increases averaged well below that amount.[234] Annual management and professional percentage increases from fiscal 2012 through to fiscal 2019 averaged 1.0%, i.e., one-third less than union increases.[235]

---

[229] Exhibit B-5, BCUC IR 1.42.5.

[230] The bargaining mandate established by the Government of B.C. provides the contract term and maximum general wage increase that can be provided by the employer in union collective bargaining. The current mandate, which applies from April 1, 2019 to March 31, 2022 at BC Hydro, requires a three year contract term with maximum annual general wage increases of 2 per cent for union employees: Exhibit B-13, BCOAPO IR 2.117.1.

[231] Exhibit B-5, BCUC IR 1.42.1.

[232] Exhibit B-1, Application, p. 5-22.

[233] Exhibit B-12, BCUC IR 2.219.1.

[234] Exhibit B-12, BCUC IR 2.219.1.

[235] Exhibit B-5, BCUC IR 1.42.5.

151. Independent benchmarking prepared by Morneau Shepell[236] indicates that, on an average total cash basis, BC Hydro employees earn 11% less than median market rates. After factoring-in the value of pension benefits and time off programs, BC Hydro's compensation package is still 2% below median market rates.[237]

152. Local and Canadian market salary surveys indicate that the median salary increase forecast for 2019 is 2.6%.[238] As such, even with the planned increases during the test period, BC Hydro will only be maintaining its current position relative to market median rates.

Employee Retention is Critical, and Compensation is a Factor in Retention

153. In its Decision on the Previous Application, the BCUC had stated that the costs and benefits of BC Hydro's total rewards initiatives[239] were unclear. The additional information that BC Hydro has provided on compensation benchmarking and its voluntary turnover rate provide compelling evidence of value. Specifically, BC Hydro has been able to achieve above average employee retention — as demonstrated by a voluntary turnover rate of 1.9% in fiscal 2019[240], which is below the 3.8% average for the power utilities industry[241] — at compensation levels that are below median market rates.

154. The importance of maintaining this low voluntary turnover rate cannot be understated. Many of the skillsets required by BC Hydro are specialized, and the complexity of the assets and operations requires an experienced workforce. These skills and experience are difficult to find in the market and require significant time and costs to develop.[242]

---

[236] Exhibit B-1, Application, p. 5-47; Exhibit B-5, BCUC IR 1.52.3. Please refer to Exhibit B-6, BCOAPO IR 1.6.1, for a copy of the Morneau Shepell report and summary of market rates compared to BC Hydro rates by job and affiliation. In the confidential response to Exhibit B-12, BCUC 2.227.2. BC Hydro provided the 2017 Morneau Shepell assessment in Attachment 1 and a summary of the total rewards comparison by job in Attachment 2.

[237] The benchmarking is discussed further in Section I of this Part.

[238] Exhibit B-5, BCUC IR 1.42.6. The Conference Board of Canada forecasted the average pay increase for non-unionized Canadian employees to be 2.6 per cent in 2019: Exhibit B-13, Zone II IR 2.35.2.

[239] BC Hydro's total rewards offer includes salary, pension, benefits and time off.

[240] Exhibit B-5, BCUC IR 1.62.13.3.

[241] Exhibit B-1, Application, p. 5-47.

[242] Exhibit B-1, Application, p. 5-47.

155. Falling further behind median market rates would pose a challenge to attraction and retention of employees.[243] BC Hydro's Chief Human Resources Officer, Carolynn Ryan, explained:

> We're in a little bit of a catch up period and we are trying to stay consistent with market increases which, according to the Conference Board of Canada, are anticipated to be 2.6 percent. So in order to keep our rates competitive to attract and retain the employees that we need at BC Hydro in the management/professional job categories, we don't want to fall further behind. So there is a little bit of catch up there.[244]

Incentive Pay Structure Also Drives Value for Customers

156. The incentive pay component of the total rewards program also drives value.

157. There are two types of incentive pay at BC Hydro:

- Approximately 1% of BC Hydro's management and professional employees receive incentive pay, in the form of a salary holdback.[245] The maximum annual award an employee can receive is 10% (for the President and non-executive positions) and 20% (for all executive positions except the President). Awards are based on the results achieved on BC Hydro's Service Plan performance measures (i.e., corporate measures) and individual performance objectives.[246] Each Executive's personal performance is measured against, among other things, meeting operating and capital budgets.[247]

- Unionized employees receive gainsharing which provides a maximum annual award of 5% of the union employee's wages paid in the fiscal year based on BC

[243] Exhibit B-5, BCUC IR 1.42.1.

[244] Tr. 8A, p. 1123, ll. 8-16 (Layton).

[245] Exhibit B-5, BCUC IR 1.42.10.

[246] Exhibit B-5, BCUC IR 1.42.10.1.

[247] Tr. 6, p. 734, ll. 4-9 (Wong).

Hydro's Service Plan performance measures and results achieved on department specific objective(s).[248]

158. BC Hydro's salary holdback program reinforces the high performance expectations of BC Hydro's Executive and Director-level employees. It is performance pay in the truest sense of the word, and employees cannot take for granted that they will receive it. The evidence is that, in fiscal 2019:

- No eligible employees received their full holdback amount;
- No eligible employees received the full *corporate* component of the holdback;
- The average *individual* rating was 0.72, meaning that, on average, employees who were eligible for holdback pay received 72% of the individual component of their holdback pay; and
- Only 13% of eligible employees received 100% of the individual component of their holdback pay, since it is awarded for exceptional performance only.[249]

(d) Changes in the Discount Rate Increased BC Hydro's Pension Costs

159. Changes in interest rates between the time BC Hydro filed its Application and the Evidentiary Update increased BC Hydro's forecast operating costs due to the corresponding impact on pension discount rates, which is outside of BC Hydro's control.

160. The discount rate is based on 'AA' Canadian Corporate bonds and is calculated by BC Hydro's external actuary. The discount rate used to value BC Hydro's pension costs decreased from 3.83% as of September 30, 2018 to 3.33% as of April 1, 2019. The discount rate decrease

[248]Exhibit B-12, BCUC IR 2.220.2.

[249] Exhibit B-37, BC Hydro Undertaking No. 10.

resulted in higher current service pension costs, relative to the Application, by $15.9 million in fiscal 2020 and $16.1 million in fiscal 2021.[250]

161. BC Hydro, consistent with its standard practice, made no adjustments to the discount rates provided by its external actuary.[251] As Mr. Layton explained "we rely on Morneau Shepell's expertise to give us the correct rate for BC Hydro and they did so in that e-mail. In other words, no subsequent information changed that rate in that e-mail, that is the rate that we used and it's always been the correct rate."[252]

162. While AMPC appears to prefer the original discount rate from the Application,[253] accounting rules require BC Hydro to use the discount rate at the start of the fiscal year to determine current service costs for fiscal 2020.[254] BC Hydro's external actuary had provided BC Hydro with a new discount rate in the ordinary course of business. It followed the timing cycle dictated by BC Hydro's year end (an updated discount rate is a requirement for BC Hydro's annual financial statements).[255] The timing was also consistent with what had been done in the compliance filing for the Previous Application.[256] This is discussed further in Part Twelve.

F. BC HYDRO HAS USED A NUMBER OF MEANS TO CONTROL COSTS AND ABSORB NEW UNCONTROLLABLE OPERATING COST PRESSURES

163. BC Hydro has achieved material offsetting savings and absorbed new work and cost pressures through a variety of means, including: the Workforce Optimization Program; the

---

[250] Section 1.3 of the Evidentiary Update, as corrected by Exhibit B-11-2. The lower discount rate also increased BC Hydro's fiscal 2019 non-current pension costs. However, this increase is deferred to the Non-Current Pension Cost Regulatory Account (i.e., it does not affect operating expenses) and is amortized into rates over a 13-year period, which increases the required recovery by $40.8 million in both fiscal 2020 and fiscal 2021. Current pension costs are captured in Schedule 5.7 of the Evidentiary Update (Exhibit B-11) as "Corporate Costs": Exhibit B-17, AMPC IR 3.6.1.

[251] Exhibit B-17, AMPC IR 3.5.1.

[252] Tr. 7, p. 869, ll. 10-15 (Layton).

[253] Exhibit C11-11, InterGroup Report, Recommendation 17.

[254] Exhibit B-28, BC Hydro Rebuttal Evidence, pp. 14-15.

[255] When BC Hydro filed its Evidentiary Update (Exhibit B-11), BC Hydro's current service pension costs and non-current pension costs were updated to reflect the actual pension discount rate as at March 31, 2019 (i.e., BC Hydro's most recent fiscal year-end).

[256] Exhibit B-17, AMPC IR 3.5.3.

Accenture repatriation; the consistent approach to a vacancy factor; re-purposing the unallocated funds budget; lease consolidations; reduced spending on advertising; paperless billing; the Work Smart Program; and, the "making it easier to get work done" initiative. The diversity of these initiatives highlights that, after several years of cost containment, the "low hanging fruit" is already harvested.

(a) Replacing Contractors with Internal FTEs (Workforce Optimization) Has Decreased Total Costs by $18.5 Million Annually

164. The Workforce Optimization Program, which was created in fiscal 2016 and is now closed, primarily allows BC Hydro's KBUs to replace external contractors with internal FTEs when it is beneficial to do so.[257] The Workforce Optimization Program resulted in the addition of 706 FTEs in total. The Program has decreased BC Hydro's total costs by an estimated $18.5 million annually. These benefits continue to accrue during the Test Period and are reflected in the requested rates.

165. Table 5-9 from the Application,[258] reproduced below, provides a summary of annual net (i.e., operating, capital and deferred) savings from the Workforce Optimization Program for fiscal 2020, by Business Group.

Table 5-9 Workforce Optimization Program Annual Net Savings (Fiscal 2020)

Business Group	Costs ($ millions)	Savings ($ millions)	Net Savings ($ millions)
Integrated Planning	9.7	12.7	3.0
Capital Infrastructure Project Delivery	31.2	34.3	3.0
Operations	16.9	24.7	7.9
Safety	4.0	5.3	1.3
Finance, Technology, Supply Chain	24.4	26.6	2.2
People, Customer, Corporate Affairs	6.1	6.4	0.3
Other	1.2	1.9	0.8
Total	**93.5**	**112.0**	**18.5**

[257] Exhibit B-1, Application, p. 5-29. BC Hydro has provided examples of Workforce Optimization initiatives. Exhibit B-1, Application, p. 5-33.

[258] Exhibit B-1, Application, p. 5-29.

166. The BCUC, in its Decision on the Previous Application, inquired about whether BC Hydro was giving adequate consideration to the longer term costs of replacing contractors with employees. BC Hydro has answered this concern in its evidence. Under the Program, insourcing decisions require a workforce adjustment request document that provides both quantitative and qualitative support for converting a contractor to an employee.[259]

167. The financial analysis calculates the costs associated with the FTE(s) being requested, including labour costs at the standard labour rate as well as travel and business expenses. It compares those costs to the expected savings from reducing the budget for the resources being replaced by the workforce adjustment position(s). The analysis accounts for both the short-term and long-term effects and costs of hiring contractors as employees (e.g., including pension costs which represent the largest long-term cost difference between contractors and employees).[260] BC Hydro elaborated:

> Both the immediate and ongoing costs (over the term of employment) and future costs (i.e. retirement costs) associated with hiring internal FTEs rather than continuing to use contractors are considered in each workforce adjustment request.
>
> The FTE labour cost included in each request is calculated at BC Hydro's Standard Labour Rate which includes the immediate on [sic — and] ongoing costs such as base salary/wages and other benefits, as well as future costs such as pension. While the Standard Labour Rates for internal employees will increase annually, these increases are not expected to exceed the rate of increase for external contractor rates.
>
> In addition to FTE labour costs, each workforce adjustment request considers the on-going nature of the work for the requested FTEs so that FTEs are only added for on-going and sustainable resourcing needs.[261]

---

[259] Exhibit B-1, Application, p. 5-29. See also, Exhibit B-5, BCUC IR 1.46.1.

[260] Exhibit B-1, Application, p. 5-34 provides additional information on this point. In its Previous Decision, the BCUC expressed concern that there did not appear to be an assessment of the long-term effects and costs of hiring contractors as employees. BC Hydro has now provided the information to demonstrate that such matters are, in fact, considered.

[261] Exhibit B-5, BCUC IR 1.46.4.

168. In some cases, there are additional non-financial benefits to replacing contractors with employees. BC Hydro provided the example of cybersecurity:

> The program supports workforce stability as employees are typically retained as part of BC Hydro's workforce for a longer period than contractors. This helps secure resources for high-demand positions that may at times be difficult to source from contractor labour. For example, the Technology KBU has brought critical cybersecurity monitoring and response capability in-house. While the impact of this change was cost neutral it reduces the risk of not being able to source contractor resources for this in-demand and limited supply labour function going forward. It also avoids potential cost escalation that could occur due to supply and demand imbalance.
>
> The program also supports workforce stability by retaining the same resources who are familiar with our business and systems. For example, retaining Engineers that we need on a continuous basis ensures a consistent approach and the benefit of existing knowledge of our system such as a particular piece of equipment or facility.[262]

169. While non-financial benefits are considered and can be material, financial considerations are paramount. No Business Group had a net cost increase as a result of the Workforce Optimization Program.[263] There were "no instances where FTEs were hired in lieu of contractors when it was less cost-effective to hire FTEs on a long-term basis."[264]

A Small Number of Workforce Optimization Program FTEs Were Associated With Non-Labour Savings, Repurposed Vacancies and New Revenues

170. BC Hydro was asked about the small number of FTEs accounted for as part of the Program that did not involve conversion of contractors. For context, the vast majority of FTEs associated with the Workforce Optimization Program — 673 of 706, or 95% — were funded entirely by reductions to external contractor costs.[265] The categorization of the remaining 5%

---

[262] Exhibit B-5, BCUC IR 1.47.7

[263] Exhibit B-12, BCUC IR 2.224.6. Note in Exhibit B-12, BCUC IR 2.224.3 BC Hydro provided a corrected version of the original attachment provided in Exhibit B-5, BCUC IR 1.46.2, such that the results now show no net cost increases.

[264] Exhibit B-5, BCUC IR 1.46.3.

[265] Exhibit B-12, BCUC IR 2.225.8. Exhibit B-5, BCUC IR 1.47.5 provides a breakdown of all FTEs added through the Workforce Optimization Program, by funding source.

as being related to the Program was only to take advantage of the Program's existing governance structure. The benefits to customers, while different, are nonetheless clear.

171. In every case, there was an offsetting cost savings or revenue source:

- Two FTEs (i.e., 0.3% of the total Workforce Optimization FTEs) were funded through the reduction of non-labour expenditures.[266]

- 24 FTEs (i.e., ~3% of the total Workforce Optimization FTEs) represented repurposed vacancies.[267] BC Hydro followed the same principles for re-purposing vacant positions as followed for the conversion of external contractors to internal FTEs. This includes calculating the cost reduction of the vacancy compared to the labour cost of the additional FTEs.[268]

- Seven FTEs (i.e., less than 1% of the total Workforce Optimization FTEs) were added in fiscal 2019 to manage the Customer Crisis Fund, which were funded through the rate rider approved by BCUC Order No. G-166-17 to recover the overall costs of this pilot program.[269] The Program provided a useful framework for the assessment of these FTEs because the objective was similar, i.e., ensuring that any FTE additions were funded without increasing KBU base operating budgets.

[266] Exhibit B-5, BCUC IR 1.47.5. In Exhibit B-5, BCUC IR 1.47.3, BC Hydro provided an example: "In the Supply Chain KBU, a Materials Coordinator FTE addition was approved to support and manage the logistics flow for contractors to pick up materials at a centralized location in order to improve efficiencies and controls for both BC Hydro and the contractor crews. This position was funded through transportation cost savings which result from centralizing the location of contractors to pick up materials."

[267] This refers to positions repurposed to fund a higher priority position or area where increasing workloads required additional resourcing (refer to Exhibit B-12, BCUC IRs 2.225.3 and .225.5) and to additional FTEs that were absorbed within the existing labour budget by taking into account temporary vacancy periods for the existing FTEs within the group (refer to Exhibit B-12, BCUC IR 2.225.5).

[268] Exhibit B-12, BCUC IR 2.225.6.

[269] In the Application these were grouped in with the "reduction of other expenditures category", which was somewhat of a misnomer.

172. The inclusion of these exceptional cases under the umbrella of the Workforce Optimization Program made sense from a governance perspective. The Workforce Optimization Program provided a framework that required rigour around any staffing decisions. As BC Hydro put it: "While contractor conversions were the focus, the Program was used to manage all regular time FTE additions. This consistent governance model was used so that optimal labour resourcing decisions were made in all situations and not just for work previously done by contractors." [270]

The Workforce Optimization Program Has Achieved its Objective and is being Discontinued

173. BC Hydro expects to have all planned conversions implemented by the end of fiscal 2020. There are no planned contractor conversions in fiscal 2021.[271] While the Workforce Optimization Program has achieved its objective and is being closed, "BC Hydro will continue to manage its labour resources in an optimal manner to execute our work plans."[272]

(b) Accenture Repatriation Provides $8.2 Million of Annual Savings During the Test Period

174. In May 2018, BC Hydro successfully transitioned important services previously performed by Accenture back into BC Hydro.[273] The Test Period revenue requirements include approximately $8.2 million in annual savings associated with the repatriation of work from Accenture. The annual net savings from repatriation have exceeded BC Hydro's original projections by $1.2 million.[274] Table 5-11 in the Application breaks down the annual savings:[275]

---

[270] Exhibit B-12, BCUC IR 2.225.2.

[271] Exhibit B-5, BCUC IR 1.48.2.

[272] Exhibit B-12, BCUC 2.224.7.

[273] In Exhibit B-1, Application, pp. 5-40 and Exhibit B-16, CEC IRs 1.31.1 to 1.31.4 BC Hydro elaborated on the evolving customer needs and expectations that led to BC Hydro's decision to repatriate the services provided by Accenture.

[274] Exhibit B-1, Application, p. 5-40; Exhibit B-5, BCUC IRs 1.49.1 and 1.63.4 explains why the savings exceeded expectations.

[275] Exhibit B-1, Application, p. 5-41. Exhibit B-6, CEC IR 1.26.3 confirms that the costs in the table are fully loaded. They are based on BC Hydro's forecast standard labour rate, as well as incremental employee related costs such as travel, training and professional dues. It includes all Management and Professional positions required for supervision of the repatriated services. There are no changes in space requirements or related costs.

Table 5-11 Summary of Accenture Repatriation Savings and FTE Impact

KBU/Function	Services - ABS F2019 RRA ($ million) (1)	Services - ABS Reduction ($ million)	Incremental Operating Costs ($ million) (2)	Annual Operating (Costs) Savings ($ million) (3 = 1 - 2)	FTEs
Customer Service	27.8	(27.8)	21.9	5.9	281
Human Resources	5.1	(5.1)	3.5	1.6	32
Properties	1.8	(1.8)	0.4	1.4	7
Supply Chain	2.5	(2.5)	2.4	0.1	23
Technology	0.0	0.0	0.5	(0.5)	5
Communications and Community Engagement	0.0	0.0	0.7	(0.7)	7
Finance	0.0	0.0	0.3	(0.3)	2
Sub-Total	**37.2**	**(37.2)**	**29.8**	**7.4**	**357**
Tempworks[164]	4.2	(4.2)	4.2	0.0	0
Field Service Representatives[165]	7.9[166]	(7.9)	7.1	0.8	66
Total	**49.3**	**(49.3)**	**41.1**	**8.2**	**423**

175. BC Hydro's immediate objective for the transfer from Accenture has been to repatriate services on a "like-for-like" basis to mitigate the risks that could be caused by wide-scale process and organizational changes. BC Hydro carried over the staff and retained favourable terms and conditions (e.g., wage scales) from the Accenture-MoveUP collective agreement.[276] It is reasonable to expect that the staffing and cost structure of the repatriated services was appropriate. Accenture was financially motivated to minimize the costs of delivering its services, and therefore had a strong focus on process improvement and cost reduction.[277]

176. With post-repatriation operations now stabilized, BC Hydro has begun assessing whether there are opportunities to improve the cost structure. Its current assessment is that "the staffing levels seem appropriate."[278] However, the Contact Centre and Billing Operations department in the Customer Service KBU has several operational reviews underway, described in BC Hydro's response to BCUC IR 2.226.6, to identify areas for process improvements that could lead to cost savings. These initiatives started only recently so it is premature to estimate

[276] Exhibit B-5, BCUC IR 1.49.11.2

[277] Exhibit B-12, BCUC IR 2.226.6; Exhibit B-5, BCUC IRs 1.49.4 and 1.49.9.

[278] Exhibit B-5, BCUC IR 1.49.4. See also, Exhibit B-5, BCUC IR 1.49.9; Exhibit B-5, BCUC IR 1.49.8 includes a discussion on how BC Hydro determined staffing requirements.

the potential cost savings that may be achieved or the enhancements to IT systems that may be necessary to implement them.[279]

(c) BC Hydro Has Reflected Vacancy Factor Savings in the Revenue Requirements

177. A vacancy factor is a reduction in the labour budget to recognize that positions would not remain filled 100% of the time.[280] The practice had been applied inconsistently by the KBUs in past budgets. BC Hydro has achieved forecast annual savings of $5.6 million starting in fiscal 2020 by applying a consistent approach to identifying vacancy factor savings.[281]

178. There is considerable rigour behind the $5.6 million estimate of vacancy factor savings. BC Hydro assessed each KBU individually. It considered (i) historical operating labour expenditures, (ii) estimated future vacancies, and (iii) charge out expectations (i.e., operating labour costs excluding labour costs charged to capital or maintenance work programs).[282] The factor applied differed by KBU.[283] Mr. Layton explained this approach, stating:

> If I can add a little bit of colour to that, so if I was going to talk to a KBU manager, say Ms. Ryan, you would look at both the historical experience that her KBU has experienced, so in other words, is it a KBU that tends to have a lot of vacancies throughout the year or is it one that doesn't? But we also look at the future. In other words, we don't accept that the past is necessarily an indicator of the future. Perhaps there's a unique circumstance operating in Ms. Ryan's department coming up and she might say, for example, "I had a vacancy in this area last year, we didn't fill that for whatever reason but we're going to be filling it very soon." And so yes, that position's been vacant but it's not going to continue that way. And so that would be one that we would look at and consider both – in other words both the past and our expectations of the future. Of

[279] Exhibit B-12, BCUC IR 2.226.6.

[280] BC Hydro has provided a list of all vacancies approved for recruitment as of March 31, 2019 as an attachment to Exhibit B-5, BCUC IR 1.35.1. The file includes the KBU, department, position title, date the recruitment requisition was created, and the reason for postings that have been open for more than six months. Further explanation is provided in the response to Exhibit B-5, BCUC 1.35.1.2.

[281] Exhibit B-1, Application, p. 5-25, Table 5-6. See also, Exhibit B-5, BCUC IR 1.40.6; Exhibit B-5, BCUC IR 1.35.1.1; Exhibit B-5, BCUC IR 1.43.1; Exhibit B-12, BCUC IR 2.229.4.

[282] Exhibit B-12, BCUC IR 2.230.7.

[283] Exhibit B-12, BCUC IR 2.230.7. Vacancy factor savings are embedded into BC Hydro's forecast labour costs for the test period. Accordingly, the amounts shown in Exhibit B-1, Application, Appendix A, Schedules 5.0 to 5.7 are net of the $5.6 million vacancy factor savings for the test period: Exhibit B-12, BCUC IR 2.230.1.1.1.

> course we don't have actual data for the future. I can't go to Ms. Ryan and say, "How many vacancies will you have next year?" Don't know. We have to, again, look at historical data to help us and future expectations on the work and the circumstances in a given department, those are the two factors there. And then the charge out expectations are, some workers charge to what we call "work," which may be capital in nature, and if we expect some of those percentages are going to be changing in a specific business, then we'd want to consider that as well as we build the vacancy factor for that KBU.[284]

179. BC Hydro provided the following example of how the approach was applied in the Regulatory and Rates KBU:

> For example, vacancy factor savings of $0.05 million were applied to the Regulatory and Rates KBU for fiscal 2020 and fiscal 2021. While Regulatory and Rates is a small KBU (28 FTEs), due to the complex and technical nature of the positions, recruitment for vacancies, when they arise, can take some time to fill. The vacancy factor savings applied to the KBU reflect these circumstances and are informed by a review of the historical vacancy trends within the KBU.[285]

180. Estimating future expectations is a more appropriate approach than solely examining the number and type of vacancies at any particular point in time. A point in time tally is unlikely, on its own, to be indicative of future results.[286]

181. Vacancy factor savings relate to operating costs. Vacancy factor savings were not specifically applied during the Test Period for capital and deferred labour costs and FTEs. Internal labour vacancies for capital and deferred projects and programs are balanced and managed through the deployment of external contractors.[287]

(d) BC Hydro Has Eliminated the Unallocated Funds Budget

182. The Test Period revenue requirements reflect (a) $15 million in annual incremental savings from the re-purposing of unallocated funds, and (b) a further $1.9 million in annual

[284] Tr. 8A, p. 1161, l. 7 to p. 1162, l. 12 (Layton).

[285] Exhibit B-12, BCUC IR 2.230.8.

[286] Exhibit B-12, BCUC IR 2.230.7.

[287] Exhibit B-12, BCUC IR 2.230.2.

incremental savings from the re-purposing of budget that had been set aside in fiscal 2019 for unanticipated trailing costs associated with the Accenture repatriation.[288]

183. In the Previous Application, an unallocated funds budget had been included in Corporate Costs.[289] The unallocated funds budget was held centrally to facilitate managing the funding of *ad hoc* projects and unanticipated expenses incurred by the Business Groups throughout the fiscal year.[290] Over the course of the fiscal 2017 to fiscal 2019 test period, additional net savings of $8.5 million were identified and added to the unallocated funds budget, increasing it to $15.0 million.[291] Over the fiscal 2017 to fiscal 2019 test period, the unallocated funds budget was used to fund additional lines and stations maintenance work. It was also used for unplanned initiative costs, such as the planning work for the acquisition of the remaining two-thirds of Waneta and the planning work for the Accenture repatriation.[292]

184. During the Test Period, there is no unallocated funds budget of any kind.[293] All funding of unplanned work demands and unanticipated cost pressures will need to come through budget target adjustments that equal zero on a net basis or will result in a direct impact to the shareholder, all else equal.[294]

---

[288] Exhibit B-5, BCUC IR 1.63.4.

[289] Exhibit B-5, BCUC IR 1.63.5.

[290] Exhibit B-5, BCUC IR 1.63.2.1.

[291] Exhibit B-5, BCUC IR 1.63.2.

[292] Exhibit B-5, BCUC IR 1.63.3. BC Hydro responded to a number of information requests regarding the unallocated funds budget, as well as its use and management during the Previous Application proceeding. Two of these responses are provided as Attachment 1 and Attachment 2 to Exhibit B-5, BCUC IR 1.63.5. See also, Exhibit B-12, BCUC IR 2.231.10.

[293] Exhibit B-5, BCUC IR 1.63.2; Exhibit B-12, BCUC IR 2.231.2.

[294] Exhibit B-5, BCUC IR 1.36.3.

185. BC Hydro underscored that "Without the unallocated funds budget…it will be a significant challenge to manage within the overall operating budget during the test period."[295] As Mr. Layton reiterated the point:

> And maybe just speaking for the overall budgeting perspective, I think we've talked a little bit this week about how we're about nine and a half months into the year, and I think you've heard evidence from a number of members that the budget this year is very, very tight. There's no doubt that in previous applications, we did – and we've talked about this, we had some unallocated funds that grew over time. For example, when we repatriated Accenture, that helped create an unallocated funds amount in the previous fiscal years and that helped be able to absorb increases in cost pressures that were happening across our business. As you know, in this application there's no unallocated funds budget and therefore those two fact, the fact that we are very, very tight in our budget nine and a half months into the year, and that we have no allocated funds to deal with cost pressures, again I think speaks to what Mr. Wong said, which [would] be that reductions in any case would be impactful.[296]

(e) Eliminating a Property Lease is Expected to Generate Additional $1.2 Million in Savings

186. BC Hydro consolidated its lease at Central Park Place in Burnaby, eliminating three floors of office space. It relocated staff into BC Hydro owned buildings through increased space utilization in those buildings. The initiative resulted in forecast savings of $1.2 million.[297]

(f) BC Hydro Has Reduced the Communications Budget by an Additional $1.2 Million

187. BC Hydro reduced planned advertising and marketing costs, resulting in forecast annual savings of $1.2 million.[298]

(g) Expansion of Paperless Billing Expected to Generate Additional $1 Million in Savings

188. BC Hydro has continued to reduce the number of paper bills, which is resulting in an additional $1 million in annual savings during the Test Period.[299]

---

[295] Exhibit B-12, BCUC IR 2.231.2.

[296] Tr. 8A, p. 1092, l. 24 to p. 1093, l. 18 (Layton).

[297] Exhibit B-1, Application, p. 5-25, Table 5-6; Exhibit B-5, BCUC IR 1.40.7.

[298] Exhibit B-1, Application, p. 5-25, Table 5-6; Exhibit B-5, BCUC IR 1.40.7.

[299] Exhibit B-1, Application, p. 5-25, Table 5-6.

(h) Work Smart Program Creates Capacity to Manage Workload and Avoids Costs

189. The Work Smart Program is BC Hydro's program for continuous process improvement. It is based upon widely-recognized Lean Six Sigma principles.[300] As discussed below, the Program has been very successful.[301] Ratepayers benefit from the capacity hours gained under the Program, since they represent an avoided cost.

Work Smart Has Been Very Successful and BC Hydro Is Continuing to Invest in It

190. Mr. Layton explained that, while BC Hydro employees strive to make improvements in their work every day, the Work Smart Program provides a structure to enable more fundamental improvements:

> I think employees every day in BC Hydro look to make improvements in the way they do their work and their processes. Those are generally, I think, fairly smaller kind of improvements. Hopefully, I think we all do that, we look for ways to do everyday tasks better and smarter. What Work Smart's doing though is coming in and looking at a process. We're not trying to improve it a little bit, we're trying to improve it a lot, and I think that kind of big improvement takes a lot more effort and a lot more structure and framework and that's what we're able to do through Work Smart that employees probably just on their own would struggle to be able to achieve.[302]

191. BC Hydro's response to BCUC IR 1.39.3[303] provides a good example of a completed Work Smart initiative.

192. Successful Lean Six Sigma programs select capacity gained or costs avoided as their key metric.[304] As of the end of fiscal 2018, BC Hydro has realized an estimated 80,000 annual

---

[300] Exhibit B-1, Application, p. 5-16. Lean is a business philosophy focusing on streamlining work as well as identifying and eliminating non-value-added activities. Mr. Layton elaborated on the history and methodology of the Lean initiatives at the hearing: Tr. 8A, p. 1150 l. 21 to p. 1152 l. 3.

[301] Exhibit B-5, BCUC IRs 1.38.4 and 1.38.4

[302] Tr. 8A, p. 1141, ll. 5-18 (Layton).

[303] Exhibit B-5.

[304] Exhibit B-5, BCUC IR 1.39.5. Exhibit B-5, BCUC IR 1.39.6 provides information showing how the objectives of the successful programs at Results Washington and ICBC are similar to BC Hydro's objectives for Work Smart.

capacity hours gained[305] as a result of Work Smart program initiatives. The estimated realized hours gained exceed the forecast amount of 46,550 annual hours by the end of fiscal 2018, provided by BC Hydro in the Previous Application.[306] Mr. Layton noted that, as of the end of fiscal 2019, BC Hydro has realized an estimated 100,973 annual capacity hours gained.[307]

193. The cost / benefit analysis for Work Smart tells a compelling story. BC Hydro has imputed a value to the capacity hours gained using the average hourly compensation of employees participating in processes improved through the program. The following table[308] provides a summary of the cost / benefit analysis for Work Smart, based on the imputed values:

	A	B	C	D = C/A
Fiscal Year	Incremental Cost ($)	Capacity Hours Gained	Imputed Value ($)	Value/ Cost
2015 + 2016 (Note 1)	821,971	17,417	1,594,966	1.9
2017	257,151	22,631	2,171,186	8.4
2018	460,831	39,965	3,871,659	8.4
Total through 2018	1,539,955	80,013	7,637,811	5.0

194. For the period from inception to the end of fiscal 2018, the life to date incremental cost of the program was approximately $1.5 million. The estimated benefit (imputed value) was $7.6 million. In other words, the life to date imputed value over that period was is 5.0 times the incremental costs.[309] The $7.6 million represents an estimate of how much costs would have increased if not for the initiatives delivered through the Work Smart program. In other

[305] Exhibit B-1, Application, p. 5-16. Capacity hours gained is the difference between the work effort of the process before the Work Smart initiative is undertaken and after the implementation of the Work Smart recommendations. Exhibit B-5, BCUC IR 1.38.1 explains the methodology for calculating/determining capacity hours gained.

[306] Exhibit B-1, Application, p. 5-16.

[307] Tr. 7, p. 996, ll. 13-16 (Layton).

[308] Exhibit B-5, BCUC IR 1.38.9.

[309] Exhibit B-5, BCUC IR 1.38.9.

words, without Work Smart initiatives to date, BC Hydro estimates that its annual costs would be $7.6 million higher than applied for in the Application.[310]

195. Based on its success to date, the Work Smart program is expected to continue for the foreseeable future.[311] Planned costs for the Work Smart program in fiscal 2020 are approximately $953,000. The increase from fiscal 2018 ($460,831) to fiscal 2020 ($953,359) is due to the addition of 2.5 FTEs to support a greater volume of projects, training offerings, and new tools including Design Thinking and Lean Daily Management.[312] BC Hydro expects to implement 31 Work Smart initiatives in fiscal 2020, which is more than previous years.[313] The initiatives for fiscal 2021 are not yet available. However, planned costs in fiscal 2021 are expected to be consistent with fiscal 2020 plus any adjustments to the standard labour rate.

Capacity Hours Gained Represent an Avoided Cost for Customers

196. In its Decision, the BCUC expressed its belief that the efficiency savings generated by BC Hydro's Work Smart program should result in incremental cost savings.[314] In fact, the Program, as designed, is generating savings for ratepayers by avoiding costs.

197. As indicated above, in the absence of the Work Smart initiatives to date, BC Hydro's annual costs "would be $7.6 million higher than applied for in the Application."[315]

198. The increasing complexity of BC Hydro's regulatory and compliance environment is increasing the demands on BC Hydro's workforce, and new Work Smart initiatives are playing a key role in avoiding the need to add staff to perform the work. BC Hydro explained:

> BC Hydro is focused on managing operating costs to limit or absorb costs increases within the existing operating cost budget. Over the Test Period and

[310] Exhibit B-12, BCUC IR 2.223.9.

[311] Program momentum will be maintained through the means identified in Exhibit B-5, BCUC IR 1.37.2.

[312] Exhibit B-5, BCUC IR 1.38.13.1; Exhibit B-12, BCUC IR 2.223.3.

[313] Exhibit B-12, BCUC IR 2.223.11. Exhibit B-6, BCUC IR 1.38.13 provides a list of Work Smart projects planned for fiscal 2020. Exhibit B-5, BCUC IR 1.38.3 discusses the associated expected capacity hours gained.

[314] Previous Decision, p. 34.

[315] Exhibit B-12, BCUC 2.223.9. See also, Exhibit B-5, BCUC IR 1.38.11.1.

> beyond BC Hydro continues to implement initiatives such as Work Smart to achieve efficiencies and process improvements. These efficiencies help absorb cost pressures resulting from the increasing complexity of work such as those described in BC Hydro's response to BCUC IRs 1.64.1 and 2.214.1. For example, the increasing compliance requirements resulting from the North American Electric Reliability Corporation Critical Infrastructure Protection (NERC CIP) program results in significant cost pressures. Initiatives such as the Work Smart program are critical to ensuring BC Hydro is able to absorb these types of cost pressures.[316]

199. BC Hydro confirmed that in the absence of Work Smart BC Hydro would expect its operating costs to be driven higher as a direct result of increased regulatory and compliance requirements.[317]

200. BC Hydro submits that ratepayers would be ill-served by the adoption of an approach that had as an objective using capacity hours gained to reduce the current labour budget or number of FTEs:

> BC Hydro notes that a number of questions, as well as comments in the BCUC's decision from the Previous Application, seek to understand why capacity hours gained (which can be considered avoided costs) are BC Hydro's measure of the effectiveness of the Work Smart program instead of other measures such as incremental savings and headcount reductions. A fundamental principle of the Work Smart program is that employees have the solutions to improve processes and their participation in Work Smart initiatives is vital in identifying and implementing them, which leads to capacity hours gained that enable employees to deal with workload challenges and focus on the highest value work. Work Smart team members do not have these solutions – instead, Work Smart provides the tools, facilitation skills, and structure to collaboratively identify and implement the solutions from employee teams.
>
> As noted in BC Hydro's response to BCUC IR 1.64.1, BC Hydro faces a growing and more complex workload caused by a number of factors. Since BC Hydro's headcount (excluding Workforce Optimization, Accenture Repatriation, and Site C) has not been growing as shown in Table 5-12 of Chapter 5 of the Application, and since BC Hydro has been unable to fund many cost pressures as discussed in BC Hydro's response to BCUC IR 1.34.3, capacity hours delivered through Work Smart initiatives are a critical way for BC Hydro to make its processes more

[316] Exhibit B-12, BCUC IR 2.213.2.

[317] Exhibit B-12, BCUC IR 2.214.4.

> efficient, enable a growing workload to be absorbed, and to minimize cost increases.
>
> If, on the other hand, Work Smart solutions were required to deliver incremental cost and headcount savings (instead of avoiding higher costs), the program would not be successful. More specifically, employees and teams facing a growing and more complex workload would not participate since they would not obtain the capacity hours gained that they need. Instead, they would be disincented to participate and offer the best solutions to improve processes as their position could be terminated as a result. Without positive participation from employees involved in the process, Work Smart initiatives would be unsuccessful.
>
> Our approach is also consistent with that of other companies with similar Work Smart programs.[318]

201. At the hearing, Mr. Layton added a tangible example of why focussing on avoided costs is preferable:

> We continue to focus on avoided costs and I appreciate the panel's feedback but we do feel very strongly that Work Smart is a program about productivity savings. It is not a program, in our view, about reducing costs. If in the examples that I used, I'll take Site C for example, we freed up a whole bunch of time for them to carry on the project through those leave to commence processes. If we came to them and said, "Hey, we saved you guys 22 days per each of those instances and you have 100 of them each year, that's 2200 hours, therefore, we're going to reduce your budget by two people," we don't think that's a valid concept, because as we know that project is facing many, many challenges and that process was simply taking too long for them in the first place and, therefore, just causing their workers to work harder and not get to the tasks they need to get to. So if we came to them and said, "Help us improve this process, and then we'll take away some of your people and some of your budget," they would never engage in the first place, and in our estimation, that's not a practice that we'd want to see.[319]

202. The Work Smart program is a critical means by which BC Hydro has been able to remain within budget during the Test Period. BC Hydro will continue to measure the annual number of capacity hours gained and the imputed value of the capacity hours gained.[320] In years following

[318] Exhibit B-12, BCUC IR 2.223.9.

[319] Tr. 8A, p. 1144, l. 12 to p. 1145, l. 8 (Layton).

[320] Exhibit B-12, BCUC IR 2.223.12.

the implementation of a Work Smart initiative, the improved processes are revisited on a sample basis with the process owner to ensure the approved future state is still in effect and that the capacity hours gained remain.[321]

(i) "Making it Easier to Get Work Done" Initiative Offsets Increased Complexity of Work

203. The new "making it easier to get work done" initiative is similar to Work Smart in that it is intended to help BC Hydro avoid operating cost increases.[322]

204. The initiative is focused on making "relatively small but meaningful improvements to tools, information, processes and workflow for frontline workers, to offset increasing complexity in their daily tasks."[323] BC Hydro's response to BCUC IR 2.214.2[324] provides a list of projects/activities currently being undertaken as part of the "make it easier to get work done" initiative.

205. BC Hydro has not attempted to quantify the capacity hours gained associated with these initiatives, since the initiatives are aimed at improving employee experience.[325] However, there is no doubt that most of the projects/activities listed indirectly contribute to capacity hours gained. BC Hydro confirmed that, like Work Smart, in the absence of this initiative "BC Hydro would expect its operating costs to be driven higher, as a result of increased regulatory and compliance requirements."[326]

G. FTE NUMBERS REFLECT WORK ON SITE C AND COST-EFFECTIVE INSOURCING

206. In its Decision on the Previous Application, the BCUC reviewed BC Hydro's FTEs over time.[327] BC Hydro submits that it is in the best interest of customers for BC Hydro to continue managing the business with a focus on total cost, rather than the number of FTEs *per se*. Actual

[321] Exhibit B-5, BCUC IR 1.38.7.2. See also, Exhibit B-5, BCUC IRs 1.38.5 and 1.38.6.1.

[322] Exhibit B-12, BCUC IR 2.214.4.

[323] Exhibit B-12, BCUC IR 2.214.4. See also, Exhibit B-12, BCUC IR 2.214.2.

[324] Exhibit B-12.

[325] Exhibit B-12, BCUC IR 2.214.3.

[326] Exhibit B-12, BCUC IR 2.214.4.

[327] Previous Decision, pp. 34 to 35 and 87.

FTEs in recent years and Planned FTE's for the Test Period reflect BC Hydro's work on Site C and the two initiatives (discussed above) that involved adding FTEs to generate savings — Workforce Optimization and Accenture Repatriation.

(a) FTE's Have Remained Relatively Flat Since Fiscal 2012 Except For Capital Projects

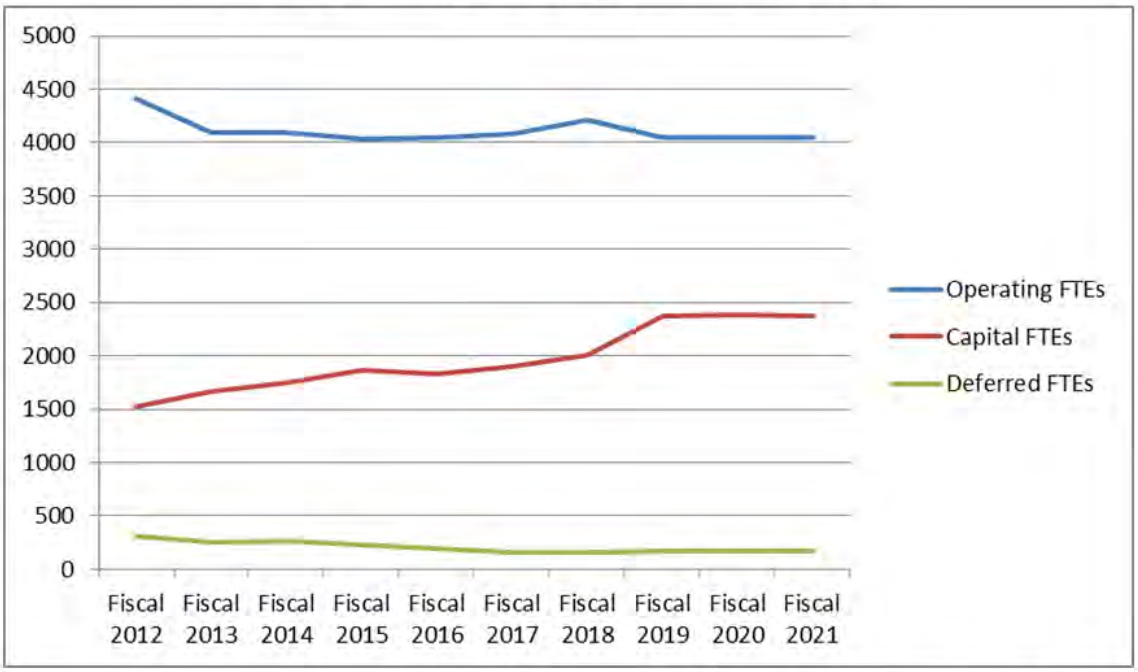
207. The following figure and table,[328] reproduced from the Application, shows BC Hydro's FTEs over a ten year period (8 years of actual plus the plan for the Test Period) categorized by (a) operating, (b) capital, and (c) deferred.[329] The key take-away from this information is this: apart from growth in the workforce directly related to increased capital investment and the Accenture repatriation, BC Hydro's FTEs have remained relatively flat since fiscal 2012 and are forecast to remain flat over the Test Period.[330] BC Hydro submits that this track record reflects BC Hydro's governance around vacancy management.

[328] Exhibit B-1, Application, p. 5-42.

[329] Exhibit B-11, Application, pp. 5-41 and 5-42. In Exhibit B-5, BCUC IR 1.50.1, BC Hydro confirmed that the method for calculating FTEs in the Application is consistent with the method applied for fiscal 2012 to fiscal 2019.

[330] Exhibit B-11, Application, p. 5-42, fn. 168. The numbers referenced exclude FTEs related to the Accenture Repatriation, the Smart Metering Infrastructure Project and the Site C Project. These FTEs were removed to avoid skewing the trend line. All FTEs related to the Workforce Optimization Program, are included.

Figure 5-8 FTEs [168,169] (Fiscal 2012 to Fiscal 2021)



	Fiscal 2012 Actual	Fiscal 2013 Actual	Fiscal 2014 Actual	Fiscal 2015 Actual	Fiscal 2016 Actual	Fiscal 2017 Actual	Fiscal 2018 Actual	Fiscal 2019 Actual	Fiscal 2020 Actual	Fiscal 2021 Actual
Operating	4,415	4,096	4,089	4,089	4,042	4,082	4,209	4,051	4,047	4,043
Capital	1,527	1,662	1,752	1,872	1,828	1,905	2,013	2,378	2,383	2,370
Deferred	309	250	258	223	188	161	162	165	164	164
Total FTEs	**6,251**	**6,007**	**6,099**	**6,131**	**6,058**	**6,148**	**6,385**	**6,593**	**6,594**	**6,577**

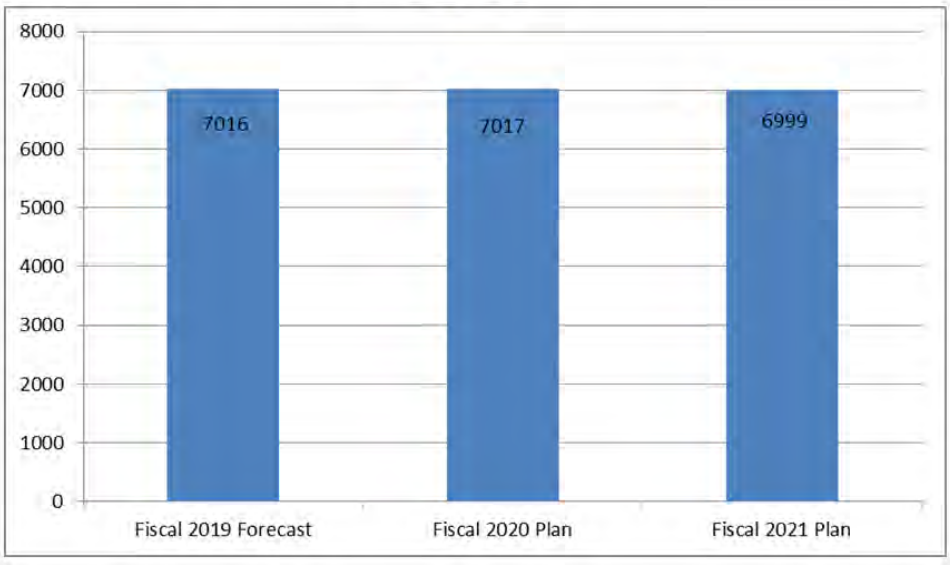
(b) Site C Project is the Only Organizational Need Driving Net New Positions in the Test Period

208. The Site C Project is the only organizational need driving the addition of net new positions, and the related costs are not affecting the Test Period revenue requirements.[331] FTEs, including overtime, are otherwise flat during the test period, as shown in the figure below,[332] reproduced from the Application.

[331] Labour costs on Site C are capitalized to the project once Site C goes into service.

[332] Exhibit B-1, Application, p. 5-44.

Figure 5-9 Total FTEs (including overtime, excluding Site C)



209. The following table,[333] reproduced from the Application, shows the composition of FTE changes for fiscal 2019 Plan to fiscal 2020 Plan.[334] There are 61 FTE additions related to the Workforce Optimization Program, but these are replacing existing contractor resources and are generating savings.[335] Those FTEs are also to be fully offset by planned reductions of 61 FTEs in fiscal 2020 and 18 FTEs in fiscal 2021 associated with reduced requirements for apprentices and trainees and less planned overtime.[336] Site C thus accounts for all but one of the planned increase of 72 FTEs from fiscal 2019 plan to fiscal 2020.[337] There are an additional 12 FTEs planned for Site C in fiscal 2021.[338] Labour costs associated with FTEs working on the Site C

[333] Exhibit B-1, Application, p. 5-45.

[334] The change from fiscal 2019 RRA Plan (i.e., the forecast in the Previous Application) to fiscal 2019 forecast in the Application is explained in Exhibit B-6, CEC IR 1.27.1. The change was associated with Site C, Workforce Optimization and Accenture repatriation, the latter two generating additional savings.

[335] The increase of 61 FTEs planned in fiscal 2020 related to the Workforce Optimization Program includes 13 FTEs required for BC Hydro to perform the Reliability Coordination function (Exhibit B-13, BCOAPO IR 2.114.1). Further details on these FTEs are provided in Exhibit B-5, BCUC IR 1.85.5.

[336] Exhibit B-5, BCUC IR 1.35.2. BC Hydro explained in Exhibit B-5, BCUC IR 1.51.1 how the reduction to Apprentices and Trainees will be achieved. In Exhibit B-5, BCUC IR 1.51.2 BC Hydro explained that the reduction of 29 FTEs in planned overtime between fiscal 2019 forecast and fiscal 2020 plan is primarily due to the reduction in the planned number of apprentice and trainee intakes and the associated overtime FTEs planned (Learning and Development KBU).

[337] FTEs are increasing by from 7,405 (fiscal 2019 forecast) to 7,477 (fiscal 2020 plan), for a net increase of 72 FTEs. A breakdown of these FTEs by KBU is provided in Table 5-23 of of the Application.

[338] Exhibit B-5, BCUC IR 1.35.2.

Project are capitalized to the project, which means that they do not affect the Test Period revenue requirements.[339]

Table 5-13 Summary of FTE Changes (Fiscal 2019 Forecast to Fiscal 2020 Plan)

Item	FTEs
Fiscal 2019 Forecast FTEs	7,405
Workforce Optimization Program	61
Reduction to Apprentices and Trainees (see Chapter 5D, section 5D.5.2)	(32)
Reduction in planned overtime	(29)
Site C Project	71
Fiscal 2020 Plan FTEs	7,477[177]

(c) BC Hydro Uses Overtime Only When it Makes Financial Sense

210. BC Hydro uses overtime where it is cost-effective to do so, and has (as discussed immediately above) reduced the amount of planned overtime.

211. Overtime at BC Hydro is primarily used in the Operations Business Group, which is responsible for the ongoing maintenance of the system. In response to information requests, BC Hydro identified factors that can result in the use of overtime being an efficient management strategy. The factors included, for instance, responding to emergent customer outages and equipment issues outside of regular business hours, and supporting planned work outside of regular business hours to minimize customer disruptions.[340] Hiring additional short-term or permanent employees to reduce overtime in such circumstances would be neither feasible, nor cost-effective. The current collective bargaining agreements preclude BC Hydro from reclassifying overtime hours to regular hours. Seasonal work demands and compressed work schedules are time limited in duration. It is typically more efficient and/or cost effective to utilize existing employees who are trained, qualified and authorized to perform work, than to hire external service contractors.[341]

[339] Exhibit B-1, Application, p. 5-28, fn 159.

[340] Exhibit B-5, BCUC IR 1.51.6.

[341] Exhibit B-5, BCUC IR 1.51.6.

212. BC Hydro explained that overtime has been budgeted for the Test Period considering factors such as project(s), work location(s) and expected work requirements in the coming year.[342] Once the budget has been set, BC Hydro actively manages overtime using the following strategies:[343]

- ***Setting overtime targets:*** KBUs set targets to manage monthly and annual overtime.
- ***Pre-approval:*** Planned overtime must be pre-approved by the manager.
- ***Approvals and tracking***: Managers approve employee time sheets and review weekly and monthly overtime reports. The monthly report includes a list of IBEW employees trending over the departmental targets for annual overtime.
- ***Resource Management:*** BC Hydro has implemented a work allocation process that compares the capacity of internal workers to the anticipated demand.
- ***Power Line Technician/Apprentice Overtime Management Working Groups:*** BC Hydro and the IBEW meet regularly to manage the process of allocating and incurring overtime so that scheduled overtime, on average, is at or below KBU overtime targets.

213. These strategies have resulted in the overtime hours for the Operations Business Group being within 1% of Plan from fiscal 2017 to fiscal 2019.[344]

H. BC HYDRO IS OPTIMIZING POWER SYSTEM MAINTENANCE

214. Maintenance costs are accounted for in BC Hydro's operating costs, and are thus discussed here. However, they are integral to BC Hydro's broader asset management strategy that involves capital investments as well. BC Hydro's witnesses on Panel 4, who are responsible

[342] Exhibit B-12, BCUC IR 2.221.3.

[343] Exhibit B-5, BCUC IR 1.51.6.

[344] Exhibit B-12, BCUC IR 2.221.2. The response provides a detailed breakdown of overtime by KBU.

for asset planning, thus spoke to both maintenance and capital investments. Capital costs are addressed in Part Seven below.

215. Strong business practices have enabled BC Hydro to mitigate increases in Power System maintenance expenditures in recent years, despite a growing Power System asset base, aging assets, higher delivery costs, outstanding condition-based and corrective maintenance needs, and additional regulatory and compliance requirements.[345] While BC Hydro has continued with that approach in the Test Period, it expects budgets will need to increase after this Test Period.

(a) BC Hydro Uses Industry-Leading Maintenance Practices

216. BC Hydro describes in detail in Chapter 5 of the Application the exercise it goes through to determine the extent of preventative, condition-based, and corrective maintenance.[346] Mr. Kumar explained that "when we are dealing with maintaining or replacing a capital, it's all about risk management." He added that maintenance is an essential complement of sustainment capital investments:

> So initially when we replace capital, our risk goes down because we put a new asset in place and all our safety, environmental and financial risks are lower.
>
> As you go through the lifecycle of that asset, you actually keep that risk profile of that asset low by doing adequate maintenance. So capital replacement and maintenance are actually complimentary to each other as opposed to thinking in terms of should we maintain or should we invest capital. You actually have to invest capital and then maintain it to get the full economic life of that asset.[347]

217. In broad terms, the overall maintenance budget amounts are based on three factors:

- A review of historic planned and actual spending levels;
- Changes (improvements or degradation) in asset condition and system performance, as indicated by asset health ratings and performance measures; and

[345] Exhibit B-1, Application, pp. 5-66 and 5-67.

[346] Exhibit B-1, Application, starting at p. 5-68.

[347] Tr. 11, p. 1891, l.9 to p. 1892, l. 4 (Kumar).

- The amount of new assets added to the system less any asset retirements.[348]

218. BC Hydro's cost mitigation initiatives have included improvements to grid intelligence and control, system automation, crew utilization and business processes, strategic asset management and capital investment planning.[349]

219. Navigant has identified business practices used by BC Hydro as being used by "leading performers". In fact, BC Hydro was using these practices over 10 years ago, and in some cases almost 20 years ago.[350] A report by the Office of the Auditor General of BC stated that: "BC Hydro has good asset management practices, not by accident, but as a result of a decade-long plan and associated efforts."[351]

(b) BC Hydro Benchmarks Very Well on Maintenance Costs

220. BC Hydro's use of industry-leading practices comes through in the results of maintenance cost[352] benchmarking undertaken in the ordinary course of business. While there are inherent limitations in all benchmarking,[353] the results do provide additional evidence that BC Hydro is managing costs appropriately.

Favourable Results on Distribution and Transmission Maintenance Costs

221. First Quartile provides an annual comparison of the transmission and distribution line maintenance costs of approximately 40 utilities. First Quartile uses a variety of normalizing

[348] Exhibit B-12, BCOAPO IR 2.125.1.

[349] Exhibit B-1, Application, p. 5-66.

[350] Exhibit B-1, Application, p. 5-62; Exhibit B-5, BCUC IRs 1.58.3 and 1.61.4.

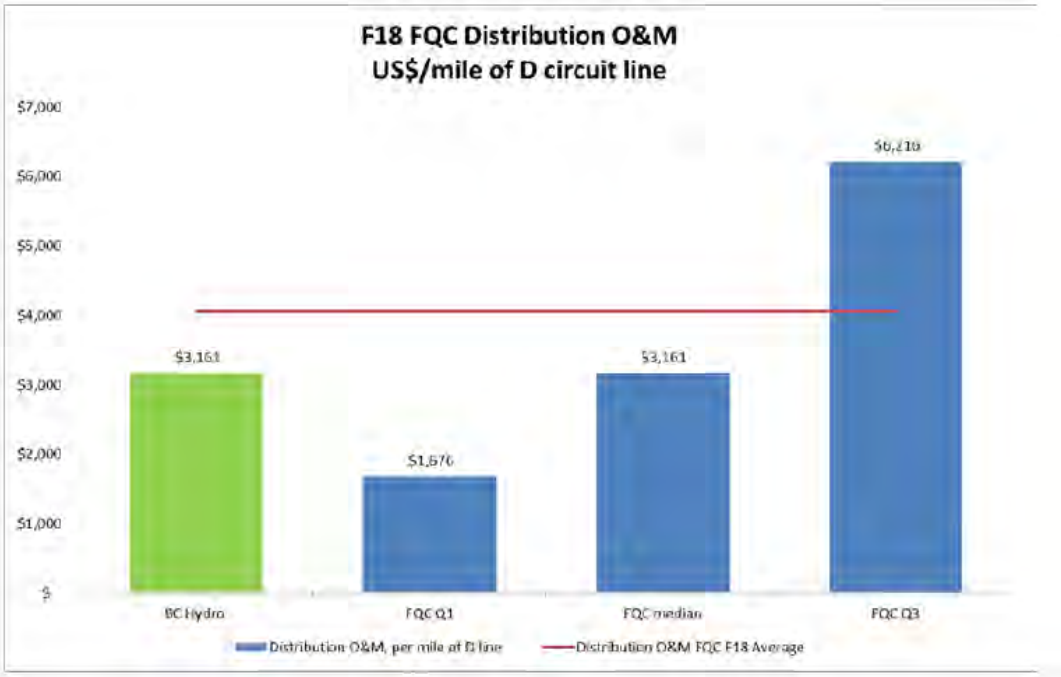
[351] Exhibit B-1, Application, section 6.2.1.1 and Appendix F.

[352] BC Hydro defines maintenance costs as costs of work activities incurred to preserve or restore an asset's operational condition without extending its useful life or increasing the service value of the asset: Exhibit B-5, BCUC IR 1.58.1.

[353] Exhibit B-5, BCUC IR 1.59.1. BC Hydro also noted in Exhibit B-5, BCUC IR 1.59.1.2 that "The distribution peer group for the fiscal 2018 study included 31 companies and the transmission peer group included 23 companies. There is a significant diversity amongst this peer group, which makes it difficult to draw definitive conclusions from the results."

factors in presenting their benchmarking results, such as the number of customer accounts, number of circuit miles, or total MWh sold.[354] First Quartile has found that:

- BC Hydro's operations and maintenance costs were below the average for the utilities included in the distribution category, as shown in the figure below from the Application.[355]

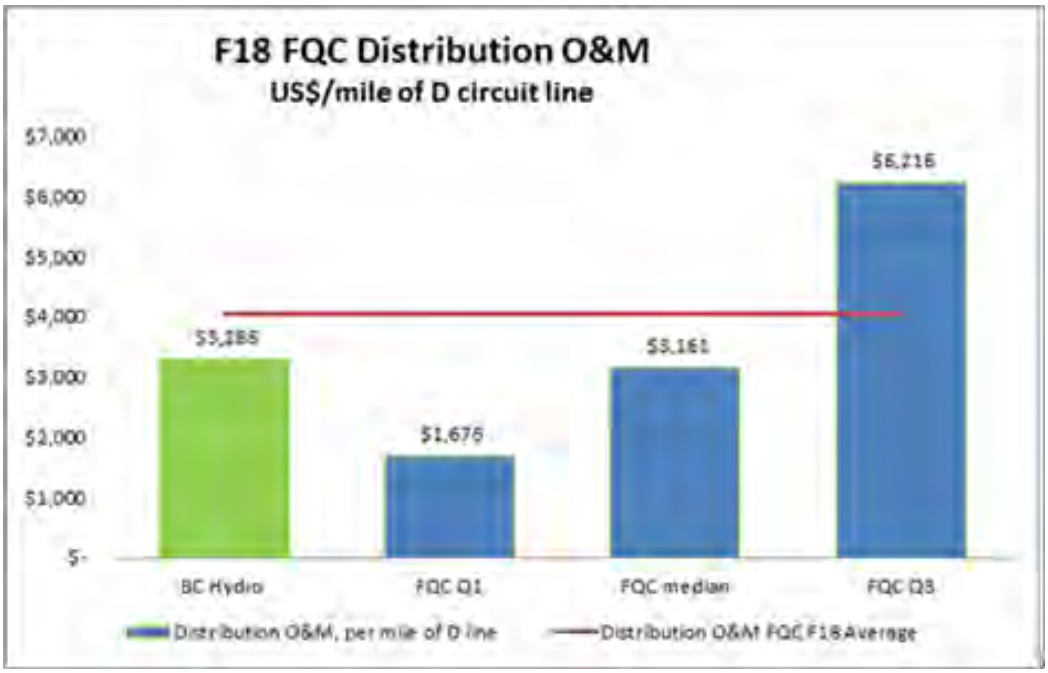


- BC Hydro's operations and maintenance costs were below average for the utilities included in the transmission category, as shown in the figure below from the Application.[356]

[354] Exhibit B-5, BCUC IR 1.58.5.

[355] A corrected version of the figure was provided in Exhibit B-5, BCUC IR 1.59.1.

[356] Exhibit B-1, Application, p. 5-58.



- BC Hydro's vegetation operations and maintenance costs are below average when compared to utility peers.[357]

222. The First Quartile results were particularly notable because the distribution and transmission peer groups included some U.S. utilities with less challenging terrain and climate than BC Hydro's service area. BC Hydro's mountainous terrain and colder climate could be expected, other things being equal, to increase maintenance costs.[358]

Generation Station Maintenance Costs Are Low Compared to Stations of Similar Age and Size

223. External benchmarking of generation station maintenance costs, commissioned from Navigant in the ordinary course of business, reveals a similar pattern to distribution and transmission maintenance costs. Navigant has reviewed 16 of BC Hydro's stations, comparing them to stations of similar type, age and size owned by other utilities.[359] Controlling for type,

[357] A Exhibit B-1, Application, p. 5-60. Factors that affect benchmarking results for vegetation maintenance costs are discussed in Exhibit B-5, BCUC IR 1.60.1.

[358] Exhibit B-1, Application, p. 5-58 and 5-59 (line maintenance), and p. 5-60 (vegetation maintenance).

[359] Navigant's comparables included generating stations of numerous Canadian utilities, as well as international stations. See Exhibit B-6, CEC IR 1.36.2.

size and age of generation facilities removes the influence of the inherent economies of scale associated with BC Hydro's large hydroelectric generation.[360] The results showed that 88% of BC Hydro's stations sampled were performing as expected or better in maintenance and operations costs, where "better" represents lower costs than expected.[361]

(c) The Increases Planned in the Test Period Provide for Only Limited New Activity

224. The maintenance budgets have increased from fiscal 2019 to fiscal 2020. However, the increases will not translate into a significant amount of new planned maintenance work being undertaken. The following table shows that:[362]

- Close to half of that amount ($11.1 million of $27.0 million) is uncontrollable, being the product of reflecting recent storm activity in the rolling five-year average used to budget for storm restoration costs.[363]

- Almost one-third of the increase ($7.9 million of $27.0 million) from fiscal 2019 plan is covered by the re-purposing of unallocated funds discussed in Section F above (the unallocated funds no longer exist). This is, in large measure, a recognition of the current state rather than a true increase. In prior years, BC Hydro's maintenance budgets were insufficient and unallocated funds had to be used to fund necessary maintenance activities.[364]

- "Net Re-organization impacts" were net neutral to BC Hydro.

---

[360] Exhibit B-1, Application, p. 5-62. Exhibit B-5, BCUC IR 1.58.4: The Navigant study results are segmented into various groups based on the area being analyzed (e.g., station group capacity, age or net capacity factor). The use of these segments "makes it easier to compare facilities on an "apples to apples" basis, despite differences among the companies themselves."

[361] Exhibit B-1, Application, p. 5-61.

[362] The corrected table is in Exhibit B-13, BCOAPO IR 2.125.3. For further information on the increase in maintenance funding from fiscal 2019 to fiscal 2020, please refer to Exhibit B-5, BCUC IR 2.233.1 and Exhibit B-6, BCOAPO IR 2.125.3.

[363] Exhibit B-1, Application, p. 5-67.

[364] Exhibit B-1, Application, p. 5-67.

- The Standard Labour Rate increases are the only other driver, and reflect a small portion of the overall increase. The reason for Standard Labour Rate increases is discussed in Section E above.

Table 5-18: Maintenance Cost Increases (Fiscal 2019 Forecast to Fiscal 2020 Plan)

($ million)	Line Asset Maintenance	Stations Asset Maintenance	Distribution Emergency Response	Total
Storm Restoration Five Year Average	0	0	11.1	11.1
Standard Labour Rate Increases	1.3*	2.5*	0.8	4.6
Net Re-organization impacts**	0.3	3.2	0	3.5
Re-purposing of unallocated funds	3.1	4.7	0	7.9
Total	4.7	10.3	11.9	27.0

* corrected values

** offset by equivalent reductions to the Business Unit Support KBU of the Operations Business Group and the Engineering KBU of the Integrated Planning Business Group

225. The largest planned increase is for stations asset maintenance. Generation maintenance funding has remained stable from fiscal 2015 through fiscal 2019. Actual expenditures for preventative maintenance and condition-based maintenance are showing upward trends while corrective maintenance is relatively flat. These trends indicate a shift towards more proactive maintenance work, which is more cost effective because the work can be planned and scheduled.[365] The pressure on substation maintenance budgets is discussed in BC Hydro's responses to BCOAPO IR 2.127.4[366] and BCUC IR 2.233.1.[367]

(d) Vegetation Management is a Priority and Will Need Additional Investment After this Test Period

226. BC Hydro was asked whether sufficient vegetation maintenance is being planned. The answer for the Test Period is "yes", but the evidence suggests that increases will be necessary thereafter.

---

[365] Exhibit B-5, BCUC IR 1.61.2.1. Exhibit B-1, Application, Chapter 5, section 5.8.1. The appropriateness of the level of maintenance spending in fiscal 2020 and fiscal 2021 on generation is discussed in Exhibit B-6, BCOAPO IR 2.127.2.

[366] Exhibit B-13.

[367] Exhibit B-12.

227. It is true that vegetation management costs have been relatively static in recent years, as shown in the table below:[368]

Vegetation Program	F2015 Actual	F2016 Actual	F2017 Actual	F2018 Actual	F2019 Forecast	F2020 Plan	F2021 Plan
Transmission	**19.5**	**16.8**	**17.5**	**18.0**	**17.7**	**17.7**	**17.8**
Distribution	**23.9**	**24.1**	**23.8**	**23.4**	**24.2**	**24.4**	**24.4**

228. Nevertheless, BC Hydro's maintenance program does include measures to mitigate wildfire risk. For instance:

- BC Hydro has developed and implemented a wildfire probability/consequence risk model to prioritize vegetation maintenance and fuel debris management to reduce the risk of spread of wildfire along power line corridors. It facilitates taking preventative mitigation actions in high fire prone areas.[369]

- BC Hydro inspects the transmission and distribution powerline corridors to inform its preventative maintenance. On the overhead transmission system, BC Hydro inspects the entire length of every circuit for vegetation growth once per calendar year. In some cases, circuits in higher vegetation growth areas may receive two or more vegetation inspections per year. On the overhead distribution system, the vegetation maintenance inspection cycle varies across the province from three to five years, depending on growth rates and vegetation species.[370]

229. Mr. O'Riley expressed the view that spending on vegetation management will likely need to increase in future test periods to address regulatory standards and growing public aversion to wildfire risk:

> And I think the approach of utilities towards vegetation is changing significantly and it's changing for three reasons. One is the seemingly increased prevalence of

[368] Exhibit B-5, BCUC IR 1.63.15.

[369] Exhibit B-5, BCUC IR 1.63.14.

[370] Exhibit B-5, BCUC IR 1.79.2.

> storms that we're experiencing and the reliability effects of that particularly in rural areas. So we're having more and more development in rural areas of the province and seeing reliability effects of that and customer complaints on that.[371]
>
> …
>
> We are also increasingly concerned in our industry about forest fires, and you've seen the extraordinary situation in California and of course in Australia which is a cautionary tale for us all, but the one in California is very close to home. And you know, we've certainly reviewed that situation and the legal context there is quite different, and I'm not suggesting that would apply here at all, but you know, I think the tolerance around starting forest fires from power systems is not what it was years ago, five, ten, twenty years ago, and I think that is going to push utilities, including BC Hydro, towards more vegetation management on lines for distribution and transmission. And then the third is we have these mandatory reliability standards that govern vegetation, and what that does is really increase the penalty cost if you find yourself with a violation. And I think that's going to drive up our management and quality control, and quality assurance and the actual spend on vegetation.[372]

I. BRATTLE REPORT AND INDICATIVE COMPARISON SUPPORTS THE REASONABLENESS OF BC HYDRO'S OPERATING COSTS

230. The BCUC expressed an interest in benchmarking in its Decision on the Previous Application. In addition to providing information on benchmarking that BC Hydro undertakes in the ordinary course of business, BC Hydro undertook operating cost benchmarking and comparisons specifically for the purposes of addressing the BCUC's comments. Although inherent limitations in any benchmarking preclude definitively ascribing particular causes to that favourable performance, the strong showing should provide additional reassurance that BC Hydro is on track when it comes to controlling costs.[373]

---

[371] Tr. 5, p. 505, ll. 3-10 (O'Riley).

[372] Tr. 5, p. 505, l. 18 to p. 506, l. 12 (O'Riley).

[373] Exhibit B-5, BCUC IR 1.62.14. BC Hydro put it this way: "Benchmarking studies are used to provide a high-level point of comparison with a peer group. They represent one point of data in testing the organization's performance compared to peers, and on their own are not used to make specific management decisions or draw definitive conclusions. In cases where BC Hydro is significantly out of line with comparators, additional review may be useful to understand why this is the case."

(a) BC Hydro Benchmarks Favourably Against U.S. Peer Group on Operating Costs (Brattle Report)

231. BC Hydro retained Brattle, which has expertise in benchmarking.[374] Brattle's methodology is summarized in the Application,[375] and detailed in its report ("Brattle Report").[376] The Brattle Report shows that BC Hydro's operating costs benchmark favourably against a peer group of U.S. utilities,[377] regardless of the metric used. The peer group data was compiled from annual reports using the Federal Energy Regulatory Commission ("FERC") Uniform System of Accounts.[378]

232. A useful comparison can be made with respect to BC Hydro's *non-power production* costs (which Brattle refers to as "non-power production NFOM"). BC Hydro's very low *power production* unit costs are influenced favourably by the inherent efficiencies that BC Hydro enjoys by virtue of having large hydroelectric facilities. In contrast, the *non-power production* costs (which include distribution, transmission and customer-facing functions), tend to be driven by size and number of customers, as well as various other factors, such as density, topography and climate.[379] The Brattle Report states that the *non-power production cost* comparison "provides a meaningful indicator for BC Hydro's comparative cost performance".[380] In response to information requests, Mr. Zarakas of Brattle reaffirmed his confidence in the usefulness of the results for non-power production costs:

> Differences among utilities will always exist. The fact that the utilities discussed here are not identical to BC Hydro does not disqualify them from inclusion in a peer panel. Rather, it is important to rely on judgment to ensure that the comparison utilities are sufficiently similar on the dimensions that are the most

[374] Exhibit B-1, Application, p. 5-50. See also *curriculum vitae* of Mr. Zarakas, filed as part of the Brattle Report.

[375] Exhibit B-1, Application, p. 5-50.

[376] Exhibit B-1, Application, Appendix T, Brattle Group Benchmarking Study.

[377] Mr. Zarakas of the Brattle Group explained why the peer group was appropriate in his responses to Exhibit B-5, BCUC IRs 1.53.1 and 1.53.1.1. In Exhibit B-5, BCUC IR 1.53.3, he explained that changing the peer group does not affect the results; BC Hydro still performs well even if the peer group is changed. He has included figures showing the results.

[378] Exhibit B-1, Application, p. 5-51.

[379] Exhibit B-5, BCUC IR 1.53.2. See also, Exhibit B-5, BCUC IR 1.55.2.

[380] Exhibit B-1, Application, Appendix T, Brattle Group Benchmarking Study, p. 29, para. 54.

relevant to the benchmarking exercise. As I discuss in the response to BCUC IR 1.53.2, the lack of U.S. utilities that have hydroelectric facilities on the scale of BC Hydro should not unduly affect the benchmarking exercise with respect to non-power production NFOM, or with respect to the functional NFOM levels that comprise non-power production NFOM.[381]

233. Brattle benchmarked non-power production costs as a whole, and by transmission, distribution and administrative sub-functions. BC Hydro performs very well in each case, and appears to be improving relative to the other companies in the peer group. Brattle noted that: "BC Hydro was in the 2nd quartile of unit cost performance for this metric in the early years of this study (2013) and improved to the 1st quartile by 2015, mainly due to improvements in its cost performance in transmission and distribution."[382] The results for *non-power production costs* ($/customer and $/delivered MWh), to which Brattle was referring, are shown below. The equivalent graphs by sub-function (transmission, distribution, administrative) are included in the Brattle Report, and reinforce the above conclusion.[383]

Figure 5-10 Non-Power Production NFOM ($ per Customer) [182]

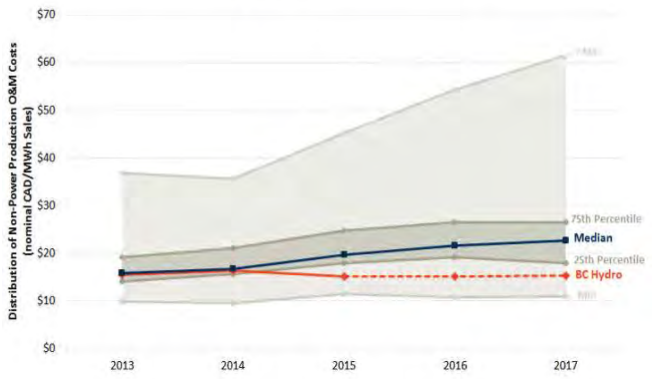
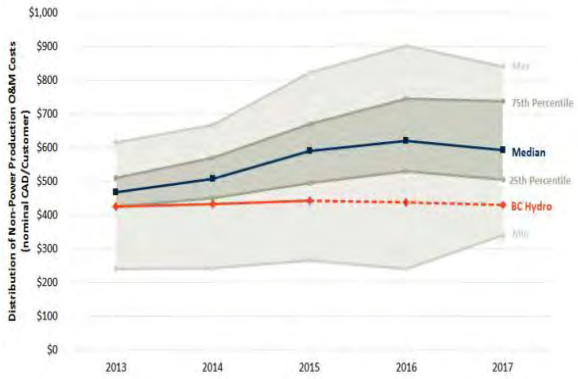


Figure 5-11 Non-Power Production NFOM ($ per Delivered MWh) [183]



234. The extent of BC Hydro's favourable performance relative to the U.S. utilities in the peer group may well be understated. BC Hydro is subject to significant environmental requirements, a duty to consult with First Nations, and many regulatory compliance and safety requirements.

[381] Exhibit B-5, BCUC IR 1.53.1.

[382] Exhibit B-1, Application, Appendix T, Brattle Group Benchmarking Study, p. 29.

[383] Exhibit B-1, Application, pp. 5-52 and 5-53.

In addition, as a Crown Corporation, BC Hydro may be subject to regulations that are not applicable to utilities in the peer group.[384]

(b) BC Hydro Compares Well in Indicative Canadian Utility Comparison

235. In recognition that the Brattle Report used a peer group of U.S. utilities, BC Hydro also undertook a high-level indicative comparison of its operating costs against those of three other major Canadian hydroelectric utilities.[385] BC Hydro compares well (lowest on cost per customer and "middle of the pack" on cost per MWh).[386] While the results provide only a high level indication due to limitations in the methodology, the fact that BC Hydro is in the same range as other utilities when it comes to operating costs provides some additional reassurance that BC Hydro is on the right track when it comes to managing operating costs.

236. In the Canadian utility cost comparison, BC Hydro's operating costs per MWh of sales and customers are shown as increasing. This is largely due to two factors: (a) accounting treatment changes related to capitalization that may not be applicable to the other utilities; and (b) sustainment costs related to the Smart Metering Infrastructure Program, which had been deferred in fiscal 2015 and fiscal 2016 and started to be included in base operating costs in fiscal 2017.[387]

(c) Value of Continuing to Prepare Uniform System of Accounts Must Be Weighted Against Other Priorities and Costs

237. BC Hydro has requested to discontinue preparing information for regulatory purposes using the BCUC's Uniform System of Accounts (Directive 57 of the BCUC's Decision on BC

[384] Exhibit B-5, BCUC IR 1.55.4.

[385] The benchmarking methodology used, and its limitations, are described in Exhibit B-1, Application, pp. 5-53 and 5-54. BC Hydro explained why it selected FortisBC, Manitoba Hydro, Hydro Quebec as comparable utilities in its response to Exhibit B-6, CEC IR 1.34.1. Additional information on the data sources and the steps taken to improve the comparability of data are described in Exhibit B-5, BCUC IRs 1.56.1, 1.56.4 and 1.57.2.

[386] Exhibit B-1, Application, pp. 5-55 and 5-56. BC Hydro emphasized: "Consistent with the caution by The Brattle Group about the limits of benchmarking, we recognize that extraneous factors can influence these metrics. … As such, when evaluating these results, we look more to the fact that BC Hydro is within the same range as these utilities when it comes to operating costs, as opposed to any particular rank ordering."

[387] Exhibit B-5, BCUC IR 1.57.3; Exhibit B-6, CEC IR 2.103.1.1.1. The accounting changes related to overhead costs, which are no longer eligible to be capitalized under IFRS.

Hydro's Fiscal 2009 to Fiscal 2010 Revenue Requirements Application).[388] As BC Hydro explained:

> Rescinding Directive 57 would not prevent BC Hydro from preparing USoA financial schedules in the future, if those schedules were required for additional benchmarking analysis. Rather, it would provide BC Hydro management with the discretion to determine whether and how often to prepare these schedules.
>
> Preparing the USoA financial schedules is labour intensive and would create additional cost pressures. In BC Hydro's view, having the discretion to prioritize these pressures against other requirements is an important part of our ongoing efforts to limit overall base operating cost increases.[389]

238. While Brattle was able to use the BCUC's Uniform System of Accounts to inform its benchmarking study, the BCUC's Uniform System of Accounts is different from the FERC Uniform System of Accounts, which was the source of the peer group data used in the Brattle Report.[390]

239. BC Hydro noted that if the BCUC and interveners found the Brattle Report valuable, then reporting based on the FERC Uniform System of Accounts would likely provide greater value, going forward, compared to reporting based on the BCUC Uniform System of Accounts. BC Hydro explained that there would be some initial effort to set-up a Uniform System of Accounts reporting framework and to manage this work on an ongoing basis.[391]

240. However, as Mr. O'Riley explained, there have been many opportunities put forward by interveners and, in aggregate, the costs of these opportunities add up and push against BC Hydro's ability to keep rates affordable and competitive.[392] The additional costs of presenting BC Hydro's accounts according to the FERC Uniform System of Accounts should be evaluated within this context. BC Hydro submits that the value of taking this step is insufficient at the

[388] Exhibit B-1, Application, p. 1-33.

[389] Exhibit B-13, BCOAPO IR 2.123.1.

[390] Tr. 7, p. 1012, l. 24 to p. 1013, l. 23 (Layton).

[391] Tr. 7, p. 1013, ll. 1-6 (Layton); Tr. 7, p. 1014, l. 20 to p. 1015, l. 24 (Layton).

[392] Tr. 5, p. 443. l. 24 to p. 444, l. 10 (O'Riley).

present time to justify a directive that would remove the ability of management to prioritize this work against other pressures, as appropriate.

J. CONCLUSION AND REQUESTED FINDINGS

241. The BCUC should find, based on the evidence discussed above, that the forecast operating expenses in the Test Period are reasonable.

PART SEVEN: CAPITAL EXPENDITURES AND ADDITIONS

A. INTRODUCTION

242. This Part of BC Hydro's Final Submissions discusses BC Hydro's forecast capital expenditures and additions in the Test Period. BC Hydro's forecast capital expenditures and additions are summarized in Tables 6-1 and 6-2 of the Application.[393] The evidence discussed below demonstrates the reasonableness of BC Hydro's Test Period capital forecasts.

243. We highlight the following supporting points:

- First, 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.

- Second, 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.

- Third, BC Hydro has reduced its capital forecast to balance affordability, system performance and risk.

- Fourth, BC Hydro delivers capital projects efficiently and effectively, as demonstrated by its ability to deliver it portfolio of projects within 5% of Original Approved Expected Cost.

- Fifth, BC Hydro's capital asset management processes have been endorsed by third parties, including the Auditor General and project management organizations.

[393] Exhibit B-1, Application, pp. 6-6 and 6-7.

- Sixth, BC Hydro's Amortization of Capital Additions Variance Accounts will ensure that customers only pay actual costs.

- Seventh, BC Hydro has answered specific issues raised in the proceeding relating to planning, project execution and cost recovery.

- Eighth, 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.

B. BC HYDRO'S EVIDENCE SUPPORTING CAPITAL FORECASTS IS SUBSTANTIAL AND ACCORDS WITH APPROVED CAPITAL FILING GUIDELINES

244. BC Hydro has filed a significant volume of evidence supporting its capital forecasts for the Test Period, including the evidence listed below. The nature of the information filed is consistent with BC Hydro's Capital Filing Guidelines as proposed at the time of filing.

- Chapter 6 of the Application describes in detail BC Hydro's capital planning and delivery processes, as well as BC Hydro's forecast capital expenditures and additions over the Test Period. It includes descriptions of key drivers and explanations of changes in the forecast from year to year;

- Appendix F is the Auditor General's December 2018 audit of Capital Asset Management in BC Hydro, which found that BC Hydro has good asset management practices as a result of a decade-long plan and associated efforts and had no recommendations for improvement;

- Appendix G explains variances between planned and actual capital additions and expenditures for fiscal 2017 and fiscal 2018 (while Appendix G of the Evidentiary Update explains variances for fiscal 2019);

- Appendix H is BC Hydro's Fiscal 2020 to Fiscal 2024 Capital Plan ("Capital Plan");

- Appendix I is a detailed spreadsheet with information on all projects and programs over $5 million, and all Technology projects over $2 million;
- Appendix J provides a summary of all capital projects over $20 million;
- Appendix K provides an overview of the current state of BC Hydro's Power System and a summary of the capital strategies, plans and studies that are related to the projects described in Appendix I or J;
- Appendix L is BC Hydro's Technology Strategy and 5-Year Plan;
- Appendix M is asset health statistics for BC Hydro's generation assets;
- Appendix N is asset health statistics for BC Hydro's transmission and distribution assets; and
- Leading up to the oral hearing, BC Hydro has also filed updates to the information on its capital projects to keep the BCUC and interveners informed of key changes.[394]

245. Seven witnesses, including the executives responsible for capital planning and delivery, testified.[395] These individuals have extensive experience in their areas. Witnesses on Panel 4 were involved in the preparation of the current Capital Plan.[396]

C. BC HYDRO HAS A ROBUST CAPITAL PLANNING PROCESS

246. BC Hydro's Test Period capital forecast is the product of an enterprise-wide capital planning process. It incorporates top-down limitations, and risk-based project prioritization to balance affordability, system performance and risk. BC Hydro has developed an ex-plan

[394] Exhibit B-26 and Exhibit B-29.

[395] Mr. Morison (information technology), Ms. Pinksen (portfolio optimization and management), Ms. Daschuk (executive responsible for capital planning), Mr. Darby (stations), Mr. Kumar (transmission and distribution), Ms. Holland and Mr. Leonard (executives responsible for project delivery).

[396] Tr. 11, p. 1839, ll. 3-19 (Kumar and Pinksen).

governance process to respond to evolving circumstances. BC Hydro submits that the rigour applied to capital planning through these processes should provide considerable comfort that the forecast expenditures and additions in the Test Period are reasonable.

(a) The Top-Down and Bottom-Up Approach Permits Balancing Affordability, System Performance and Risk

247. BC Hydro's top-down/bottom-up capital planning process is detailed in section 6.3 of the Application and summarized below.

Step 1: Top-Down Strategic Direction and Capital Program Parameters

248. The first step in the annual enterprise capital planning process is the Executive Team's direction on long-term capital investment levels.[397] The top-down strategic direction provided by the Executive Team is important for constraining both operating and capital spending levels. Mr. O'Riley commented in his Opening Statement:

> As a result of a changing operating environment, a lot of rigour goes into our budgeting process. The Commission had questions about our budgeting coming out of our last revenue requirements application and my strong view is that our top-down and bottom-up budgeting process has limited operating and capital cost increases and that a fully zero-based budgeting approach that lacks the top-down constraint would see greater cost increases.[398]

249. As discussed in Section D below, the strategic direction from the Executive Team in relation to the Capital Plan resulted in a reduction in capital expenditures compared to the previous capital plan.

Step 2: Bottom-Up Planning and Portfolio Development by Asset Category

250. In the second step, BC Hydro uses a bottom-up process to develop forecast capital investments for each asset category (i.e., Power System (including Generation, Transmission and Distribution), Technology, Properties and Fleet).[399] The bottom-up process is tailored to

[397] Exhibit B-1, Application, p. 6-19.

[398] Tr. 5, p. 358, ll. 11-19 (O'Riley).

[399] Exhibit B-1, Application, p. 6-28.

the characteristics of each asset category and is scaled as required. For example, Power System portfolios, being the largest and most complex, generally require more complex and detailed planning processes. They also involve a broader discussion with internal stakeholders across BC Hydro.[400]

251. In general, these bottom-up processes identify recommended capital investments in the planning period based on an understanding of the issues, risks and opportunities associated with the particular asset category. During these bottom-up processes, BC Hydro considers changes in need, regulation, priorities, strategies and circumstances to determine what projects and programs are required and the appropriate timing of the investments.[401]

Step 3: Collaborative Prioritization Within Corporate Investment Framework

252. In the next step of the process, BC Hydro consolidates the capital planning information for collaborative peer reviews at the enterprise level, validates alignment with BC Hydro's strategic direction and priorities, and identifies any potential areas for improvement in the process for the next annual capital planning cycle.[402]

253. BC Hydro classifies its investments into one of three categories: (1) mandatory investments driven by legal and regulatory requirements (including customer interconnection requests); (2) committed investments not to be postponed; and (3) investments to be prioritized, which includes projects that could be re-prioritized without significant costs, impacts to system reliability or compromising BC Hydro's ability to connect new customer load. Under this framework, BC Hydro assesses investments based on the primary driver, considering the financial, reliability, safety, environmental and reputational impacts associated with delaying the investment:[403]

---

[400] Details on the specific bottom-up planning process for the Generation, Transmission and Distribution, Technology, Properties and Fleet asset categories are set out in sections 6.4.2, 6.4.4, 6.5.3, 6.6.2, 6.7.1 and 6.8 of the Application, respectively.

[401] Exhibit B-6, BCOAPO IR 1.64.3.

[402] Exhibit B-1, Application, pp. 6-29 and 6-30.

[403] Exhibit B-1, Application, p. 6-29; Exhibit B-13, BCOAPO IR 2.134.1.

- investments that primarily mitigate risk are scored for prioritization using a methodology that is aligned with the BC Hydro Corporate Risk Matrix;[404] and

- investments that primarily create value are scored for prioritization using a net value per dollar invested metric.

254. BC Hydro considers the resulting risk or value scores and other criteria, including resource and outage constraints, when making prioritization decisions.[405] Ms. Pinksen explained that the risk and value scores are just one tool used in the prioritization process.[406] Mr. Kumar elaborated:

> …a risk score is an input into our prioritization. It is not something that defines what the outcome of a capital plan looks like. Because if we actually ended up taking just the risk score and compared the risk score of a dam safety project versus a feeder project, we would never be building anymore feeders… So that's why…you also…have to look at what the driver for the project is, what part of the system we are serving. And we collectively sit down and take that into account in terms of criticality of the system, the risk score, what are the risks we are trying to avoid, so all those are inputs into it. It's not just you get a risk score of 11 and it trumps a project that is a risk score of 8. It doesn't happen like that. You have to look at it in totality in terms of what the impact of those projects is going to be.[407]

Step 4: Senior Management and Board Review

255. In the final step, the Executive Team and Board of Directors assess whether the plan meets BC Hydro's overall business objectives and provides a consistent and appropriate management of risks across all asset categories.[408]

---

[404] BC Hydro's Capital Panel explained how to read the risk matrix. In essence, the capital risk matrix has two components, severity and probability. The risk is not a project delivery risk, rather (per Ms. Pinksen) "It's more of a risk to BC Hydro if we don't undertake the investment." Mr. Kumar added: "So we define risk in terms of environmental, financial, public safety, reputation, so those are the different categories we define the risk on. And depending on what project we are looking at we pick the highest risk that the project is exposing the organization to." Tr. 11, p. 1848, l. 17 to p. 1849, l. 22 (Pinksen, Kumar and Daschuk).

[405] Exhibit B-13, BCOAPO IR 2.134.1.

[406] Tr. 12, p. 2304, ll. 6-10 (Pinksen).

[407] Tr. 13, p. 2382, l. 17 to p. 2383, l. 11 (Kumar).

[408] Exhibit B-1, Application, p. 6-30.

(b) Affordability is Reflected Throughout the Capital Planning Process

256. Ms. Pinksen confirmed that affordability considerations are reflected throughout the capital planning process:

> 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.[409]

(c) BC Hydro Has Improved the Governance Framework for Ex-Plan Projects

257. BC Hydro's Capital Delivery Management Committee monitors the approved capital plan on an ongoing basis to assess whether actual and forecast capital expenditures remain aligned with the original capital plan. BC Hydro may reallocate the budget within the capital plan as new information becomes available, considering financial impacts, the enterprise risk profile, and labour resource availability.[410] This may include making changes to the timing of other investments to fund a required ex-plan investment.[411]

258. Decisions to reallocate the budget to accommodate an ex-plan project are referred to as the ex-plan governance process.[412] BC Hydro described the ex-plan governance process as follows:

> BC Hydro considers an ex-plan project as a project that was not included in the approved Capital Plan (fiscal 2020 to fiscal 2024) or a project that was in the approved Capital Plan outside of the current test period, but that is required to address an immediate need such that the project must be advanced into the current year.
>
> When submitting a project as ex-plan, the responsible KBU must validate that the project meets the ex-plan criteria described above. In addition, the

[409] Tr. 11, p. 1850, ll. 4-15 (Pinksen).

[410] Exhibit B-1, Application, pp. 6-30 and 6-31.

[411] Exhibit B-12, BCUC IR 2.254.1.

[412] Exhibit B-1, Application, p. 6-31.

> responsible KBU will determine if the ex-plan project's capital expenditures in the current fiscal year can be accommodated within its own current fiscal year capital plan. If the KBU cannot manage the additional investment within their current fiscal year capital plan, redirection from another KBU will be considered based on the latest portfolio forecasts.
>
> For capital ex-plan investments driven by the need to connect new customers and/or expand the system to serve load growth, offsets in the form of contribution in aid and/or expected increases to revenue are also considered when determining if redirection or plan reductions are required.[413]

259. Ms. Pinksen explained that the ex-plan governance process represents an improvement since the Previous Application in two respects:

> What I would characterize as new in this application compared to previous applications is two things. So first of all the governance around the initiation of ex-plan projects. We have established a clear governance through our capital delivery and management committee, which establishes thresholds for the levels of review required depending on the size of the project. So a very small project, about 100K, myself as a member of the working group, the enterprise working group, I would be able to endorse the initiation. And what I want to make clear is that that's not superseding the financial approval, it's really just an assessment of yes this project merits initiation at this time as an ex-plan project as opposed to waiting to the next capital planning cycle. And so those tiers move all the way up to a review by the entire capital delivery management committee for projects over 10 million. So that's one thing that's new is that that level of governance.
>
> …
>
> And I did want to say the second thing that's new is we are now tracking [ex-]plan projects as part of our scorecard. And the reason for doing that is we want to look for opportunities to improve our process. So if we start to see a number of [ex-]plan projects being identified we want to go back and say, "was there something we can do better in our process of establishing the original plan to try to capture those as part of the capital planning process." So those two things are new for us.[414]

[413] Exhibit B-5, BCUC IR 1.110.1.

[414] Tr. 11, p. 1873, l. 21 to p. 1875, l. 20 (Pinksen).

260. Mr. Kumar emphasized that the governance is intended to limit the ex-plan process to system requirements:

> So we are actually managing that project quite judiciously and making sure that process is not used for just bringing in any need that arises on the system, we actually have a fairly strict and robust process to make sure that we actually move that project through only if there's a need for that project from a system perspective.[415]

261. Ms. Pinksen gave the example of having to initiate a NERC CIP v. 7 project as an ex-plan project in order to achieve compliance by a standard deadline. In the case of this ex-plan project, BC Hydro had to delay some other projects until fiscal 2021 to accommodate the project within the existing budget.[416]

(d) New Value-Based Assessment Approach Represents the Evolution of BC Hydro's Capital Prioritization Process

262. Mr. Kumar explained that the current risk-based framework does a good job of prioritizing to address risk, and that project benefits are reflected under the risk-based approach.[417] The new value-based approach that BC Hydro is investigating involves recasting the risk and benefits in terms of value. It is the next step in the evolution of the prioritization process:

> So over the last 12 years Hydro has actually worked quite hard in terms of developing an industry leading framework that is based on a risk prioritization tool, and it's aligned with our objectives at a corporate level. And you've got great feedback from the Auditor General in terms of our planning process that we used. What Ms. Pinksen was talking about is the next evolution of the capital planning process, which is going from a risk-based framework over to a value-based framework which helps us define the value of projects it's providing as opposed to the risk that the project is avoiding. They are both sides of the same coin, it's just a different way of defining how you move forward with the project.

---

[415] Tr. 11, p. 1876, ll. 13-19 (Kumar).

[416] Tr. 11, p. 1877, l. 20 to p. 1878, l. 3 (Pinksen).

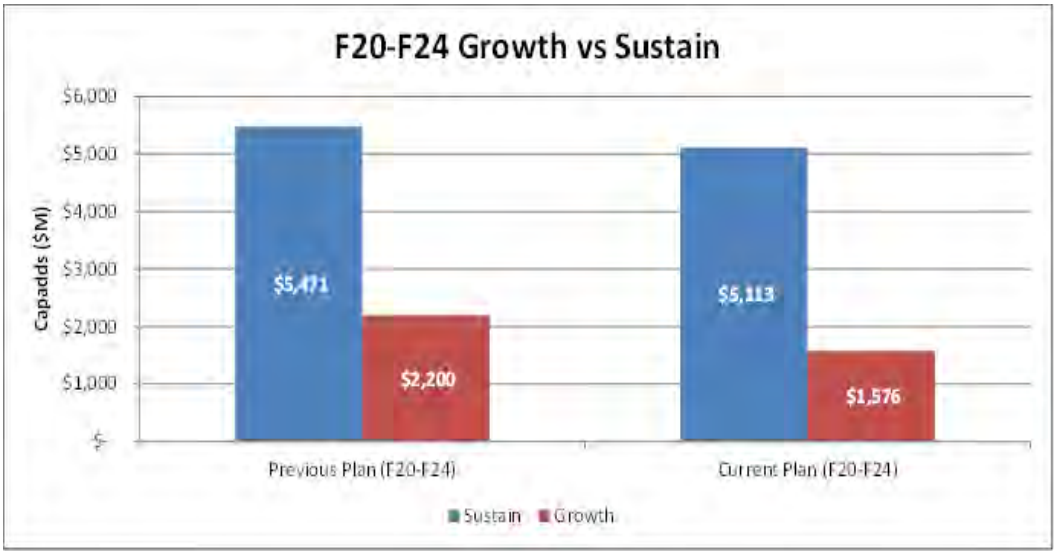
[417] Tr. 11, p. 1855, l. 17 to p. 1856, l. 13. (Kumar).

> So I would say our capital plan is well-defined in terms of cost effectiveness by using a risk-based framework. What we are talking about here is taking that framework to the next level and defining it in a level that allows us to capture the value of the project, not just the risk side of a project.[418]

D. BC HYDRO HAS REDUCED THE CAPITAL FORECAST TO BALANCE AFFORDABILITY, SYSTEM PERFORMANCE AND RISK

263. The 2020-2024 Capital Plan reflects a 13 percent reduction in BC Hydro's capital forecast relative to the previous Capital Plan, as shown in the figure below, reproduced from the Application.[419] The evidence, discussed below, demonstrates that this material reduction was warranted as a means of balancing affordability, system performance and risk.

Figure 6-5: Comparison of Fiscal 2020 to Fiscal 2024 Planned Capital Additions



(a) Strong System Performance and Slower Demand Growth Created Opportunity for Moderating Capital Spending

264. During step two of the annual capital planning process (bottom-up planning and portfolio development by asset category), BC Hydro determined that there was an opportunity to moderate the planned investment in sustainment to mitigate impacts on customers without

[418] Tr. 11, p. 1854, l. 16 to p. 1855, l. 11 (Kumar).

[419] Exhibit B-1, Application, p. 6-20, Figure 6-5.

materially impacting system performance.[420] This opportunity arose due to BC Hydro's strong system performance, as indicated by the following:[421]

- In the past decade, BC Hydro's "all events" System Average Interruption Duration Index ("SAIDI") trend performed as well as or better than the Canadian Electricity Association ("CEA") composite, with the exception of fiscal 2016 due to the August 2015 summer wind storm.[422]

- BC Hydro's "all events" System Average Interruption Frequency Index ("SAIFI") trend also consistently outperformed the CEA SAIFI composite.[423]

- Normalized SAIDI was 3.28 hours in fiscal 2017 — a strong result. It further improved to 3.07 hours in fiscal 2018.[424]

- Normalized SAIFI was 1.59 disruptions in fiscal 2017 — also a strong result. It further improved to 1.51 disruptions in fiscal 2018.[425]

- The reliability scores in BC Hydro's Customer Satisfaction Index indicate that customers continue to be satisfied with the level of reliability they are receiving.[426]

- Asset related safety incidents on the transmission and distribution system have declined, indicating that BC Hydro's investment plans are addressing safety related risks on the system.[427]

---

[420] Exhibit B-1, Application, pp. 6-19 to 6-25.

[421] Exhibit B-1, Application, pp. 6-20 and 6-21.

[422] Exhibit B-1, Application, p. 6-21.

[423] Exhibit B-1, Application, p. 6-22.

[424] Exhibit B-1, Application, pp. 6-22 and 6-23. Normalized SAIDI measures the total outage duration with storm impact adjustments experienced by an average customer in a year.

[425] Exhibit B-1, Application, pp. 6-23 and 6-24. Normalized SAIFI measures the number of sustained disruptions per year excluding major events.

[426] Exhibit B-1, Application, pp. 6-24 and 6-25.

[427] Exhibit B-1, Application, p. 6-25.

265. Given the strong system performance, BC Hydro eliminated a previously planned ramp-up of sustainment expenditures in the Capital Plan relative to the previous plan. The majority of reductions were realized in fiscal 2025 to fiscal 2029.[428] However, as shown in Figure 6-5 of the Application above, BC Hydro also reduced the overall level of planned sustainment capital additions in the fiscal 2020 to fiscal 2024 period.[429] BC Hydro did not reduce dam safety expenditures.[430]

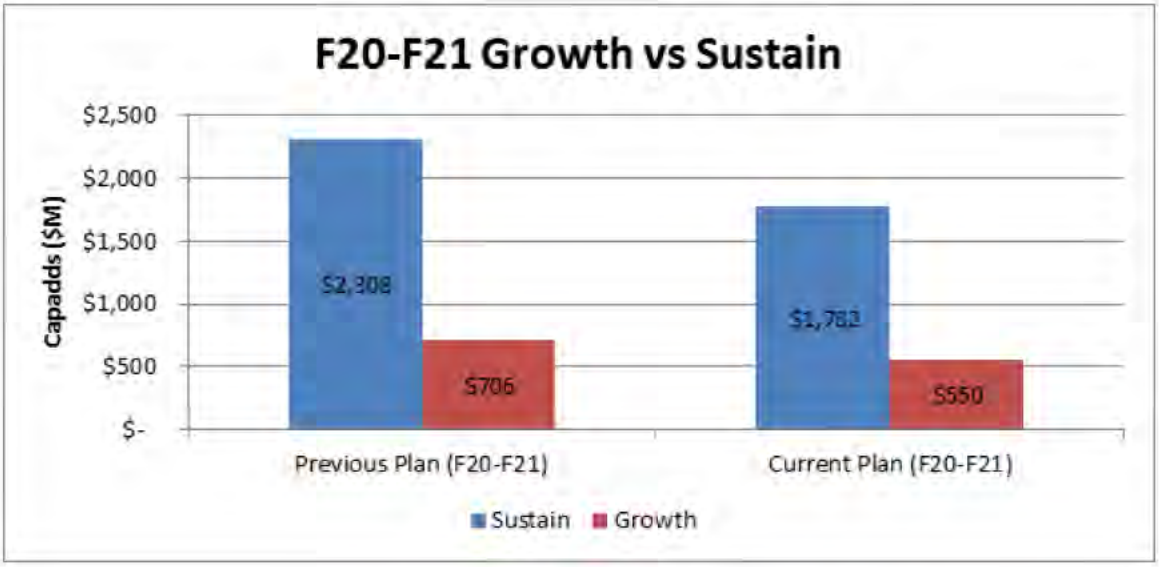
266. In addition, the demand for electricity is growing at a more moderate rate than previously anticipated, which allowed BC Hydro to delay some planned investments to expand the system beyond the ten year time frame of the Capital Plan.[431] The deferral or cancellation of growth investments based on an expected change in load growth is beneficial for customers.[432]

267. Based on system performance and the demand for electricity, the reductions to the Capital Plan consist of:

- reductions due to decisions to defer investments; and
- updates to forecasts for active projects which resulted in a net reduction in capital expenditures or additions within the period, primarily due to project schedule changes.[433]

268. Over the Test Period, the reduction is $682 million or 22.3 percent as follows:[434]

[428] Exhibit B-1, Application, p. 6-26.
[429] Exhibit B-1, Application, p. 20.
[430] Exhibit B-1, Application, p. 6-26.
[431] Exhibit B-5, BCUC IRs 1.108.2 and 1.108.1.1.
[432] Exhibit B-5, BCUC IR 1.108.1.3.
[433] Exhibit B-5, BCUC IR 1.108.1.1.
[434] Exhibit B-5, BCUC IR 1.108.1.



269. Approximately $137 million of the reduction over the Test Period is attributable to decisions to defer investments.[435] These investments were deferred considering the risk score assessment, along with the latest project cost forecast, system performance data and asset information.[436] The remainder of the reduction is due to updates to forecasts for active projects.[437]

(b) Asset Condition and Performance Will Be Monitored

270. The impact on asset health of moderating capital spending is expected to vary across the system.[438] BC Hydro explained:

> - BC Hydro's generation facilities are categorized as "Key", "Strategic" or "Available" according to the significance of the facility to BC Hydro's system. Under the Capital Plan, the condition of BC Hydro's "Key" and "Strategic" generation facilities is expected to improve. For example, investments are planned for the G.M. Shrum, Mica, Bridge River and Cheakamus facilities; and

[435] Exhibit B-5, BCUC IR 1.108.1.

[436] Exhibit B-5, BCUC IR 1.108.2.

[437] Exhibit B-5, BCUC IR 1.108.1.

[438] Exhibit B-1, Application, pp. 6-26 and 6-27.

- The recent trend of asset health degradation within some parts of the Power System is expected to continue at this level of capital investment. For example, over the next five years, the percentage of substation assets in Poor and Very Poor condition is expected to increase from 16 per cent to 19 per cent and the percentage of distribution assets in Poor and Very Poor condition is expected to increase slightly from 13 per cent to 14 per cent. The condition of the assets within BC Hydro's "Available" generation facilities, which provide less than 1 per cent of BC Hydro's annual energy, are expected to continue to deteriorate.

271. BC Hydro does not expect any operational impacts from the deferral of sustainment projects, although it has accepted the potential for additional maintenance of some assets.[439] The deferral or cancellation of sustainment investments is not expected to have a material impact on customer reliability due to asset redundancy and the installation of automated devices on the system.[440]

272. BC Hydro will carefully monitor asset condition and performance and will respond as needed.[441] BC Hydro monitors system performance and forecast demand for electricity at both a system and regional level. 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.[442]

(c) Additional Reductions in Capital Spending Would Be Undesirable

273. Overall, based on forecast load growth and system performance, BC Hydro's planned level of capital investment from fiscal 2020 to fiscal 2024 reflects an appropriate balance of system performance, risk and affordability.[443] BC Hydro's evidence is that any further

[439] Exhibit B-5, BCUC IR 1.108.1.2.

[440] Exhibit B-1, Application, p. 6-27; Exhibit B-5, BCUC IR 1.108.1.3.

[441] Exhibit B-1, Application, pp. 6-26 and 6-27.

[442] Exhibit B-1, Application, p. 6-27.

[443] Exhibit B-1, Application, p. 6-28.

reductions to forecast capital expenditures would degrade asset condition and asset health more than anticipated, with a corresponding negative impact on customer service levels.[444]

E. BC HYDRO DELIVERS CAPITAL PROJECTS EFFICIENTLY AND EFFECTIVELY

274. The evidence, discussed below, demonstrates that BC Hydro has implemented delivery processes tailored to the size and complexity of projects, is engaged in continuous improvement of those processes, has rigorous financial approval processes in place, and has been delivering its portfolio of projects on budget.

(a) BC Hydro's Planning and Delivery Functions Work Together to Ensure Seamless Transition and Accountability

275. BC Hydro's planning and delivery functions are well integrated.[445] Mr. Kumar emphasized the high level of interaction throughout the capital management process, including that the Project Delivery function must account for whether project objectives have been achieved:

> So I think just to add to what Ms. Holland was saying, for all the projects that are implements by Ms. Holland's team, the initiator, which is Andy [Darby], myself and Mr. Schubak, we would be heavily involved in all the different processes for moving the project forward and we don't sign off on the project completion report unless the objectives of those projects have been delivered, because that's what we are looking from an asset management perspective.
>
> So I think there's a enough checks and balances within the organization that the deliver group has to come back to the initiating group to make sure that objectives of the project have been delivered as we expected it to. So I think that's another area that we have it controlled within the organization of making sure that our objectives are met for the delivery side.[446]

(b) BC Hydro's Delivery Processes Are Tailored to the Size and Complexity of Projects

276. BC Hydro uses delivery processes that are appropriate for the size and complexity of the projects being delivered.

---

[444] Exhibit B-12, BCUC IR 2.255.3.

[445] Exhibit B-1, Application, pp. 6-56 and 6-58.

[446] Tr. 11, p. 1859, l. 23 to p. 1860, l. 13 (Kumar).

Project Delivery KBU Uses the Program and Portfolio Management System to Deliver Larger, More Complex Projects

277. The Project Delivery KBU is responsible for delivering the larger, more complex Power System projects, which comprise approximately 54% of the planned capital investments in the Power System for fiscal 2020 to fiscal 2021. It uses the Project and Portfolio Management ("PPM") system for consistent management of project risk, scope, schedule and cost. PPM reflects the principles of ISO 9001, 2008 Quality Management Systems Requirements, and other industry standards such as the Project Management Institute's Project Management Book of Knowledge and the Association for the Advancement of Cost Engineering International Recommended Practices.[447]

278. In broad terms, the delivery lifecycle of PPM projects uses a staged approach to project definition and gate approvals. The lifecycle is divided into four phases: Initiation, Identification, Definition and Implementation. Each phase is further divided into various stages. As projects move through the lifecycle, they become more defined and cost estimates are developed and updated. At various points of the project lifecycle, there are formal approval points (gate approvals), where key information on project cost, schedule, scope, procurement and risk is presented to the Gate Board.[448] The Application details the key components of the PPM system, including practices, tools and learning.[449] It also describes BC Hydro's governance structure, including providing a description of each role.[450] The PPM project lifecycle is depicted in Figure 6-13 of the Application, reproduced below.

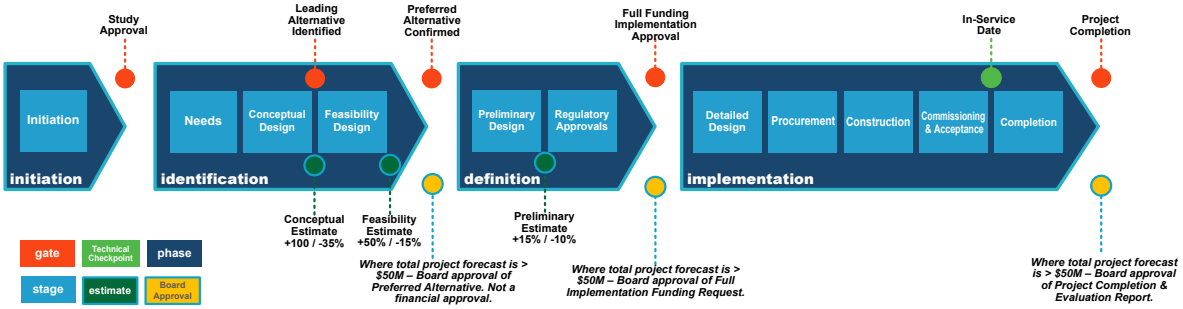
[447] Exhibit B-1, Application, p. 6-59.

[448] Exhibit B-1, Application, p. 6-64.

[449] Exhibit B-1, Application, sections 6.4.7.2 to 6.4.7.4.

[450] Exhibit B-1, Application, pp. 6-69 to 6-74.

Figure 6-13 PPM Project Lifecycle



BC Hydro Uses a Simplified Framework for Routine Power System Investments

279. The Program and Contract Management KBU delivers less complex and repetitive Power System capital investments on BC Hydro's Power System, which comprise approximately 26% of planned capital investments in the Power System for fiscal 2020 to fiscal 2021.[451] These capital investments are typically "like for like" replacements based on pre-defined design standards, are routine in nature, have a lower risk profile and require minimal, if any acquisition of property or rights of way.[452]

280. The Program and Contract Management KBU applies a simplified version of the PPM practices, given the lower complexity of the projects it delivers. It develops annual program and project delivery plans in collaboration with the KBUs in the Integrated Planning and Capital Infrastructure Project Delivery Business Groups. Internal FTEs are used to deliver a significant volume of the small capital work, with external contractors being used to provide scalability due to fluctuations in demand. When specialized services, equipment or materials are required, standing blanket services contracts or master purchasing agreements are used.[453] These standardized processes are efficient and effective for the nature of the capital investments being undertaken.

[451] Exhibit B-1, Application, pp. 6-74 and 6-75.

[452] Exhibit B-1, Application, pp. 6-74 and 6-75.

[453] Exhibit B-1, Application, pp. 6-74 and 6-75.

BC Hydro Uses a Standardized Process for Routine Customer Driven Work

281. The Distribution Design and Customer Connections KBU is responsible for work related to customer requests for new or upgraded connections to BC Hydro's distribution system under 5MW, which comprises approximately 16% of the planned capital investments in the Power System for fiscal 2020 to fiscal 2021.[454] This KBU provides technical design services and project management for customer driven new connections work under 5 MW in size. As explained by Ms. Daschuk, the Distribution Design and Customer Connections KBU manages approximately 35,000 simple customer connections and approximately 5,000 more complex design interconnections each year.[455] The Distribution Design and Customer Connections KBU designs to standards, with engineering support where required. It follows a project management structure that involves standardized work order packages, with environmental, archeological, safety and job planning processes and checklists. This simplified process enables project cycle times to align with customer requirements.[456]

Technology Projects Use Information Technology Delivery Standard Practices

282. BC Hydro manages its Technology projects using a technology-specific delivery framework called Information Technology Delivery Standard Practices ("ITDSP"). ITDSP aligns with PPM Practices and uses standard PPM phases with uniquely defined stages. Gate approval points are positioned at the end of project stages so that management can confirm that the proposed project solution remains in alignment with business drivers, and is ready to progress to the next phase or stage. Each gate is a formal approval point, where key information is presented to the gate board, typically related to cost, schedule, scope, procurement, and risk.[457]

---

[454] Exhibit B-1, Application, p. 6-76.

[455] Tr. 12, p. 2101, l. 14 to p. 2102, l. 7 (Daschuk). These customer connections are distinguished from the customer interconnections of over 5 MVA and over $2 million.

[456] Exhibit B-1, Application, p. 6-76.

[457] Exhibit B-1, Application, pp. 6-146 and 6-147.

(c) BC Hydro is Continuously Improving its Delivery Processes

283. BC Hydro has demonstrated that it is engaged in continuous improvement of its capital delivery processes. In the Application, BC Hydro provided a lengthy list of improvements that it has made to its Power System delivery processes.[458] BC Hydro also annually updates its ITDSP.[459] As discussed in Subsection (g) below, BC Hydro's delivery of its Technology projects has improved using this ITDSP updating process.

(d) BC Hydro Has Rigorous Financial Approval Processes in Place for All Investments

284. BC Hydro's Management and Accounting Policies and Procedures and Financial Approval Authority Policy set the funding approvals required for capital investments through each phase of the project lifecycle. The policies and procedures apply to all groups delivering BC Hydro's capital investments.[460] The required financial approvals under these policies depend on the type of capital investment and the nature of the risk it represents:[461]

- ***Phased capital projects require phase-by-phase funding approval:*** Capital projects delivered using the standard PPM phases are the highest risk projects. Accordingly, they require funding approval prior to the commencement of work for each stage or phase. The financial approver level is dependent on the stage or phase as well as the funding amount being requested.

- ***Non-phased capital projects require business case and authorization****:* Non-Phased Capital Projects are similar to a one-time capital investment, such as the purchase of new equipment or office furniture. Non-phased capital investments over $0.5 million require an approved business case and Expenditure Authorization Request form prior to any capital spending. These authorization documents are approved based on the total investment amount.

[458] Exhibit B-1, Application, pp. 6-82 and 6-83.

[459] Exhibit B-1, Application, p. 6-142.

[460] Exhibit B-1, Application, p. 6-77.

[461] Exhibit B-1, Application, p. 6-78 to 6-81.

- ***Recurring capital investments are approved annually:*** Recurring Capital Investments are generally lower risk, involving like-for-like unit replacements (e.g., the annual distribution wood pole replacement program). These investments are authorized at the beginning of each fiscal year using the Recurring Capital Annual Expenditure Authorization Form.

- ***Approved work orders are required for low cost recurring capital projects:*** Expenditure Authorization Request Exempt Capital Investments are recurring capital projects with a low cost and high volume. Examples include work activities to connect distribution customers, which are required under the Electric Tariff and cost less than $1 million. These investments are approved through BC Hydro's Work Order system.

(e) BC Hydro Evaluates Power System Projects Upon Completion

285. A key outcome of the Implementation Phase of Power System projects is a Project Completion and Evaluation Report.[462] Chairman Morton asked how BC Hydro assesses whether project objectives have been achieved in circumstances where the benefits are expected to accrue over time. Mr. Darby explained that the vast majority of BC Hydro's capital investments are intended to mitigate risks and, therefore, benefits are realized immediately upon completion.[463] In such cases, "you get the benefits instantly" by virtue of the project having been completed.[464]

286. Citing Sustaining capital projects related to polychlorinated biphenyl ("PCB") reduction or generation asset replacement as an example, Mr. Darby noted: "So once you've implemented those projects and you get the benefits we wouldn't track them over time because the risk has been mitigated."[465] Mr. Darby explained that the same logic applies for most of the Growth portion of BC Hydro's capital portfolio, including spending related to

[462] Exhibit B-1, Application, p. 6-68.

[463] Tr. 11, p. 1861, ll. 9-16 (Darby); Exhibit B-6, CEABC IR 1.13.1.

[464] Tr. 11, p. 1861, ll. 9-16 (Darby).

[465] Tr. 11, p. 1861, ll. 19-21 (Darby).

customer connections and building capability of the system to allow for the retirement of end-of-life assets. This leaves only a small portion of the growth portfolio for which benefits are realized over time:

> If we turn to the growth portion of the portfolio, we then noted it's important to understand how that's broken out. So a significant portion of that is customer connections, so again with those, those are customer driven. We'll get the benefits as soon as the customer is connected, so again that isn't something that we would track over time. A portion of those are benefits associated with building capability of the system so that we can potentially retire other assets. So for example I can use a substation as an example, we might build or grow an existing substation so that we can retire a separate substation somewhere else. So again that, while it's in the growth portfolio you'd achieve the benefits as soon as you've done it or as soon as you're retired the other asset. Because it's—while in the growth portfolio it is still very much around risk avoidance and risk mitigation.
>
> The only portion really where you'd be tracking benefits over time for growth perspective, I think, would be for example a DCAT where you'd be looking at if you build a line has the growth materialized and how does that achieve—how is that achieved over time.
>
> So it's mostly a very small portion of the portfolio as a whole, and I think we've captured that through the ongoing planning processes where as a cyclical nature we'll look at how are things growing, do we need to add additional infrastructure to the system? And that is the little bit that we would have to look at over time in terms of getting the benefits. And I'm not sure that we would look at it specifically in terms of the benefits, I think it would just fold into the broader planning process.
>
> But I do want to highlight that it's very small portion of the portfolio. The vast majority of it is risk based and you get the benefits instantly.[466]

287. Further, to track benefits of projects that primarily create value (as opposed to mitigate risk), BC Hydro is piloting a benefits-realization methodology.[467]

(f) BC Hydro Has Delivered its Capital Portfolio On Budget

288. BC Hydro has performed very well in delivering its Capital Plan.

---

[466] Tr. 11, p. 1862, l. 8 to p. 1863, l. 18 (Darby).

[467] Exhibit B-1, Application, pp. 6-149 to 6-151.

BC Hydro Delivered its Overall Portfolio Within 0.40% of Budget Over the Last Five Years

289. The key performance metric BC Hydro uses to evaluate the performance of delivering capital projects is to compare the actual project costs for in-service projects to the Original Approved Expected Cost (also called First Full Funding), over an aggregated five-year period.[468] This performance measure is included in BC Hydro's Service Plan, with a target of actual costs falling within +5% / -5% of the Original Approved Expected Cost in aggregate, excluding project reserve amounts. This metric is calculated using the results of all Generation and Transmission projects as well as major Distribution and Properties projects.

290. Table 6-3 of the Application,[469] reproduced below, shows that BC Hydro has met its Service Plan metric over the past five years. For the most recent five year period shown below (fiscal 2014 to fiscal 2018), BC Hydro delivered 493 projects within 0.40% of budget.[470]

Table 6-3 Five-Year Aggregate Project First Full Funding to Actual Cost (2010 to 2018)

	Capital Infrastructure Project Delivery Project Budget to Actual Cost (2010 - 2018)				
	F2010-F2014	F2011-F2015	F2012-F2016	F2013-F2017	F2014-F2018
# of Projects	661	563	563	540	493
Original Aggregate Budget ($ millions)	3,330	3,924	6,491	6,363	6,936
Actual Aggregate Cost ($ millions)	3,184	3,852	6,479	6,303	6,963
Aggregate Cost Variance ($ millions)	-146.2	-71.8	-12.0	-59.9	27.9
% variance from original budget	-4.39	-1.83	-0.18	-0.94	0.40

291. Consideration of five-year aggregate costs, rather than performance on an individual project basis, is appropriate. The Original Approved Expected Cost is a P50 cost estimate for most projects, such that there is an expectation that the estimate would be exceeded 50 per

[468] Exhibit B-12, BCUC IR 2.228.3.

[469] Exhibit B-1, Application, p. 6-11.

[470] Negative variances indicate that the actual aggregate cost was less than (under) the original aggregate budget.

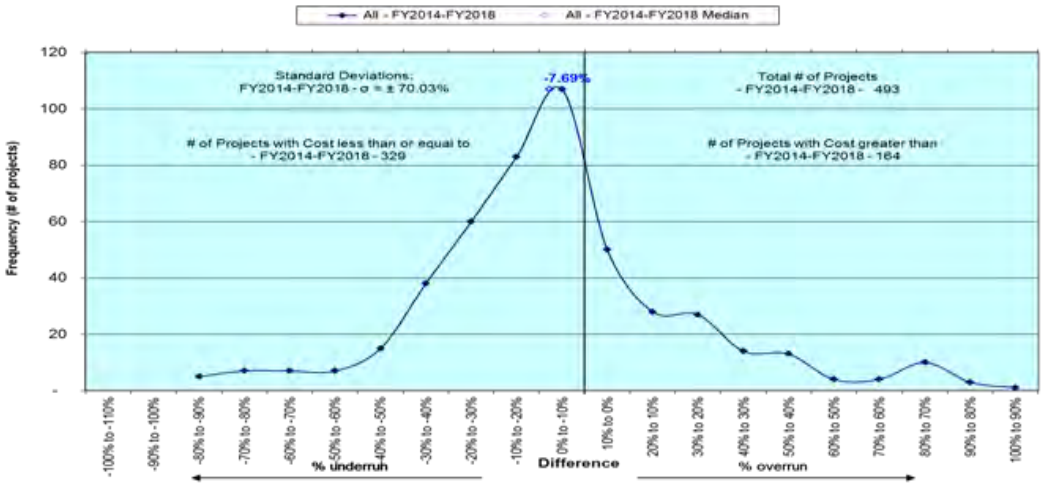
cent of the time.[471] Probabilities dictate that there will be projects that are over budget and others that are under budget.[472] Therefore, delivering the portfolio of projects within the capital performance metric targets is an indication that BC Hydro is prudently managing capital expenditures on a portfolio basis.

A Strong Majority of Projects of All Sizes Come in Under Budget

292. BC Hydro also considers budget performance on individual projects,[473] and the data on individual projects tells the same story.

293. Approximately two-thirds (66.5%) of the 493 projects included in the analysis for BC Hydro's Service Plan metric had an actual cost that was less than the Original Approved Expected Cost. The median project was 7.7% below the Original Approved Expected Cost. This is illustrated in Figure 6-2 of the Application,[474] which is reproduced below.

Figure 6-2 Summary of Actual Cost to Original Approved Expected Cost



[471] Exhibit B-12, BCUC IR 2.228.3.1.

[472] Exhibit B-5, BCUC IR 1.76.2.

[473] Exhibit B-5, BCUC IR 1.76.2.

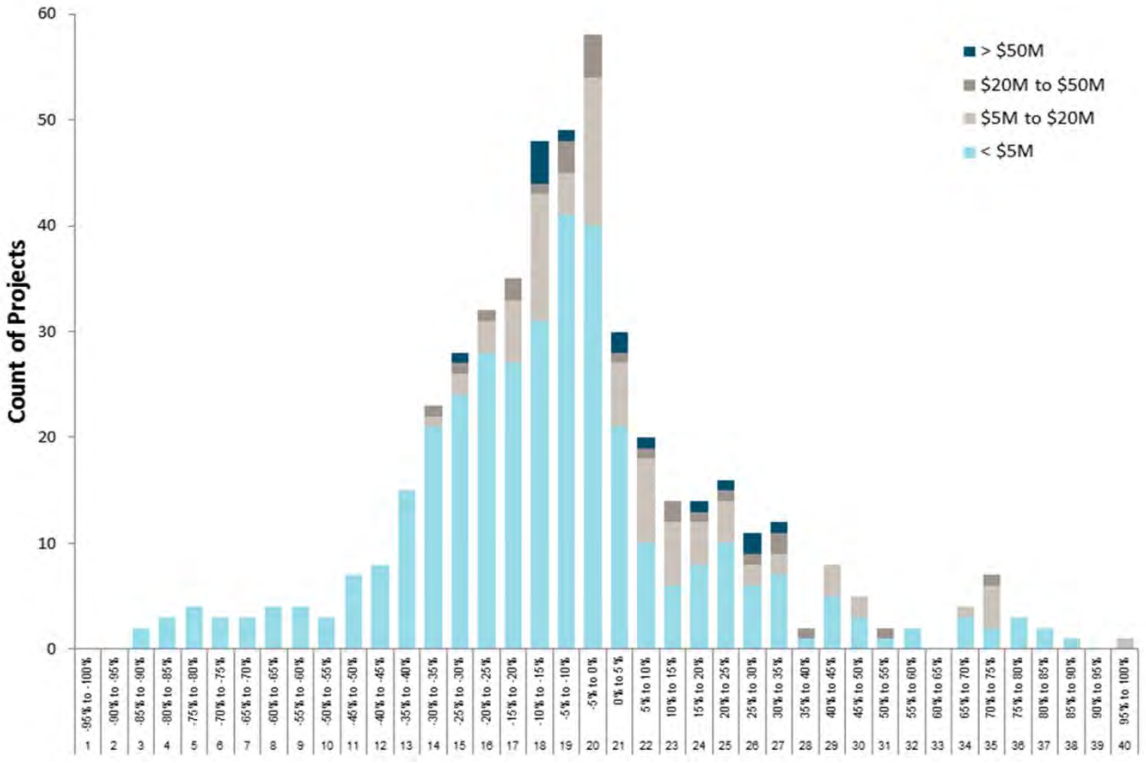
[474] Exhibit B-1, Application, p. 6-12.

294. BC Hydro has performed well for projects of all sizes, including large projects. From fiscal 2014 to fiscal 2018, the average variance between the Original Approved Expected Cost and actual cost is:

- 1.20% for projects greater than $50 million;
- 0.27% for projects between $20 million and $50 million;
- 2.83% for projects between $5 million and $20 million; and
- -9.82% for projects less than $5 million.

295. These results are illustrated in Figure 6-3 of the Application,[475] which is reproduced below.

Figure 6-3 In-Service Projects (Expected Cost vs Actual Cost) – Fiscal 2014 to Fiscal 2018



[475] Exhibit B-1, Application, p. 6-13.

KBU-Specific Measures Similarly Show Favourable Performance

296. The Project Delivery, Technology and Properties KBUs, which deliver the majority of BC Hydro's capital plan, have KBU-specific capital expenditure performance measures:[476]

- Project Delivery KBU - Number of projects placed in-service within the Original Approved Expected Amount;
- Technology KBU - Percentage of Technology projects completed within the Original Approved Expected Amount; and
- Properties KBU - Percentage of completed projects with total spend within the Original Approved Expected Amount.

297. These KBUs have succeeded in meeting their capital performance measures in the majority of years.[477] For example, the Technology KBU completed a total of 94 projects between fiscal 2016 and fiscal 2018, with total Original Approved Expected Amount of $135.1 million and total actual costs of $134.5 million. This represented a favourable variance of $0.6 million or -0.4%.[478]

Achievement of Service Plan Reliability Metrics is Another Indicator of Success

298. Mr. Kumar also cited, as another measure of success, the fact that BC Hydro is meeting reliability metrics in the Service Plan:

> I think the capital plan actually has a huge impact on our ability to deliver on the metrics and the service plan. So for example, if you look at the reliability [metrics] that we use in the service plan, like the SAFI and the SADI which is reflection of our frequency of outages and duration of outages, and even the forced factor that we use for our generation side. All those are driven by the success of development of a comprehensive capital plan and a maintenance plan. Because if you are not able to deliver comprehensive capital and

[476] Exhibit B-12, BCUC IR 2.228.3.

[477] Exhibit B-12, BCUC IR 2.228.3.2.

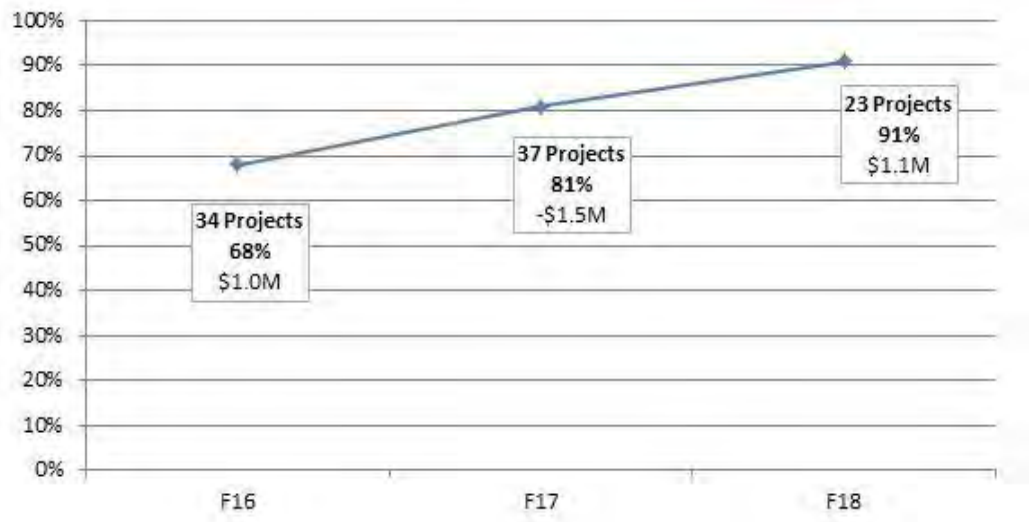
[478] Exhibit B-1, Application, p, 6-148.

maintenance plans, you won't be able to deliver on those metrics across the system.[479]

(g) Improvements in Technology Processes Have Brought Strong Results

299. BC Hydro's practice of annually updating its Information Technology Delivery Standard Practices,[480] as described earlier in this Part, has improved the company's delivery of its Technology projects. This is shown in Figure 6-17 of the Application,[481] reproduced below. It is a summary of BC Hydro's performance in delivering Technology capital projects, comparing total approved First Full Funding for projects to total actual project costs.[482]

Figure 6-17 Number of Technology Projects Completed Within Total Approved First Full Funding Amount



300. The strong results above compare favourably to the industry generally. The Project Management Institute's Pulse of the Profession Report stated in its global project management survey that 57% of technology projects are completed on budget.[483]

---

[479] Tr. 11, p. 1852, l. 4 to p. 1853, l. 9 (Kumar); Tr. 11, p. 1857 l. 20 to p. 1858, l. 6 (Kumar).

[480] Exhibit B-1, Application, p. 6-142.

[481] Exhibit B-1, Application, p. 6-148.

[482] For technology projects, the estimated accuracy range for the First Full Funding Approval cost is +15 per cent / -10 per cent, which is equivalent to an AACE International Class 3 cost estimate. Exhibit B-6, CEC IR 1.64.2.

[483] Exhibit B-1, Application, pp. 6-148 and 6-149.

301. BC Hydro is also piloting a Technology benefits realization process that will track the realization of benefits claimed in the business cases of Technology projects.[484] The benefits realization methodology is being piloted on four of BC Hydro's non-mandatory, business-driven technology initiatives.[485] BC Hydro provided detailed reports on the status of the Technology projects in the pilot, including variances between benefits of the projects in their respective businesses cases and benefits realized to date.[486] BC Hydro expects the pilot to continue through fiscal 2020. BC Hydro will then prepare a report, which it anticipates will be available for review in the next RRA proceeding.[487] BC Hydro expects to use its experience from the pilot to develop a benefits realization process for all Technology projects.[488]

F. BC HYDRO'S CAPITAL MANAGEMENT PROCESSES HAVE BEEN ENDORSED BY THIRD PARTIES

302. Over the past decade, BC Hydro has demonstrated consistent and ongoing efforts to improve its capital planning and delivery processes. The results of these efforts have been recognized by third parties.[489]

- A December 2018 report by the Office of the Auditor General cited BC Hydro's advanced level of maturity in asset management practices:[490]

  > BC Hydro has a generally advanced level of maturity in asset management. Its success in this regard is a result of concerted effort over several years by a set of skilled professionals focused on ensuring that a reliable source of electrical power will be supported by a mature asset management practice.

  The Auditor General, for the first time in many years, made no recommendations for improvement.[491]

---

[484] Exhibit B-1, Application, p. 6-149.

[485] Exhibit B-1, Application, pp. 6-149 and 6-150.

[486] Exhibit B-5, BCUC IR 1.114.2.

[487] Exhibit B-13, CEC IR 2.127.1; Tr. 7, p. 853, ll. 11-22 (Morison); Tr. 7, p. 858, l. 23 to p. 859, l. 9 (Morison).

[488] Exhibit B-6, CEC IR 1.66.2 and 1.66.3.

[489] Exhibit B-6, CEC IR 1.4.2.

[490] Exhibit B-1, Application, p. 6-9.

- In 2016, BC Hydro completed its second Organizational Project Management Maturity Model Assessment, receiving the highest score among approximately 50 participating organizations from around the world. A highly experienced auditor performed the independent assessment[492] and BC Hydro received an overall score of 91%. It achieved 100% in meeting best practices in project management, program management and portfolio management.[493]

- In 2016, BC Hydro received the Project Management Office of the Year Award from the Project Management Institute.[494]

303. Third-party recognition provides added assurance that BC Hydro's capital planning and delivery processes are mature and in line with industry best practices.

G. AMORTIZATION OF CAPITAL ADDITIONS REGULATORY ACCOUNT WILL ENSURE THAT CUSTOMERS ONLY PAY ACTUAL COSTS

304. The Amortization of Capital Additions Regulatory Account captures the differences between the forecast and actual amortization of capital additions, with variances recovered over the next test period.[495] Actual capital expenditures and additions are expected to vary from forecast due to factors such as changes in project timing and scope changes. The account ensures that customers will only pay for actual costs when this occurs.

---

[491] Exhibit B-1, Application, p. 6-9. The full report of the Independent Audit of Capital Asset Management in BC Hydro is included as Appendix F of the Application. See also, Tr. 11, p. 1852, l. 4 to p. 1853, l. 9 (Kumar).

[492] Exhibit B-6, CEC IR 1.45.4. The auditor who performed the assessment was Claudia M. Baca from Project Management Consulting Services. Ms. Baca has Project Management Office experience in multiple industries across all disciplines of portfolio, program, and project management. Ms. Baca has written five books and co-authored papers on the effective development of Project Management Offices and was the chair and co-author for Managing Change in Organizations: A Practice Guide, published by the Project Management Institute.

[493] Exhibit B-1, Application, p. 6-10; Exhibit B-6, CEC IR 1.45.2.

[494] Exhibit B-1, Application, p. 6-10.

[495] Exhibit B-1, Application, p. 7-36.

305. For clarity, the amortization of existing assets is not within the scope of the Amortization of Capital Additions Regulatory Account; therefore, variances between forecast and actual amortization of existing assets are to the account of the shareholder.[496]

H. EXPENDITURES ON RIP RAP FOR W.A.C. BENNETT DAM WERE PRUDENT

306. BC Hydro's $700,000 expenditure for the riprap stockpile for the W.A.C. Bennett Dam was prudently incurred and should be recovered in rates.

307. The BCUC rejected BC Hydro's request for approval of $4.3 million for stockpile costs in BC Hydro's November 13, 2015 application to upgrade the riprap on the W.A.C. Bennett Dam. The BCUC directed that, in future revenue requirement applications, BC Hydro should either confirm that no expenditures relating to emergency stockpile riprap were included in the revenue requirements or explain otherwise. BC Hydro followed the approach of providing a rationale for its new plan and by seeking recovery of the associated costs in the Application. This does not require any reconsideration of the BCUC's past determinations.[497]

308. The actual cost for the riprap stockpile was $700,000, i.e., $3.6 million less than the original amount.[498] BC Hydro was able to realize significant cost savings on the stockpile costs by using smaller rocks and restricting the volume to what it could produce from waste rock left over from the quarrying of Class 1 riprap rock. BC Hydro also saved on overhead and interest during construction, since the costs were much lower than expected and were expended at the end of the project timeline.[499]

309. The stockpile will provide substantial benefits, which makes the $700,000 a highly cost-effective investment. BC Hydro's Application described the benefits as follows:[500]

---

[496] Exhibit B-13, BCOAPO IR 2.136.1. Amortization variances on existing assets may arise as a result of a reduction in the useful life of an asset or a write-off of an asset during a test period.

[497] Exhibit B-5, BCUC IR 1.112.1.

[498] Exhibit B-1, Application, pp. 6-90 and 6-91.

[499] Exhibit B-5, BCUC IR 1.112.2.

[500] Exhibit B-1, Application, pp. 6-92 and 6-93. See also, Exhibit B-5, BCUC IR 1.112.4.

- **An inexpensive way to extend the life of the project** – The expected 50 year life of the riprap could be extended by 50 to 100 per cent with proper maintenance and repair, utilizing limestone rock from the MES [Maintenance and Emergency Stockpile of riprap]. Any type of rock has natural variability, such as freeze/thaw splitting or breakage characteristics and a significant storm event could happen at any time, causing damage that could impact the underlying dam structure if it is not quickly identified and addressed. If BC Hydro was required to implement a reactive maintenance program, it would cost considerably more than $0.7 million;

- **Higher quality rock** – A pre-existing sandstone stockpile at the W.A.C. Bennett Dam is not acceptable for maintenance or emergency purposes. Sandstone riprap does not have the same life expectancy as limestone riprap and repairs using sandstone riprap would require subsequent replacement in the future, ultimately leading to higher costs. A temporary fix, in an emergency situation, followed by a subsequent replacement project would also likely require reservoir re operation which would result in lost revenue or higher energy costs from other sources;

- **A Readily Available Source of Limestone Riprap** – As the Riprap Upgrade project has now been completed, the quarry would need to be re-opened to acquire additional limestone rock, which would require additional permitting, consultation with First Nations, and securing a contractor willing to take on the relatively small production. This would likely take one to two years, or more, to complete. While there is a limestone quarry located 170 kilometres from the W.A.C. Bennett Dam, quarrying from this site would also require lengthy consultation, permitting and procurement processes; and

- **Best practice for maintenance and emergency purposes** – In 2018, BC Hydro polled the members of the Center for Energy Advancement through Technical Innovation (CEATI) Dam Safety Interest Group to confirm whether it was best practice to stockpile rock for maintenance and emergency purposes. BC Hydro received 20 responses, and all respondents, except for those that have ready access to emergency quarry supplies and transportation, indicated that they also maintain maintenance and emergency stockpiles and that this is considered best practice. BC Hydro does not have ready access to maintenance and emergency quarry supplies for the W.A.C. Bennett Dam.

310. The evidence that this expenditure is cost-effective and beneficial for customers is compelling, and the costs should be recovered in rates.

I. VARIANCE OF DIRECTIVE 3 IS WARRANTED AND MIN TO LNG CANADA PROJECT IS EXEMPT

311. BC Hydro has requested that the BCUC reconsider and vary Directive 3 of the BCUC's Decision on the Previous Application[501] to remove the direction to BC Hydro to file a CPCN application for the Northwest Substation Upgrade project, which was designed to serve LNG Canada's load interconnection request. The BCUC has requested that BC Hydro address in argument: "Whether the Minette Station to LNG Canada Interconnection project meets the requirements of the Transmission Upgrade Exemption Regulation, as amended by B.C. Reg. 160/2018, to exempt the project from Part 3 of the *Utilities Commission Act*".[502]

312. The original Northwest Substation Upgrade project that was the subject of Directive 3 has been cancelled due to LNG Canada splitting its load interconnection request into two phases. The new MIN to LNG Canada Interconnection project facilitates the first phase of the LNG Canada load interconnection request and includes scope items that were formerly part of the exempt Northwest Substation Upgrade Project.[503] The capital expenditures for the Test Period for the MIN to LNG Canada Interconnection project are $28.2 million in fiscal 2020 and $26.6 million in fiscal 2021.[504] Under its Facilities Agreement with BC Hydro, 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.[505] Since the in-service date is after the Test Period, the project has no impact on the Test Period revenue requirements.[506]

[501] Exhibit B-1, Application, p. 32.

[502] Exhibit A-31.

[503] Exhibit B-5, BCUC IR 1.1.1; Tr. 12, p. 2291, ll. 6-14 (Holland).

[504] Exhibit B-1, page 4 of Appendix I of the Application, (Transmission, Line 20, IPID 93786).

[505] Tr. 12, p. 2292, ll. 8-15 (Kumar); Exhibit B-57, BC Hydro Undertaking No. 43.

[506] Exhibit B-5, BCUC IR 1.1.9.

313. The MIN to LNG Canada Interconnection project is exempt pursuant to the *Transmission Upgrade Exemption Regulation*.[507] Specifically:

- Section 2(1)(e) of the *Transmission Upgrade Exemption Regulation* exempts, from Part 3 of the *UCA*, the addition of shunt capacitors at the Minette substation, including associated protection and control equipment, which is part of the MIN to LNG Canada Interconnection project.

- The MIN to LNG Project is necessary to provide service to LNG Canada's LNG facility in the District of Kitimat. Section 2(2) of the *Transmission Upgrade Exemption Regulation* exempts from Part 3 of the *UCA*: "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." Further to the requirement in section 2(3) of the *Transmission Upgrade Exemption Regulation*, BC Hydro reasonably expects that the MIN to LNG Canada Interconnection project will be in service before October 1, 2025.

314. LNG Canada has yet to make a decision to proceed with phase 2 of its load interconnection request.[508] BC Hydro's projects to serve phase 2 would also be exempt.[509]

315. BC Hydro acknowledges that the cancellation of the Northwest Substation Upgrade project means that the directive to file a CPCN for that project is no longer applicable.[510] However, varying Directive 3 would 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

[507] Exhibit B-12, BCUC IR 2.247.2.

[508] Tr. 12, p. 2293, ll. 3-12 (Holland and Daschuk); Tr. 13, p. 2461, l. 18 to p. 2462, l. 8 (Holland).

[509] Exhibit B-12, BCUC IR 2.247.2.

[510] Exhibit B-5, BCUC IR 1.1.1.

projects associated with LNG Canada's updated request that are expected to come into service before October 1, 2025.

J. BC HYDRO HAS ANSWERED SPECIFIC ISSUES RAISED

316. The subsections below address issues raised in the information requests and at the oral hearing.

(a) The PRES Project is a Prescribed Undertaking

317. The PRES project[511] is a prescribed undertaking under section 18 of the *Clean Energy Act* and section 4(2) of the GGRR.[512]

318. Section 4(2) of the GGRR describes a class of prescribed undertaking, as follows:

> (2) A public utility's undertaking that is in a class defined as follows is a prescribed undertaking for the purposes of section 18 of the Act:
>
> > (a) for the purpose of reducing greenhouse gas emissions in British Columbia, the public utility constructs or operates an electricity transmission or distribution facility, or provides for temporary generation until the completion of the construction of the facility, in northeast British Columbia primarily to provide electricity from the authority to
> >
> > > (i) a producer, as defined in section 1 (1) of the Petroleum and Natural Gas Royalty and Freehold Production Tax Regulation, B.C. Reg. 495/92,[513] or
> > >
> > > (ii) an owner or operator of a natural gas processing plant;
> >
> > (b) the public utility reasonably expects, on the date the public utility decides to carry out the undertaking, that the facility will have an in-service date no later than December 31, 2022.

[511] This project is summarized in Exhibit B-1, Appendix J, p. 71.

[512] Exhibit B-5, BCUC IR 1.119.2.

[513] In the *Petroleum and Natural Gas Royalty and Freehold Production Tax Regulation*, "producer" means (a) a holder of a location who markets or otherwise disposes of oil, natural gas or both, that has been produced by (i) the holder of the location, or (ii) a person authorized to do so by the holder of the location, and (b) a person authorized by a holder of a location to produce and market or otherwise dispose of, on the holder's behalf, oil, natural gas or both.

319. The PRES project satisfies the in-service date requirements of section 4(2)(b) of the GGRR. The planned in-service date for the PRES project is October 2021.[514]

320. Consistent with section 4(2)(a) of the GGRR, BC Hydro's written evidence and testimony is that the purpose of the PRES project is to construct and operate electricity transmission facilities to reduce GHG emissions in B.C. by enabling the electrification of natural gas production, processing and compression in the South Peace region.[515] The majority of the existing and forecast load in this region is from natural gas producers.[516] The PRES project will reduce GHG emissions by targeting these new loads, and BC Hydro estimates that GHG reductions will be 560 tonnes of CO2e per GWh.[517] In the absence of the PRES project, these new gas processing loads would have no choice but to combust fossil fuels for power supply, resulting in a significant increase in greenhouse gas emissions in the province.[518] As an additional benefit, the PRES project also increases reliability for existing customers.[519]

321. There is abundant evidence that the PRES project is consistent with and driven by provincial and federal GHG policy. The Government of B.C. has expressed its support for the PRES project in that context:

(a) In August 2017, the provincial government's Mandate Letter identified "advancing government's climate action strategies including through fuel switching and electrification initiatives in the transportation, oil and gas, and other sectors" as a key responsibility for BC Hydro. This mandate placed an expectation on BC Hydro that it should be in a position to meet the electrification needs of customers in the Peace Region, as accomplished by the PRES project.[520]

---

[514] Exhibit B-23, CEABC IR 4.59.1; Exhibit B-5, BCUC IR 1.119.2.

[515] Exhibit B-12, BCUC IR 2.250.1; Tr. 7, p. 1064, ll. 2-12 (Fraser); Tr. 12, p. 2312, l. 23 to p. 2313, l. 18 (Kumar).

[516] Exhibit B-5, BCUC IR 1.119.3.

[517] Exhibit B-23, GJOSHE IR 4.1.8.

[518] Exhibit B-5, BCUC IR 1.119.1.

[519] Exhibit B-12, BCUC IR 2.250.7; Tr. 12, p. 2262, l. 19 to p. 2263, l. 2 (Kumar).

[520] Exhibit B-1, Appendix J, Capital Expenditures > $20 million, Attachment 1, p. 71.

(b) The CleanBC Plan, released in December 2018, included the goal of increasing access to clean electricity for planned natural gas production in the Peace Region and increasing access to clean electricity for large operations with new transmission lines and interconnectivity to existing lines.[521] The PRES project is explicitly referred to in the CleanBC Plan, at page 43: "the Peace Region Electricity Supply (PRES) project will make it easier to replace natural gas combustion with electricity. Switching to clean electricity will make B.C.'s natural gas the cleanest in the world."

(c) In April 2019, the Government of Canada announced that it is providing up to $83.6 million towards the PRES project through the Investing in Canada Plan, which is designed to facilitate the expansion of transmission systems that result in the reduction of greenhouse gas emissions.[522]

(d) In August 2019, the Government of Canada and the Government of B.C. announced a Memorandum of Understanding to support the electrification of the natural gas sector in British Columbia (the "MOU"). The preamble of the MOU states: "The governments of British Columbia and Canada have a shared interest in electrifying natural gas production and liquefied natural gas production to build Canada's clean energy brand as a supplier of the world's cleanest natural gas." The MOU refers to the PRES project as an example of the investments that BC has been making in its grid to enable electrification of the natural gas industry.[523]

---

[521] CleanBC Plan, p. 9.
Online: https://blog.gov.bc.ca/app/uploads/sites/436/2019/02/CleanBC_Full_Report_Updated_Mar2019.pdf.

[522] Exhibit B-23, INCE IR 4.16, referencing the Memorandum of Understanding between the Government of Canada and the Government of B.C. to support the electrification of the natural gas sector in British Columbia, online: https://pm.gc.ca/en/news/backgrounders/2019/08/29/memorandum-understanding-between-government-canada-and-government; Tr. 11, p. 2098, ll. 5-14 (Daschuk and Holland).

[523] Exhibit B-23, INCE IR 4.16, referencing the Memorandum of Understanding between the Government of Canada and the Government of B.C. to support the electrification of the natural gas sector in British Columbia, online: https://pm.gc.ca/en/news/backgrounders/2019/08/29/memorandum-understanding-between-government-canada-and-government.

322. BC Hydro submits that the BCUC must allow BC Hydro to recover the costs of the PRES project pursuant to section 18 of the *Clean Energy Act* and the GGRR.

(b) Bear Mountain Terminal to Dawson Creek Transmission Voltage Conversion and North Montney – Transmission Development Projects May Also be Prescribed Undertakings

323. BC Hydro also identified two other projects related to transmission system upgrades for the LNG and oil and gas sectors in the Peace Region: the Bear Mountain Terminal to Dawson Creek Transmission Voltage Conversion, and the North Montney Transmission Development.[524] BC Hydro advanced these two projects, along with the Prince George to Terrace Capacitors project, as ex-plan[525] projects in order to:[526]

- Encourage new load growth and revenue, and ensure that BC Hydro is able to provide transmission services in the timeline required for customer need and desire to electrify their operations;[527]
- Support the CleanBC Plan to provide clean electricity to planned natural gas and LNG production;[528] and
- Access federal investment to reduce costs to BC Hydro's customers.[529]

324. Ms. Pinksen explained why they were brought forward as ex-plan projects:

> So our capital plan is updated annually, but we use the ex-plan process when we find in between those cycles of update, we need to initiate the project prior to the approval of the next plan. And so these projects were initiated between the approval of the Fiscal '20 capital plan, and the Fiscal '21 capital plan. And they were brought forward to our capital delivery management committee, and presented as to why it was prudent to initiate them at that time. And it was

[524] Exhibit B-12, BCUC IR 2.254.2 and 2.247.6.1.

[525] Tr. 12, 2272, l. 12 to p. 2275, l. 10 (Pinksen).

[526] Exhibit B-12, BCUC IR 2.254.2.

[527] Tr. 9, p. 1514, l. 21 to p. 1515, l. 8 (Rich); Tr. 9, p. 1517, ll. 12-21 (Rich).

[528] Tr. 9, p. 1517, ll. 12-21 (Rich).

[529] Tr. 12, p. 2275, l. 24 to p. 2276, l. 13 (Daschuk and Kumar).

> really about preserving the potential in-service date, and needing to initiate the project as opposed to waiting for the next cycle.[530]

325. BC Hydro has advanced the projects to allow for more meaningful discussions with potential customers about their load and electrification, while minimizing cost outlay.[531]

326. Both these projects are referenced in the MOU as projects that the Canada-British Columbia Clean Power Planning Committee will advance.[532] In light of the purpose of these two projects, they may qualify as prescribed undertakings pursuant to section 18 of the *Clean Energy Act*, and as such may be exempt from Part 3 of the *UCA*.[533]

327. Chairman Morton commented during the hearing that it would be useful if there was a mechanism for the BCUC assess to the applicability of the GGRR in advance.[534] Mr. O'Riley expressed openness to look at the issue.[535] BC Hydro confirms that, following this proceeding, it will be considering the legal and practical issues around Chairman Morton's question and will initiate further discussions with BCUC Staff to explore potential options.

(c) Electric Vehicle Investments are Added to Rate Base per Direction No. 8

328. The BCUC requested that BC Hydro address in its argument the following:

> Whether British Columbia Hydro and Power Authority's investments in electric vehicle charging infrastructure should be included in rate base during the current test period and recovered from ratepayers or be separately tracked and excluded from rate base until the British Columbia Utilities Commission directs otherwise, given the developing landscape of the electric vehicle charging stations market in BC.[536]

---

[530] Tr. 2274, ll. 12-23 (Pinksen).

[531] Tr. 12, p. 2281, ll. 5-23 (Kumar).

[532] The MOU is available online at: https://pm.gc.ca/en/news/backgrounders/2019/08/29/memorandum-understanding-between-government-canada-and-government.

[533] Exhibit B-12, BCUC IR 2.250.3.

[534] Tr. 6, p. 742, l. 20 to p. 743, l. 14 (Morton).

[535] Tr. 6, p 743, l. 15 to p. 744, l. 7 (O'Riley).

[536] Exhibit A-31.

329. BC Hydro's capital additions related electric vehicle charging stations, net of any contribution from Government or third parties,[537] are included in rate base pursuant to section 1 of Direction No. 8.[538] Given the effect of Direction No. 8, the BCUC cannot direct BC Hydro to exclude its investments in electric vehicle charging stations from its rate base.

330. However, amounts included or excluded from rate base have no practical effect during the Test Period because BC Hydro's net income is not dependent on a specific rate base amount. Rather, BC Hydro's net income is currently prescribed by section 3 of Direction No. 8 to be a specific dollar amount of $712 million per fiscal year in each of fiscal 2020 and fiscal 2021.[539]

331. Whether investments in electric vehicle charging stations should be included in rate base in the future should not be considered in this proceeding. First, the matter has no relevance to the Test Period revenue requirements or rates. Second, the BCUC has held an Inquiry into the Regulation of Electric Vehicle Charging Service and has made its recommendations to Government in its Phase Two Report.[540] At this time, BC Hydro is expecting Government to respond with legislation clarifying the role of BC Hydro in the electric vehicle area. Until this clarification is provided, it would be inappropriate to deny recovery in rates or to make determinations on the treatment of future investment in electric vehicle charging stations.

(d) BC Hydro is Managing Cybersecurity Risks

332. Cybersecurity risk is a significant issue for BC Hydro. The evidence, discussed below, demonstrates that BC Hydro has been managing that risk appropriately. It is likely, however,

---

[537] Exhibit B-5, BCUC IR 1.122.4.

[538] Direction No. 8.

[539] Direction No. 8.

[540] *Inquiry into the Regulation of Electric Vehicle Charging Service*, Phase Two Report, dated June 24, 2019. Online: https://www.bcuc.com/Documents/Proceedings/2019/DOC_54345_BCUC%20EV%20Inquiry%20Phase%20Two%20Report-web.pdf.

that additional investment will be required following the Test Period given the increasing challenges faced by the company.[541]

333. In response to increasing cybersecurity risks, BC Hydro continually assesses cybersecurity risks and its management of those risks, improves security processes, and assesses its resourcing requirements.[542] As an illustration of these efforts, BC Hydro is responding to recommendations from internal and third party audits and, in particular, will be expanding investment and efforts on assets not covered by MRS.

Strong Governance Structures and Best Practices Underpin Cybersecurity Efforts

334. The foundation for BC Hydro's cybersecurity is strong governance structures and following best practices:

- BC Hydro's Security Policy and Standards follow the International Organization for Standardization 27001 Framework. BC Hydro also follows the Center for Internet Security standards for baseline configurations of devices and operating systems.[543]

- There are 40 FTEs across BC Hydro with cybersecurity work as their main job function.[544] Their work is overseen by two steering committees: the MRS Steering Committee and the Cybersecurity Oversight Committee.[545] The former is accountable for ensuring BC Hydro meets all MRS compliance requirements,[546] while the latter is accountable for enterprise-wide cybersecurity of all Technology systems including Critical Infrastructure Protection (CIP) cybersecurity. BC Hydro's Chief Information Officer (CIO) sits on both the

[541] Tr. 5, p. 358, l. 21 to p. 359, l. 8 (O'Riley); Tr. 7, p. 981, l. 2 to p. 982, l. 6 (Morison).

[542] Tr. 6, p. 730, ll. 8-19 (Wong).

[543] Exhibit B-5, BCUC IR 1.123.6.

[544] Exhibit B-5, BCUC IR 1.123.8.

[545] Exhibit B-5, BCUC IR 1.123.9.

[546] BC Hydro's Senior Vice President of Safety and Compliance is designated as BC Hydro's Compliance Officer, is responsible for BC Hydro's MRS compliance program and leads the MRS Steering Committee, which provides governance for the MRS program.

cybersecurity and MRS governance committees, to coordinate the efforts of these governance functions.[547]

- BC Hydro conducts regular internal and external compliance reviews, has a cybersecurity awareness program for employees, and requires vendors to complete an annual review of BC Hydro's cybersecurity policies and standards.[548]

- BC Hydro tests its Cybersecurity Incident Response Plan at least once every 15 months, participates in bi-annual mock cyber-attack exercises, and conducts quarterly IT Service Continuity Management Plan table top exercises.[549]

BC Hydro Has Made Ongoing Investments in Cybersecurity

335. Another aspect of maintaining effective cybersecurity is ongoing investment. BC Hydro has made significant investments to upgrade electronic and physical security for equipment used to control and monitor industrial control systems connected to the bulk electric system to meet critical infrastructure standards prescribed by NERC. As of March 31, 2019, BC Hydro has invested $30.2 million on the NERC CIP version 5 compliance initiative.[550] BC Hydro forecast $17.3 million in capital expenditures on the NERC CIP version 5, version 6 and version 7 initiatives over the test period.[551] BC Hydro applies learnings from the MRS program to other assets, as appropriate.[552]

336. BC Hydro also continuously improves security processes and implements new controls through active projects. For example, BC Hydro improved security controls for transient and removable devices in its facilities through the NERC CIP version 6 project, is improving its Cybersecurity Incident Response Plan, and is investigating the feasibility of a 24x7 Cybersecurity

[547] Exhibit B-12, BCUC IRs 2.257.15 to 2.257.18.

[548] Exhibit B-5, BCUC IR 1.123.7.

[549] Exhibit B-12, BCUC IR 2.257.28.

[550] Exhibit B-5, BCUC IR 1.123.3; Exhibit B-12, BCUC IR 2.257.9.

[551] Exhibit B-5, BCUC IR 1.123.12.

[552] Exhibit B-12, BCUC IR 2.257.11.

Operations Center.[553] BC Hydro is also completing the Station Gateway System which will replace manual processes with an inventory of cyber assets with the capability to automatically collect configuration data from BC Hydro's industrial control systems.[554] This project will reduce the risk of cybersecurity incidents and compliance violations and improve efficiency of sustainment processes in transmission stations related to maintaining the CIP standards.[555]

BC Hydro Performs Ongoing Risk Assessment and Implements Audit Recommendations

337. BC Hydro maintains a cybersecurity risk register, which includes key cybersecurity threats and a qualitative risk assessment. BC Hydro assesses its cybersecurity risks and its management of those risks through the advice of third-party experts and its own audits.[556]

338. The Marsh Data Breach Quantification report and the Bitsight assessment of BC Hydro's cybersecurity profile are good examples of BC Hydro's use of external expertise.[557]

339. BC Hydro's 2016 internal audit provided a baseline for measuring the overall effectiveness of the cybersecurity program, and BC Hydro implemented the internal audit recommendations.[558] BC Hydro's 2019 Internal Cybersecurity Audit focused on enterprise-wide and critical areas of threat vulnerability management and incident response, and a newly emerging threat in vendor management.[559] The 2019 audit generally affirmed that BC Hydro is on the right track when it comes to managing cybersecurity risk, but made some recommendations that BC Hydro is implementing.[560] The audit found that:[561]

[553] Exhibit B-12, BCUC IR 2.257.5.
[554] Exhibit B-12, BCUC IR 2.257.13.
[555] Exhibit B-12, BCUC IR 2.257.13.
[556] Exhibit B-12, BCUC IR 2.257.2.2.
[557] Exhibit B-5, BCUC IR 1.123.4.
[558] Exhibit B-5, BCUC IR 1.123.5.
[559] Exhibit B-12, BCUC IR 2.257.21.3.
[560] Exhibit B-5, BCUC IR 1.123.5.
[561] Exhibit B-12, BCUC IR 2.257.18.2. The 2019 audit is attached as Confidential Attachment 1 to BCUC IR 2.257.21.

- Effective processes are in place to detect and respond to cybersecurity incidents in the Information Technology and NERC CIP regulated Operational Technology environments;

- Potential cybersecurity incidents are directed to Cybersecurity Operations for immediate triage and analysis. Handling of declared incidents is prioritized based on urgency and impact; and

- Large scale, joint incident response exercises occur on a regular basis with key participants across the enterprise. These exercises strengthen BC Hydro's capability to identify and respond to cyber incidents and receive appropriate support from senior management and participating business units.

340. The Auditor General also conducted a review of BC Hydro's cybersecurity efforts related to Industrial Control Systems, including those not covered by MRS. The Auditor General generally found that BC Hydro was doing well in managing cybersecurity risks on the parts of system covered by MRS, but needs to increase effort on parts that are not subject to MRS. Consistent with BC Hydro's risk-based and compliance approach to cybersecurity and information protection,[562] BC Hydro has focussed on meeting mandatory requirements on higher-risk bulk electric system assets. The facilities not under MRS are lower risk because disruptions in non-bulk electric system facilities are expected to have low or no impact on the interconnected grid. Many are in remote areas with very limited network connection, and many serve a relatively small number of customers compared to other facilities.[563] However, in response to the audit, BC Hydro is conducting a risk assessment of the environments identified by the Auditor General's report. Following the results of this assessment, BC Hydro will prioritize investments and efforts that will address the audit recommendations, including extending MRS requirements to assets not covered by those standards as appropriate.[564]

[562] Exhibit B-1, Appendix L, BC Hydro Technology Strategy and 5-Year Plan, p. 15; Exhibit B-12, BCUC IR 2.257.10.1.

[563] Exhibit B-5, BCUC IRs 1.123.1 and 1.123.1.1.

[564] Exhibit B-5, BCUC IR 1.123.1; Exhibit B-12, BCUC IR 2.257.10.

Cybersecurity Risk Management Can Be Expected to Drive Higher Costs in the Future

341. The audit results, reinforced by BC Hydro's ability to handle cybersecurity incidents to date, demonstrate that BC Hydro's cybersecurity response structure, investments, and processes are meeting current needs.[565] However, there is no question that cybersecurity complexity and risks are increasing due to:

(a) the increasing number and complexity of threats;

(b) the expansion of cybersecurity monitoring of BC Hydro's power system and the resulting alerts; and

(c) the further digitization of power systems.[566]

342. BC Hydro will be assessing its current capabilities in fiscal 2020, which may result in recommendations with regards to facilities, services, processes, tools, and people.[567]

(e) BC Hydro is Appropriately Coordinating Projects in the Same Location and Individual Projects at the Same Location Should Not Be Combined

343. BC Hydro was asked questions directed at determining whether the company takes appropriate steps to coordinate projects in the same location. The evidence, discussed below, demonstrates that BC Hydro coordinates projects when it is operationally necessary or where there are opportunities for efficiencies and/or risk reduction. It avoids otherwise entangling disparate projects in a way that would increase risk.[568] BC Hydro submits that this approach is appropriate.

BC Hydro Avails Itself of Opportunities for Efficiency and/or Risk Reduction

344. BC Hydro explained that it coordinates projects to take advantage of, for example, common outages, common procurement strategies and planned reservoir operations.

[565] Exhibit B-12, BCUC IR 2.257.18 series and 2.257.27; Tr. 7, p. 981, ll. 2-4 (Morison).

[566] Exhibit B-12, BCUC IR 2.257.18.3; Tr. 8A, p. 1117, ll. 10-14 (Morison).

[567] Exhibit B-12, BCUC IR 2.257.18 series; Tr. 7, p. 981, l. 2 to p. 982, l. 6 (Morison).

[568] Exhibit B-12, BCUC IRs 2.252.3 and 2.252.4.

Coordinated project planning and construction activities can reduce risk and achieve efficiencies where there is a need for managing items such as the use of site laydown space, the use of common resources and the risk related to asset interfaces. For example, BC Hydro has coordinated the MCA 1-4 Transformer Replacement and the MCA Digital Controls projects because they take place in the powerhouse, have some common interfaces and share an outage.[569]

345. BC Hydro also considers strategic or planning decisions related to the work on a single facility in its facility asset plans, examples of which are included in Attachment K of the Application. This approach enables BC Hydro to optimize capital resources across all sites and all asset types.

Disparate Projects at Same Site Should Not Be Combined

346. While opportunities for coordination should be (and are) taken, individual projects at the same site should not be combined into a single project or "Program of Projects". The evidence is that this approach would be detrimental.

347. BC Hydro explained how projects at a single site can have different drivers and requirements:

> The projects taking place at a single site do not constitute a Program of Projects. A Program of Projects is intended for situations where a common business driver results in multiple similar projects in response, all of which together achieve the common objectives articulated in the business case. The projects at a single site, however, can vary greatly in their nature, ranging from heavy civil construction, such as blasting and quarrying, to upgrades of mechanical systems such as gates and hoists, to installation of sophisticated electronic control and communication systems.
>
> BC Hydro does not view all individual projects at a single site to be a single overarching project. A project is time-bound, one time undertakings to buy, to replace, to maintain, or to rehabilitate a distinct asset, a set of assets, or a group of assets to achieve specified set of objectives. In contrast, the projects planned

[569] Exhibit B-12, BCUC IR 2.252.3.

> for, and delivered at, a single site can be numerous, with new projects continually being identified over time, with varying objectives.[570]

348. BC Hydro has shown that projects at a single site can differ drastically, have different drivers, and lack any interdependencies or opportunities for coordination.[571] BC Hydro explained that managing such disparate activities as a single project would increase risk, not reduce it. It would require greater supervision and management effort, would extend timelines, and would make project estimates less certain.[572]

349. Ms. Pinksen explained that BC Hydro's internal project management practices and policies ensure that projects are appropriately defined:

> So what we demonstrated in [the Review of Capital Expenditures and Projects] proceeding was that we really use our internal capital management practices and particularly our financial approval practices to ensure that what we're defining as a project has a standalone benefit. And what that means is that when we put that project in service, we are not dependent on any future project to ensure that we're delivering what we anticipated under that project.
>
> And so it's really through our financial policy that we're performing that oversight and governance. And so I think maybe what Mr. Darby can speak to then is around how, when we look at the facility, either the individual facilities on the Bridge River system, that we are looking at ensuring that each of these defined projects are undertaken, will deliver their own benefit and we aren't making any formal financial commitment to require a future project in order to deliver those benefits.
>
> And I think really what we explored with the panel in the capital expenditures and projects review, that it was the level at which we approved projects internally at BC Hydro is the appropriate way for us to then present those projects to the Commission for approval, either through a CPCN or section 44.2.[573]

350. In its Order No. G-313-29 and Decision on the Review of Capital Expenditures and Projects, the BCUC agreed with BC Hydro's proposals with regards to how to review projects:

---

[570] Exhibit B-12, BCUC IR 2.252.4.

[571] Exhibit B-12, BCUC IRs 2.252.1, 252.2, 2.252.3, 2.253.1 and 2.253.3.

[572] Exhibit B-12, BCUC IR 2.253.3.

[573] Tr. 13, p. 2448, l. 18 to p. 2449, l. 21 (Pinksen).

> Subject to the additional information requirements identified below, the Panel finds BC Hydro's proposals related to projects and programs information to be filed with the BCUC are appropriate.
>
> …
>
> Regarding the question of whether the individual project, as defined by BC Hydro, is the appropriate level for the BCUC's review of capital expenditures, as noted above, the Panel considers it optimal for the BCUC to review capital expenditures at the same level they are required to be approved under BC Hydro's implemented capital expenditure approval policies (i.e. its Financial Approval Authority Limits).[574]

351. While the BCUC indicated that "the BCUC can inquire into the potential linkages between projects and can order joint CPCNs for extension projects where the BCUC considers this is appropriate,"[575] there are no projects identified in this proceeding where a joint CPCN would be appropriate.

352. A good example of a situation where treating disparate activities at a single site as a single project would be detrimental is the MCA Townsite Augment Accommodations Capacity project and the MCA Recoat Intake Maintenance Gates & Draft Tube Maintenance project. These projects have different technical requirements, different construction timing and durations, use very different design and supply vendors, are located in different areas at the site, and have very limited use of common project resources.[576]

353. The projects on the Bridge River system are another example of disparate projects that should be managed separately. These projects are in various states of the project lifecycle[577] and each addresses specific risks to specific assets.[578] As explained above, each of these

---

[574] *BC Hydro Review of the Regulatory Oversight of Capital Expenditures and Projects*, Decision and Order No. G-313-19, December 2, 2019, at pp. 22-23.
Online: https://www.bcuc.com/Documents/Proceedings/2019/DOC_56448_2019-12-02-BCH-Review-of-BCH-Capital-Expenditures-Decision.pdf ("Capital Expenditures Decision").

[575] Capital Expenditures Decision, p. 24.

[576] Exhibit B-12, BCUC IR 2.252.3.

[577] Tr. 13, p. 2447, l. 23 to p. 2448, l. 1 (Darby).

[578] Tr. 13, p. 2450, ll. 10-21 (Darby).

projects will vary greatly in their nature and combining them would increase risk and uncertainty.

354. In particular, the Bridge River 1 Replace Units 1 to 4 Generators project ("Bridge 1 to 4 Project") and the Bridge River Transmission Project should not be linked. 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 licence), this does not represent a substantial linkage between the projects. In fact, the need for each project is independent of the other:

(a) The Bridge River 1 to 4 Project is a Sustaining capital project driven by asset condition and the need for reliable water conveyance and generation. The project description in Appendix J reads:[579]

> The purpose of the project is to improve generation reliability due to the Poor and Unsatisfactory health conditions of the Bridge River 1 Generating Facility Units 1 to 4 generators and related equipment, and to provide reliable water conveyance capacity within the Bridge River system.

As Mr. Darby stated: "There just happens to be an incidental opportunity to increase the capacity of the plant and I believe it's by about eight megawatts. So it's not a lot."[580]

(b) The Bridge River Transmission Project is needed to support the area as a whole, even without the 8 MW from the Bridge River 1 to 4 Project. As set out in the project description, the capacity of 2L90 is already insufficient to accommodate Bridge River generation, and BC Hydro is currently restricting Bridge River generation to prevent overloads of 2L90.[581] As Mr. Kumar and Mr. Darby explained, the transmission system was sufficient for BC Hydro's Bridge River

[579] Exhibit B-1, Appendix J, p. 50.

[580] Tr. 13, p. 2458, ll. 14-16 (Darby).

[581] Exhibit B-1, Appendix J, Capital Expenditures > $20 million, Attachment 1, p. 75.

generation, but BC Hydro has added about 400 MW of IPP generation in the area with an additional 50 MW of IPP generation forecast.[582] Therefore, the Bridge River Transmission Project is needed even if the 8MW from the Bridge River 1 to 4 Project were not to be added.

355. Consistent with BC Hydro's approved Capital Filing Guidelines, BC Hydro plans to file a section 44.2 application for the Bridge River 1 to 4 Project.[583] BC Hydro will also file a CPCN for the Bridge River Transmission Project if it is over $100 million. This will give the BCUC an opportunity to review BC Hydro's most significant investment in this system, and the broader context of the Bridge River system as a whole.[584]

(f) Strategic Property Purchases in Vancouver Support Substation Projects and Will Be Included in Future Substation CPCN Applications

356. BC Hydro made two strategic property purchases in Vancouver to advance two substation construction projects, for which BC Hydro will file separate CPCN applications to the BCUC in due course. In each case, customers are well-served by BC Hydro's decision to purchase the properties in advance of CPCN proceedings. In the CPCN proceedings, the BCUC will have the opportunity to review all alternatives for the substations.

DVES: West End Substation - Property Purchase

357. There are two components to the DVES: West End Strategic Property Purchase project: the purchase of the subsurface land at Lord Roberts Annex School and the acquisition of the distribution and transmission statutory rights-of-way through Nelson Park. Neither of these purchases are amortized for accounting purposes, so there will be no amortization expense over the Test Period.[585]

---

[582] Tr. 13, p. 2453, l. 8 to p. 2458, l. 18 (Kumar and Darby).

[583] Exhibit B-5, BCUC IR 1.115.2. The project will result only in the restoration of the capacity of the existing plant. This project is described in detail in Exhibit B-1, Appendix I, p. 52. Appendix J, p. 50 and Appendix K, p. 7.

[584] Tr. 13, p. 2450, l. 22 to p. 2451, l. 7 (Darby).

[585] Exhibit B-53, BC Hydro Undertaking No. 46.

358. In fiscal 2019, BC Hydro acquired the underground property rights from the Vancouver School Board at the location of the Lord Roberts Annex School for $66.8 million.[586] The property rights will allow construction of a new underground substation in the West End of downtown Vancouver as part of the West End Substation Construction and System Reinforcement Project.[587] The substation will replace the existing Dal Grauer substation as part of the first stage of the 30-year Downtown Vancouver Electricity Supply ("DVES") Plan.[588]

359. Acquiring property to accommodate a new substation is an important step to mitigate risk. The need to replace the aging Dal Grauer substation is clear. More than half of the assets are expected to degrade to poor or very poor condition in the next 10 to 20 years, presenting a reliability risk. Physical space constraints at Dal Grauer make redevelopment of the substation in its current location a challenge.[589] At the same time, BC Hydro was constrained by the limited supply of suitable properties in the West End that could meet the technical requirements for the substation.[590] Mr. Leonard explained that technical requirements can be particularly constrained in a downtown urban core.[591] BC Hydro summarized the requirements for the property, as follows:

> The required property attributes include a minimum size of the parcel (approximately a half-city block), a minimum number of sides available for transmission cable ingress and distribution feeder egress, minimum length required on one side to accommodate the transformers, reasonable access and constructability, acceptable geotechnical and environmental conditions, proximity to customer load, proximity to existing transmission infrastructure and proximity to existing substations for off-loading.[592]

---

[586] Exhibit B-16, BCUC IR 3.291.2; Tr. 12, p. 2244, ll. 9-18 (Kumar and Leonard).

[587] Exhibit B-4, update to Appendix J - Attachment 1, p. 69. BC Hydro's West End Substation Construction and System Reinforcement Project will involve a new 230/12 kV to 25 kV, 400 MVA, underground substation.

[588] The project is described in Exhibit B-1, Appendix J - Attachment 1, p. 80; the Downtown Vancouver Electricity Supply Plan is summarized in Exhibit B-1, Appendix K - Attachment 1, p. 54; Tr. 11, p. 1905, ll. 6-24 (Kumar).

[589] Exhibit B-1, Appendix J - Attachment 1, p. 80.

[590] Exhibit B-5, BCUC IRs 1.117.1 and 1.117.1.1.

[591] Tr. 12, p. 2247, l. 23 to p. 2248, l. 7 (Leonard).

[592] Exhibit B-5, BCUC IR 1.117.1.

360. The acquired property meets these requirements. BC Hydro performed a 30-year present value analysis on the site and worked closely with brokers in moving forward with the acquisition.[593]

361. BC Hydro's acquisition serves to confirm the viability of the preferred long-term solution for the project.[594] As Mr. Leonard explained, BC Hydro acquired the land well in advance of the operation of the new substation to provide BC Hydro with certainty with respect to the site, cost and schedule.[595] Ms. Holland similarly emphasized the importance of knowing where the substation property will be in order to prepare designs and an estimate that can be reviewed by the BCUC as part of a CPCN application.[596] She stated:

> And if we don't know where a project is going to be located we really have no hope of preparing any reasonable estimate, nor addressing some of the other issues that the Commission would review in a CPCN, including stakeholder consultation and other items.[597]

362. Ultimately, the BCUC will be able to review the West End Substation Construction and System Reinforcement Project when BC Hydro files for a CPCN for the project, which is currently anticipated to be in fiscal 2023.[598] The funds spent on acquiring property rights will be accounted for in the CPCN application.[599] In its CPCN application, BC Hydro will explain the alternatives considered to supply the Downtown Vancouver area, the process to select a preferred alternative, the reasons why building a new substation in the West End neighborhood is the preferred alternative, and site options within the West End neighborhood suitable for a substation.[600]

---

[593] Tr. 12, p. 2246, l. 17 to p. 2247, l. 4 (Leonard).

[594] Exhibit B-1, Appendix J - Attachment 1, p. 80; Exhibit B-5, BCUC IRs 1.117.1 and 1.117.1.1.

[595] Tr. 12, p. 2245, l. 15 to p. 2246, l. 7 (Leonard).

[596] Tr. 12, p. 2247, ll. 11-22 (Holland).

[597] Tr. 12, p. 2247, ll. 11-22 (Holland).

[598] Tr. 12, p. 2244, ll. 22-24 (Leonard).

[599] Exhibit B-5, BCUC IR 1.118.1.

[600] Exhibit B-5, BCUC IR 1.117.1.1; Tr. 12, p. 2249, l. 19 to p. 2250, l. 1 (Leonard); Tr. 12, p. 2251, ll. 3-9 (Holland).

New Murrin Strategic Property Purchase - East Vancouver Substation

363. The New Murrin Strategic Property Purchase – East Vancouver Substation project involved the fiscal 2017 purchase of an East Vancouver property.[601] The property will be used for a new substation that is an integral component of BC Hydro's 30-year DVES Plan.[602] BC Hydro has identified the substation project as requiring a CPCN.[603] The purchase of this property represented prudent risk management because the need for a new site is clear, and suitable properties are scarce.

364. BC Hydro's evidence is that a new substation on a new site is required because the Murrin substation:[604]

- presents a reliability risk as it was built in 1947 and is getting close to end-of-life with more than half of the assets expected to degrade to poor or very poor condition in the next 10 to 20 years;
- is on seismically unstable soil, with approximately half of the switchyard vulnerable to severe earthquake damage from liquefaction and settlement; and
- has physical space constraints which make redevelopment of the substation in its current location challenging and costly.

365. There is a limited supply of suitable properties in East Vancouver with the specific property attributes required for the replacement substation. The purchased property meets the requirements for the substation project, as it is:[605]

---

[601] Exhibit B-16, BCUC IR 3.291.5; Tr. 12, p. 2244, ll. 9-21 (Kumar and Leonard).

[602] The East Vancouver – Substation Construction Project will replace the Murrin substation by building a new 230/12 kV to 25 kV, 400 MVA, station in the Eastside/Strathcona neighbourhood of Downtown Vancouver as part of the second stage of the 30-year Downtown Vancouver Electricity Supply Plan. The project is described in Exhibit B-1, Appendix J, Attachment 1, p. 79; the Downtown Vancouver Electricity Supply Plan is summarized in Exhibit B-1, Appendix K, Attachment 1, p. 54.

[603] Exhibit B-1, Appendix I, Capital Expenditures > $5 million, p. 4.

[604] Exhibit B-13, BCOAPO IR 2.133.2.

[605] Exhibit B-13, BCOAPO IR 2.133.2.

- close to the established transmission cable (which is in the lane adjacent to the property) and close to an eventual second transmission cable on Hastings Street, avoiding the need for higher incremental transmission costs to connect it to the power system;
- on seismically stable ground;
- in the middle of the load serving area, avoiding the need for higher incremental distribution costs to connect to customers; and
- in a light industrial area, minimizing future stakeholder issues.

366. Further, the property is currently leased to a creditworthy commercial tenant, which minimizes BC Hydro's holding costs until the construction of the East Vancouver Substation is initiated.[606]

367. As with the West End Substation, acquiring the land well in advance provides certainty with respect to the site, cost and schedule.[607] BC Hydro performed a 30-year present value analysis on the site and worked closely with brokers in moving forward with the acquisition.[608]

368. The BCUC will review the East Vancouver – Substation Construction project when BC Hydro files for a CPCN for the project. The funds spent on acquiring property rights will be accounted for in the CPCN application.[609] As with other major projects, BC Hydro's application will address the need for and alternatives to the project, including alternative sites.[610]

[606] Exhibit B-13, BCOAPO IR 2.133.2.

[607] Tr. 12, p. 2245, l. 15 to p. 2246, l. 7 (Leonard); Tr. 12, p. 2247, ll. 11-22 (Holland).

[608] Tr. 12, p. 2246, l. 17 to p. 2247, l. 4 (Leonard).

[609] Exhibit B-5, BCUC IR 1.118.1.

[610] Exhibit B-5, BCUC IR 1.118.2.1; Tr. 12, p. 2249, l. 19 to p. 2250, l. 1 (Leonard); Tr. 12, p. 2251, ll. 3-9 (Holland).

(g) Project Write-Offs Demonstrate Maturity of Capital Planning and Delivery Processes

369. BC Hydro's Test Period revenue requirements include a forecast of project write-offs.[611] BC Hydro's approach is reasonable because the write-offs reflect prudent capital management practices.

370. BC Hydro evaluates its capital plans and projects on an ongoing basis. It adjusts plans with updated information, including on the load forecast, asset health information, and cost estimates. BC Hydro's approach reflects the maturity of the company's asset management practices, which (as described in Section F above) have been endorsed by the Auditor General and other third party experts. Mr. Layton explained:

> So I think I'd refer back to the page where we started with, on page 8-21 and you can see starting on line 7 some of the logic here. And I think the way I would summarize it is that sometimes write-offs are a very prudent decision to make. In other words, sometimes it makes sense to stop a project and that can be part of a very mature project management practice.
>
> And that's what we've seen, that rather than blindly go forward with a project that doesn't make sense to continue, it sometimes makes very good sense to stop. And when we make those kind of prudent decisions, write-offs can happen. And so our proposal is to have a budget amount for that. We think, again, those are prudently incurred costs and, therefore, the ratepayers should be willing to pay for a reasonable amount there. As I said, amounts above and beyond that we propose to remain to the account of the shareholder.[612]

371. BC Hydro exceeded the forecast of write-offs for the Test Period with the write-off related to the Metro North project.[613]

(h) BC Hydro Has Explained Variances from Plan on Past Projects

372. As discussed in Section E above, BC Hydro has completed its capital portfolio on budget. BC Hydro explained variances between plan to actual capital expenditures and additions in

[611] Exhibit B-1, Application, p. 8-21.

[612] Tr. 7, p. 1003, l. 13 to p. 1004, l. 5 (Layton).

[613] Tr. 7, p. 1004, ll. 6-18 (Layton). See also, Exhibit B-56, BC Hydro Undertaking No. 49.

Appendix G of the Application and the Evidentiary Update. It elaborated in responses to information requests.[614] The evidence demonstrates that these variances occurred in the context of prudent project management by BC Hydro.

373. AMPC asked a number of questions about the Interior to Lower Mainland ("ILM") Project, suggesting that an arbitration decision related to the Project (as discussed in the ILM Project's Completion and Evaluation Project[615]) reflected imprudence on the part of BC Hydro. There are two answers to this suggestion.

- First, the arbitration concerned the appropriate allocation of cost under the contract, not an assessment of prudence. The work that was the subject of the dispute was necessary. BC Hydro and its contractor just disagreed about who was responsible for certain costs. The arbitrator decided in favour of the contractor in relation to some — but certainly not all — of those costs. BC Hydro demonstrated appropriate contract management by seeking to hold its contractors to the terms of their contracts over the course of a large and complex project.[616]

- Second, in any event, the ILM Project came into service in 2015, such that project costs are recoverable in rates pursuant to Direction No. 8.[617]

374. Counsel for AMPC also questioned past decisions by BC Hydro to conduct geotechnical investigations in the Implementation Phase, rather than earlier project phases.[618] BC Hydro makes the following points in response:

---

[614] Exhibit B-5, BCUC IR 1.107.2 and Exhibit B-13, AMPC IR 2.36.2.

[615] Exhibit B-17, AMPC IR 3.20.1.

[616] Exhibit B-17, AMPC 3.20.1, ILM Project Completion Report, p. 8 of 52, and May 16, 2018 Letter from BC Hydro President & COO to BCUC on Interior to Lower Mainland Transmission Line arbitration decision (Online: https://www.bchydro.com/news/press_centre/news_releases/2018/bchydro-ilm-project-decision.html).

[617] Section 4(a) of Direction No. 8 provides that the BCUC must not disallow for any reason the recover in rates of 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 fiscal 2017.

[618] Tr. 12, p. 2196, l. 13 to p. 2198, l. 3 (Holland); Tr. 12, p. 2203, l. 9 to p. 2221, l. 23 (Holland).

- First, geotechnical conditions exist and will result in costs regardless of when they are identified. As Ms. Holland emphasized: "whether you find them later or you find them earlier they're going to result in cost and schedule."[619]

- Second, while BC Hydro's practice was mixed in the past, BC Hydro made it its general practice to conduct geotechnical investigations prior to the Implementation Phase because doing so results in better cost and schedule estimates by the end of the Definition Phase.[620] Ms. Holland stated:

> We changed the practice so that at the end of the definition phase we can get a much better estimate of the work that will be done during the construction phase. We want to have a really good first full funding estimate that includes a well-informed understanding of the work that we're going to be faced with. And if there's very difficult geotech conditions, we want to know that before we get the first full funding approved so that we can include that into the schedule, as well as into the cost estimate.[621]

- Third, it is an accepted principle that prudence should be judged without the benefit of hindsight.[622] BC Hydro has only learned through experience on a number of projects that it is better to do geotechnical investigations prior to the Implementation Phase.[623]

- Fourth, waiting until implementation did not result in any material redundant costs on the projects in question. For the Campbell River Substation Capacity Upgrade Project, "geotechnical issues required design additions such as the design of piles, a new retaining wall, new seismic keys, new drainage, and

---

[619] Tr. 12, p. 2210, ll. 14-20 (Holland).

[620] Tr. 12, p. 2196, ll. 19-26. (Holland).

[621] Tr. 12, p. 2209, l. 20 to p. 2210, l. 4 (Holland).

[622] *Enbridge Gas Distribution Inc. v. Ontario (Energy Board),* 2006 CanLII 10734 (ON CA) ("*Enbridge*"), at paras. 8-12. Online: https://www.canlii.org/en/on/onca/doc/2006/2006canlii10734/2006canlii10734.html.

In its Reasons for Decision, *BC Hydro F2009 and F2010 Revenue Requirements*, dated March 13, 2009, p. 38, the BCUC determined that two-part test articulated in *Enbridge* should apply when conducting prudence reviews. Online: https://www.bcuc.com/Documents/Proceedings/2009/DOC_21286_BCH-2009RR_WEB.pdf.

[623] Tr. 12, p. 2209, ll. 12-17 (Holland).

additional soil replacements"; however: "There was no design redundancy, and there was no additional costs related to demobilization or idle time caused by design changes."[624] For the Big Bend Substation Project, costs related to design redundancy for piling estimates are estimated to be less than $50,000.[625]

(i) Industrial Load Interconnection: BC Hydro Has and Is Improving the Process

375. BC Hydro was asked a number of questions at the hearing, primarily by AMPC and CEABC, about its load interconnection practices. The evidence discussed below demonstrates that 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, however, continuing to look for opportunities to improve the process.

Distribution and Transmission Interconnection Processes Are Governed by the Tariff and Published Business Practices

376. Industrial Load interconnections follow either the Large Industrial Connection (Transmission Service) process or the Large Industrial Connection (Distribution Service) process. Transmission load interconnection requests are governed by Tariff Supplement No. 6, as approved by the BCUC. Distribution load interconnection requests are governed by section 8 of the Electric Tariff, as approved by the BCUC. A step-by-step guide for both processes appears on BC Hydro's website.[626] BC Hydro also has a queue management business practice for applications under Tariff Supplement No. 6, which is used to determine the order for initiating load interconnection studies, cost allocation for infrastructure required to supply a new load, and the customer's obligations for remaining in the queue.[627]

---

[624] Exhibit B-56, BC Hydro Undertaking No. 41.

[625] Exhibit B-56, BC Hydro Undertaking No. 41.

[626] Exhibit B-13, AMPC IRs 2.35.2 and 2.35.4.

[627] The queue business practice is available on BC Hydro's website (Business Practice for Load Interconnection Queue Management) at: https://app.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/regulatory-matters/00-2014-11-18-queue-management-business-practice.pdf

BC Hydro Has Engaged in Continuous Improvement of Interconnection Processes

377. The evidence shows that BC Hydro has made numerous improvements to its customer interconnections process over the past years.

378. More than 4 years ago, BC Hydro commissioned Black & Veatch to review the overall effectiveness of its interconnection processes. Black & Veatch's report of April 2016 made a number of recommendations to improve processes. However, it also observed that many utilities were dealing with the same issues:

> While this report documents a number of issues and recommendations for improvement, Black & Veatch believes that BC Hydro's T&D Interconnections Group and other departments and groups involved in various parts of its Transmission Generator and Load Interconnection processes to be professional and dedicated. At the core, these processes require BC Hydro to balance: 1) the need to be responsive in addressing the issues faced by Transmission Generators and Load Customers, 2) the need to protect the interest of ratepayers, and 3) the obligation to meet all applicable reliability standards (MRS; Western Electricity Coordinating Council, WECC; North American Electric Reliability Corporation, NERC; etc.). Furthermore, the peer utilities interviewed by Black & Veatch as part of this project indicated that many of them have dealt with or are currently addressing many of the same issues facing BC Hydro.[628] [Emphasis added.]

379. Black & Veatch also described the actions BC Hydro had or was in the process of undertaking to improve the interconnections processes, as follows:[629]

- Efforts to improve process efficiency, especially for projects with low complexity, and improvements to the project delivery process to increase accuracy of the cost and schedule estimates. In February 2015, BC Hydro underwent a corporate reorganization that resulted in the creation of Capital Infrastructure Project Delivery Group, which is led by the Deputy CEO. This resulted in a standardization of the project delivery approach and philosophy for all major capital projects including interconnection projects.

[628] Exhibit B-47, BC Hydro Undertaking No. 32, Attachment 1, p. 5 of 76.

[629] Exhibit B-47, BC Hydro Undertaking No. 32, Attachment 1.

- Update of the guide and requirements for new Load Interconnections. Consultation with various industry advocacy groups and select customers has occurred over the last two years. A revised guide will be ready in 2016 for final stakeholder review.

- Initiation of the RDA Module 2 in 2014, which includes the review and revision of Tariff Supplements 5 and 6 which apply to Transmission Load Interconnection projects. The target date to submit BC Hydro recommendations to the BC Utilities Commission (BCUC) is mid-2017.

- Development of Indirect Interconnection Tariff (Tariff Supplements 87 and 88). This new tariff enables BC Hydro to serve new Transmission Load Customers who are connected to BC Hydro's system via third-party owned facilities. The Indirect Interconnection Tariff was approved on March 6, 2016.

- Increasing transparency and collaboration with customers throughout the interconnection process by:

    - Providing more detailed cost estimates and schedules, and collaborating on key project risks and decision points.

    - Improving current data tracking and metrics so key milestones for interconnection projects can be reported to our customers and key stakeholders. The target date to issue the first report is Q1 2017.

    - Improving BC Hydro's external websites to provide more up-to-date and useful information to the customers.

    - Revising study cover letters and report templates to highlight critical information such as assumptions used for cost estimates,

clarification on cost accuracy range, comments on the schedule, etc.

- Developing the Transmission Load Interconnection Queue Management Business Practice. The latest version (November 2014) is posted on the website and was reviewed by stakeholders at one of the RDA workshops.

- Reviewing and implementing opportunities for customers to perform BC Hydro's scope of work for Load Interconnection projects. For example, the customer's contractor can design and construct the tap on behalf of BC Hydro.

380. Since the 2016 Black & Veatch report, BC Hydro has undertaken internal changes to address organizational structure issues, matured the delivery process for interconnection work, and made several process improvements.[630] BC Hydro highlighted the various actions it has taken to improve interconnection timelines for new industrial load interconnection requests. BC Hydro has:[631]

- streamlined the project's hand over process from the Integrated Planning Business Group to the Capital Infrastructure Project Delivery Business Group;

- expedited the transmission interconnection process for new load requests at sites that already have transmission service and have capacity available with no system reinforcements required to meet the new load;

- implemented a process allowing customers to design and build transmission taps on BC Hydro's behalf in order to give the customer more control over the project schedule and costs;

[630] Exhibit B-47, BC Hydro Undertaking No. 32.

[631] Exhibit B-13, AMPC IR 2.35.8. See also, Tr. 11, p. 1921, l. 14 to p. 1923, l. 10 (Kumar).

- re-structured the Capital Infrastructure Project Delivery Business Group to create a project delivery team that focuses on interconnection projects and scaling the delivery process;

- developed performance metrics for interconnection study timelines to track performance against targets, to identify trends and to evaluate the effectiveness of interconnection process improvement; and

- initiated three ex-plan projects to ensure that BC Hydro is able to provide transmission services in the timeline required for customer need and desire to electrify their operations.

Interconnections Are Prioritized in the Capital Planning Process and Well Supported

381. BC Hydro's focus on customer connections translates directly to how BC Hydro undertakes its capital planning. BC Hydro's planning approach is to prioritize customer interconnections over other work. Mr. Kumar explained:

> One thing that I would like to add is from a planning perspective, my group and Mr. Darby's group are looking at these studies. The number one priority we assign from a planning perspective is to excel customer requests. Whether it is IPPs or load customers. So those are the highest priority.[632]

Prioritizing customer connections over other capital work means that any resource or capital challenges associated with increased interconnection activity would be reflected in other non-customer driven projects.[633]

382. Ms. Daschuk elaborated on the efforts of BC Hydro to support the interconnection process through adequate resourcing and Executive oversight:

> By Hydro has done a number of things to support the customer interconnection process. One of them is, by example, we have executive committees that

[632] Tr. 11, p. 1937, ll. 19-24 (Kumar).

[633] Tr. 12, p. 2181, l. 19 to p. 2182, l. 5 (Holland); Tr. 12, p. 2288, l. 6 to p. 2289, l. 12 (Daschuk); Tr. 13, p. 2354, l. 11 to p. 2355, l. 2. (Kumar).

> provide support. So myself, Mr. Leonard, Ms. Fraser, we meet on a, I think it's a monthly basis and we review customer interconnection requests from various sectors, including the oil and gas sector, the mining sector and transportation. The purpose of that group is to understand if there are any roadblocks that are preventing these interconnections from moving forward, and our goal is to support that.
>
> Also, within the interconnections team, with the indefinite suspension of the standing offer program, all of the resources that had previously been working on generator interconnections, for the most part those have been reallocated to the transmission load interconnections. As I mentioned, we had a dedicated project delivery group. We also have completed a work smart initiative and the work smart initiative was looking at the processes for interconnections and identifying ways in which it could be improved.
>
> We're also taking a look at whether we should be initiating some projects in advance of having a committed customer. Those are the examples that I've given previously, which is the Prince George to Terrace capacitors project, the Bear Mountain voltage conversion and the North Montney project. And by doing some work up front we're able to potentially reduce the amount of time.[634]

383. Mr. Leonard also spoke of the emphasis placed on customer connections at the Executive level of BC Hydro:

> I mean, the only other thing that I would add to this is being one of the fellow executives that sits on this committee and, as Ms. Daschuk mentioned, we meet on a monthly basis. You know, it takes a number of areas of our organization to ensure that we're fulfilling these needs. And so myself and Ms. Fraser and Ms. Daschuk, this is an area of keen focus for us and then we in turn are asked upon in many circumstances to help if there is direction that is needed or if one of our organizations is requiring something, we are there to help move those things along. Realizing that at the end of this we have a customer that is asking for, you know, a product or a service and that is our role to deliver that. So I can't stress enough the role of the executive in this.[635]

384. Ms. Daschuk, Mr. Leonard and Ms. Holland also noted that the compensation of senior management and executives responsible for the planning and capital delivery functions are tied

[634] Tr. 11, p. 1919, l. 2 to p. 1920, l. 5 (Daschuk).

[635] Tr. 11, p. 1942, l. 25 to p. 1943, l. 14 (Leonard).

to meeting interconnection timelines.[636] Appropriate incentives are in place to maintain the company's focus on continuous improvement.

BC Hydro Is Engaging with Customers on its Interconnection Processes

385. BC Hydro has ongoing discussions with new interconnection customers on its interconnection process and tariff.[637] BC Hydro has also conducted a number of workshops and engagement sessions with industrial stakeholders on its interconnection processes and associated interconnection tariffs.[638] BC Hydro surveyed customers in 2017 and solicited feedback as part of its continuous improvement process.[639]

BC Hydro Has Been Meeting its Internal Targets and Also Benchmarks Favourably

386. There is objective evidence, in the form of both performance against internal targets and benchmarking, that BC Hydro is carrying out interconnection work in a diligent manner.

387. BC Hydro sets internal targets each year for the time to deliver on the studies to facilitate a load interconnection.[640] The targets are based on the average duration of the studies, since timelines for each type of study vary significantly depending on the size, location, type of load, type of interconnection, and the complexity of the system upgrades required to serve the new load interconnection request.[641] At the transmission level, the targeted average duration for System Impact Studies is 150 days and the targeted average duration for Facilities Studies is 180 days. At the distribution level, the targeted average duration for Planning Studies is 60 days and the targeted average duration for Facilities Studies is 365 days.

---

[636] Tr. 11, p. 1949, l. 21 to p. 1951, l. 6 (Daschuk, Leonard and Holland).

[637] Tr. 11, p. 1922, l. 17 to p. 1923, l. 10 and p. 1925 ll. 12-14 (Kumar).

[638] Exhibit B-47, BC Hydro Undertaking No. 33 (PDF pp. 139-140).

[639] Exhibit B-47, BC Hydro Undertaking No. 34 (PDF pp. 141-149).

[640] Exhibit B-13, AMPC IR 2.35.7.

[641] Mr. Kumar gave the example of adding a significant LNG load to a radial line to Kitimat, which would be inherently more complex than adding a smaller load to a strong system in the Lower Mainland where there is ample capacity: Tr. 11, p. 1923, l. 11 to p. 1924, l. 23 (Kumar).

388. The table below shows that BC Hydro has completed its studies on average within its targets:[642]

	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.**

389. Ms. Daschuk noted the improvement from fiscal 2019 to fiscal 2020 year to date:

> A couple of things I wanted to mention in terms of performance. Last year, in our Fiscal 2019, we completed 79 percent of the studies on time. That's not a number that we were happy with. This year, year to date, 97 percent of all of the studies have been completed on time. I think that's a real reflection of some of the significant effort that we've been putting in as an organization to improve the interconnection process to make it easier for our customers to connect.[643]

390. Ms. Daschuk confirmed that the timelines for the studies reflect dates agreed to with the customer.[644]

391. The April 2016 Black & Veatch report included benchmarking on the duration and cost of customer interconnections, although it cautioned that there are differences between jurisdictions that make benchmarking challenging.[645] Given the improvements made since 2016, the benchmarking conducted by Black & Veatch is now out of date.[646] However, as

---

[642] Exhibit B-13, AMPC IR 2.35.5.

[643] Tr. 11, p. 1920, ll. 6-15 with errata noted in Tr. 15 (Daschuk).

[644] Tr. 11, p. 1920, ll. 23-24 (Daschuk).

[645] Exhibit B-47, BC Hydro Undertaking No. 32 Attachment 1, pp. 33 and 34 of 76. Potential differences identified include ownership and governance, size of territory, nature of terrain and system characteristics, generation types (e.g. hydroelectric), and whether there is an independent system operator managing interconnections.

[646] Exhibit B-47, BC Hydro Undertaking No. 32 Attachment 1, pp. 34 and 35 of 76.

shown in the table below, BC Hydro's targets compare well to other utilities using information published as of April 2019.[647]

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 Will Continue to Improve Interconnection Process

392. While progress has been made and BC Hydro's interconnection process is performing well, BC Hydro will continue to improve its customer interconnection process. As stated by Ms. Daschuk:

> I'm pleased with the performance and the improvements that we've made on the interconnections process. That's not to say that we are perfect or there aren't further things that could be done, because there are, and I'm hoping that you're seeing the commitment from Mr. Leonard and myself and from everyone on this panel that we will continue to work to drive improvements in that process.[648]

K. CONCLUSION AND REQUESTED FINDINGS

393. BC Hydro submits that the evidence shows that BC Hydro has well-developed planning and delivery processes and that BC Hydro is delivering its projects effectively and efficiently. The BCUC should find that the resulting planned capital additions and expenditures for the Test Period are reasonable.

[647] Exhibit B-13, AMPC IR 2.35.6. See also, Exhibit B-49, BC Hydro Undertaking No. 38. The figures in the table below for BC Hydro, Sask Power and Hydro One are the ranges of their published target durations. The figures for AESO are the median durations of greenfield load projects completed in the previous two-year period.

[648] Tr. 11, p. 1945, l. 3 to p. 1946, l. 5 (Daschuk).

PART EIGHT: REGULATORY ACCOUNTS

A. INTRODUCTION

394. All but one[649] of BC Hydro's regulatory accounts are BCUC-approved for ongoing use.[650] As such, BC Hydro is seeking very few orders regarding regulatory accounts. It is proposing to close four regulatory accounts,[651] and to make a limited number of changes. It is not requesting approval of any new regulatory accounts.[652]

395. While Government has repealed directions regarding some of BC Hydro's regulatory accounts, the underlying rationale for the accounts remains sound. The BCUC's approval of most of the accounts predated the Government directions, and the Government directions mirrored regulatory policy reflected in the BCUC's own guidelines for utilities. The Government-directed account that faced the most challenges gaining acceptance – the Rate Smoothing Regulatory Account – has been written-off and BC Hydro is proposing to close it. There is ample evidence, discussed in this Part, to demonstrate that BC Hydro's current use of regulatory accounts, its proposals to close and modify some of them, and its forecasted additions are just and reasonable.[653]

396. This Part is organized around the following supporting points:

- First, BC Hydro's approved regulatory accounts are in accordance with International Financial Reporting Standards ("IFRS"), and are consistent with the BCUC's Regulatory Account Filing Checklist ("BCUC Checklist").
- Second, the assessment of BC Hydro's regulatory accounts should focus on the merits of each account and the benefits it provides to BC Hydro and ratepayers, not the number of accounts.

---

[649] The Dismantling Cost Regulatory Account.

[650] Exhibit B-16, BCUC IR 3.301.6; Exhibit B-5, BCUC IR 1.139.3.

[651] Exhibit B-1, Application, Table 7-9, starting on p. 7-60; Exhibit B-5, BCUC IR 1.40.3.1.

[652] Exhibit B-1, Application, pp. 7-21 to 7-23.

[653] Exhibit B-5, BCUC IR 1.139.3.

- Third, BC Hydro's current use of regulatory accounts is beneficial to customers.
- Fourth, the Auditor General has removed her qualification on Government's financial statements regarding BC Hydro's use of rate-regulated accounting.[654]
- Fifth, BC Hydro is taking the necessary steps to manage regulatory account balances, using appropriate recovery mechanisms and exercising discipline over controllable costs.
- Sixth, BC Hydro's proposed changes to accounts are warranted.
- Seventh, BC Hydro's forecast for Real Property Sales Regulatory Account, as reflected in the Evidentiary Update, is reasonable for setting rates during the Test Period.

B. BC HYDRO'S REGULATORY ACCOUNTS ADHERE TO ACCOUNTING STANDARDS AND BCUC GUIDELINES

397. BC Hydro uses regulatory accounts for four purposes: (1) to ensure that customers pay actual costs (no more, no less) where uncontrollable and unpredictable factors could otherwise produce unfair results, (2) to defer differences between forecast and actual costs or revenues due to uncontrollable risks, (3) to smooth out the rate impact of large, non-recurring costs, and (4) to better match costs and benefits for customers.[655] BC Hydro's use of regulatory accounts complies with IFRS and the BCUC Checklist.

398. Rate-regulated accounting is permitted under IFRS 14, *Regulatory Deferral Accounts*.[656]

[654] Exhibit B-12, BCUC IR 2.201.3; Exhibit B-1, Application, pp. 7-7 and 7-8.

[655] Exhibit B-1, Application, p. 7-14. Exhibit B-1, Application, p. 7-1. The general purpose of a regulatory account is to defer costs or revenues for future recovery or refund. In the absence of rate-regulated accounting, costs or revenues would be recognized in the current accounting period.

[656] Exhibit B-1, Application, pp. 7-13, 8-25 and 8-26.

399. The BCUC Checklist contemplates five types of regulatory accounts. The following table summarizes how all of BC Hydro's accounts fall within the categories identified in the BCUC Checklist.

BCUC Category	**BCUC Description of Category**	**BC Hydro Accounts**
Forecast variance account	"A forecast variance account captures the variance between forecast costs or revenues and actual costs or revenues."	Heritage Non-Heritage Trade Income Storm Restoration Costs Amortization of Capital Additions Total Finance Charges Remediation Dismantling Cost Foreign Exchange Gains/Losses Non-Current Pension Costs PEB Current Pension Costs Debt Management Rock Bay Remediation[657] Customer Crisis Fund[658] Mining Customer Payment Plan[659] Real Property Sales[660] Arrow Water Systems (applying to close)
Rate smoothing account	"A rate smoothing account can mitigate rate shock resulting from the impact of large forecast onetime items, mitigate rate shock resulting from forecast overall general rate increases, or reduce rate volatility."	Rate Smoothing (applying to close)
Benefit matching (capital-like) account	"A benefit matching account defers recovery of costs that under Generally Accepted Accounting Principles (GAAP) would otherwise be required to be expensed in the current accounting period to a future period (when the benefits of those costs are realized) if they provide long-term benefits to current and future ratepayers."	Demand Side Management First Nations Costs Site C Pre-1996 Contributions in Aid of Construction SMI Capital Project Investigation Costs (applying to close)

[657] BC Hydro will apply to close this account in its next revenue requirements application.

[658] BC Hydro may apply to close this account in a future application.

[659] BC Hydro may apply to close this account in a future application.

[660] BC Hydro may apply to close this account in a future application.

BCUC Category	BCUC Description of Category	BC Hydro Accounts
Retroactive expense account	"A retroactive expense account applies only to an uncontrollable cost or revenue that occurs in a period where rates have already been approved and set by the Commission. For example, recover through amortization expense in the revenue requirements or through a rate rider. Recovery timelines may be short term (1 year or less), medium term (1-3 years), or long term (3+ years)."	N/A
Other	"While it is expected that the majority of regulatory account requests would fall within the four categories described above, there may be others which the Commission would consider on a case-by-case basis. Example: In certain situations, a regulated entity may recognize a non-cash GAAP provision which results in a request for a Commission-approved regulatory asset account to offset the liability (provision) recorded under GAAP."	First Nations Provisions Environmental Provisions IFRS Property, Plant and Equipment (IFRS Transition Account)[661] IFRS Pension (IFRS Transition Account)[662] Arrow Water System Provisions (applying to close)

C. FOCUS ON THE MERITS OF EACH ACCOUNT, NOT THE NUMBER OF ACCOUNTS

400. InterGroup, referencing the number of BC Hydro's regulatory accounts, recommends that the BCUC direct BC Hydro to simplify its accounts as a long-term priority.[663] Mr. O'Riley, in response, highlighted the importance of regulatory accounts, and expressed hope for a consensus that we should move beyond counting the number of accounts.[664] Sound logic underlies Mr. O'Riley's comments, as explained below.

(a) Regulatory Accounts Are Common and Numbers Vary Widely Among Utilities

401. Regulatory accounts are a widely-accepted and widely-used tool, including in this jurisdiction. InterGroup identified some utilities that have relatively few accounts. BC Hydro had no difficulty identifying other examples of utilities that have a similar or greater number of

[661] See discussion in Exhibit B-1, Application, pp. 7-18 to 7-20.

[662] See discussion in Exhibit B-1, Application, pp. 7-18 to 7-20.

[663] Exhibit C11-11, InterGroup Report, Recommendation 7.

[664] Tr. 5, p. 430, l. 23 to p. 431, l. 2 (O'Riley).

accounts than BC Hydro.[665] This evidence suggests that the use of regulatory accounts differs among utilities in North America. There is no "gold standard" for the number of accounts.

402. Mr. Layton, during cross-examination by Mr. Keen (counsel for AMPC), elaborated on why he took issue with focussing on the number of BC Hydro's accounts relative to other utilities:

> No, I don't think so. I think all we were trying to say in that sentence is that if one merely looks at the number of regulatory accounts an entity has, it's a piece of information but it's only one piece of information that is interesting and relevant if one wants to compare across entities.
>
> I can quote another utility that they amalgamated. Encana Utility has 50 something regulatory accounts. But unless one looks at why they have those accounts, unless one looks at the balances of those accounts, unless one looks at why those were approved and to what they relate, it's only one piece of the puzzle and our point is simply that only looking at the number of regulatory accounts doesn't provide a great deal of insight in our view.[666]

403. Mr. Wong echoed that "what we should be looking at, is what is going into the deferral accounts, why we are deferring those balances, how we are recovering those costs."[667]

404. Direct comparisons of the number of accounts can be challenged by the potential for different practices regarding how deferred costs are grouped for regulatory accounting purposes. Mr. Wong observed: "So you could take three or four and put them into one, and say that is one deferral account. And so I believe, actually, that BC Hydro having the 29 that it does, we are very clear in itemizing what goes into each deferral account."[668] The fact that BC Hydro has two Cost of Energy Variance Accounts to differentiate between costs associated with Heritage and Non-Heritage resources is a tangible example of this; both accounts have the same amortization period and serve a similar purpose.

---

[665] Tr. 6, p. 822, ll. 2-16 (Layton); Exhibit B-28, BC Hydro Rebuttal Evidence, p. 11.

[666] Tr. 6, p. 882, ll. 2-16 (Layton).

[667] Tr. 6, p. 707, ll. 9-14 (Wong).

[668] Tr. 6, p. 707, ll. 4-8 (Wong).

405. The use of Performance Based Regulation at some utilities adds further complexity to comparisons based on the number of accounts. "Flow-through" mechanisms (e.g., Y-factors) achieve the same result as a regulatory account.

(b) BC Hydro is Proposing to Close Four Regulatory Accounts, With Up to Four More Soon to Follow

406. In any event, BC Hydro is closing accounts when the balances are recovered and the accounts are no longer required.[669] BC Hydro anticipates closing up to eight accounts in the next four years, four of which are to close as an outcome of this proceeding.[670] BC Hydro also plans to limit when it applies for new forecast variance accounts to circumstances where there is un-forecast and non-controllable expenditures greater than $10 million in a fiscal year.[671]

D. BC HYDRO'S REGULATORY ACCOUNTS ARE BENEFICIAL TO CUSTOMERS

407. BC Hydro's use of regulatory accounts is beneficial to ratepayers, which is a more meaningful way to assess the merits of BC Hydro's accounts than counting them. We address below the accounts that were a focus of information requests, questions or the InterGroup evidence.

(a) Cost of Energy Variance Accounts Manage Uncontrollable Factors and Volatility

408. The Cost of Energy Variance Accounts have been in place since 2004; the BCUC approved them following the extensive BCUC Heritage Contract Inquiry. They provide a

---

[669] Exhibit B-28, BC Hydro Rebuttal Evidence, p. 8, ll. 15-18.

[670] Exhibit B-1, Application, Table 7-9, starting on p. 7-60; Exhibit B-5, BCUC IR 1.40.3.1. BC Hydro is applying to close the Rate Smoothing Regulatory Account, the Capital Project Investigation Costs Regulatory Account, the Arrow Water Systems Regulatory Account and the Arrow Water Systems Provision Regulatory Account. BC Hydro has also identified an additional four accounts – the Rock Bay Remediation Regulatory Account, the Real Property Sales Regulatory Account, the Customer Crisis Fund Regulatory Account and the Mining Customer Payment Plan Regulatory Account - that may be able to be closed by fiscal 2024. At that point, BC Hydro would have 21 accounts.

[671] Exhibit B-1, Application, p. 7-21; Exhibit B-16, BCUC IR 3.301.4. BC Hydro responded to questions about whether a similar threshold should be used to determine whether existing accounts should be closed. This is generally a moot point; most variance accounts experience variances of greater than $10 million. The Cost of Energy variance accounts have experienced variances in the hundreds of millions in recent years. However, there are also important conceptual reasons to avoid this approach: Exhibit B-16, BCUC IR 3.294.3 and Exhibit B-6, CEC IR 1.69.1.

valuable benefit to BC Hydro and ratepayers. They ensure that ratepayers pay the actual Cost of Energy. They avoid the shareholder and ratepayers experiencing significant windfall gains and losses due to uncontrollable factors. Specifically:

- The **Heritage Deferral Account** captures variances between the forecast and actual cost of Heritage Energy, Market Electricity Purchases, Surplus Sales and Domestic Transmission costs related to Surplus Sales, and other items approved by BCUC Order No. G-96-04. These costs vary due to uncontrollable factors that are difficult to predict such as water inflows, system load requirements, market commodity prices, exchange rates and transmission rates. From fiscal 2015 to fiscal 2019, cost variances have ranged from ($154.6) million to $81.7 million (-38% to +23%).[672]

- The **Non-Heritage Deferral Account** captures variances between the forecast and actual cost of Non-Heritage Energy, which includes IPP purchases and Long-Term Commitments and Net Purchases (Sales) from Powerex.[673] These costs also vary due to uncontrollable factors that are difficult to predict, including water inflows, surplus sales, electricity and gas market prices and domestic load.[674]

  Domestic load is subject to unpredictable volatility due to factors such as weather and economic conditions. From fiscal 2015 to fiscal 2019, variances between the actual and forecast Cost of Energy arising from differences between actual and forecast domestic customer load alone have ranged from ($193.5) million to $352.7 million.[675]

[672] Exhibit B-16, BCUC IR 3.294.3.

[673] Exhibit B-1, Application, p. 7-25.

[674] Exhibit B-16, BCUC IR 3.301.5.1.

[675] Exhibit B-16, BCUC IRs 3.301.4 and 3.301.5.

409. The BCUC has approved similar mechanisms for FortisBC Inc., the other major electric utility in this province, to address revenue variances as a result of uncontrollable factors. In its 2012 Decision approving FortisBC Inc.'s revenue variance account, the BCUC stated:

> The Commission Panel notes that these accounts for the most part represent variances in current period expenses which are proposed to be trued up in the short-term. In the Panel's view, the creation of these deferral accounts represents a reasonable attempt to manage the uncertainty and unpredictability associated with accounts which are largely uncontrollable in nature.[676]

In 2014, as part of FortisBC Inc.'s 2014-2019 performance-based ratemaking plan, the BCUC maintained the same treatment by ordering that revenue variances be deferred through the flow-through mechanism.[677]

410. BC Hydro also included in its Rebuttal Evidence information from Standard & Poor's that showed the widespread use of accounts of this nature in the United States.[678]

(b) Non-Current Pension Cost Regulatory Account Manages Uncontrollable Factors and Volatility

411. The Non-Current Pension Costs Regulatory Account captures (a) variances between the actual experience gains or losses related to BC Hydro's pension and other post-employment benefit plans, and (b) variances between actual and forecast non-current pension costs.[679] Actual experience gains and losses are adjustments to the net pension plan liability and the other post-employment benefit plan liabilities due to changes in discount rates, rates of return on pension plan assets, and any experience gains or losses or changes in assumptions. Variances between actual and forecast non-current pension costs are the differences in net interest expense of the retirement benefit plans, which arise primarily due to the difference in the rate (i.e., rate of return versus liability discount rate) used to determine the return on plan

[676] Order No. G-110-12, p. 110; Order No. G-139-14, p. 228.

[677] Order No. G-139-14.

[678] Exhibit B-28, BC Hydro Rebuttal Evidence, p. 9, A. 5.

[679] Exhibit B-16, BCUC IR 3.300.2.

assets between the Application and the actual results.[680] In both cases, most of the factors impacting these costs are beyond BC Hydro's control as they are largely market driven.[681] The account thus avoids windfall gains and losses for either the shareholder or ratepayers, consistent with the purpose of variance accounts as identified in the BCUC Checklist.

(c) Real Property Sales Regulatory Account Allows Ratepayers to Receive Benefits that Would Otherwise Flow to the Shareholder

412. The Real Property Sales Regulatory Account allows ratepayers to receive significant benefits from planned sales of surplus property and property rights (e.g., statutory rights of way) that would otherwise flow to the shareholder. As discussed below, proposed rates in the Test Period would be higher but for this account.

The Law Defaults to Flowing Proceeds of Sale to the Shareholder, Not Ratepayers

413. The underlying legal context is key to understanding the importance of this account to ratepayers. The Supreme Court of Canada's 2006 decision in *ATCO Gas & Pipelines Ltd. v. Alberta (Energy & Utilities Board)* governs. It held that the shareholder, not ratepayers, is entitled to the proceeds of sale from properties that are no longer used and useful for utility purposes. The Court stated, for instance:

> The fact that the utility is given the opportunity to make a profit on its services and a fair return on its investment in its assets should not and cannot stop the utility from benefiting from the profits which follow the sale of assets. Neither is the utility protected from losses incurred from the sale of assets. In fact, the wording of the sections quoted above suggests that the ownership of the assets is clearly that of the utility; ownership of the asset and entitlement to profits or losses upon its realization are one and the same.[682]

Thus, in the absence of BC Hydro's regulatory account, customers would not receive the proceeds of sale of surplus properties.

---

[680] Exhibit B-16, BCUC IR 3.300.1.

[681] Exhibit B-16, BCUC IR 3.300.5.

[682] *ATCO Gas & Pipelines Ltd. v. Alberta (Energy & Utilities Board),* 2006 SCC 4. See for example, para. 67. Online: https://www.canlii.org/en/ca/scc/doc/2006/2006scc4/2006scc4.html.

BC Hydro and its Shareholder Want to Flow Net Sale Proceeds to Customers

414. In the current situation, BC Hydro has properties and property rights purchased over the decades for utility purposes, but that are now surplus to BC Hydro's requirements.[683] Mr. Leonard gave examples of the types of properties and property rights involved and how they became surplus to BC Hydro's requirements. He emphasized that BC Hydro has sold surplus properties and property rights over the years, and there are currently only a limited number of properties at issue.[684] Prior to the establishment of the Real Property Sales Regulatory Account, pursuant to Direction No. 7 to the BCUC, net gains from sales of surplus properties and property rights would have gone to the Government of B.C., as BC Hydro's shareholder, consistent with the law outlined above. The government directed the establishment of the account to help take pressure off rates as part of the 10 Year Rates Plan.

415. Mr. Layton explained that, in the former 10 Year Rates Plan, BC Hydro committed to achieving $100 million of net proceeds from sales of surplus properties and to provide that benefit to ratepayers over the period ending in fiscal 2024.[685] The desired outcome is achieved by (1) forecasting an amount of sales revenues for inclusion in the revenue requirements, combined with (2) the use of the Real Property Sales Regulatory Account to capture variances between forecast and actual net sale proceeds within each fiscal year.[686] As the actual gains from the sales of these surplus properties are received, it reduces the balance in the account. Mr. Layton noted that "subject to interest, that account should…self-clear."[687]

416. In other words, ratepayers have been getting the benefit of these sales in advance, annually and on a consistent basis since fiscal 2015. Rates since fiscal 2015 have been lower than they otherwise would have been had BC Hydro continued to flow those benefits to the shareholder. Similarly, rates in the Test Period will be lower than they otherwise would be by

---

[683] Mr. Leonard explained that "In order to be deemed surplus, it is not needed for operational business purposes currently or in the future": Tr. 13, p. 2525, ll. 18-21 (Leonard).

[684] Tr. 13, p. 2530, l. 25 to p. 2532, l. 11 (Leonard).

[685] Tr. 8A, p. 1179, ll. 11-26 (Layton); Tr. 8A, p. 1188, ll. 21-23 (Layton).

[686] Exhibit B-16, BCUC IR 3.299.3.

[687] Tr. 8A, p. 1179, ll. 11-26 (Layton). See also, Exhibit B-16, BCUC IR 3.299.3.

virtue of the inclusion of a forecast $10 million[688] of net gains in each of fiscal 2020 and fiscal 2021. The current plan, subject to what the BCUC decides in this proceeding, would be to do the same in fiscal 2022 to fiscal 2024.

BC Hydro Has Turned a Profit on Every Sale

417. As of March 31, 2019, the balance in the Real Property Sales Regulatory Account was $49 million, which reflects the fact that actual sales have been less than anticipated at this point in time.[689] However, this is not a "loss" in either the financial sense or from the perspective of ratepayers:

- BC Hydro has turned a profit on every sale, and expects that to continue.[690]
- From a ratepayer perspective, it means that customers have received benefit for some sales that have yet to materialize.[691] It is a timing issue that has favoured (not harmed) current ratepayers. While the intent was for the benefits reflected in rates each year to approximate the pace that BC Hydro actually realized the net gains from sales, customers effectively received an "advance" on the benefits over the past four years to the extent sales did not keep pace.

418. While the BCUC has discretion to discontinue use of this regulatory account, this would be disadvantageous to customers. First, the account would still have to remain open and the BCUC would still have to allow recovery of the balance as at March 31, 2019 by virtue of

[688] Exhibit B-16, BCUC IR 3.299.3. BC Hydro is forecasting annual net gains on real property sales of $19.1 million. 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 so that it will self-clear by fiscal 2024.

[689] Exhibit B-19, Evidentiary Update, Appendix D, Table D-2. BC Hydro described the reasons for the slower sales in BCUC IR 3.299.1, and they are discussed further later in this Part of the Submissions. BCUC IR 3.299.7 provides a list of properties that BC Hydro has sold, and will be sold, to achieve the $100 million in net gains by the end of fiscal 2024.

[690] Tr. 13, p. 2527, ll. 2-14 (Leonard).

[691] Tr. 8A, p. 1183, ll. 1-5 and 21-26 (Layton); Tr. 8A, p. 1217, ll. 1-5 (Layton).

Direction 8.[692] Second, BC Hydro still expects some combination of these properties to be sold to achieve a target of $100 million in net gains by fiscal 2024.[693] Precluding new additions to this regulatory account would foreclose the opportunity for customers to benefit from those sales. It would result in the net proceeds flowing to the shareholder and higher rates (other things equal) for customers in the Test Period and beyond. Accordingly, the account should remain in place, and BC Hydro should continue to include forecast net proceeds in annual revenue requirements until the targeted sales of $100 million are achieved.

419. The question of what amount represents a reasonable forecast of net sale proceeds in each year of the Test Period is a distinct issue from the merits of the account itself. The former issue is really a matter of timing (i.e., how fast can BC Hydro reasonably expect to reach the $100 million target). BC Hydro explains below in Section H of this Part why it is reasonable to forecast annual sales revenue of $19.1 million in each of fiscal 2020 and fiscal 2021.[694]

Costs Incurred to Bring Properties to Market Are Dwarfed by the Sale Proceeds

420. BC Hydro was asked at the hearing about the costs of preparing the properties for sale, and the carrying costs in the interim (e.g., property taxes). Commissioner Mason inquired whether BC Hydro was, in effect, engaging in property speculation.[695] BC Hydro understood the questions on this topic to be asking whether it was fair for customers to be paying for those costs through rates, or whether they should be to the account of the shareholder. BC Hydro submits that 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:

---

[692] Section 4 of Direction No. 8 states that the BCUC must not disallow recovery in rates of the balance of BC Hydro's regulatory accounts as at March 31, 2019; Exhibit B-1, Application, p. 2-9.

[693] Exhibit B-16, BCUC IR 3.299.7.

[694] Exhibit B-16, BCUC IR 3.299.3. Annual forecast net gains on real property sales of $19.1 million are included in the Evidentiary Update. 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.

[695] Tr. 13, p. 2546, ll. 10-15 (Leonard).

- The account, which is what allows ratepayers to benefit from surplus property sales, is premised on net proceeds (i.e., sale proceeds, less costs) flowing to the account. Put another way, the shareholder agreed to flow net proceeds to customers; it did not agree to forego gross sale proceeds while continuing to bear all associated costs. The current treatment is symmetrical.

- The $100 million target for net proceeds, portions of which have been flowing to ratepayers annually even before the sales are realized, was premised on BC Hydro taking prudent steps to bring the property to market.

- The carrying and site improvement costs being paid by customers in rates are dwarfed by the sale proceeds from which they are benefitting. Customers are better off under the proposed approach, relative to one in which the shareholder pays the carrying costs and keeps the sale proceeds.

421. BC Hydro submits that it would be incorrect to characterize BC Hydro's efforts to maximize sale proceeds from surplus properties as land speculation. BC Hydro acquired these properties decades ago for utility purposes, not as an investment or to "flip" for a quick profit. Mr. Leonard confirmed that BC Hydro is moving the properties to market as they are ready, but there are challenges that slow the process.[696] He also noted that, with unique properties (e.g., rights of way), the "market" may consist of one person who is not ready to buy.[697]

(d) DSM Regulatory Account Ensures Intergenerational Equity by Matching Costs and Benefits

422. BC Hydro's Demand Side Management Regulatory Account captures all of BC Hydro's traditional DSM costs and low-carbon electrification ("LCE") expenditures, recognizing that these investments are integral to the success of the DSM portfolio and the achievement of the benefits. The DSM Regulatory Account matches the recovery of all the costs to achieve the

[696] Tr. 13, p. 2547, l. 16 to p. 2548, l. 5 (Leonard).

[697] Tr. 13, p. 2545, l. 25 to p. 2546, l. 9 (Leonard).

benefits with the realization of the associated benefits over time.[698] Benefit matching is a recognized principle in the BCUC Checklist, and the deferral of DSM costs is a common accounting treatment in the industry.[699] Mr. Bowman, who generally favours reducing the use of regulatory accounts, agrees with the use of a benefits matching account to address DSM.[700]

423. As the entire portfolio of DSM costs is required to generate the savings and other benefits achieved, it is reasonable and appropriate for all DSM costs to be deferred to the DSM Regulatory Account. As stated by Mr. Hobson: "we've got a combined portfolio, it's got programs, it's got some supporting initiatives, and they all combine as necessary costs to achieve the stream of savings."[701]

424. In particular, Mr. Hobson emphasized the importance of costs for its Public Awareness Supporting Initiative, which include public awareness, education and outreach, as described in section 11 of the DSM Plan. This supporting initiative includes communication costs to increase public education and awareness. As described in the DSM Plan, these are foundational activities that are designed to overcome barriers to participation in DSM programs: awareness of activities and programs and acceptance of those programs.[702] Mr. Hobson explained:

> We don't measure benefits specific to components, I would say, within our plan in terms of cost components. We do it more based on the program itself in terms of what the offers are to drive up the savings. But the way that we would take a look at it would be the cost that we're incurring to make customers aware, help customers work through some of the acceptance issues they have with efficiency, are an important cost that are necessary to achieve the benefits.[703]

425. Mr. Hobson also clarified that, while the Conservation Energy Management group leverages other parts of the organization to carry out its initiatives, all of these costs are

---

[698] Exhibit B-5, BCUC IR 1.150.7.

[699] Exhibit B-5, BCUC IR 1.150.2.

[700] Exhibit C11-11, InterGroup Evidence, p. 24.

[701] Tr. 15, p. 2892, ll. 20-25.

[702] Exhibit B-1, Appendix X, p. 75.

[703] Tr. 15, p. 2895, ll. 12-21 (Hobson).

included within the DSM portfolio.[704] Therefore, it is reasonable and appropriate that all of the costs of the DSM portfolio be captured by the DSM Regulatory Account.

426. We explain in Subsection F(c) below why BC Hydro's amortization period accomplishes the desired matching.

(e) Remediation Regulatory Account Manages Uncontrollable and Unpredictable Costs

427. The Remediation Regulatory Account captures variances between forecast and actual asbestos remediation costs and costs related to compliance with polychlorinated biphenyl (PCB) regulations. The scope of this account had originally been limited to asbestos remediation costs, consistent with a requirement of Direction No. 7. However, in BCUC Order No. G-47-18, the BCUC approved the expansion of this account to include variances in PCB costs. The Decision stated that:

> …the Panel concurs with BC Hydro that PCB costs are similar in nature to asbestos costs in that they involve long-term estimates, the actual expenditures are susceptible to variances in amount and timing and differences from forecast due to the timing and scope of work undertaken.[705]

428. In other words, the BCUC recognized the underlying rationale for including remediation cost variances in a regulatory account independently of any legislated requirement. The same rationale applies today. The Remediation Regulatory Account has experienced significant variances.[706]

E. BC HYDRO AND GOVERNMENT HAVE ADDRESSED THE AUDITOR GENERAL'S CONCERNS ABOUT REGULATORY ACCOUNTS

429. Phase One of the Comprehensive Review resulted in enhanced BCUC oversight, BC Hydro fully adopting IFRS, and BC Hydro writing-off the balance in the Rate Smoothing Regulatory Account.[707] As a result, the Auditor General removed her qualification regarding the

[704] Tr. 15, p. 2893, ll. 5-16 (Hobson).

[705] Exhibit B-1, Application, p. 7-40.

[706] Exhibit B-15, BCUC IR 3.301.1.

[707] Exhibit B-1, Application, pp. 7-7 and 7-8.

use of rate-regulated accounting at BC Hydro on the Government of B.C.'s fiscal 2019 financial statements.[708] With the Auditor General's concerns resolved, the BCUC can, and should, make its determinations regarding BC Hydro's regulatory accounts by focussing on the purpose served by each account and how BC Hydro is managing the balances.

F. BC HYDRO IS MANAGING REGULATORY ACCOUNT BALANCES APPROPRIATELY

430. Section 4 of Direction No. 8 states that the BCUC must not disallow recovery in rates of the balance of BC Hydro's regulatory accounts as at March 31, 2019; however, the BCUC retains discretion over how and when the balances are recovered.[709] The evidence, outlined below, demonstrates that BC Hydro is taking the necessary steps to manage regulatory account balances, using appropriate BCUC-approved recovery mechanisms and exercising discipline over controllable costs.

(a) Overall Regulatory Balance Has Declined Significantly from its Peak

431. BC Hydro's regulatory account balances have declined by approximately 30% between fiscal 2017 and fiscal 2019, from $5.908 billion at the end of fiscal 2016 to $4.193 billion at the end of fiscal 2019.[710] Although a material portion of the reduction in recent years has come from the write-off of the balance of the Rate Smoothing Regulatory Account, it is also attributable to ongoing recovery of the balances in almost all of BC Hydro's regulatory accounts in rates based on BCUC approved recovery mechanisms, higher than planned Powerex net income, and the adoption of IFRS 15.[711]

---

[708] In the Independent Auditor's Report included in the Public Accounts 2018/19, the Auditor General stated: "For the year ending March 31, 2019, BC Hydro has implemented International Financial Reporting Standards (IFRS), including IFRS 14 (Regulatory Deferral Accounts). Government has made a number of changes to the regulatory framework, giving the regulator the ability to influence costs and rates. I believe the changes made to the regulatory framework are sufficient to allow me to remove my qualification on the use of rate-regulated accounting for the year ending March 31, 2019." See also the Office of the Auditor General's report titled "Understanding Our Audit Opinion on B.C.'S 2018/19 Summary Financial Statements": Exhibit B-12, BCUC IR 2.201.3.

[709] Exhibit B-1, Application, p. 2-9.

[710] Exhibit B-19, Evidentiary Update, Appendix D, Table D-2, p. 4 and Exhibit B-1, Application, Table 7-1, p. 7-9.

[711] Exhibit B-1, Application, pp. 7-2 and 7-3.

(b) Approximately 80% of the Fiscal 2024 Forecast Balance is Associated With Longer-Term Accounts

432. BC Hydro has BCUC-approved recovery mechanisms to collect, in rates, the balances in almost all if its regulatory accounts.[712] Approximately 80% of the forecast balances in fiscal 2024 resides in five regulatory accounts that are being, or will be, recovered over a longer period of time to promote intergenerational equity.[713] Specifically:

- The First Nations Provisions Regulatory Account, which is drawn down as annual settlement payments are made over a longer period of time;
- The DSM Regulatory Account, for which the expenditures added each year are recovered over the 15-year benefit period;
- The Site C Regulatory Account, which is not yet being recovered in rates because the Site C project is not yet in-service. In a future application, BC Hydro will propose that the balance in the account be recovered over the average life of the Site C assets, as that is the period that customers will benefit from those costs; and
- The two IFRS Transition Accounts, which are being amortized into rates over the same period of time as under the previous CGAAP accounting rules.[714]

(c) Appropriate BCUC-approved Recovery Mechanisms Are in Place

433. BCUC-approved mechanisms are in place for the Test Period to recover the balances in rates, with the exception of three accounts where recovery mechanisms are not yet required.[715] Inquiries about BCUC-approved recovery mechanisms focussed on a limited

[712] Exhibit B-1, Application, pp. 7-20 and 7-21. The Mining Customer Payment Plan Regulatory Account, Customer Crisis Fund Regulatory Account, and the Site C Regulatory Account do not have approved recovery mechanisms as they are not yet required.

[713] Exhibit B-19, evidentiary Update, Appendix D, Table D-2 shows the forecast balances for each of BC Hydro's regulatory accounts to fiscal 2024.

[714] Exhibit B-1, Application, p. 7-11.

[715] Exhibit B-1, Application, pp. 7-20 and 7-21.

number of accounts, which are addressed below. BC Hydro submits that the mechanisms in place for each of these accounts reflect the underlying purpose of the account and remain appropriate.

Recovery of IFRS Transition Regulatory Accounts Maintains Revenue Requirement Impacts of Previous Accounting Rules

434. In fiscal 2013, BC Hydro transitioned to the Prescribed Standards, which were based on the principles of IFRS, combined with regulatory accounting. The change impacted the method of accounting for capital overheads. It also required BC Hydro to recognize on its balance sheet all unamortized actuarial gains and losses on its pension and other post-employment benefit plans. The IFRS Property, Plant and Equipment Regulatory Account and the IFRS Pension Regulatory Account capture the financial impact of these changes.[716]

435. The rates in the Test Period include amounts for the amortization of the account balances, consistent with the approved methodology. There will be no further additions to the IFRS Property, Plant and Equipment Regulatory Account after the end of the Test Period. There are no further additions to the IFRS Pension Regulatory Account. The recovery periods for these regulatory accounts remain appropriate, since they result in approximately the same revenue requirement impact as there would have been under the previous accounting rules.[717]

436. BC Hydro was asked about the ongoing effect of the original BCUC order that addressed amortization of these accounts (Order No. G-77-12A), given that the order had referenced specific dollar amounts for recovery in rates during that test period.[718] The amounts approved were determined by applying BC Hydro's proposed 20 and 40 year amortization periods for the IFRS Pension and IFRS Property, Plant and Equipment regulatory accounts, respectively. BC Hydro has interpreted Order No. G-77-12A and subsequent orders regarding these accounts as endorsement of the 20 and 40 year amortization periods because the amortization periods were explicit in the evidentiary record. If the BCUC considers that additional clarification

[716] Exhibit B-1, Application, p. 7-18.

[717] Exhibit B-16, BCUC IR 3.301.6.

[718] Exhibit B-5, BCUC IR 1.154.1.

regarding the amortization periods is required prospectively, then BC Hydro respectfully requests express approval of the current amortization periods.[719]

Recovery of DSM Regulatory Account Matches Costs and Benefits

437. The current 15-year amortization period of the DSM Regulatory Account is supported by the average effective measure life (or "persistence") of DSM initiatives.

438. Effective measure life is used by BC Hydro and other utilities to inform the amortization period for a DSM regulatory account because it matches costs and benefits.[720] BC Hydro determined effective measure life values with reference to credible third-party research, using professional judgement in those specific cases where third-party research was unavailable.[721] There are a significant number of persistence studies across the DSM industry, and it is standard industry practice to use these persistence studies to inform effective measure life assumptions.[722] BC Hydro has provided detailed evidence supporting the measure lives values for its DSM initiatives.[723]

439. Table 10-14 of the Application, reproduced below, shows that the weighted average measure life of DSM expenditures over the Test Period is 15 or more years.[724]

[719] Exhibit B-5, BCUC IR 1.154.1.

[720] Exhibit B-5, BCUC IR 1.150.2.

[721] Exhibit B-1, Application, pp. 10-35 and 10-36. BC Hydro referenced research from the Public Service Commission of Wisconsin, the California Public Utilities Commission, the 2001 Database for Energy Efficiency Resources, and Skumatz Economic Research Associates Inc., among others.

[722] Exhibit B-5, BCUC IR 1.178.1.1.

[723] Exhibit B-1, Application, pp. 10-35 to 10-37; Exhibit B-5, BCUC IRs 1.150.2, 1.178.1, and 1.178.1.1; Exhibit B-12, BCUC IRs 2.275.1 and 2.275.2.

[724] Exhibit B-1, Application, p. 10-37.

Table 10-14 Average Measure Life (years)

	2-Year Period F2020-F2021		10-Year Period F2020-F2029	
	GWh Weighted	**$ Weighted**	**GWh Weighted**	**$ Weighted**
Codes and Standards	30.0	30.0	30.0	30.0
Conservation Rates	1.3	1.3	1.2	1.2
DSM Programs	10.4	12.2	11.8	13.2
Low-Carbon Electrification	27.0	24.9	24.4	19.8
Codes and Standards, Conservation Rates, and DSM Programs	**18.7**	**13.5**	**17.9**	**14.7**
DSM Programs and Low-Carbon Electrification	**17.1**	**15.0**	**16.2**	**15.0**

440. The values in the above table are conservative because the calculation equates persistence to the effective measure life of a DSM initiative and does not consider that some customers will re-install an efficient measure when the initial measure has reached its end-of-life, rather than revert to an inefficient measure. In these cases, the persistence of the DSM initiative continues beyond the effective measure life. For this reason, the California Public Utilities Commission uses a deemed assumption that 50 per cent of savings persist beyond the expiration of the measure's life in its Energy Efficiency Policy Manual.[725]

441. A 15 year amortization period is also reasonable when considering the average measure life of all DSM measures in the Regulatory Account at the end of fiscal 2021: 14.5 years on an energy (GWh) weighted basis and 14 years on an expenditure weighted basis.[726] Again, these amounts are conservative as they do not account for reinstallation of efficiency measures, as accounted for by the California Public Utilities Commission.

[725] Exhibit B-1, Application, p. 10-37.

[726] Exhibit B-5, BCUC IR 1.150.5.1.

442. Continuing to use the 15 Year amortization period, in light of the evidence above, will have the following benefits:[727]

- Matching – the current amortization period of 15 years appropriately matches the costs with the period of time that the benefits will be realized by customers (i.e., average measure life of DSM measures);

- Intergenerational equity – as benefits of DSM measures will be realized in future periods, BC Hydro believes that it is fair and equitable that these costs should be paid by future customers that will benefit from these expenditures. In other words, current ratepayers are not unduly burdened by having to pay for the full DSM costs today when these costs will provide benefits into the future. The current amortization period of 15 years supports intergenerational equity between current and future ratepayers; and

- Rate stability - maintains the status quo and therefore does not result in an adverse rate impact for ratepayers in the current Test Period. A shorter amortization period would result in higher rates for customers.

443. Shortening the amortization period materially would not be justified based on the evidence of effective measure life. Amortizing the balance in the Demand Side Management Regulatory Account over 10 years, for example, would result in over-collecting costs during that period.[728] This would undermine intergenerational equity, as current customers would begin paying for a higher share of current DSM expenditures, while in past years customers have been paying for a lesser share based on the lengthy persistence of DSM benefits.[729] Further, shortening the amortization period will result in higher rates for customers. In BC Hydro's submission, maintaining the status quo is preferable as it is supported by the average measure

[727] Exhibit B-5, BCUC IR 1.150.6.1.

[728] Exhibit B-16, BCUC IR 3.298.4.

[729] Exhibit B-5, BCUC IR 1.150.6.1.

life, results in customers being treated similarly as in past years, and will avoid unnecessary rate increases.

Recovery of Non-Current Pension Costs Regulatory Account Matches Updated External Valuation

444. BCUC Order No. G-47-18 approved BC Hydro's proposal that variances transferred to the Non-Current Pension Costs Regulatory Account be amortized over the expected average remaining service life (EARSL) of the active plan members.[730]

445. The amortization period used in the Application was 12 years, reflecting the EARSL of the active plan members at the time the Application was being prepared. BC Hydro's external actuary subsequently completed an actuarial valuation and EARSL increased to 13 years due to changes in termination rates and retirement rates. The Evidentiary Update was thus based on a 13-year amortization period.[731]

446. InterGroup's report suggested that BC Hydro ought to have recognized in the Evidentiary Update the favourable impact on non-current pension costs of anticipated changes in legislation relating to B.C.'s Medical Services Plan. Accounting standards precluded BC Hydro from recognizing the impact of these changes before the required legislation had been passed. This meant that the impact was not recorded until this Test Period. The BCUC's orders require BC Hydro to record variances arising during this Test Period in the Non-Current Pension Costs Regulatory Account, for amortization in the *next* test period.[732] Mr. Bowman conceded during cross-examination that BC Hydro was following the BCUC's orders.[733]

(d) Cost Control Measures Are in Place for Deferred Controllable Costs

447. While many deferred costs are uncontrollable (the uncontrollable nature of costs is a rationale for many accounts), this is not always the case. In some instances, the account is

[730] Exhibit B-5, BCUC IR 1.40.3.1.

[731] Exhibit B-17, AMPC IR 3.5.4.2.

[732] Exhibit B-28, BC Hydro Rebuttal Evidence, p. 14.

[733] Tr. 11, p. 2064, ll. 5 to 16 (Bowman).

managing timing uncertainty or matching costs and benefits. The evidence discussed throughout these Submissions shows that processes and procedures are in place to manage controllable costs recovered through regulatory accounts.[734]

G. BC HYDRO'S PROPOSED CHANGES TO REGULATORY ACCOUNTS ARE WARRANTED

448. BC Hydro has demonstrated that its proposed changes to regulatory accounts are warranted.[735] The material changes (with the exception of the proposal to defer low-carbon electrification expenditures to the Demand Side Management Regulatory Account, which is addressed in Part Eleven of this Submission) are addressed below.

(a) Proposal to Reduce the DARR and Refund the Balance in the Cost of Energy Variance Accounts over the Test Period Promotes Intergenerational Equity and Rate Stability

449. BC Hydro is proposing to (a) reduce the DARR from 5% to 0% on April 1, 2019, and (b) refund 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.[736] Based on the Evidentiary Update, these proposals result in a refund to the benefit of ratepayers during the Test Period of approximately $630.8 million.[737]

450. As between the two Test Years, BC Hydro is proposing to refund most of this amount in fiscal 2021. The proposed allocation as between the two Test Years avoids the need to adjust the bill impact associated with the BCUC's interim rate order for fiscal 2020 (1.76% net bill increase).[738] Avoiding a bill adjustment for fiscal 2020 also eliminates a potential source of customer confusion, since fiscal 2020 will be over by the time the BCUC renders its decision. We provide further discussion demonstrating the merits of this approach in Part Twelve Section B below.

---

[734] Exhibit B-5, BCUC IR 1.40.3.1. See also, Tr. 6, p. 824, ll. 9-17 (Layton).

[735] Exhibit B-1, Application, pp. 7-21 to 7-23.

[736] Exhibit B-1, Application, p. 7-22.

[737] Exhibit B-17, ZONE II RPG IR 3.60.1.

[738] BCUC Order No. G-45-19. Exhibit B-19, Evidentiary Update, p. 10.

451. BC Hydro was asked whether the account balance should be amortized over a longer period of time, e.g., by using the DARR table mechanism. BC Hydro submits that returning the balance to customers during the Test Period best achieves intergenerational equity. A significant portion of the net credit balance in the Cost of Energy Variance Accounts is due to a one-time accounting adjustment of $319 million related to the recognition of revenues under the Skagit River Agreement. This adjustment resulted in a retroactive decrease in unearned revenues, which effectively means that previous ratepayers have overpaid. BC Hydro's request allows the impact of this adjustment to be returned to ratepayers sooner.[739]

452. BC Hydro modelled a number of other options put forward by parties and BCUC staff for returning the balance in the Cost of Energy Regulatory Accounts to customers. These scenarios are discussed in Part Twelve of these Final Submissions, which addresses Implementation of rates. Generally speaking, BC Hydro's proposal is simpler to administer, more transparent, and produces more stable rates during the Test Period.[740]

(b) Proposal to Defer Variances Related to EPAs that are Leases Under IFRS 16 to the Non-Heritage Deferral Account Means Ratepayers Will Pay Actual Costs through Stable Rates

453. BC Hydro is proposing to defer to the Non-Heritage Deferral Account any variances related to the treatment of certain EPAs as leases under IFRS 16.[741] The adoption of IFRS 16 impacts the timing of expenses associated with these EPAs. In the absence of the accounting change, these costs would have been borne by ratepayers in future periods.[742] The proposal places customers in the position they would have been in but for the accounting change, and promotes rate stability. Ratepayers will pay the actual costs that BC Hydro incurs over the term of the EPAs.

---

[739] Exhibit B-5, BCUC IR 1.148.5.

[740] Exhibit B-16, BCUC IR 3.296.3. Specifically refer to the discussion with regards to Scenarios A, B(i), B(ii) and K.

[741] Exhibit B-1, Application, pp. 7-22 and 7-27.

[742] Exhibit B-5, BCUC IR 1.146.2; Exhibit B-16, BCUC IR 3.302.3.1.

454. The expenses attributable to EPAs recognized on the balance sheet as leases under IFRS 16 are classified as finance charges and depreciation expense and not as Cost of Energy. Variances related to *finance charges* are eligible for deferral to the Total Finance Charge Regulatory Account. However, *depreciation* variances attributable to EPA leases are not eligible for deferral within any existing regulatory account.[743]

455. BC Hydro prepared the Application using a preliminary estimate of the impacts of IFRS 16. The Evidentiary Update reflected BC Hydro's complete assessment, which included discussions with the Office of the Auditor General (BC Hydro's external financial statement auditor).[744] Consistent with BC Hydro's proposal, the Evidentiary Update reflects the deferral of the resulting net change of $82.8 million to the Non-Heritage Deferral Account.[745]

456. The alternatives to BC Hydro's proposed treatment would be highly detrimental to customers:

- Significant rate volatility could be expected if the BCUC were to instead direct depreciation variances attributable to EPA leases be deferred to the Amortization of Capital Additions Regulatory Account. The fiscal 2021 net bill decrease of 1.01% would (other things equal) change to an estimated bill decrease of 10.0%. It would be followed in fiscal 2022 by an estimated required bill increase of approximately 19%.[746]

- Similar extreme volatility could be expected if the BCUC were to decline to defer the $64.8 million opening balance adjustment to the Non-Heritage Deferral Account and not direct the deferral of depreciation variances attributable to EPA leases. The fiscal 2021 net bill decrease of 1.01% in the Evidentiary Update

[743] Exhibit B-5, BCUC IR 1.146.1. It does not fall within the scope of, for instance, the Amortization of Capital Additions Regulatory Account.

[744] Exhibit B-16, BCUC IR 3.302.7.

[745] Exhibit B-19, Evidentiary Update, Appendix F, p. 1.

[746] Exhibit B-16, BCUC IR 3.302.6.

would change to an estimated bill decrease of 10%, with an estimated required bill increase in fiscal 2022 of approximately 15%.[747]

457. Additional variances in finance charges and depreciation expense as a result of accounting treatment could arise in various ways. For instance:

- The Auditor General's agreement with BC Hydro's impact assessment in the First Quarter financial statements was conditional upon completing its audit of BC Hydro's annual fiscal 2020 financial statements.[748] If the Auditor General does not agree with BC Hydro's implementation of IFRS 16 for EPA leases, then BC Hydro would adjust its financial statements.[749] A change in the assessed accounting treatment from non-lease to a lease for one EPA could result in a balance sheet adjustment in excess of $100 million.[750]

- Variances will arise for existing EPAs that are considered leases due to the need to adjust the measurement of the right of use asset balance and the lease obligation for actual inflationary increases, which may differ from forecast inflation assumptions.[751]

- If a new EPA is recognized, there could be variances due to the timing of the commencement of recognition or the amount of the depreciation and interest expenses.[752]

458. BC Hydro submits that the evidence is compelling that its proposed approach is in the best interests of the company and customers.

---

[747] Exhibit B-16, BCUC IR 3.302.6.
[748] Exhibit B-16, BCUC IR 3.302.7.1.
[749] Exhibit B-16, BCUC IR 3.302.7.2
[750] Exhibit B-5, BCUC IR 1.146.4.
[751] Exhibit B-16, BCUC IR 3.302.2.
[752] Exhibit B-16, BCUC IR 3.302.2

(c) Proposal to Defer Variances Between Forecast and Actual Amounts Related to Biomass Energy Program Means BC Hydro Will Recover its Costs, as Directed

459. BC Hydro is proposing to defer any variances between forecast and actual amounts related to the Biomass Energy Program to the Non-Heritage Deferral Account. The forecast costs in the Test Period associated with the Biomass Energy Program ($36 million for fiscal 2020 and $81 million for fiscal 2021) have been accounted for as Cost of Energy.[753] However, BC Hydro may be required to account for some of these costs as amounts other than Cost of Energy (variances related to which would generally be deferred to the Non-Heritage Deferral Account pursuant to existing orders). BC Hydro will not know the amount of those costs or how to appropriately account for them until contracts are completed.[754] The proposal will ensure that BC Hydro recovers its costs with respect to the Biomass Energy Program, consistent with legislative requirements.[755]

(d) Proposal to Continue Deferring Dismantling Costs Recognizes Uncontrollable Nature and Supports Regulatory Efficiency

460. BC Hydro is proposing to continue to defer to the Dismantling Cost Regulatory Account, on an annual and ongoing basis, any variances between forecast and actual dismantling costs. BC Hydro is also proposing (a) to continue to apply interest to the balance of the account, (b) to recover the forecast interest charged to the account each year, and (c) to continue to recover the forecast account balance at the end of a test period, over the next test period.[756] BCUC Order No. G-47-18 approved this proposal for the fiscal 2017 to fiscal 2019 test period. In its Decision, the BCUC stated that, in its view, the timing of dismantling activities is largely within BC Hydro's control, but that the establishment of the account for the fiscal 2017 to fiscal 2019 period would allow BC Hydro to gain more experience with forecasting the timing of

[753] Exhibit B-5, BCUC IR 1.147.3.1.

[754] Exhibit B-1, Application, p. 7-28.

[755] Exhibit B-1, Application, p. 7-22; Exhibit B-6, BCSEA IR 1.11.2. Order in Council No. 158/2019 requires the BCUC to allow BC Hydro to recover the costs associated with the Biomass Energy Program.

[756] Exhibit B-1, Application, p. 7-22.

expenditures.[757] BC Hydro submits that, based on the evidence in the current proceeding, BC Hydro's proposed orders make sense.

461. First, BC Hydro's recent experience has demonstrated that the timing of dismantling activities continues to be uncontrollable and difficult to forecast accurately. Since fiscal 2012, annual variances have ranged from $14.1 million below plan to $31.7 million above plan (a range between -41% to +89% of plan).[758]

462. Second, the potential for such significant variances to arise is unsurprising. 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. Any delays or advancements to capital project schedules could result in these expenditures being incurred earlier or later than planned. In addition, the full scope and cost of dismantling activities may not be known until the work is underway and emergency dismantling of assets or unplanned dismantling may be required from time to time.[759]

463. Third, BC Hydro has significant dismantling costs planned during the Test Period ($67 million in fiscal 2020 and $43 million in fiscal 2021). In the absence of the Dismantling Cost Regulatory Account, significant gains or losses could accrue to ratepayers or BC Hydro's shareholder. Continued use of the account for the Test Period will mean that ratepayers pay the actual costs of dismantling activities.[760]

464. Fourth, BC Hydro's use of the Dismantling Cost Regulatory Account is efficient. In fiscal 2018, BC Hydro had over 300 projects with dismantling costs, including 10 projects with dismantling costs greater than $1 million. It would be very inefficient to seek approval to defer

[757] Exhibit B-1, Application, pp. 7-28 and 7-29.

[758] Exhibit B-1, Application, p. 7-29; Exhibit B-5, BCUC IR 1.149.1.

[759] Exhibit B-1, Application, pp. 7-29 and 7-30; Exhibit B-5, BCUC IR 1.149.2.

[760] Exhibit B-1, Application, p. 7-30.

dismantling costs on a case by case basis.[761] The BCUC has previously rejected the approach of requesting specific deferral treatment for the dismantling costs associated with specific projects, preferring to address all dismantling costs in a consistent manner in a revenue requirements application proceeding.[762] The resulting uncertainty from having to apply on an individual project basis could lead to increased project costs and schedule delays.[763]

465. BC Hydro was asked about the potential for substantial annual variances to offset over a longer time horizon. BC Hydro submits that the potential for windfalls to shareholders and customers to offset each other over the longer term in the absence of a variance account would be an invalid basis for ceasing to use Dismantling Cost Regulatory Account (or, for that matter, any other variance account). Rates are set based on forecast costs in a particular test period, and aggregated variances over a period of time are not indicative of future volatility in a particular test period. Proper regulatory accounting mechanisms should be used to recognize or shift impacts across multiple test periods.[764]

H. FORECAST FOR REAL PROPERTY SALES IS REASONABLE

466. Subsection D(c) of this Part outlined why customers are better off as a result of the Real Property Sales Regulatory Account. This section demonstrates the reasonableness of BC Hydro's forecast of real property sales for the Test Period.

467. BC Hydro has forecast net gains on real property (i.e., land and interest in land) sales of $10 million per year from fiscal 2020 to fiscal 2024. This represents the remainder of BC

[761] Exhibit B-16, BCUC IR 3.297.2.

[762] BCUC Order No. G-96-17, with regard to BC Hydro's Salmon River Diversion Ceasing of Operations Application, stated: "At this time, the Panel does not consider there to be anything special or unique about the costs to Cease Operation and Decommission the Diversion that would warrant alternate treatment from the general dismantling costs treatment that will be determined in the RRA. The Panel considers that treatment of the costs to Cease Operations and Decommission the Diversion should be consistent with the general treatment of BC Hydro's other dismantling costs." See also: Exhibit B-16, BCUC IR 3.297.2.

[763] Exhibit B-16, BCUC IR 3.297.2.

[764] Exhibit B-16, BCUC IR 3.297.1.1.

Hydro's $100 million target for net gains from surplus real property sales, which BC Hydro expects to achieve by fiscal 2024.[765]

468. Mr. Leonard explained that, since BC Hydro set the original target of $50 million in net sale proceeds by fiscal 2024, the value of surplus real properties increased. BC Hydro also identified new surplus properties that can be sold. These developments justified increasing the target to $100 million.[766]

469. Mr. Leonard provided an update on the sales as of the end of January 2020. He indicated that BC Hydro has sold 17 properties and a number of rights-of-way. The gains on those sales have reflected the anticipated amounts. The sales contribute to approximately $14.65 million in net proceeds.[767]

470. BC Hydro submits that it is still reasonable to expect sales to occur in the coming years, despite the slower than anticipated sales activity in previous years. The factors that have delayed sale completions to-date include: (a) progress of consultation with First Nations on property dispositions; (b) required subdivision, re-zoning and environmental remediation prior to sale; (c) fluctuating market interest in the properties; and (d) the time for buyers' due diligence and processes to complete a purchase.[768] However, property sales have already been completed in fiscal 2020 with additional sales scheduled to complete. 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.[769]

---

[765] Exhibit B-16, BCUC IR 3.299.3. BC Hydro is forecasting annual net gains on real property sales of $19.1 million. 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 so that it will self-clear by fiscal 2024.

[766] Tr. 13, p. 2522, l. 22 to p. 2524, l. 5 (Leonard).

[767] Tr. 13, p. 2525, ll. 6-14 (Leonard).

[768] Exhibit B-16, BCUC IR 3.299.1.

[769] Exhibit B-16, BCUC IR 3.299.2.

471. BC Hydro filed a (confidential) current list of properties, some combination of which will be sold to achieve the $100 million in net gains target by the end of fiscal 2024.[770]

472. BC Hydro provided, in response to an undertaking, the impact on the proposed rates based on the assumption that the BCUC forecasted zero dollars flowing to this account for the Test Period. The result was a rate decrease of 0.64% in fiscal 2021 instead of the 1.01% rate decrease proposed by BC Hydro (i.e., a forecast of zero dollars would increase fiscal 2021 rates by 0.37%).[771] The benefits to ratepayers do not disappear under this scenario, provided that the regulatory account remains in place; rather, the benefits are shifted to years following the Test Period. BC Hydro underscores that the continued existence of the account is essential for net proceeds from the sale of these properties to fiscal 2024 to flow to ratepayers, rather than the shareholder.

I. CONCLUSION AND REQUESTED FINDING

473. The evidence discussed above is compelling and should be accepted. The BCUC should find that BC Hydro's current use of regulatory accounts, its proposals to close and modify some of them, and its forecasted additions are just and reasonable.

[770] Exhibit B-16, BCUC IR 3.299.7, Attachment 1.

[771] Exhibit B-58, BC Hydro Undertaking No. 54. For the purpose of forecasting the estimated rate impact, BC Hydro assumed that the requested rate increase for fiscal 2020 remained the same, and therefore the entire two-year impact of forecasting zero net gains from real property sales (i.e., lower net gains of $10 million per year) would be reflected in rates in fiscal 2021.

PART NINE: OTHER REVENUE REQUIREMENTS ITEMS

A. INTRODUCTION

475. Chapter 8 of the Application covers Other Revenue Requirements Items. This Part of BC Hydro's Final Submissions focusses on three aspects of the Other Revenue Requirements Items that were addressed in AMPC's evidence: depreciation rates, finance charges and return on equity. We make the following points:

- First, BC Hydro's depreciation rates are appropriate for the purposes of setting rates in the Test Period. BC Hydro's upcoming depreciation study will provide stakeholders with additional confidence in BC Hydro's depreciation rates going forward.

- Second, regarding BC Hydro's forecast finance charges:

  - The forecast finance charges in the Evidentiary Update are reasonable for the purposes of setting rates during the Test Period, being the product of independent projections of future interest rates and a debt management strategy to lock-in interest rates.

  - BC Hydro's existing Total Finance Charges Regulatory Account is an efficient mechanism to ensure that customers will pay the actual finance charges in circumstances where actual interest rates differ from those reflected in the forecast finance charges.

- Third, BC Hydro's return on equity has been determined by Direction No. 8 for the Test Period. Matters related to the return on equity in future test periods should be addressed by the BCUC panel hearing the upcoming cost of capital application.

B. TEST PERIOD REVENUE REQUIREMENTS REFLECT APPROPRIATE DEPRECIATION RATES

476. BC Hydro recognized from the outset of this proceeding that it has been some time since a comprehensive depreciation study has been completed. The timing of the next comprehensive depreciation study has been one of those instances, to which Mr. O'Riley alluded, where BC Hydro management has had to prioritize competing financial and work demands on the organization.[772] BC Hydro has agreed to advance the study (though it will not be done in time for the next revenue requirements application[773]), recognizing that a new study appears to be necessary for some stakeholders to have confidence in BC Hydro's depreciation rates going forward.[774] The evidence summarized below explains the basis for BC Hydro's comfort in deferring a depreciation study until now. It also demonstrates that the current depreciation rates are reasonable for the purposes of setting rates in the Test Period.

477. First, BC Hydro has regularly reviewed depreciation rates and has reflected new information as part of meeting accounting standards and audit requirements. International Accounting Standard ("IAS") 16 outlines, in paragraph 51, the requirements for annual reviews of residual values and useful lives:

> 51 The residual value and the useful life of an asset shall be reviewed at least at each financial year-end and, if expectations differ from previous estimates, the change(s) shall be accounted for as a change in an accounting estimate in accordance with IAS 8 Accounting Policies, Changes in Accounting Estimates and Errors.[775]

478. BC Hydro complies with this requirement by reviewing, on an annual basis, whether there have been any changes in the factors that affect the useful lives of asset classes that are

---

[772] Tr. 5 p. 376 l. 1 to p. 377, l.6 (O'Riley); Tr. 5, p. 435, ll. 1-23 (Wong).

[773] The last depreciation study took approximately one year to complete from the completion of terms of reference to the final report. Meanwhile, the next RRA would typically be filed in February 2021 and, in response to feedback from the BCUC, BC Hydro has committed to exploring whether it would be possible to file that application earlier. Additionally, forecast inputs (such as depreciation expense) for Revenue Requirement Applications, are required months before the actual filing. Exhibit B-28, BC Hydro Rebuttal Evidence, p. 16; Exhibit B-43, BC Hydro Response to Oral Hearing Feedback.

[774] Exhibit B-43, BC Hydro Response to Oral Hearing Feedback.

[775] Exhibit B-13, AMPC IR 2.41.4.

expected to have a material impact on BC Hydro's depreciation expense. BC Hydro considers annually whether there are any: (a) impaired assets, (b) assets that are no longer being used, or (c) any instances of significant write-offs of assets in-service. BC Hydro confirmed that, when it identifies that assets will be removed from service prior to the end of their expected useful lives and they have a material book value, the remaining useful life of the asset is reduced to reflect the change in expected life.[776] BC Hydro provided examples where it has reviewed and subsequently revised the useful lives of its asset classes to reflect new information.[777]

479. BC Hydro is under an obligation to ensure that its financial statements are free from material misstatement. The obligation necessitates BC Hydro reviewing assumptions that feed into the assessment of its material expenses, including depreciation expense, to ensure that they continue to be reasonable. Mr. Layton explained that BC Hydro's external financial statement auditors have reviewed BC Hydro's depreciation expense and have not identified any material misstatement:

> So if they thought that our depreciation expense was incorrect and resulted in a material error, they would tell us and if we didn't adjust our financial statements, they would qualify our financial statements and say they're not materially correct. And even more than that, that materiality can actually be a high number, but what our auditors do is even if they thought it was a couple of million dollars incorrect, they would raise it to management and if we didn't make adjustments, they would raise it to our board. And what I can tell everyone in the room is that they haven't raised that concern.[778]

480. Second, a review conducted by BC Hydro in fiscal 2010 of the useful lives of all of its assets illustrates that, when considered in aggregate, potential life changes over time are having a relatively limited impact on depreciation expense. The review indicated that the

[776] Exhibit B-13, AMPC IR 2.41.9.

[777] For example, the useful lives of analog meters were reduced as approved by BCUC Order No. G-115-11 because the useful lives were shortened as a result of the meters being replaced prior to end of life as a result of the Smart Metering Initiative. In addition, as identified in section 8.2.1 of Chapter 8 of the Application, the useful lives of Burrard assets were reduced due to changes in the expected useful life of the facility.

[778] Tr. 7, p. 944, l. 15 to p. 945, l. 1 (Layton).

aggregate impact of the potential life changes on depreciation expense was less than $1 million.[779] Mr. Layton explained:

> What was looked at was the classes themselves and working with Gannett Fleming and taking their advice on do we think any of these have changed. And they did identify a couple of potentially changes and what we did in terms of quantitative analysis was if those changes were to be done, what would the impact be? And as we stipulated in an IR, we think that the impact would have been less than a million dollars, and therefore we didn't make any changes at that time.[780]

481. Third, analysis completed by BC Hydro in response to an AMPC information request further underscores that the depreciation expense reflected in the Test Period revenue requirements is reasonable. AMPC asked BC Hydro to identify any material assets that exceeded their estimated service life for the particular assets, as set out in the last depreciation study. Using a materiality threshold of assets with an original cost of $10 million or higher, BC Hydro did not identify any individual specific assets that had a net book value of zero at March 31, 2019 and were still in use.[781]

482. InterGroup provided a schedule of asset classes that it suggested may warrant life extensions, identifying BC Hydro's useful lives and the useful life ranges used by peer utilities. If anything, InterGroup's comparison to other utilities should provide additional comfort about the reasonableness of the Test Period depreciation expense. BC Hydro's asset lives are within the range provided for the peer utilities for nine of the 10 identified asset classes.[782]

[779] Exhibit B-13, AMPC IR 2.41.2.

[780] Tr. 7, p. 928, ll. 16-25 (Layton).

[781] Exhibit B-13, AMPC IR 2.41.6.

[782] Exhibit B-28, BC Hydro Rebuttal Evidence, p. 16.

C. BC HYDRO'S FORECAST FINANCE CHARGES ARE A REASONABLE BASIS FOR SETTING RATES

483. Finance charges are primarily comprised of interest charges on BC Hydro's debt, but also include interest related to non-current pension costs and leases recognized as lease obligations under IFRS 16. BC Hydro's forecast finance charges reflect:

- Actual interest rates on debt that has already been issued;
- Market forward rates for hedged debt that has not yet been issued; and
- Independent interest rate forecasts from the Treasury Board of the Government of B.C. for unhedged debt that has not yet been issued. [783] [784]

BC Hydro submits that the forecast finance charges in the Evidentiary Update are reasonable for the purposes of setting rates during the Test Period.

(a) Hedging Strategy has Mitigated Interest Rate Risk

484. Since fiscal 2017, BC Hydro has locked in interest rates on forecast future long-term debt issuances by entering into financial contracts that hedge interest rate risk.[785] BC Hydro has hedged approximately 71% of its total forecast borrowing requirements for the Test Period.[786] Hedging provides cost certainty regarding hedged future long-term debt issuances.

485. The purpose of the hedging strategy is to lock in a rate. Mr. Wong explained BC Hydro's debt management strategy using the simplifying analogy of a fixed mortgage rate:

> And essentially what we want to do is lock in, to create certainty for BC Hydro and ratepayers, the interest rate we're going to have on our debt that we're going to be issuing over the next five years. So what we do is we transact interest rate hedges, or we call them here future debt hedges, to lock in the interest rate today. And so it's very much like if you were to do a mortgage on your house and you take a fixed rate mortgage, you're locking in that rate on your mortgage for

[783] Exhibit B-1, Application, pp. 8-10 and 8-11.

[784] The total interest costs that ratepayers will pay in respect of hedged debt is seen in finance charges and via the Debt Management Regulatory Account. That's because hedging gains or losses are deferred to the Debt Management Regulatory Account and are amortized over the term of the debt pursuant to BCUC Order No. G-42-16. Exhibit B-31, BCUC Panel IR 2.17.4 provides an explanation of how these factors offset and how ratepayers pay the hedged rate over time as a result.

[785] Exhibit B-1, Application, p. 8-10.

[786] Exhibit B-28, BC Hydro Rebuttal Evidence, p. 18.

> five years at a fixed rate so you're not subject to the variability of interest rates going up or going down and you have certainty over what your cost is going to be.[787]

486. Future Debt Hedges fluctuate in value before they are settled as forward interest rates change. If forward interest rates increase/decrease relative to the hedged rate, then the Future Debt Hedges will incur an unrealized gain/loss. However, any actual gain/loss on the Future Debt Hedges will be offset by higher/lower interest costs when the associated future debt is issued.[788] Accordingly, as Mr. Wong explained, the objective of BC Hydro's hedging strategy is based on the ability to lock in interest rates based on expected future debt issuances, rather than targeting a gain/loss that may occur over time.[789] It has accomplished its purpose.

(b) Evidentiary Update Used the Most Recent Interest Rates Available for Unhedged Debt

487. BC Hydro uses forecasts that are developed by the Treasury Board of the Government of B.C. to forecast finance charges for unhedged long-term and short-term debt.[790] Mr. Wong explained:

> We have a methodology on how we forecast interest rates, and the Government of B.C. provides the forward curve based on their accumulation of several banks. They are the ones that go and issue debt for us. So BC Hydro has no – I don't think we have any expertise that would be better than what the province is saying, and so that's how we come up with our best estimate in the forecast.[791]

488. The Evidentiary Update used the most recent interest rates forecast available to BC Hydro from the Government of B.C. at the time the forecast was prepared (as of January 4, 2019).[792]

---

[787] Tr. 7, p. 953, ll. 2-16 (Wong).

[788] Exhibit B-31, BCUC Panel IR 2.17.4.

[789] Tr. 7, p. 956, ll. 17-20 (Wong).

[790] Exhibit B-1, Application, pp. 8-10 and 8-11.

[791] Tr. 7, p. 896, ll. 18-25 (Wong).

[792] Exhibit B-28, p. 13. Based on this forecast, the interest rates used to forecast finance charges on unhedged long-term debt were 3.46% for fiscal 2020 and 3.76% for fiscal 2021 and the interest rates used to forecast finance charges on short-term debt were 2.35% for fiscal 2020 and 2.69% for fiscal 2021: Exhibit B-6, BCOAPO IR 1.72.1.

(c) Regulatory Accounts Are an Efficient Means of Addressing Interest Rate Changes Since the Evidentiary Update

489. InterGroup recommends that, for unhedged debt and sinking funds, BC Hydro further updates its finance charge forecasts to be based on: long-term debt interest rates that are consistent with the rates for long-term debt that has been issued since the Evidentiary Update; updated short-term debt interest rates; and updated sinking fund rates, if applicable.[793] BC Hydro submits that it is unnecessary to update finance charges again in the manner posited by InterGroup. BC Hydro's Total Finance Charges Regulatory Account is an efficient mechanism to ensure that customers will pay the actual finance costs in the event that interest rates emerge differently from forecasts.[794] The reality is that markets change on a daily basis. The BCUC had directed BC Hydro to create the account in 2009 (i.e., well before Direction No. 7) and the account has been re-approved in several subsequent orders.[795]

490. BC Hydro addresses in Part Twelve, Section C why it would be particularly unreasonable to update finance charges without updating pension costs (which, unlike finance charges, increase as interest rates decline).

D. INTERGROUP'S RECOMMENDATIONS REGARDING BC HYDRO'S FUTURE RETURN ON EQUITY ARE PREMATURE

491. BC Hydro's return on equity is fixed by regulation for the Test Period.[796] InterGroup nonetheless makes recommendations relating to BC Hydro's return on equity in future test periods, including factors it believes should be considered to determine BC Hydro's future return on equity.[797] BC Hydro submits that the Panel should not opine on matters related to the upcoming cost of capital proceeding.[798] This Panel cannot fetter the discretion of the BCUC

[793] Exhibit C11-11, InterGroup Report, Recommendations 14 to 16.

[794] Exhibit B-28, BC Hydro Rebuttal Evidence, p. 13, ll. 10-16.

[795] The history of the account is described in the Exhibit B-1, Application, pp. 7-36 and 7-37.

[796] Direction No. 8, section 3.

[797] Exhibit C11-11, InterGroup Report, Recommendations 4 to 6.

[798] Tr. 5, p. 426 ll. 1-17 (O'Riley and Wong).

Panel hearing a future application. In any event, there is an insufficient evidentiary basis for this Panel to make considered recommendations on this matter to a future BCUC Panel.

E. CONCLUSION AND REQUESTED FINDINGS

492. The BCUC should find that BC Hydro's depreciation rates and forecast finance charges are reasonable for the Test Period. It should refrain from making any findings or recommendations with regards to BC Hydro's future return on equity.

PART TEN: TRANSMISSION REVENUE REQUIREMENTS

A. INTRODUCTION

493. This Part addresses the Transmission Revenue Requirements (the "TRR"), which are the subject of Chapter 9 of the Application and Appendix E of the Evidentiary Update.[799] The TRR includes the costs associated with the transmission lines and high-voltage station equipment that are used to provide transmission service under BC Hydro's Open Access Transmission Tariff ("OATT"). BC Hydro's evidence in the Application, Evidentiary Update and responses to information requests demonstrates that BC Hydro's updated OATT rates, which will collect the TRR from transmission customers, are just and reasonable.

B. THE TRR AND OATT RATES REFLECT ESTABLISHED COST OF SERVICE METHODOLOGY AND APPROVED RATE DESIGN

494. There are two overarching reasons why the BCUC should have confidence in BC Hydro's determination of the TRR and OATT rates:

- First, the cost allocation methodology used to derive the TRR is based on cost causation and is consistent with past practice.[800] The allocation and direct assignment of costs is described in detail in section 9.2, Chapter 9 of the Application and is depicted in Figures 9-1 and Figure 9-2.[801]

- Second, the calculation of the OATT rates is consistent with the design of the OATT rates previously reviewed and approved by the BCUC for BC Hydro and the British Columbia Transmission Corporation ("BCTC").[802] Past BCUC Orders approving the OATT rate design begin with Order No. G-43-98 and include over

[799] Exhibit B-11. The Evidentiary Update increased the Transmission Revenue Requirement by $43.4 million in fiscal 2020 and $42.2 million in fiscal 2021. Further information is provided in Appendix E of the Evidentiary Update.

[800] Exhibit B-1, Application, p. 9-2.

[801] Exhibit B-1, Application, pp. 9-3 and 9-4.

[802] Exhibit B-1, Application, p. 9-2.

25 subsequent Orders.[803] These subsequent Orders include major rate design approvals such as Order No. G-58-04, when BCTC became the transmission provider, and Order Nos. G-102-09 and G-103-09, when the OATT was updated in response to major reforms to the FERC *pro forma* OATT in FERC Order No. 890.

495. BC Hydro responded to a number of information requests, providing additional details on its cost allocation methodology and the OATT rate design. For example:

- BC Hydro explained how the TRR cost allocation methodology relates to BC Hydro's 2016 cost of service study (the "2016 COSS"), including explaining why not all components of the 2016 COSS are applicable to the TRR.[804]

- BC Hydro explained how the Network Integration Transmission Service ("NITS") charge is calculated. Among other things, BC Hydro confirmed that the current NITS charge is calculated as the residual TRR, as approved by the BCUC in Order No. G-58-05, and remains consistent with the FERC *pro forma* tariff.[805]

- BC Hydro explained that the long-term point-to-point ("LT PTP") rate design and use of the maximum capacity supply billing determinant to establish the LT PTP Rate is consistent with past practice and was also approved by the BCUC through Order No. G-58-05.[806]

- BC Hydro explained that the short-term point-to-point ("ST PTP") discount rate design remains valid because (a) the main markets that border B.C. are still fundamentally the same as when the ST PTP discount rates were designed, and (b) the rates continue to be simple, easy to understand, stable, and help to

[803] Exhibit B-31, BCUC Panel IR 2.8.5.2.

[804] Exhibit B-31, BCUC Panel IRs 2.8.1 and 2.8.2.

[805] Exhibit B-31, BCUC Panel IR 2.14.3.

[806] Exhibit B-5, BCUC IR 1.166.3.

balance the objectives of promoting the use of the transmission system and cost recovery.[807]

496. BC Hydro submits that all issues raised regarding the TRR and proposed OATT rates have been addressed in responses to information requests. The evidence demonstrates that the cost allocation methodology and calculation of the OATT rates are reasonable, consistent with past practice and past BCUC Orders, and are calculated on a comparable basis to rates in neighboring jurisdictions in the United States. As such, BC Hydro submits the proposed OATT rates should be approved as just and reasonable.

C. RE-EXAMINING THE MERITS OF THE OATT RATE DESIGN IS UNNECESSARY

497. BC Hydro responded to a number of information requests that seemed to be directed at the merits of the OATT rate design itself.[808] BC Hydro is not requesting any determination in this proceeding on OATT rate design, as this revenue requirements proceeding is focussed on recovery of BC Hydro's costs during the Test Period. In any event, as discussed below, BC Hydro's responses to the information requests show that the OATT rate design remains valid.

498. The OATT rate design has a long and complex history, has implications for the interplay between BC Hydro's system and the rest of the Western Interconnection, and has been the subject of numerous BCUC proceedings and decisions.[809] The complexity of BC Hydro's OATT, which is publicly available on BC Hydro's website,[810] is readily apparent on its face. BC Hydro has developed detailed OATT business practices, which are also available online, to describe how it implements various aspects of the OATT and to assist wholesale transmission customers.[811] BC Hydro and other wholesale transmission customers are sophisticated parties, well-equipped to navigate the terms and conditions of the OATT and business practices.

---

[807] Exhibit B-5, BCUC IR 1.166.6; Exhibit B-31, BCUC Panel IR 2.16.1.1.

[808] E.g., Exhibit B-31, BCUC Panel IRs 2.8.5 to 2.8.8.

[809] Exhibit B-31, BCUC Panel IR 2.8.5.2.

[810] Online: https://www.bchydro.com/toolbar/about/planning_regulatory/tariff_filings/oatt.html

[811] Online: https://www.bchydro.com/energy-in-bc/operations/transmission/transmission-scheduling/business-practices.html. Exhibit B-5, BCUC IR 16.3.1, Attachments 1 to 9.

499. Significantly, BC Hydro's 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 United States,[812] which generates Trade Income for the benefit of BC Hydro's ratepayers.[813] The current OATT accomplishes that critical outcome.

500. BC Hydro responded to several information requests that outline the impetus for the OATT and demonstrate how the OATT provides fair, non-discriminatory access to the wholesale transmission grid:

- BC Hydro provided a review of the development of the electric industry and markets within the western interconnection, including British Columbia, and how the OATT rates were developed to be reflective of these developments.[814]

- BC Hydro discussed how an eligible customer can become a transmission customer and how PTP can be used to deliver energy from a generator to a load, including for the import and export of electricity.[815] Indeed, the OATT was established in response to government policy to enable private sector investment in B.C. to access the wholesale transmission grid to take advantage of trade opportunities in wholesale power markets. While these developments did not materialize in B.C., the OATT remains in place to facilitate this activity should markets change.[816]

- BC Hydro explained how NITS is used to supply domestic load customers from designated network resources and how network economy service, a secondary service under NITS, can be used to supply network load from non-designated generation resources.[817]

[812] Exhibit B-5, BCUC IR 1.162.2.

[813] Exhibit B-31, BCUC Panel IR 2.8.5.1.

[814] Exhibit B-31 BCUC Panel IRs 2.8.5 to 2.8.5.1.

[815] Exhibit B-5, BCUC IRs 1.163.1 to 163.1.4.

[816] Exhibit B-31 BCUC Panel IR 2.8.5.1.

[817] Exhibit B-5, BCUC IR 1.163.5; Exhibit B-31 BCUC Panel IRs 2.12.1.1 and 2.12.3.

501. BC Hydro has also demonstrated in response to information requests that it is continuing to monitor changes made to FERC's *pro forma* OATT and is regularly bringing forward applications to the BCUC to amend its OATT to maintain consistency with FERC's *pro forma* and to address changes in the market.[818] For example, BC Hydro is currently engaging with transmission customers and interested parties to develop its response to three FERC Orders related to generation interconnection procedures and ancillary rates schedules to take into account the speed and accuracy of regulation resources.[819]

D. CONCLUSION AND REQUESTED FINDINGS

502. The BCUC should find that the Test Period OATT rates as filed in Exhibit B-11-2[820] are just and reasonable and should be approved.

[818] Exhibit B-5, BCUC IR 1.162.2; Exhibit B-31, BCUC Panel IRs 2.8.5, 2.8.5.1, 2.8.5.2 and 2.8.6.

[819] Exhibit B-31, BCUC Panel IR 2.8.5.1.

[820] Exhibit B-11-2 is the corrected version of the Evidentiary Update filed on January 21, 2020. The OATT rates are in Appendix E.

PART ELEVEN: DEMAND-SIDE MANAGEMENT

A. INTRODUCTION

503. This Part addresses BC Hydro's traditional[821] DSM expenditures and LCE expenditures, which are the subject of Chapter 10 of the Application.

504. BC Hydro is seeking acceptance pursuant to section 44.2 of the *UCA* of its traditional DSM expenditure schedule set out in Table 10-1 of the Application, as amended in BC Hydro's Evidentiary Update.[822] BC Hydro's traditional DSM expenditure schedule consists of traditional DSM expenditures of $90.8 million in fiscal 2020 and $89.1 million in fiscal 2021. These expenditures are described in detail in the Fiscal 2020 to Fiscal 2022 Demand Side Management Business Plan in Appendix X of the Application (the "DSM Plan").

505. BC Hydro's LCE expenditures are described in detail in the Low Carbon Electrification Program in Appendix Y of the Application, as updated in Attachment 1 to BCUC Panel IR 2.18.2.[823] They are recoverable in rates by virtue of being prescribed undertakings pursuant to section 18 of the *Clean Energy Act* and section 4 of the GGRR. BC Hydro is also requesting approval to defer its LCE expenditures over the Test Period to the DSM Regulatory Account, as per the *Direction to the BCUC Respecting Undertaking Costs*.

506. The following points, each of which is demonstrated in this Part, support findings that BC Hydro's traditional DSM expenditure schedule is in the public interest and that BC Hydro's LCE expenditures should be deferred to the DSM Regulatory Account:

- First, BC Hydro's moderation approach continues to be a reasonable response to the energy surplus and need to limit forecast rate increases.

[821] As explained on page 10-4 of the Application, BC Hydro uses the term "traditional" DSM to refer to its energy efficiency and conservation as well as capacity-focused initiatives. Traditional DSM does not include LCE initiatives.

[822] Exhibit B-11. The Evidentiary Update reduces BC Hydro's DSM expenditure schedule 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. This update was first provided in Exhibit B-5, BCUC IR 1.182.1.

[823] Exhibit B-31, BCUC Panel IR 2.18.2, Attachment 1.

- Second, BC Hydro's DSM expenditure schedule reflects changes that address directions and recommendations from the Commission's Decision in the Previous Application, the priorities of the Government of BC, and the *Demand-Side Measures Regulation* (the "DSM Regulation").

- Third, the Commission should rescind Direction 61 from Order No. G-96-04 as it is inconsistent with the DSM Regulation and industry standard practice and is inappropriate for marginal decision making regarding DSM programs.

- Fourth, BC Hydro's traditional DSM expenditure schedule is aligned with the *Clean Energy Act*, *UCA* and DSM Regulation.

- Fifth, BC Hydro is no longer forecasting expenditures over the Test Period in its Thermo-Mechanical Pulp Program, and the requested expenditure schedule reflects this change.

- Sixth, BC Hydro's LCE expenditures are within a class of prescribed undertakings described in section 4 of the GGRR, and the BCUC has been directed to defer the LCE expenditures to the DSM regulatory account.

- Seventh, BC Hydro is reasonably and effectively managing its traditional DSM an LCE initiatives.

B. MODERATION APPROACH CONTINUES TO BE A REASONABLE RESPONSE TO ENERGY SURPLUS

507. BC Hydro's proposed DSM expenditure schedule continues the moderation approach first recommended in the 2013 IRP, given the continued energy surplus and continued 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.

It continues to use a market price screening filter to ensure that traditional DSM spending lowers BC Hydro's revenue requirements overall.[824]

508. In its Decision in the Previous Application, the BCUC found that the moderation strategy provided a balanced approach:

> The Panel finds the overall size of the funding envelope in BC Hydro's proposed DSM expenditure schedule provides a balanced response to a reduction in the load forecast and the need to meet certain targets under the 2013 10 Year Rates Plan. The Panel agrees with BC Hydro that key considerations are the changing system needs and the ability of BC Hydro to meets its rate objectives.
>
> BC Hydro now expects to be in an energy surplus situation until F2022 (without committed resources) and F2032 (with committed resources). The Panel acknowledges concerns raised by interveners that cost-effective DSM decreases customer bills overall, but considers that, given the energy surplus situation, the use of a market priced screening filter to identify cost-effective DSM is reasonable.
>
> The Panel also considers that higher levels of DSM spending could challenge BC Hydro's ability to meet targets under the 2013 10 Year Rates Plan and place further upward pressure on the size of the rate smoothing account. In the absence of this pressure on rates, the benefits of spending more on cost-effective DSM programs would have been given greater consideration.
>
> The Panel also considered in its deliberations the Minister's letter supporting BC Hydro's reduction in DSM spending compared to the 2013 IRP and BC Hydro's submission that it would meet the CEA objective of reducing BC Hydro's expected increase in demand by the year 2020 by at least 66 percent (even if energy savings from codes and standards are excluded). …[825]

509. The BCUC's reasoning, as quoted above, remains applicable in the Test Period. First, BC Hydro remains in a surplus position and continues to need to limit forecast rate increases.[826] Thus, BC Hydro's continued use of a market priced screening filter[827] for traditional DSM

[824] Exhibit B-1, Application, pp. 10-19 to 10-20; Exhibit B-6, BCNPHA IR 1.2.0.

[825] Decision on Previous Application, pp. 78-79.

[826] Exhibit B-1, Application, p. 10-15.

[827] The market price used in the Utility Cost Test is a forecast of prices with values that vary from year to year. The levelized value of $30/MWh (fiscal 2018$) is a reference point, calculated based on the market price forecast over a 15-year period from fiscal 2020 to fiscal 2034 (Exhibit B-6, AMPC IR 1.5.9).

programs is reasonable as it ensures that any surplus energy generated will reduce BC Hydro's overall revenue requirements and reduce overall customer bills.[828] In other words, without the use of a market price screening filter, traditional DSM programs could result in increased surplus energy that BC Hydro would have to sell at a loss, resulting in a higher revenue requirement and an increase in overall customer bills.

510. Second, the Government of B.C. continues to support the moderation approach. It reviewed the DSM Plan as part of Phase One of the Comprehensive Review[829] and found:

> Demand Side Management is an important part of BC Hydro's resource plan, providing the flexibility to meet future supply needs or build efficient load, depending on system needs. Demand Side Management is a low cost energy resource with little to no environmental impact. This area was examined, and, consistent with the government's focus on affordability, in its upcoming Revenue Requirements Application, BC Hydro will be proposing to increase the amount of spending for the residential sector and low income ratepayers, while keeping Demand Side Management expenditures at the same level overall.[830]

511. Third, BC Hydro's planned traditional DSM initiatives continue to meet the target set out in section 2(b) of the *Clean Energy Act:* "to take demand-side measures and to conserve energy, including the objective of the authority reducing its expected increase in demand for electricity by the year 2020 by at least 66%".[831]

512. Fourth, BC Hydro's DSM Plan retains the ability to ramp-up traditional DSM activities in the future in response to the next IRP or the CleanBC Plan. Using the results of the conservation potential review ("CPR"), BC Hydro is considering options for the level of DSM in future years to be examined as part of the next IRP.[832] Over the Test Period, BC Hydro is

[828] Exhibit B-1, Application, pp. 10-28 and 10-29. Exhibit B-13, BCOAPO IR 2.155.1.

[829] Exhibit B-1, Application, Appendix C, Comprehensive Review of BC Hydro Phase 1 Final Report, p. 40.

[830] Exhibit B-6, BCNPHA IR 1.2.0.

[831] Exhibit B-1, Application, p. 10-15 and Exhibit B-5, BCUC IR 1.173.1.

[832] Exhibit B-1, Application, p. 10-21; Tr. 14, p. 2784, ll. 5-9 (Hanlon).

maintaining its 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 CleanBC Plan.[833]

513. Therefore, BC Hydro submits that the level of traditional DSM spending proposed is a reasonable and balanced approach and is in the public interest.

C. BC HYDRO'S TRADITIONAL DSM PLAN RESPONDS TO BCUC DIRECTIVES, GOVERNMENT PRIORITIES AND DSM REGULATION

514. While keeping within a similar level of spending as in the previous test period, BC Hydro made a number of changes to the DSM Plan in response to BCUC direction, to support Government priorities related to residential affordability, and to respond to changes to the DSM Regulation. As discussed in the sections below, the changes improve the balance in spending amongst customer sectors, demonstrate BC Hydro's responsiveness to feedback, and support BC Hydro's view that the DSM expenditures schedule is in the public interest.

(a) BC Hydro Has Increased Residential Initiatives by Approximately 50%

515. BC Hydro's proposed traditional DSM expenditure schedule reflects an increase of approximately 50% in residential initiatives.

516. The increase is responsive to Directive 21 of the BCUC's Decision on the Previous Application. It recommended that BC Hydro consider more DSM programs directed at residential customers due to "the relatively low level of DSM spending for residential customers (including low income customers)".[834] The increase in spending on the residential sector is also consistent with the Mandate Letter of the Government of B.C. and the outcome of the Phase One of the Comprehensive Review.[835]

---

[833] Exhibit B-6, BCSEA IR 1.35.4. However, it would be challenging to ramp up expenditures in the Test Period given the lead times required for the implementation of customer projects (Exhibit B-6, BCSEA IR 1.35.2).

[834] Exhibit B-1, Application, pp. 10-7 to 10-8.

[835] Exhibit B-5, BCUC IR 1.171.1 and Exhibit B-12, BCUC IR 2.273.2.

517. A key focus of BC Hydro is on continuing to increase participation in the low-income program.[836] As a result of BC Hydro's focus in this area, low Income expenditures and participation rates have been steadily increasing since fiscal 2016. BC Hydro's fiscal 2021 planned expenditures are approximately double actual expenditures in fiscal 2018. The planned number of participants in fiscal 2021 is 27,310, which is approximately 10,000 higher than the actual participation of 17,089 in fiscal 2018.[837]

518. Another key focus of BC Hydro has been on increasing participation in the Home Renovation Rebate Program through additional measures and increased incentives. The Home Renovation Rebate Program focuses on customers who can make their electricity bills more affordable by reducing their space heating load. BC Hydro increased incentives for measures such as insulation. It also expanded the number of measures available for incentives, such as heat pumps and smart thermostats.[838]

519. BC Hydro was able to accommodate the increase in residential sector by reducing in the commercial and industrial sectors of the DSM portfolio in alignment with expected spending in these sectors.[839] The redirection of funding was aligned with BC Hydro's updated projections of commercial and industrial sector participants, which was lower than previously planned, and lower incentive levels needed for commercial projects.[840] Mr. Hobson explained:

> I think we outlined some of our reasons for the adjustment that we made in the commercial forecast of expenditures and it had, I think, more to do with taking a look at…the offering that we had put in place coming out of the last application, and as a result of that, seeing what projects we anticipated coming forward, what expenditures we were going to need to move those projects ahead in terms of incentive levels, and those were probably the bigger factors that we

[836] Exhibit B-1, Application, Appendix X, pp. 3 and 30; Exhibit B-6, Zone II RPG IRs 1.19.3 and 1.25.8; Exhibit B-6, Ince IR 1.12.5; Exhibit B-12, BCUC IR 2.276.1; Exhibit B-13, Zone II IR 2.43.1.

[837] Exhibit B-6, BCSEA IR 1.44.1.

[838] Exhibit B-1, Application, pp. 10-8, 10-9 and 10-24 and Appendix X, p. 34; Exhibit B-6, BCSEA IRs 1.43.2.1, 1.43.2.2, 1.43.2.3., 1.43.2.4, 1.43.3.5 and 1.46.1; Exhibit B-13, Zone II IR 2.43.1.

[839] Exhibit B-6, AMPC IR 1.5.6.

[840] Exhibit B-6, BCSEA IR 1.43.1; Exhibit B-12, BCUC IR 2.273.2.

were seeing at the time in terms of making adjustments in this application to the commercial expenditures.[841]

520. As result of the increase in residential expenditures, the percentage split amongst the residential, commercial/light industrial and large industrial categories is now relatively even at 30%, 38% and 32%, respectively.[842] The reallocation of funding also better aligns the portfolio with the fully allocated cost of service allocation referenced in the BCUC's Decision on the Previous Application.[843]

(b) BC Hydro Has a New Commercial Social Housing Initiative

521. As part of the Leaders in Energy Management – Commercial program, BC Hydro launched a new Social Housing Retrofit Support Offer for Multi-Unit Residential Buildings, which is designed to help housing providers identify and implement energy-efficient projects.[844] The offer includes energy study funding, implementation support (engineering design, tendering and project management), and a wide variety of incentives for qualifying equipment, such as commercial kitchen equipment, commercial refrigeration equipment, heat pumps and electric water heaters, LED lighting and controls, and variable speed drives.[845]

522. BC Hydro responded in detail to concerns raised with respect to its initiatives in the social housing sector, describing its extensive efforts in this area since fiscal 2007.[846] The new Social Housing Retrofit Support Offer expands on past initiatives, and will supplement incentives offered through the Residential Low Income Program.[847] BC Hydro will continue to monitor program performance, market barriers, and technology advancements, will continue to

[841] Tr. 14, p. 2647, l. 23 to p. 2648, l. 8 (Hobson).

[842] Exhibit B-1, Application, p. 10-8, Table 10-3.

[843] Exhibit B-1, Application, Table 10-4; Exhibit B-6, AMPC IR 1.5.6.

[844] Exhibit B-1, Appendix X, pp. 15 and 45.

[845] Exhibit B-17, BCSEA IR 3.85.2.

[846] Exhibit B-17, BCSEA IR 3.85.1.

[847] Exhibit B-17, BCSEA IR 3.85.2.

engage with related organizations, and will modify the program as needed to adapt to changing market conditions.[848]

(c) BC Hydro Has Increased its Activities in Non-Integrated Areas

523. BC Hydro increased its activities in non-integrated areas ("NIA") in response to Directive 23 from the Decision in the Previous Application, which, amongst other things, directed BC Hydro to report back on how it addressed the DSM concerns raised by Non Integrated Areas Ratepayers Group (NIARG) and Zone II Ratepayers Group (Zone II) regarding the activities in the NIA.[849] BC Hydro's increased activities in the NIA are also aligned with the Government's policy mandate regarding affordability, and are a natural progression from BC Hydro's pilot initiatives in the NIA.[850]

524. The new NIA program is a comprehensive program that builds on the pilot work conducted to explore delivery approaches and efficiency measures tailored for the NIA.[851] The NIA program includes new residential and commercial program offers to assist NIA customers in saving electricity, reducing utility bills and improving home comfort.[852] It also includes Community Support, which BC Hydro described as follows:

> Within Community Support, we have planned to provide financial and technical resources to Indigenous communities in Non-Integrated Areas to support them in pursuing energy upgrades. This includes:
>
> - Salary support to Indigenous Bands to hire community members who will visit homes in the community to review energy upgrade opportunities and install basic energy saving products.
> - Training for these community members on how to review energy upgrade opportunities and install basic energy saving measures in homes.

---

[848] Exhibit B-6, BCNPHA IR 1.3.0; Exhibit B-6, Zone II RPG IR 1.20.2. Also see Zone II RPG IR 1.20.1 and 1.20.1.1 regarding the role of the Low Income Advisory Council.

[849] Exhibit B-1, p. 10-11 to 10-12.

[850] Tr. 15, p. 2856, ll. 20-23 (Hanlon).

[851] Exhibit B-6, Zone II RPG IR 1.26.1; Exhibit B-13, Zone II RPG IR 2.52.2.

[852] Exhibit B-1, Application, pp. 10-11 and 10-12 and Appendix X, section 5.5.

- Training to Indigenous Bands that are planning to lead their own home renovation work and participate in our residential rebates. This training will be based on the Best Practice Guide: Air Sealing and Insulation Retrofits for Single Family Homes (2018 Second Edition).

- Other support as necessary to encourage energy upgrades and conservation behaviours in the community (e.g., presentations at community meetings, Elder and youth engagement, engagement with facility managers, etc.).[853]

525. The NIA program accounts for unique considerations for the NIA, including:

- increasing the incentives on energy saving measures, including weatherization measures, to address the higher cost of products and services and more extreme weather in the NIA;

- adding energy saving measures, such as freezers, to support the need for food storage in remote and Indigenous communities;

- removing the income qualification requirement for energy-savings kits ("ESKs") for NIA residential customers to increase access to basic energy saving measures for all households;

- offering both full service/direct install and do-it-yourself delivery methods; and

- hiring a dedicated resource to support community access to DSM programs.[854]

526. The cost effectiveness of the NIA program has been calculated from the bottom up,[855] and benefits from a higher avoided cost of energy due to the cost of diesel generation.[856] This

[853] Exhibit B-6, Zone II RPG IR 1.26.8. Note that the Community Support initiative is separate from the Indigenous Communities Support element of the Codes and Standards initiatives, which is described in Exhibit B-6, Zone II RPG IR 1.22.2.1 (Exhibit B-6, Zone II RPG IR 1.26.8.1).

[854] Exhibit B-5, BCUC IR 1.185.2.1.

[855] Exhibit B-5, BCUC IRs 1.185.2 and 1.185.2.1.

[856] Exhibit B-5, BCUC IR 1.185.1.

accounts for the positive benefit cost ratio of the NIA program, even without the 40% adder under the DSM Regulation.[857]

527. The budget for the NIA program is based on the expenditures required to deliver the program to the estimated level of participation.[858] As explained by Mr. Hobson, increasing participation in the NIA program relies heavily on relationships and working within the community.[859] This makes the designated NIA program manager and relationship lead positions[860] integral parts of the NIA program's success. While uptake of the offers has been slower than expected in fiscal 2020, BC Hydro expects participation to pick up in fiscal 2021 based on agreements signed with communities in fiscal 2020 and the interest of communities within the NIA.[861]

528. The NIA program is included in BC Hydro's longer-term DSM planning, illustrating BC Hydro's expectation that it will be available long-term.[862]

529. While BC Hydro believes the NIA program is a comprehensive offer, BC Hydro is open to considering new information and opportunities.[863] Ms. Hanlon emphasized that "it is a new program, and we want to continue to engage with communities and get feedback on how to increase the participation estimates, and so we are very interested in working with communities on how we can increase participation."[864] Therefore, BC Hydro will continue to work with Indigenous communities on the specific issues and barriers they face with respect to conservation and energy management.[865]

---

[857] Exhibit B-5, BCUC IR 1.185.2; Exhibit B-13, BCOAPO IR 2.152.3.2; Exhibit B-13, Zone II IR 2.46.7; Tr. 15, p. 2880, p. 12 to p. 2881, l. 7 (Hanlon).

[858] Exhibit B-6, Zone II RPG IR 1.26.3.

[859] Tr. 15, p. 2870, l. 23 to p. 2871, l. 15 (Hobson).

[860] Tr. 15, p. 2871, l. 16 to p. 2872, l. 22 (Hanlon and Hobson).

[861] Tr. 15, p. 2870, l. 6 to p. 2871, l. 15 (Hanlon and Hobson); Exhibit B-57, BC Hydro Undertaking No. 66.

[862] Exhibit B-6, Zone II RPG IR 1.26.6.

[863] Exhibit B-6, Zone II RPG IR 1.26.4.1.

[864] Tr. 15, p. 2870, ll. 17-22 (Hanlon).

[865] Exhibit B-1, Application, p. 10-12.

(d) BC Hydro Has Updated How it Presents its Codes and Standards Savings

530. BC Hydro updated its practice for presenting savings from codes and standards in response to Directive 22 from the Decision in the Previous Application. The BCUC had expressed concern that the cost effectiveness results for codes and standards could be overstated or that other program cost effectiveness results could be understated. The BCUC therefore directed BC Hydro to review if its approach for attributing savings that occur from the implementation of codes and standards was consistent with industry practice.[866]

531. BC Hydro retained a third party expert, the Cadmus Group, to assess industry practice. The Cadmus Group concluded that industry practice regarding codes and standards attribution is varied. Approaches include: not quantifying or attributing any savings from codes and standards; quantifying savings from codes and standards to reflect their impact on load forecasts and revenue requirements; and, attributing a portion of the savings from codes and standards to utility efforts.[867]

532. BC Hydro took the following steps to improve the presentation of its codes and standards savings:

> First, we have excluded codes and standards savings from benefit cost calculations and levelized costs. This means that those results are not distorted at the portfolio level by the codes and standards savings; and
>
> Second, BC Hydro is not attributing codes and standards savings to individual programs. Instead, codes and standards savings are presented as a stand-alone bucket of energy and associated capacity savings, separate from programs. BC Hydro is not claiming these savings (or a portion of them) as a credit towards DSM cost effectiveness calculations. Rather, a forecast of codes and standards savings is provided and incorporated into BC Hydro's Load Forecast. As shown in the Cadmus report, this aligns with the approach taken in the two Canadian jurisdictions (Ontario and Manitoba).[868]

---

[866] Exhibit B-1, Application, p. 10-9.

[867] Exhibit B-1, Application, pp. 10-9 and 10-10. The Cadmus Group report attached as Appendix CC to the Application.

[868] Exhibit B-1, Application, p. 10-10.

533. In short, while BC Hydro has extensive codes and standards support activities as outlined in section 9 of Appendix X of the Application, BC Hydro has chosen not to quantify or attribute the contribution of its support for codes and standards. This ensures that there is no distortion to the cost-effectiveness results of the traditional DSM programs. As BC Hydro's codes and standards expenditures are still included at the portfolio level, the result is that the cost effectiveness of the DSM portfolio is more conservative than if the codes and standards savings were included. However, all of BC Hydro's traditional DSM initiatives are cost-effective without any attribution from codes and standards.[869]

(e) BC Hydro Has Extended the Funding Period for Capacity Focused Initiatives

534. The DSM Plan continues to include capacity focused pilots and trial offers directed at shifting the timing of peak demand in areas where BC Hydro faces capacity constraints. BC Hydro has extended the timeline for these initiatives by two years (to fiscal 2021) and reduced (by 12%) the overall budget for these initiatives over the fiscal 2017 to fiscal 2021 period. It was necessary to extend the time period due to the complexity of assessing the impacts and value of capacity focused DSM to BC Hydro's system, and to incorporate past learnings into new activities, to consider changing technologies, and to accommodate the long lead times required for some customer projects.[870]

535. BC Hydro provided a detailed description of the results of the pilots and trial offers to date.[871] Over the Test Period, BC Hydro will continue to conduct demand response trials in the residential, commercial and industrial sectors.[872] BC Hydro anticipates that the majority of technical trials will be complete by the end of the Test Period, and that the resource options in the upcoming IRP will be informed by the findings of the capacity-focussed DSM trials and pilots.[873]

---

[869] Exhibit B-1, Application, pp. 10-10 and 10-11; Exhibit B-5, BCUC IR 1.184.1.

[870] Exhibit B-1, Application, pp. 10-21 to 10-22.

[871] Exhibit B-5, BCUC IR 1.183.1.

[872] Exhibit B-1, Application, p. 10-22.

[873] Exhibit B-13, BCSEA IR 2.72.1.

(f) BC Hydro Has Re-categorized Energy Management Activities to Align with DSM Regulation

536. BC Hydro re-categorized its energy management activities into a new program called Energy Management Activities within each sector. The change aligns with 2017 amendments to the DSM Regulation that added "Energy Management Program" (meaning a program to assist customers to optimize energy use) to the definition of "Specified Demand Side Measure". Energy Management Activities assist customers in managing and optimizing their energy use by bringing energy specialists directly into customer operations, increasing customers' knowledge of their options, encouraging behavior change, and providing knowledgeable trades in the industry that can help customers make the right choices.[874] Section 4(4) of the DSM Regulation requires that the cost effectiveness of "Specified Demand Side Measures" be evaluated at the portfolio level, meaning that the costs of Energy Management Activities should not be evaluated as part of the costs of other programs.

D. DIRECTION 61 REGARDING ALLOCATION OF PORTFOLIO COSTS SHOULD BE RESCINDED

537. BC Hydro is requesting that the BCUC rescind Directive 61 from its October 2004 Decision on BC Hydro's Fiscal 2005 to Fiscal 2006 Revenue Requirements Application.[875] Pursuant to this direction, BC Hydro was required to allocate a prorated amount of costs from portfolio level initiatives to the cost of each program based on the energy savings. However, BC Hydro submits that for the following reasons, that costs should only be attributed to programs if they are solely connected to a specific program:

(a) **Consistent with the DSM Regulation:** BC Hydro's proposed approach is consistent with section 4(4) of the DSM Regulation. It requires that "specified demand side measures", which include energy efficiency training, community engagement and energy management programs, be evaluated at a portfolio

[874] Exhibit B-1, Application, pp. 10-38 to 10-40 and Appendix X, pp. 2, 37-41, 49-53 and 59-62; Exhibit B-5, BCUC IR 1.181.3.1; Exhibit B-13, BCOAPO IR 2.153.2.1.

[875] Exhibit B-1, Application, p. 10-33. 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 as used in Exhibit B1-81."

level. Directive 61 is inconsistent with this requirement. These types of programs could be considered portfolio level costs, which Directive 61 would require be allocated to programs.[876]

(b) **Consistent with Industry Practice:** BC Hydro's proposed approach is consistent with industry practice which has developed over the 16 years since the BCUC issued Directive 61. Notably, the National Standard Practice Manual issued in May 2017 states that "fixed portfolio-level costs should not be allocated to programs for the purpose of assessing the cost-effectiveness of individual programs". In addition, BCUC Order No. G-10-19 issued in 2019 indicates that FortisBC Energy Inc. is not required to allocate portfolio-level costs to programs. In step with industry practice, BC Hydro should now only allocate costs to programs if they are solely connected to the specific programs.[877]

(c) **Facilitates Marginal Decision Making:** It is appropriate to consider portfolio level costs only when looking at the cost effectiveness of the overall portfolio, so that decisions on individual programs are based entirely on the merits of the program itself. The inclusion of portfolio level costs when assessing cost effectiveness of a program could shift the result for a program from a net benefit to a net cost, which could lead to a decision not to implement a program that actually has a net benefit.[878]

E. TRADITIONAL DSM IS ALIGNED WITH THE *UCA*, *CLEAN ENERGY ACT*, AND DSM REGULATION

538. BC Hydro's expenditure schedule for traditional DSM is aligned with the framework of the *UCA*, *Clean Energy Act*, and the DSM Regulation. The parameters on the BCUC's discretion

[876] Exhibit B-5, BCUC IR 1.172.1.

[877] Exhibit B-5, BCUC IR 1.172.1.

[878] Exhibit B-5, BCUC IR 1.172.1.

when considering a DSM expenditure schedule, and each of the four factors that the BCUC must consider,[879] are addressed below.

(a) The *UCA* Constrains the BCUC's Discretion in Relation to a DSM Expenditure Schedule

539. BC Hydro files its demand-side measures expenditure schedule pursuant to subsection 44.2(1)(a) of the *UCA*. Subsection 44.2(3) of the *UCA* provides that the BCUC must accept an expenditure schedule if it considers that making the expenditures referred to in the schedule would be in the public interest, or reject the schedule. Alternatively, the Commission may accept or reject a part of the expenditure schedule. In its Decision on the Previous Application, the BCUC commented on the extent of its discretion when accepting or rejecting a demand-side measures expenditure schedule as follows:

> The Panel agrees with BC Hydro that section 44.2 of the UCA does not provide the Commission with the authority to direct BC Hydro to file a DSM expenditure schedule, make additions to a DSM expenditure schedule, or change the design of a particular DSM program. However, the Panel notes that, under subsection 44.2(2), BC Hydro would not be able to recover DSM costs in final rates unless these costs have been accepted by the Commission under section 44.2.[880]

540. BC Hydro agrees with this interpretation of the BCUC's jurisdiction under section 44.2.

(b) BC Hydro's Traditional DSM Is in the Interest of Customers

541. The evidence in this proceeding demonstrates that the proposed traditional DSM expenditures are in "the interests of persons in British Columbia who receive or may receive service from [BC Hydro]" per s. 44.2(a) of the *UCA*. BC Hydro's proposed expenditures reflect a broad and cost effective range of DSM initiatives that

---

[879] The factors that the BCUC must consider under section 44.2 of the *UCA* are as follows:

(a) The interests of persons in British Columbia who receive or may receive service from BC Hydro;

(b) British Columbia's energy objectives as set out in section 2 of the *Clean Energy Act*;

(c) An applicable Integrated Resource Plan approved under section 4 of the *Clean Energy Act*; and

(d) The extent to which the demand side measures are cost effective within the meaning prescribed by the Demand Side Measures Regulation.

[880] Decision and Order No. G-47-18, dated March 1, 2018, at page 73 of 118.

- provide significant energy savings and capacity benefits;[881]
- provide customers with the opportunity to save electricity and lower their bills; and
- reduce BC Hydro's revenue requirements.[882]

542. Other benefits include GDP impacts, employment, provincial revenues, non-energy customer benefits, and GHG reductions.[883] BC Hydro submits that the benefits are significant and that the proposed traditional DSM expenditures are in the interest of BC Hydro's customers.

(c) BC Hydro's Traditional DSM Supports British Columbia's Energy Objectives

543. BC Hydro summarized how its traditional DSM expenditures support the energy objectives in the *Clean Energy Act* in Table 10-6 of the Application.[884] In particular, the DSM Plan meets the objective of reducing BC Hydro's "expected increase in demand for electricity by the year 2020 by at least 66 per cent".[885] In fact, BC Hydro's traditional DSM is forecast to reduce BC Hydro's increase in electricity demand by the end of fiscal 2021 by approximately 103%.[886]

[881] The forecast energy and capacity savings are detailed in section 10.5.1 of the Application.

[882] Exhibit B-1, Application, p. 10-14.

[883] These are summarized in section 10.5.2 of the Application and detailed further in section 3.3 of Appendix X of the Application.

[884] Exhibit B-1, Application, pp. 10-14 to 10-15.

[885] BC Energy Objective 2(b) refers to a target for energy efficiency and conservation initiatives and not low carbon electrification programs (Exhibit B-5, BCUC IR 1.173.2).

[886] Exhibit B-1, Application, p. 10-14. BC Hydro illustrated this calculation and provided supporting data in its response to Exhibit B-5, BCUC IR 1.173.1.

(d) Traditional DSM is Consistent with the IRP

544. 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. The moderation approach was originally recommended in the 2013 IRP for fiscal 2014 to fiscal 2016.[887]

(e) BC Hydro's Traditional DSM is Cost-Effective as Defined by the DSM Regulation

545. The portfolio as a whole, as well as rate structures and all programs, are cost effective using the modified total resource cost test required by the DSM Regulation.[888] The Test Period portfolio as a whole, as well as rate and all programs, also are cost effective under the more stringent requirements of the total resource cost test excluding non-energy benefits and utility cost test.[889]

546. Under the DSM Regulation, the long-run marginal cost of clean energy is an input into the total resource cost test. BC Hydro used the most recent, but outdated, long-run marginal cost of $105.[890] However, all DSM programs and the portfolio as a whole would be cost effective using a long-run marginal costs as low as $52/MWh.[891] This is sufficient for the portfolio to be cost effective using the most recent estimates of wind costs, including delivery to the Lower Mainland, which are between $54 and $80/MWh.[892] BC Hydro will update the long-run marginal cost for its next IRP.[893]

(f) Traditional DSM Meets Adequacy Requirements Under the DSM Regulations

547. Section 44.1 requires that a long-term resource plan filed by a utility must show that the utility is pursuing "adequate" DSM, as prescribed in section 3 of the DSM Regulation. While

---

[887] Exhibit B-1, Application, p. 10-15.

[888] Exhibit B-5, BCUC IR 1.175.1. See also, Exhibit B-1, Application, Appendix X, Appendix A-7.

[889] Exhibit B-5, BCUC IR 1.175.1. See also, Exhibit B-1, Appendix X, Appendix A-7. The Utility Cost and Total Resource Cost tests are standard cost tests used in the DSM industry to assess cost effectiveness (Exhibit B-1, Application, p. 10-28).

[890] Exhibit B-1, Application, pp. 10-29 and 10-30.

[891] Exhibit B-12, BCUC IR 2.274.1.

[892] Exhibit B-5, BCUC IR 1.175.3.

[893] Exhibit B-1, Application, pp. 10-29 and 10-30.

BC Hydro is not currently required to meet the adequacy requirements in section 44.1 of the *UCA*, BC Hydro's DSM Plan has been designed to be consistent with the adequacy requirements, as shown in Table 10-7 of the Application.[894]

(g) BC Hydro Retains Flexibility to Reallocate Costs in Response to Challenges and Opportunities

548. BC Hydro has submitted its DSM Plan with the intention of carrying it out as designed. However, BC Hydro retains discretion to reallocate its DSM costs during the Test Period, and this ability is important for the company and customers.

549. BC Hydro's ability under the *UCA* to reallocate funds is clear based on section 44.2 of the *UCA*, which permits BC Hydro to file a statement of DSM expenditures that it "anticipates making". Thus, the BCUC may accept DSM expenditures on a forecast basis, and, similar to BC Hydro's other forecast costs over the Test Period, actual expenditures on DSM may vary from forecast.[895] Acceptance of an expenditure schedule of anticipated DSM spending indicates that the BCUC has found the expenditure schedule, as presented, to be in the public interest. If prudently executed as described in the expenditure schedule, it is reasonable to expect that the expenditures can be recovered through rates.[896]

550. It is important for BC Hydro to have the flexibility to respond to challenges or opportunities in the market. For instance, if an initiative is over-performing or under-performing, then BC Hydro may need to reallocate funds to maintain the overall portfolio performance and portfolio balance. BC Hydro's spending may also vary from plan due to factors that are fully or in part outside its control, such as the timing of large customer projects or slower than anticipated participation in a program due to economic conditions.[897]

---

[894] Exhibit B-1, Application, p. 10-17.

[895] Exhibit B-5, BCUC IR 1.174.1.1.

[896] Exhibit B-12, BCUC IR 2.269.1.

[897] Exhibit B-5, BCUC IR 1.174.1.

551. Appropriate checks and balances are in place regarding reallocations made during the test period:

- Any reallocations of DSM expenditures are approved by individuals with the required financial signing authority based on BC Hydro's Financial Approval Authority Policy and are reported to BC Hydro's Board of Directors.[898]

- BC Hydro annual DSM reports provide an opportunity for the Commission to review BC Hydro's actual DSM expenditures. These reports describe any expenditure or savings variances compared to the accepted expenditure schedule, and any mitigation measures undertaken or planned.[899]

- BC Hydro understands that a significant deviation from the expenditure breakdown shown in the expenditure schedule could result in cost recovery risk. For instance, BC Hydro recognizes that underspending on a program as a result of a BC Hydro decision (as opposed to customer driven timing/decisions or market uptake), could give rise to cost recovery risk if the portfolio was no longer cost effective.[900]

F. THE EXPENDITURE SCHEDULE EXCLUDES THERMO-MECHANICAL PULP EXPENDITURES

552. BC Hydro's expenditures on the Thermo-Mechanical Pulp Program provide funding to increase the electrical efficiency of mills that use thermo-mechanical pulping processes.[901] The Direction to the BCUC Respecting the Authority's TMP Program requires the BCUC to allow BC Hydro to recover up to $100 million in costs incurred to carry out the program, and allow BC Hydro to defer these costs to the Demand Side Management Regulatory Account.[902] However, BC Hydro is no longer forecasting expenditures on the Thermo-Mechanical Pulp Program in the

[898] Exhibit B-5, BCUC IR 1.174.1.1.

[899] Exhibit B-1, Application, Appendix Z, Annual DSM Reports to the BCUC.

[900] Exhibit B-12, BCUC IR 2.269.1.

[901] Exhibit B-1, Application, p. 10-18 and Appendix X, pp. 57 and 58.

[902] Exhibit B-1, Application, p. 10-18 and Appendix D.

Test Period, as no applications from eligible customers were received by the application deadline.[903] Therefore, BC Hydro amended it proposed expenditure schedule to remove expenditures on Thermo-Mechanical Pulp Program.[904]

G. LOW CARBON ELECTRIFICATION EXPENDITURES ARE PRESCRIBED UNDERTAKINGS AND COST RECOVERY IS MANDATED

553. BC Hydro requests approval to defer its LCE expenditures to the DSM Regulatory Account on the basis that they are prescribed undertakings pursuant to section 18 of the *Clean Energy Act* and section 4(3)(a) to (d) of the GGRR.[905]

554. BC Hydro's LCE expenditures are described in Appendix Y of the Application, as updated in Attachment 1 to BCUC Panel IR 2.18.2.[906] BC Hydro's LCE expenditures can be divided into two categories: (1) the "Initial LCE Projects"; and (2) the "LCE Program". BC Hydro has referred to these two categories together as "LCE Project/Programs". BC Hydro's LCE Projects/Programs expenditures do not include *infrastructure* projects, such as the PRES project, which are included in the class of undertakings described in section 4(2) of the GGRR.[907]

(a) Section 18 of the *Clean Energy Act* Requires Cost Recovery for Prescribed Undertakings

555. 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 effect of section 18 of the *Clean Energy Act* is that the BCUC need only consider whether the LCE expenditures are prescribed undertakings as described in the GGRR. If the BCUC concludes that

---

[903] Exhibit B-5, BCUC IR 1.182.1.

[904] Exhibit B-11, Evidentiary Update, p. 4.

[905] B.C. Reg. 77/2017, O.C. 100/2017.
Online: http://www.bclaws.ca/civix/document/id/complete/statreg/77_2017.

[906] Exhibit B-31, BCUC Panel IR 2.18.2, Attachment 1.

[907] Exhibit B-1, Application, Appendix Y, p. 3. For a discussion of BC Hydro's infrastructure projects, see section 4 of the Greenhouse Gas Reduction (Clean Energy) Regulation Fiscal 2019 Annual Report (Exhibit B-31, BCUC Panel IR 2.18.1 Attachment 1).

they are, then it must approve rates to allow BC Hydro to collect sufficient revenue to recover the costs of the prescribed undertakings.

(b) Acceptance of a Section 44.2 Expenditure Schedule is Not Required

556. BC Hydro is not required to seek acceptance of an expenditure schedule under section 44.2 for the LCE expenditures, since section 44.2 does not impose an obligation on a public utility to file an expenditure schedule.[908] This is the case even if the LCE expenditures were also to qualify as a "demand-side measure". The accepted rules of statutory interpretation require that section 44.2 of the *UCA* and section 18(2) of the *Clean Energy Act* be read together harmoniously.[909] On the one hand, section 18(2) of the *Clean Energy Act* states that the BCUC must set rates to recover the costs of prescribed undertakings. On the other hand, section 44.2(2) of the *UCA* states that the BCUC may not approve a rate to recover the costs of a demand-side measure unless an expenditure schedule is filed and accepted under section 44.2. However, section 18(3) states that the BCUC "must not exercise a power under the Utilities Commission Act in a way that would directly or indirectly prevent a public utility referred to in subsection (2) from carrying out a prescribed undertaking". Reading these provisions together, section 18(2) and 18(3) of the Clean Energy Act create an exception to the otherwise general rule in section 44.2(2). In effect, section 18(2) of the *Clean Energy Act* reflects a public interest determination by the Government of B.C. that negates the need for an expenditure schedule to be accepted by the BCUC as being in the public interest. Therefore, it is not necessary for BC Hydro to seek or obtain the BCUC's acceptance under section 44.2 of the LCE expenditures, even if they were to qualify as a "demand-side measure".

---

[908] Section 44.2 uses permissive language, saying that a utility "may" file an expenditure schedule under section 44.2.

[909] In *Rizzo & Rizzo Shoes Ltd. (Re),* [1998] 1 S.C.R. 27, the Supreme Court of Canada relied on the following statement from Elmer Driedger in Construction of Statutes (2nd ed. 1983): "Today there is only one principle or approach, namely, the words of an Act are to be read in their entire context and in their grammatical and ordinary sense harmoniously with the scheme of the Act, the object of the Act, and the intention of Parliament." Online: https://www.canlii.org/en/ca/scc/doc/1998/1998canlii837/1998canlii837.html.

(c) BC Hydro's LCE Expenditures are Prescribed Undertakings

557. There are two broad requirements for the LCE expenditures to fall within the class of prescribed undertakings in sections 4(3)(a) to (d) of the GGRR:

(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

(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.

The LCE Expenditures Meet the Descriptions of Prescribed Undertakings

558. Sections 2 and 3 of Appendix Y[910] describe how BC Hydro's LCE expenditures on Initial LCE Projects and the LCE Program meet the descriptions of prescribed undertakings in sections 4(3)(a), 4(3)(b), 4(3)(c), and 4(3)(d) of the GGRR, which are as follows:

> (3) Subject to subsection (4), a public utility's undertaking that is in a class defined in one of the following paragraphs is a prescribed undertaking for the purposes of section 18 of the Act:
>
> > (a) a program to encourage the public utility's customers, or persons who may become customers of the public utility, to use electricity, instead of other sources of energy that produce more greenhouse gas emissions, by
> >
> > > (i) educating or training those customers respecting energy use and greenhouse gas emissions, carrying out public awareness campaigns respecting those matters, or providing energy management and audit services, or
> > >
> > > (ii) providing funds to those persons to assist in the acquisition, installation or use of equipment that uses or affects the use of electricity;
> >
> > (b) a program to encourage the public utility's customers, or persons who may become customers of the public utility, to use electricity instead of other sources of energy that produce more greenhouse gas emissions, by

[910] As updated in Attachment 1 to Exhibit B-31, BCUC Panel IR 2.18.2.

> (i) educating, training, providing energy management and audit services to, or carrying out awareness campaigns respecting energy use and greenhouse gas emissions for, or
>
> (ii) providing funds to
>
> persons who
>
> (iii) design, manufacture, sell, install or, in the course of operating a business, provide advice respecting equipment that uses or affects the use of electricity,
>
> (iv) design, construct, manage or, in the course of operating a business, provide advice respecting energy systems in buildings or facilities, or
>
> (v) design, construct or manage district energy systems;
>
> (c) a project, program, contract or expenditure for research and development of technology, or for conducting a pilot project respecting technology, that may enable the public utility's customers to use electricity instead of other sources of energy that produce more greenhouse gas emissions;
>
> (d) a project, program, contract or expenditure supporting a standards-making body in its development of standards respecting
>
> (i) technologies that use electricity instead of other sources of energy that produce more greenhouse gas emissions, or
>
> (ii) technologies that affect the use of electricity by other technologies that use electricity instead of other sources of energy that produce more greenhouse gas emissions;

559. Appendix Y[911] demonstrates that the LCE expenditures fall within the descriptions of prescribed undertakings above. For example, the LCE Program includes energy management studies, incentives, and public awareness campaigns consistent with section 4(3)(a) and (b) of the GGRR.[912]

[911] As updated in Attachment 1 to Exhibit B-31, BCUC Panel IR 2.18.2.

[912] Exhibit B-1, Application, Appendix Y, p. 10, Table 3-1.

BC Hydro Reasonably Expected the LCE Expenditures under subsections 4(3)(a) to 4(3)(b) of the GGRR to be Cost Effective

560. In addition to meeting the above descriptions, there is only one other requirement for the LCE expenditures to be prescribed undertakings. Namely, for the LCE expenditures that are in a class of undertakings defined in subsections 4(3)(a) and 4(3)(b) of the GGRR, BC Hydro must reasonably expect at the time it decides to carry out the undertakings that they are cost effective. Subsection 4(4) of the GGRR sets out this requirement

> (4) 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.

561. The meaning of the cost-effectiveness test is set out in the following definitions in section 4(1) of the GGRR:

> "benefit", in relation to an undertaking in a class defined in subsection (3) (a) or (b), means all revenues the public utility reasonably expects to earn as a result of implementing the undertaking, less revenues that would have been earned from the supply of undertaking electricity to export markets;
>
> "cost", in relation to an undertaking in a class defined in subsection (3) (a) or (b), means costs the public utility reasonably expects to incur to implement the undertaking, including, without limitation, development and administration costs;
>
> "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;

562. In summary, the cost-effectiveness test measures all the revenues BC Hydro expects to earn as a result of all of the undertakings that fall within subsections 4(3)(a) and 4(3)(b) of the GGRR (less revenues that would have been earned from the sale of that electricity to export markets), against the costs that BC Hydro expects to incur to implement all of the undertakings in those two subsections. The GGRR cost-effectiveness test does not require each individual component to be cost effective, nor does it require the BCUC to definitively determine whether

the prescribed undertakings will in fact be cost effective. Rather, the requirement is that BC Hydro must reasonably expect all of the undertakings in those two subsections on a cumulative basis to be cost-effective at the time BC Hydro decides to carry them out.

563. The NPV of all of BC Hydro's LCE expenditures that fall within the class of undertaking prescribed under sections 4(3)(a) and 4(3)(b) of the GGRR is $118.6 million and therefore is cost effective.[913]

(d) Deferral of LCE Expenditures is Required by Regulation

564. The Direction to the BCUC Respecting Undertaking Costs requires the BCUC to allow BC Hydro to defer its LCE expenditures to the Demand Side Management Regulatory Account. This direction states that the "commission must allow the authority to defer to the DSM regulatory account amounts equal to the undertaking costs". It defines "undertaking costs" as "all costs incurred by the authority to implement an undertaking within a class defined in section 4 (3) (a), (b), (c) or (d) of the Greenhouse Gas Reduction (Clean Energy) Regulation."[914] The LCE expenditures are costs incurred by BC Hydro to implement undertakings that are within these classes of undertakings.

H. BC HYDRO IS MANAGING ITS TRADITIONAL DSM AND LCE INITIATIVES EFFECTIVELY

565. BC Hydro is identifying and mitigating delivery risks and effectively managing the performance of its traditional DSM and LCE initiatives.[915] Information requests focused on BC Hydro's evaluation processes. BC Hydro's evaluation reports, copies of which have been

---

[913] Exhibit B-31, BCUC Panel IR 2.18.2, Attachment 1 LCE Program Updated in December 2019, p. 14; Exhibit B-5, BCUC IR 1.186.2.

[914] B.C. Reg. 77/2017, O.C. 100/2017.
Online: http://www.bclaws.ca/civix/document/id/complete/statreg/77_2017.

[915] See Exhibit B-1, Application, pp. 10-41 to 10-42 and Appendix X, section 4, Appendix Z, section 4 of each Annual Report, and Appendix AA.

provided in this proceeding, demonstrate the professional, detailed and thorough review of programs undertaken by BC Hydro.[916]

566. The independence of BC Hydro's evaluation function is established through the organizational structure.[917] Highly qualified external advisors play a critical role in the evaluation process.[918] BC Hydro explained the benefits of its mix of staff and contractors in the evaluation process as follows:

> 1. BC Hydro is a Crown corporation without an incentive mechanism that would make it profit from DSM impacts, and thus is not in a conflict of interest with respect to the evaluation or measurement and verification of DSM impacts. Without a DSM incentive mechanism, BC Hydro does not profit from the over-estimation of DSM impacts. This is in contrast to a number of other jurisdictions in North America, including California, where electricity is delivered by investor-owned utilities with incentive mechanisms for DSM. In these jurisdictions, utilities are in a conflict of interest with respect to the evaluation or measurement and verification of DSM impacts, since evaluation results influence incentive payments to utilities for DSM. In many of these jurisdictions, the majority of measurement and verification, and evaluation work is outsourced to contractors;
>
> 2. Costs are lower due to our use of BC Hydro staff instead of contractors. Average hourly costs for measurement and verification, and evaluation contractors are close to twice that of equivalent BC Hydro staff;
>
> 3. Quality is higher due to our use of BC Hydro staff instead of contractors. As noted above, BC Hydro measurement and verification, and evaluation staff understand BC Hydro DSM initiatives and data and, as a result, deliver better quality evaluations to support our internal client needs; and
>
> 4. Privacy requirements prevent BC Hydro from using contractors for some evaluation work. In its handling of personal information, including electricity consumption and other data pertaining to residential customers, BC Hydro must comply with the *BC Freedom of Information and Protection of Privacy Act*. The Act requires BC Hydro to safeguard

[916] Exhibit B-12, BCUC IR 2.271.2, with links to three completed evaluation reports.

[917] Exhibit B-1, Appendix AA, p. 5-6.

[918] Exhibit B-5, BCUC IR 1.188.2; Exhibit B-12, BCUC IR 2.271.1.1; Exhibit B-31, BCUC Panel IR 2.21.1 and 2.21.2.

> personal information and contains prohibitions on the storage and access of personal information outside Canada. BC is one of only two Canadian provinces with such prohibitions (the other being Nova Scotia). These prohibitions effectively mean that BC Hydro cannot outsource evaluation analytical work on residential DSM initiatives to contractors based in the United States without Canadian subsidiaries and data servers. This is significant since the vast majority of DSM evaluation consulting firms in North America are based in the United States.[919]

567. In fiscal 2017, BC Hydro's Audit Services conducted an audit to assess whether effective processes and controls are in place over DSM activities and programs. BC Hydro's Audit Services operates independently within BC Hydro and adheres to professional standards.[920] BC Hydro's Audit Services engaged independent experts from GDS Canada Consulting Ltd. to help assess whether effective processes and controls were in place for the DSM activities and programs.[921] The audit found that processes and controls are in place for DSM planning, program development, implementation and evaluation.[922]

568. With respect to program evaluation, the audit found:[923]

- Evaluations of overall programs and the measurement and verification of individual projects are effective. Standard industry protocols are followed for all work. Energy savings are verified with the repayment of incentives when required.

---

[919] Exhibit B-1, Application, Appendix AA, Demand-Side Management Measurement, Verification and Evaluation, pp. 6 and 7.

[920] Exhibit B-5, BCUC IR 1.187.6. Audit Services is independent from management by virtue of its functional reporting line to the Audit and Finance Committee of BC Hydro's Board of Directors, its Charter, and the requirement to follow internal auditing standards. Audit recommendations require management action plans, follow-ups and ongoing monitoring by Audit Services and the status is reported on a quarterly basis to the Audit and Finance Committee of BC Hydro's Board of Directors. The International Standards for the Professional Practice of Internal Auditing is included in Exhibit B-5, BCUC IR 1.12.3. See also, BCUC IR 1.12.4 regarding the process by which an entity can claim compliance with this standard.

[921] Exhibit B-1-4; Exhibit B-5, BCUC IR 1.187.6.

[922] Exhibit B-1, Application, p. 10-42; Exhibit B-1-4. GDS Canada Consulting Ltd. has over 40 years of experience in market evaluations and managing energy efficiency programs.

[923] Exhibit B-1-4, Attachment 1, p. 3 of 4.

- Evaluation, and measurement and verification work is performed in a reasonable time period based on complexity and duration of data collection.

- Energy savings are manually tracked; however, an initiative is underway to automate the process. To ensure continuous improvement, action plans are developed to address findings from program evaluations.

569. In response to the suggestion that BC Hydro perform an DSM audit for each expenditure schedule application, BC Hydro explained that the timing of audits should be left to Audit Services to determine based on the risk within BC Hydro:

> BC Hydro Audit Services prepares a two year audit plan based on areas of risk and exposure within the organization. A decision on when to complete the next DSM audit would depend on an assessment of associated risk in comparison to other areas of the organization.
>
> There is no defined cycle of DSM internal audits. A two-year audit plan was prepared in May 2019 and based on an assessment of overall risk, the decision was made to not include a DSM internal audit in the next two years.
>
> The next audit plan will be prepared in May 2021. At that time, a risk assessment will be performed and a further decision will be made on audits to be performed.[924]

570. BC Hydro is confident in the Conservation and Energy Management business function, and the Audit Service's audit plan appropriately reflects the associated risks of the organization. The increased cost of performing additional audits, with unknown benefits, outweighs the value from an audit of each expenditure application.[925]

I. CONCLUSION AND REQUESTED FINDINGS

571. The evidence demonstrates that BC Hydro's traditional DSM expenditure schedule is in the public interest and that BC Hydro's LCE Projects/Programs expenditures are a prescribed undertaking under section 18 of the *Clean Energy Act*. BC Hydro submits that the BCUC should

[924] Exhibit B-12, BCUC IR 2.272.3.

[925] Exhibit B-5, BCUC IR 1.187.7.

accept the proposed DSM expenditure schedule and approve the deferral of the traditional DSM and (per the applicable direction) LCE Projects/Programs expenditures to the Demand Side Management Regulatory Account.

PART TWELVE: IMPLEMENTATION OF RATES AND CONSIDERATION OF NEW INFORMATION

A. INTRODUCTION

572. This Part speaks to the most appropriate way to implement fiscal 2020 and fiscal 2021 rates, in light of the evidence of BC Hydro's forecast Test Period revenue requirements. The updated revenue requirements in the Evidentiary Update (as corrected by Exhibit B-11-2) had a favourable impact on customers, relative to the Application. BC Hydro proposes to implement this outcome by making the interim fiscal 2020 rates permanent, and decreasing rates by 1.01% on April 1, 2020. BC Hydro submits that its proposal is just and reasonable and produces the best outcome for customers.

573. This Part is organized around the following supporting points:

- First, among the number of rate implementation approaches that BC Hydro considered, its proposed approach best achieves principles that account for cost recovery and customer impacts.

- Second, BC Hydro's 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 so that the overall result remains reasonable.

B. BC HYDRO'S RATE IMPLEMENTATION PROPOSAL IS IN THE INTERESTS OF BOTH CUSTOMERS AND THE COMPANY

574. BC Hydro's proposal for the Test Period, based on the Evidentiary Update[926], is summarized in the following table. It involves amortizing the credit balance in the Cost of Energy variance accounts over the Test Period, with different amounts being credited in fiscal

[926] As corrected in Exhibit B-11-2.

2020 and fiscal 2021 so that the permanent rate increase for fiscal 2020 matches the interim rate increase already approved by the BCUC.[927]

Evidentiary Update: Rate Impacts, Deferal Account Rate Rider, Bill Impacts

Per Cent Increase / (Decrease)	F2020	F2021
Rate Impact	6.85	(1.01)
Cumulative Rate Impact	6.85	5.77
Deferral Account Rate Rider	0.00	0.00
Bill Impact	1.76	(1.01)
Cumulative Bill Impact	1.76	0.73

575. BC Hydro developed its rate implementation proposal using four principles relating to: recovery of the Test Period revenue requirements; rate stability in the Test Period; avoiding bill adjustments; and, avoiding the re-introduction of longer-term rate smoothing. Assessed against these principles, BC Hydro's implementation proposal is reasonable because:

- ***BC Hydro will recover its revenue requirements (i.e., its cost of service), in the Test Period, no more and no less***;
- ***It reduces year over year volatility within the Test Period —*** Volatility could create hardship for ratepayers;
- ***It avoids a one-time true-up bill adjustment to address the difference between fiscal 2020 interim rates and final rates —*** This adjustment, which would occur only after fiscal 2020 is over, could create unnecessary hardship and confusion for customers; and
- ***It avoids rate smoothing that spans beyond the Test Period, which may be undesirable in the present context —*** Longer-term rate smoothing would require reintroducing a rate smoothing regulatory account at a time when the balance in the existing account was only just written-off. BC Hydro made a deliberate decision to avoid this approach, considering past concerns raised by the Auditor

[927] Exhibit B-19, Evidentiary Update, pp. 9-10.

General.[928] Rate smoothing beyond the Test Period is also more challenging to implement because, as Mr. Wong noted, the revenue requirements for future test periods will change from what is currently forecasted.[929]

576. Alternative approaches have shortcomings, and do not measure as well against the principles identified above. The following table summarizes the bill impacts of all of the alternative scenarios addressed by BC Hydro in information requests. The comparison shows that excessive volatility results under some scenarios.[930]

Summary of Bill Impact Scenarios

Forecast Annual Bill Impacts Per Cent Increase / (Decrease)	F2020	F2021	F2022	F2023	F2024	Cost of Energy Variance Accounts Refund
Original Application	1.76	0.72	2.20	(0.02)	3.18	Over F2020 and F2021
Evidentiary Update	1.76	(0.99)	2.69	(0.26)	2.95	Over F2020 and F2021, bill impact 1.76% in F2020
Scenarios - IR reference(s)						
A - BCUC IRs 3.296.3, 3.296.5	8.03	(7.48)	(0.60)	2.32	4.00	Based on mid-year balances
B(i) - BCUC IRs 3.296.4.i, 3.296.5	6.92	(6.04)	0.43	1.26	2.95	Based on F2019 forecast year-end balances
B(ii) - BCUC IRs 3.296.4.ii, 3.296.5	4.16	(2.05)	(0.09)	0.24	3.47	Based on F2019 actual year-end balances
C - AMPC IR 3.12.1, BCOAPO IR 3.162.1, CEC IR 3.95.3, ZONE II RPG IR 3.60.2.i	3.47	(4.30)	4.49	(0.26)	2.95	Equal amounts over F2020 and F2021
D - BCSEA IRs 3.76.1, 3.76.4, INCE IR 3.3	1.76	0.00	0.66	0.74	2.95	Bill impacts 1.76% in F2020, 0% in F2021
E - CEC IR 3.95.4	(2.53)	7.86	(1.59)	(0.26)	2.96	100% in F2020
F - CEC IR 3.95.5	1.01	1.01	1.01	1.01	1.01	N/A (smoothed bill impacts, F2020 to F2024)
G - INCE IR 3.1	1.76	0.72	(0.57)	0.74	3.47	F2020 and F2021 bill impacts per Application
H - INCE IR 3.2	1.76	0.64	0.64	0.64	0.64	N/A (bill impacts 1.76% in F2020, smoothed F2021 to F2024)
I - ZONE II RPG IR 3.60.2.ii	0.44	1.65	1.33	(0.26)	2.95	75% in F2020, 25% in F2021
J - ZONE II RPG IR 3.60.2.iii	6.55	(10.02)	7.92	(0.26)	2.95	25% in F2020, 75% in F2021
K - ZONE II RPG IR 3.57.2	4.16	(4.08)	1.49	1.77	2.95	Based on F2019 actuals, then mid-year balances
L - ZONE II RPG IR 3.57.2	0.84	0.84	1.74	(0.26)	2.95	Smoothed bill impacts, F2020 and F2021

577. Scenario L (highlighted) involves smoothing over the Test Period alone. BC Hydro characterized Scenario L as "fairly comparable"[931] to its proposal, but noted that Scenario L involves a one-time bill true-up and the bill impacts from its proposal are already sufficiently stable.[932]

---

[928] Tr. 5, p. 492, ll. 3-15 (O'Riley).

[929] Exhibit B-16, BCUC IR 3.296.3; Tr. 5, p. 494, ll. 1-12 (Wong).

[930] Exhibit B-16, BCUC IR 3.296.3. The figures in the table do not reflect the decrease in the operating cost portion of the current pension costs of $1.0 million in fiscal 2021 which was corrected in Exhibit B-11-2 filed on January 21, 2020.

[931] Exhibit B-16, BCUC IR 3.296.3, p. 3.

[932] Exhibit B-16, BCUC IR 3.296.3, p. 30.

C. THE BCUC SHOULD AVOID UPDATING EVIDENTIARY UPDATE INPUTS IN ISOLATION

578. BC Hydro's proposed rates and the scenarios in the figure above are all premised on the forecasts in the Evidentiary Update. Parties have suggested changes to certain forecasts used in the Evidentiary Update. In large measure, these issues arise from the timing and duration of this proceeding. Despite the Evidentiary Update,

(a) actual data for Trade Income, Domestic Revenues and Cost of Energy is available for three quarters of fiscal 2020; and

(b) new interest rate forecasts have been released by the Ministry of Finance.

BC Hydro submits that the Evidentiary Update remains a reasonable basis for setting rates in the Test Period, and that regulatory accounts are a pragmatic and fair means of accounting for new information emerging during this protracted process. In the event that the BCUC were to determine that further updates are required in a compliance filing, it is essential to consider offsetting impacts.

(a) Snapshot: Directional Impact of Changing Evidentiary Update Inputs

579. The directional impacts of new information on various inputs are summarized in the table below. Some of the impacts push rates up while others push rates down. However, the recommendations in the InterGroup Report all drive the Test Period rates in one direction: down. Adopting InterGroup's Recommendations, without recognizing offsetting factors, could be expected to necessitate a significant rate increase in fiscal 2022.[933]

New Information Since Evidentiary Update	Directional Impact on Proposed Rates	InterGroup's Position on Updating
Trade Income (add fiscal 2019 to average)	Down	Yes
Storm Restoration Costs	Up	N/A (accepted in cross)

[933] Exhibit B-16, BCUC IR 3.313.2.2 shows that updating forecast Trade Income to be based on a five year average from fiscal 2015 to fiscal 2019 would result in a rate decrease of 3.13% in fiscal 2021. All else equal, a larger rate decrease in fiscal 2021 would result in a larger required rate increase in fiscal 2022.

New interest rate forecast from Ministry of Finance	Down	Yes
Pension discount rate decline	Up	No
MSP legislation impact on non-current pension costs	Down	Yes
Domestic Sales decline	Up	N/A

(b) Unfavourable Impact of Lower than Forecast Domestic Sales Revenue Should Be Considered Before Updating Five-Year Averages

580. The merits of using a five-year average for forecasting Trade Income and storm restoration costs appear to be non-controversial; it is an effective means of smoothing out inherent volatility and uncertainty. The issue that arose with respect to the five-year averages was, in essence, whether they should be based on data from fiscal 2014 to fiscal 2018 (per the Application and Evidentiary Update) or fiscal 2015 to fiscal 2019 (per InterGroup's recommendation). BC Hydro submits that it was, and remains, reasonable to set rates based on the forecasts included in the Evidentiary Update.

InterGroup Agreed that Storm Restoration Costs and Trade Income Should Be Treated the Same Way

581. At the outset, it is worth noting that there is consensus as between BC Hydro and InterGroup that maintaining symmetry in the preparation of the Trade Income and storm restoration costs five-year averages is the principled approach. Although InterGroup's report was silent on storm restoration costs, Mr. Bowman agreed at the hearing that, regardless of the approach taken to calculate the averages, the treatment should be the same for both accounts.[934] This is important in the current context because (as shown in the table above), the impacts of including fiscal 2019 data in the averages are partially offsetting.

[934] Tr. 11, p. 2066, ll. 14- 25 (Bowman).

It Was Reasonable for BC Hydro to Retain the Five Year Averages Based on Fiscal 2014 to Fiscal 2018 in the Evidentiary Update

582. The timing of this proceeding gave rise to the novel situation where another year of actual data (fiscal 2019) for Trade Income and storm restoration costs became available prior to BC Hydro preparing its Evidentiary Update. In the Evidentiary Update, BC Hydro was transparent about its decision to continue using fiscal 2014 to fiscal 2018 data to calculate the averages. BC Hydro submits that its reasoning was sound.

583. There is a logical distinction between:

(a) using actual fiscal 2019 data to update the starting balances in regulatory accounts that have to be amortized during the Test Period (which BC Hydro did in the Evidentiary Update); and

(b) updating an input to a forecast methodology (a five-year average), the design of which is premised on recognition that the actual results during the applicable test period will almost inevitably differ.

584. Mr. Wong explained that, given the significant volatility associated with both storm restoration costs and Trade Income, the averages from the Application (based on fiscal 2014 to fiscal 2018) did not seem any more or less reasonable than the average incorporating fiscal 2019. In both cases, there is every expectation that the actual amount will differ, which is why the regulatory accounts exist in the first place. The regulatory accounts make this an issue of timing, and the short amortization periods avoid intergenerational inequity.

585. There are any number of costs that could conceivably be updated in an Evidentiary Update. Costs change constantly in response to new pressures, and new information continuously comes available. 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 submits that it was appropriate to apply a principle that asks "Is the forecast in the Application still a reasonable basis for setting rates, based on what we know now?" The original five-year

averages for storm restoration costs and Trade Income were still reasonable based on BC Hydro's assessment of the current state, and BC Hydro was transparent about that assessment.

Unfavourable Impact of Lower than Forecast Domestic Sales Revenue Should Be Considered Before Updating Five Year Averages

586. Given the elapsed time since the Evidentiary Update, BC Hydro now has nine months of actual information from fiscal 2020 for Trade Income, Domestic Revenues and Cost of Energy. It has turned out that Trade Income for the nine months ended December 31, 2019 was $159 million, which is closer to the number produced by updating the five-year average to include fiscal 2019 actuals.[935] Considered in isolation, these results might suggest that the five-year average for Trade Income should be updated.

587. However, many variables change over time. There was also $36 million in net additions to the other Cost of Energy Variance Accounts as at December 31, 2019, primarily due to lower than forecast Domestic Revenues.[936] BC Hydro expects actual Domestic Revenues to continue to be below forecast for the remainder of fiscal 2020. In other words, nine months into the year, "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."[937] Setting rates based on the Evidentiary Update thus produces a reasonable result overall.

(c) InterGroup's Recommendation to Update Interest Rate Forecasts While Using an Out of Date Pension Discount Rate Would Produce an Unreasonable Result

588. Despite advocating for updating the forecast finance charges to reflect interest rate forecasts post-dating the Evidentiary Update, InterGroup opposed BC Hydro's decision to use

[935] This amount is approximately $40 million higher than the five-year average of fiscal 2014 to fiscal 2018. If an updated five-year average from fiscal 2015 to fiscal 2019 is used, the forecast amount is $176.3 million, which is approximately $15 million higher than actual Trade Income as at December 31, 2019, with one quarter of the year still remaining.

[936] Exhibit B-46, BC Hydro Undertaking No. 24. The lower than forecast Domestic Revenues were the result of lower than forecast sales, partially offset by lower than forecast Cost of Energy. Exhibit B-41, BC Hydro Undertaking No. 15 shows that year-to-date fiscal 2020 domestic sales as of December 31, 2019 were 2.6 per cent below forecast.

[937] Exhibit B-46, BC Hydro Undertaking No. 24.

the appropriate, updated pension discount rate available when BC Hydro prepared the Evidentiary Update. InterGroup favoured the continued use of the pension discount rate from the Application. A common feature of both of InterGroup's recommendations is that, if accepted, they would tend to reduce BC Hydro's proposed rates. BC Hydro submits that InterGroup's position would produce an unreasonable result.[938]

589. First, it was reasonable for BC Hydro to use the March 31, 2019 pension discount rate in the Evidentiary Update. It was the most recent discount rate prepared by its pension actuary, provided for use in BC Hydro's audited fiscal 2019 financial statements. InterGroup conceded that they had no reason to believe it was unreliable.[939]

590. Second, reducing finance charges to reflect a decline in interest rates since the Evidentiary Update, as InterGroup recommends, would necessarily be accompanied by increasing forecast pension costs. InterGroup's witnesses, Ms. Davies and Mr. Bowman, acknowledged that:

(a) movements in pension discount rates are generally correlated with interest rate movements;

(b) if interest rates go down, other things equal, the discount rates will also go down; and

(c) lower discount rates will increase pension costs, other things equal.[940]

591. Mr. Wong thus urged the BCUC to maintain alignment between forecast finance charges and pension costs:

> I guess what I'm recommending to the panel is that if we're going to benefit the rates by reducing the finance charges because of the lower forecasted interest

[938] Exhibit B-28, BC Hydro Rebuttal Evidence, pp. 1-2.

[939] Tr. 11, p. 2070, l.23 to p. 2071, l 9 (Bowman).

[940] Tr. 11, p. 2071, l. 25 to p. 2074, l. 7 (Bowman and Davies). On the first point, Mr. Bowman elaborated that "The pension discount rate is tied to hypothetical portfolio of long term bonds and so it's tied to the yield on those bonds which is basically an interest rate."

> rate, we should also be looking at the pension costs, because that is going to increase the pension cost with the lower discount rate, lower interest rate essentially. So I want to make sure we net the two, we just don't give back all the reduction and finance charges in the application. And then when we know that the pension costs will go up because of the reduction in interest rates, and that would have to be then deferred and captured in the future years. It's a timing issue but we want to make sure that we try to incorporate all that in the same period.[941]

592. Accordingly, it makes sense to maintain the existing interest rates forecast and discount rate, which are aligned.[942] Regulatory accounts address the variances in pension costs and finance charges in an efficient manner.[943]

(d) Regulatory Accounts Facilitate Ratesetting in the Context of Uncertainty due to COVID-19 Pandemic

593. The impacts of the novel coronavirus (COVID-19) have increased dramatically since the topic was first raised in this proceeding at the Oral Hearing. First and foremost, BC Hydro wishes to express its thoughts and sympathies to customers and their families who have faced hardships due to the virus, including those who have died, are in hospital or whose health has been impacted and those who are facing economic challenges and uncertainties.

594. On March 17, 2020, the Government of B.C. declared a provincial state of emergency to support the response to the COVID-19 pandemic. BC Hydro has created its own pandemic response plan, which has been filed in this proceeding.[944] The plan outlines how BC Hydro will continue to provide service safely to customers during this time.

595. The BCUC can take judicial notice of the fact that the COVID-19 pandemic is having ongoing detrimental economic effects and is disrupting daily life in unprecedented ways. BC Hydro acknowledges the hardships faced by its customers due to the virus, including those who

---

[941] Tr. 7, p. 892, ll. 7-21 (Wong).

[942] Tr. 7, p. 892, l. 22 to p. 894, l. 12 (Wong).

[943] Exhibit B-1, Application, pp. 7-44 to 7-46.

[944] Exhibit B-58, BC Hydro Undertaking No. 44, Attachment 1.

have died, those who are in hospital or whose health has been impacted, and those who are facing economic challenges and uncertainties.

596. The extent and duration of the impacts of the pandemic on BC Hydro's revenues and costs are uncertain. However, BC Hydro's regulatory accounts will mitigate much of the uncertainty caused by the pandemic by capturing variances from forecast which can then be returned to or recovered from customers in the next test period in accordance with existing BCUC orders. For example:

- Any impacts to cost of energy or load (e.g., potential declines in the commercial sector load) will be recorded in the Cost of Energy variance accounts.
- Any variances from forecast capital additions due to changes in project schedules will be recorded in the Amortization of Capital Additions Regulatory Account.
- Any impacts of movements in interest rates on finance charges are recorded in the Total Finance Charges Regulatory Account, and any impacts of the correlated movement of pension discount rates will be recorded in the Non-Current Pension Cost Regulatory Account.

597. The rationale for these accounts, and the other benefits they provide, are discussed in Part Eight of these Submissions.

598. Nonetheless, in this unprecedented situation, it is impossible for BC Hydro or any party to foresee all potential impacts of the pandemic. Therefore, if any particular approval from the BCUC is required over the remainder of the Test Period due to the pandemic, BC Hydro will bring forward requests to the BCUC in separate applications as needed. Filing such requests separately from the current RRA proceeding will enable the BCUC to consider them in a more expedited manner reflective of the COVID-19 crisis.

599. With this proceeding already extending more than half-way through the Test Period, it needs to be brought to a conclusion. Therefore, BC Hydro requests that the BCUC approve its

proposed rates, despite the uncertainties caused by the COVID-19 pandemic. As noted above, BC Hydro's regulatory accounts will largely mitigate the impacts of the pandemic and BC Hydro will bring forward any proposals for any particular relief needed over the remainder of the Test Period in separate applications.

D. CONCLUSION AND REQUESTED FINDING

600. The BCUC should find that the Evidentiary Update remains a reasonable basis upon which to base Test Period rates.

PART THIRTEEN: CONCLUSION AND ORDER SOUGHT

601. The Evidentiary Update, Appendix B contains a Draft Order that sets out BC Hydro's requests, as updated by the Evidentiary Update.[945] BC Hydro submits that the BCUC should approve the orders sought. The proposed rates are just and reasonable, reflecting the reasonable cost of providing service to customers in the Test Period. The proposed DSM expenditure schedule plan is in the public interest, and will provide access to appropriate programs pending the upcoming IRP.

ALL OF WHICH IS RESPECTFULLY SUBMITTED

Dated:	April 1, 2020	***[original signed by Matthew Ghikas]***
		Matthew Ghikas
		Counsel for BC Hydro
Dated:	April 1, 2020	***[original signed by Christopher Bystrom]***
		Christopher Bystrom
		Counsel for BC Hydro
Dated:	April 1, 2020	***[original signed by Tariq Ahmed]***
		Tariq Ahmed
		Counsel for BC Hydro

[945] Exhibit B-19, as corrected by Exhibit B-11-2.